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March 10, 2025

Ms. Linda C. Bridwell, P.E.
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602

Re: *In the Matter of: Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief-* **Case No. 2024-00276**

Dear Ms. Bridwell:

Please find attached Atmos Energy Corporation's ("Atmos Energy") Rebuttal Testimony of multiple witnesses in the above-styled case.

This is to certify that the foregoing electronic filing was transmitted to the Commission on March 10, 2025 that there are currently no parties that the Commission has excused from participation by electronic means in this proceeding; and pursuant to the Commission's July 22, 2021 Order in Case No. 2020-00085, no paper copies of this filing will be made.

If you have any questions, please let me know.

Very truly yours,

L. Allyson Honaker

Enclosure

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS	**)**	
ENERGY CORPORATION FOR AN	**)**	
ADJUSTMENT OF RATES; APPROVAL OF	**)**	**Case No. 2024-00276**
TARIFF REVISIONS; AND OTHER	**)**	
GENERAL RELIEF	**)**	

<u>REBUTTAL TESTIMONY OF BRANNON C. TAYLOR</u>

INDEX TO THE REBUTTAL TESTIMONY
OF BRANNON C. TAYLOR, WITNESS FOR
ATMOS ENERGY CORPORATION

I. INTRODUCTION

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

A. My name is Brannon C. Taylor. 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 810 Crescent Centre Dr. Ste 600, Franklin, Tennessee, 37067.

Q. HAVE YOU SUBMITTED DIRECT TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION") IN THIS PROCEEDING?

A. Yes.

II. PURPOSE AND SUMMARY OF REBUTTAL TESTIMONY

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 the Office of Attorney General witness ("OAG") Mr. Lane Kollen. Specifically, my rebuttal testimony will rebut Mr. Kollen's recommendation to maintain the limitations on capital currently in place for the Company's Pipeline Replacement Program ("PRP") and non-PRP capital spending, his recommendation that Atmos Energy not be allowed to include in the PRP mechanism targeted Aldyl-A replacement following bare steel replacement, and his recommendation to deny the Company's proposed Pipeline

Modernization ("PM") Rider for federally mandated requirements as well as the proposed Tax Rider for tax changes required by law. In addition, I will also rebut Mr. Kollen's assertions regarding the benefits of an Annual Review Mechanism ("ARM") as well as his recommendation to discontinue the Company's Research and Development ("R&D") Rider currently in effect. Lastly, I will rebut Mr. Baudino's assertion regarding returns for the Company's PRP or other rider-type programs. I will also comment regarding the use of the rate of return established in this Case to be used in the Company's next PRP or other rider-type filings as a policy matter.

III. REJECTION OF KOLLEN'S RECOMMENDATION TO MAINTAIN ADDITIONALLY IMPOSED LIMITATIONS ON CAPITAL INVESTMENT

Q. WHAT IS THE COMPANY'S REQUEST IN YOUR DIRECT TESTIMONY TO WHICH MR. KOLLEN IS RESPONDING?

A. Atmos Energy is requesting a regulatory framework that includes the flexibility to present to the Commission the level of capital investment needed to accomplish the objectives outlined in my direct testimony without the limitations or uncertainties regarding capital investment levels created by past Commission orders.

Q. WHAT ARE THOSE OBJECTIVES?

A. Our objectives are to continue investing in safety, modernizing infrastructure, and supporting economic growth across our service territory, all while maintaining affordable rates for the safe delivery of natural gas.

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION RELATED TO THE CAPS ON CAPITAL INVESTMENT?

A. Mr. Kollen recommends the Commission deny the Company's requests to remove the PRP and non-PRP limitations on capital expenditures.[1] Mr. Kollen claims they are not hard caps.[2] Mr. Kollen believes the limitations are necessary to impose restraint on the Company's capital expenditures and base revenue requirements.[3]

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION?

A. I do not. Mr. Kollen's recommendation suffers from a lack of any analysis regarding the Company's capital spending, requirements for safety, economic development in Kentucky, or the regulatory uncertainty created by the caps. Mr. Kollen simply cherry-picks sections of old Commission orders regarding the caps and makes unsubstantiated claims about the Company's capital spending without addressing any of the Company's points raised in direct testimony. His claims are particularly puzzling given that he does not have any objection to the Company's capital spending in the base or forecasted test period in this Case. Moreover, the OAG also has not intervened in the Company's PRP proceedings in the past several years and offered any evidence regarding its projects in those proceedings.

[1] Kollen at 35.
[2] Kollen at 35.
[3] Kollen at 35.

Q. DOES MR. KOLLEN CLAIM THE CAPITAL LIMITATIONS ARE HARD CAPS?

A. He does not. He claims the caps are not hard caps and the Company only needs to justify the additional costs.[4] Mr. Kollen also does not address the fact that Atmos Energy is the only regulated Kentucky utility that has these caps in place.

Q. DOES MR. KOLLEN DISTINGUISH BETWEEN DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM (DIMP) OR NON-DIMP CAPITAL INVESTMENT WHEN ADDRESSING HIS RECOMMENDATION?

A. No. Mr. Kollen does not distinguish between DIMP or non-DIMP spending, nor does he discuss possible effects on economic development in Kentucky created by the regulatory uncertainty in prior orders regarding the caps in his final recommendations.

Q. IS MR. KOLLEN'S VIEWPOINT THAT THE CAPS ARE NOT HARD CAPS THEREFORE ALIGNED WITH THE COMPANY'S RECOMMENDATION THAT THE CAPS BE REMOVED?

A. Possibly. If Mr. Kollen's viewpoint is simply that the caps are not hard caps and additional spending should be justified, then his recommendation is, in essence, the removal of the caps, as the Company's rates are always subject to the fair, just and

[4] Kollen at 35.

reasonable standard in utility ratemaking. However, his recommendation to maintain a cap, that is not a hard cap and therefore lacks any detail, is an example of the regulatory uncertainty I discuss below.

Q. DOES MR. KOLLEN OFFER ANY OTHER SUPPORT IN HIS RECOMMENDATION TO MAINTAIN THE CAPS AGAINST THE COMPANY?

A. No. Mr. Kollen does not cite any additional materials in the record in this case. Mr. Kollen makes unsupported claims the Company has failed to demonstrate it can properly control and manage its costs and schedules.[5] However, Mr. Kollen does not question the justification or recommend against recovery of a single project in the base period or forecasted testimony. He does not question the justification of projects proposed for the PM Rider as detailed by Company witness T. Ryan Austin. As I mentioned above, the OAG has not intervened in the Company's PRP proceedings for the past several years, where it would have an opportunity to review projects in those proceedings if the OAG believed they were not justified. Lastly, Mr. Kollen fails to address that the limit on the caps has remained static, with the exception of a $2 million increase in PRP beginning fiscal year 2025, the first increase since they were first imposed in early 2018 in which time there has been

[5] Kollen at 34

record inflation, the Covid-19 pandemic, and supply chain issues affecting the entire industry.

Q. CAN YOU PLEASE DISCUSS THE REGULATORY UNCERTAINTY CREATED BY THE CURRENT LANGUAGE OF THE CAPS?

A. Yes. As the Company stated in its response to OAG 1-22, the Commission's prior orders have not been clear on the Company's burden of proof for this non-statutory, newly imposed "requirement" for the Company's investment above the cap to be considered prudent. For instance, there has not been clarity regarding DIMP and TIMP spending compared to non-DIMP and non-TIMP spending nor has there been clarity regarding the calculation of the five-year rolling average.[6] The effect of this regulatory uncertainty is that it does create a hard cap due to the level of regulatory risk introduced by this imposition of an unclear standard beyond the prudence standard defined in Kentucky statute that has not been imposed on any other utility in the Commonwealth. Mr. Kollen's recommendation regarding the caps does nothing but continue the lack of clarity and regulatory uncertainty.

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[6] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), final Order at 24-25 ("Moreover, while the Commission is not imposing a specific limit on Atmos's non-PRP capital spending in years after the forecasted test period, the Commission may prohibit a return of and on investments that it finds unreasonable or unlawful. Atmos should ensure that the projects it selects to construct are consistent with its DIMP or TIMP. Moreover, if its total non-PRP capital spending exceeds the 5-year rolling average, Atmos should scrutinize the justification for its projects closely and be prepared to provide supporting documentation showing how each project is consistent with its DIMP or TIMP.").

Q. IS THE COMPANY WILLING TO PROVIDE ADDITIONAL INFORMATION TO THE COMMISSION ON FUTURE CAPITAL PROJECTS?

A. Absolutely. As I mentioned in my direct testimony the Company always welcomes and seeks the opportunity to discuss any planned capital projects with the Commission outside the context of rate applications. Should the Commission desire the Company to submit its capital projects before each fiscal year, or to meet quarterly or annually to discuss projects with Commission Staff the Company is available to address any concerns or questions the Commission may have concerning future proposed capital projects. Similarly, the Company is willing to do the same for the OAG.

Q. SHOULD THE CAPS BE LIFTED, WILL THE COMMISSION STILL HAVE THE OPPORTUNITY TO REVIEW ALL OF THE COMPANY'S CAPITAL INVESTMENT?

A. Yes. As also mentioned in my direct testimony, The Company's PRP and non-PRP capital investment will both still be subject to review and approval by the Commission, as it always has been and as it is for all other Kentucky regulated utilities. Through a base rate proceeding, capital rider, or information submitted at the request of the Commission, the Company is and has been committed to any review process of the Commission to ensure transparency on its capital spending.

The Company reiterated this commitment in its response to OAG DR 1-3.[7] The removal of the caps grants the Company flexibility in investing in its system from year-to-year for projects in the ordinary course of business and to be appropriately proactive. This flexibility allows the Company to be proactive in its PRP and non-PRP investment for long-term planning, safety and reliability, economic development, and regulatory compliance. Ultimately, the Commission still has complete oversight over the prudency of the Company's capital investment. If Mr. Kollen's argument for maintaining the caps is simply that spending above the caps has to be "justified" then, as I noted above, he is in effect arguing the same position as the Company.

As the Company mentioned in its response to AG 1-8, Atmos Energy confirms that its rates must be just and reasonable, and that the burden of proof to show that any proposed increased rate or charge is just and reasonable shall be upon

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[7] Company response to OAG 1-03 ("For any capital spending (including non-PRP capital spending), all of the Company's capital investment is subject to review in setting fair, just and reasonable rates by the Commission. If the caps are removed, the Commission's review of Atmos Energy's capital spending would be the same as it is for all other regulated utilities in Kentucky since Atmos Energy is the only regulated utility that currently has the caps in place. These utilities are constrained only by the requirement that all investments are prudently incurred. For the Company's non-PRP capital spending, any capital investment made between rate cases and forecasted through that current rate case would remain subject to review by the Commission. This would include any time period between rate cases, and not just base period and forecasted test period additions. In addition, as indicated in Taylor Direct Testimony at page 24, the Company has noted that it is open to any additional requirements for discussion of capital projects with the Commission outside the context of rate applications. Should the Commission desire the Company to submit its capital projects before each fiscal year (such as shown in Exhibits TRA-5 and TRA-6 of Company witness Austin's Direct Testimony), or to meet quarterly or annually to discuss projects with Commission Staff, the Company is available to address any concerns or questions the Commission may have concerning future proposed capital projects.")

the utility.[8] This legal standard is consistent with Atmos Energy's requests to allow the Company to present for review by the Commission the capital projects the Company deems to be prudent and provide evidence to support that assertion. With the removal of the caps, the regulatory uncertainty that I discussed earlier is removed, and the Company still must justify all its capital spending to the Commission through the regulatory review process.

Q. DOES MR. KOLLEN'S FINAL RECOMMENDATION FOR THE NON-PRP CAPITAL LIMITATIONS ADDRESS THE NUANCES NOTED IN YOUR DIRECT TESTIMONY AND T. RYAN AUSTIN'S DIRECT TESTIMONY?

A. It does not. Again, Mr. Kollen's recommendation to maintain the caps is completely lacking in any detailed analysis. Mr. Kollen does not distinguish between DIMP or non-DIMP spending, the calculation of a five-year rolling average, nor does he discuss possible effects on economic development in Kentucky created by the regulatory uncertainty in prior orders regarding the caps. The lack of analysis in Mr. Kollen's recommendation is especially striking as Mr. Kollen certainly seems to be aware of the nuances in the non-PRP caps as he raised these points between DIMP/TIMP capital spending and the five-year rolling average multiple times during discovery.[9]

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[8] Company response to OAG 1-08.
[9] *See, e.g.*, OAG data requests and Company responses to OAG 1-22, OAG 1-42, OAG 1-46.

Q. DOES REMOVAL OF THE CAPS AID ATMOS ENERGY IN THE COMMONWEALTH'S ECONOMIC DEVELOPMENT MISSION?

A. Yes. As mentioned in the response to OAG 1-24, Atmos Energy's desire and commitment is to be well positioned in the future to continue to support long-term economic development in Kentucky by having available gas capacity in the areas it serves. The removal of the caps grants the Company flexibility in investing in its system from year-to-year for projects in the ordinary course of business and to be appropriately proactive in economic development.

Q. ARE THERE ANY OTHER COMMENTS YOU WISH TO MAKE REGARDING THE CAPS CURRENTLY IN PLACE?

A. Yes, Atmos Energy considers itself a proud partner with the Commonwealth in the provision of safe and reliable service. The Company has been a critical partner with the Commonwealth in economic development, job creation, and investment as noted by the Kentucky Cabinet for Economic Development in the public comments in this Case. The economic development in the Company's service territory has been a factor in achieving the lowest residential rates in Kentucky among the five major LDCs as I noted in my Exhibit BCT-3. Despite having the lowest rates of the five major LDCs the Company is the only LDC that is currently subject to a cap on capital investment to the Company's knowledge.

IV. REJECTION OF KOLLEN'S RECOMMENDATION OF COMPANY'S PROPOSED RIDERS

Q. DOES MR. KOLLEN SUPPORT ANY OF THE COMPANY'S PROPOSED RIDERS OR RIDER ADJUSTMENTS IN THIS CASE?

A. Mr. Kollen does not support any of the Company's proposed riders or rider adjustments in this case. Mr. Kollen recommends that: (1) the Commission reject the inclusion of Aldyl-A pipe in the Company's Pipeline Replacement Program ("PRP"); (2) the Commission reject the Company's proposed PM Rider for projects required by law under the Mega Rule by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"); (3) the Commission reject the Company's proposed Tax Rider for tax changes required by law; (4) the Commission reject any consideration of an ARM that would streamline ratemaking and result in greater efficiency, transparency, and savings to customers; and (5) the Commission discontinue the Company's R&D Rider currently in effect. I will address each of these in turn in my rebuttal.

1. PRP RIDER AND ALDYL-A

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION ON THE COMPANY'S PRP PROPOSAL FOR INCLUSION OF ALDYL-A PIPE IN THE COMPANY'S PRP?

A. Mr. Kollen recommends that the Commission reject the Company's request for approval of an accelerated Aldyl-A replacement and recovery of the costs through the PRP in this proceeding, just as it has repeatedly rejected the same request in prior PRP and base revenue proceedings.[10]

Q. DOES MR. KOLLEN OFFER ANY ANALYSIS ON THE PHMSA GUIDELINES REGARDING ALDYL-A MATERIALS?

A. No. Mr. Kollen does not offer any analysis on the safety aspects of Aldyl-A and the PHMSA bulletins, nor does he attempt to distinguish between different Aldyl-A materials in his testimony. Mr. Kollen also incorrectly states in his testimony that the Company requested authorization for the accelerated replacement of all Aldyl-A pipeline in the Company's most recent PRP proceeding, Case No. 2023-00231, when in fact the Company only requested approval for four specific Aldyl-A projects all consisting of pre-1973 vintage material.[11] Company witness Mr. T. Ryan Austin provides further details in his rebuttal testimony on Mr. Kollen's lack of analysis of pipeline materials and existing guidance in making his recommendation.

Q. IS MR. KOLLEN IN A POSITION TO OFFER EXPERT GUIDANCE ON PHMSA REGULATIONS OR REPLACEMENT RATES?

A. No. In response to discovery from Commission Staff Mr. Kollen admits he is not

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[10] Kollen at 33

[11] *See* Kollen at 32; *see also* Case No. 2023-00231, *Electronic Application of Atmos Energy Corporation for PRP Rider Rates Beginning October 1, 2023* (Ky. PSC September 29, 2023), final Order at 14 ("In its current application, Atmos seeks approval to include four additional Aldyl-A projects in its PRP, two in Cadiz, Kentucky, one in Paducah, Kentucky, and one in Horse Cave, Kentucky.").

aware of a specific time frame for Aldyl-A or any other pipeline material replacement, and that the replacement and timeline to replace pipelines of any material should be based on the utility's assessments of condition and risk.[12]

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION TO REJECT THE LONG-TERM, STRATEGIC REPLACEMENT OF ALDYL-A THROUGH ITS PRP MECHANISM?

A. No. As I mention in my direct testimony, the Company would seek to replace Aldyl-A pipeline, an industry-identified material, and prioritize its PRP to replace pipe based on risk, and pipe in high-consequence areas, whether it be bare steel or Aldyl-A pipe.[13] As Mr. Kollen states, "it *does* (emphasis added) makes sense to replace higher priority pipeline segments based on the safety risks and leak history."[14] That is exactly the Company's proposal for Aldyl-A 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. Through the PRP mechanism, the Company submits detailed projects and costs to the Commission beforehand for review and approval, and the long-term strategic replacement of a material such as segments of Aldyl-A

[12] OAG response to Staff 1-02.
[13] Taylor direct at 8-9.
[14] Kollen at 32.

through a pipeline replacement program is in the *expressed* interest of the Commission.[15] As noted by the Commission:

> *The Commission has consistently found that the public interest is served by replacing potentially unsafe, aged gas pipelines through the adoption of pipeline replacement programs that have been approved as being fair, just and reasonable. To the extent that the pipeline eligible for replacement poses a safety risk to the utility's customers, service areas, and employees, the Commission reiterates that it is in favor accelerated replacement. The Commission believes that pipeline replacement programs improve public safety and reliability of service for customers…*
>
> *Through the PRP process, the Commission is able to separately review and scrutinize each project and expenditure annually, with the opportunity for the Attorney General, and potentially others, to intervene in the PRP proceedings. The Commission finds that the already established separately review for the accelerated replacement of bare steel pipelines in Atmos' system to be a more streamlined and efficient process than Atmos's proposal to include*

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[15] *See e.g.*, Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), Order at 14-15 ("The Commission has consistently found that the public interest is served by replacing potentially unsafe, aged gas pipelines through the adoption of pipeline replacement programs that have been approved as being fair, just and reasonable. To the extent that the pipeline eligible for replacement poses a safety risk to the utility's customers, service areas, and employees, the Commission reiterates that it is in favor accelerated replacement. The Commission believes that pipeline replacement programs improve public safety and reliability of service for customers…

Through the PRP process, the Commission is able to separately review and scrutinize each project and expenditure annually, with the opportunity for the Attorney General, and potentially others, to intervene in the PRP proceedings. The Commission finds that the already established separately review for the accelerated replacement of bare steel pipelines in Atmos' system to be a more streamlined and efficient process than Atmos's proposal to include the PRP projects in an annual base rate case. During a base rate case, a multitude of issues are examined in detail by the parties and the Commission. If PRP projects are also included in the base rate case then the Commission and the intervenors may not have adequate time to review and analyze the proposed projects"); *see also* Case No. 2018-00086 *Electronic Adjustment of the Pipe Replacement Program Rider of Delta Natural Gas Company, Inc.*, (Ky. PSC August 21, 2018) Order at pp. 3-4 ("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").

the PRP projects in an annual base rate case. During a base rate case, a multitude of issues are examined in detail by the parties and the Commission. If PRP projects are also included in the base rate case then the Commission and the intervenors may not have adequate time to review and analyze the proposed projects.[16]

Q. IS MR. KOLLEN'S RECOMMENDATION TO DENY ALDYL-A INCLUSION IN THE COMPANY'S PRP CONTRARY TO COMMISSION PRECEDENT FOR OTHER KENTUCKY UTILITIES?

A. Yes. As mentioned in direct testimony, the Company's request is no different from the authorization given to Delta Natural Gas Company, Inc. ("Delta") in Case No. 2018-00086.[17] In that order, the Commission stated:

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

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[16] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), Order at 14-15.

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

> *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.*

Like Delta, The Company's request is in line with this Commission precedent to designate the use of PRP to facilitate the long-term, strategic replacement of Aldyl-A materials based on risk in line with the public interest as stated by the Commission.

Q. IS DELTA THE ONLY UTILITY IN KENTUCKY WHERE THE COMMISSION HAS TARGETED THE REPLACEMENT OF ALDYL-A THROUGH A PIPELINE REPLACEMENT RIDER?

A. No. The Commission also amended Louisville Gas and Electric Company's ("LG&E") Gas Line Tracker ("GLT") Rider in Case No. 2015-00360 to include the replacement of all Aldyl-A pipe within the LG&E gas distribution system.[18] In its application, LG&E noted that Aldyl-A replacement programs are very similar in nature to replacement programs that target cast iron, wrought iron, and bare steel piping, and that Aldyl-A had been the subject of multiple safety advisories and the primary cause of several significant issues.[19] The Commission approved the inclusion of a comprehensive Aldyl-A replacement program stating that LGE's

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[18] Case No. 2015-00360, *Application of Louisville Gas and Electric Company for Approval of Revised Rates to be Recovered Through its Gas Line Tracker Beginning with the First Billing Cycle for January, 2016*, (Ky. PSC January 28, 2016) Order at 3; *see also* Case No. 2015-00360, (Ky. PSC October 30, 2015), Application
[19] Case No. 2015-00360, (Ky. PSC October 30, 2015), Application at 3-4.

proposal to include the replacement of Aldyl-A pipe and services in its GLT program is reasonable and should be approved.[20] The Commission further reiterated its approval for Aldyl-A inclusion in the GLT Rider in Case No. 2019-00301 and noted that Aldyl-A was included in the GLT Rider because it was **an immediate safety concern** (emphasis added).[21] The Commission noted in that case that Aldyl-A plastic pipe, manufactured between 1965 and 1991, had been the subject of a number of PHMSA safety bulletins and was considered responsible for several incidents involving fatalities, injuries, and property damage.[22]

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING THE INCLUSION OF ALDYL-A IN THE COMPANY'S PRP?

A. I recommend the Commission adopt the Company's original proposal, and reject Mr. Kollen's recommendation, regarding replacement of Aldyl-A in the PRP. The Company requests the Commission designate the use of PRP to facilitate the long-term, strategic replacement of Aldyl-A materials based on risk in line with the

[20] Case No. 2015-00360, (Ky. PSC January 28, 2016), Order at 3; *see also* Case No. 2015-00360, (Ky. PSC January 28, 2016), Order at 2 ("LG&E proposes to add a new program to its GLT to replace Aldyl-A plastic pipe. Aldyl-A, manufactured between 1965 and 1991, has been the subject of a number of safety bulletins issued by the Pipeline and Hazardous Materials Safety Administration, and is considered responsible for several incidents involving fatalities, injuries and property damage. Over time, DuPont Chemical Company, the original equipment manufacturer, determined that the inner wall of Aldyl-A pipe can become brittle, which can lead to the formation of cracks in the pipe wall, and in some instances, failure of the pipe.")

[21] Case No. 2019-00301, *Electronic Application for an Amended Gas Line Tracker* (Ky. PSC March 26, 2020) Order at 7 ("Subsequent amendments to the GLT program that were proposed by LG&E and approved by the Commission also addressed immediate safety concerns. For example, in Case No. 2015-00360, the Commission approved the addition of a program proposed by LG&E to the GLT program to replace Aldyl-A plastic pipe over two years. The Aldyl-A plastic pipe, manufactured between 1965 and 1991, had been the subject of a number of PHMSA safety bulletins and was considered responsible for several incidents involving fatalities, injuries, and property damage.")

[22] Case No. 2019-00301, (Ky. PSC March 26, 2020), Order at 7.

public interest of the Commission and prior precedent of other Kentucky utilities. The Company would 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. <u>PM RIDER</u>

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION TO REJECT THE COMPANY'S PROPOSED PM RIDER FOR PROJECTS REQUIRED BY LAW UNDER THE MEGA RULE BY PHMSA.

A. Mr. Kollen recommends that the Commission deny the requested PM Rider. He states that, "[i]t will significantly change the present ratemaking paradigm, incentivize the Company to incur greater capital expenditures earlier, shift the balance between the Company and other parties, and impose greater costs on the customers through annual rate increases."[23]

Q. HOW DO YOU RESPOND TO MR. KOLLEN'S RECOMMENDATION?

A. Mr. Kollen's recommendation lacks any analysis whatsoever of Mega Rule requirements and maintains his general opposition to any form of capital rider, focusing exclusively on costs and giving no weight to the requirements that the Company and all gas distribution utilities in regard to responsibility under PHMSA safety regulations. In contrast, the Company provided detailed testimony and exhibits by Company witness T. Ryan Austin of the scope of the Mega Rule, in

[23] Kollen at 45.

particular details of compliance for Maximum Allowable Operating Pressure ("MAOP") confirmation requirements.

Q. DO YOU AGREE WITH MR. KOLLEN'S ASSERTION THAT THE PM RIDER WILL PROVIDE AN INCENTIVE FOR THE COMPANY TO INCUR ADDITIONAL CAPITAL COSTS?

A. No. Mr. Kollen's simple claim that the PM Rider will provide an incentive for the Company to incur additional capital costs than it would without the PM Rider lacks any meaningful support.[24] Mr. Kollen's claim that the adoption of the PM Rider would put the Commission in the "untenable" position of navigating through the requirements of the Mega Rule and the better approach is "to avoid this conundrum" altogether is misplaced and ignores the precedent regarding the Commission's support for replacement related to PHMSA compliance.[25]

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION TO REJECT THE PM RIDER?

A. Absolutely not. As Company witness T. Ryan Austin will discuss in more detail in his rebuttal, Mr. Kollen's analysis is devoid of any actual details of the Mega Rule or upcoming compliance requirements mandated by PHMSA. Mr. Kollen also does a disservice to Commission Staff, in particular the Pipeline Safety Group, by

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[24] Kollen at 42.
[25] Kollen at 44.

claiming that they are not capable of navigating through the requirements of the Mega Rule and PHMSA requirements. In the Company's experience the Commission's Pipeline Safety group are knowledgeable and proactive partners in advocacy for pipeline safety, and the PM Rider allows a collaborative approach for the Company and Commission (and the OAG should they wish to intervene) on achieving Mega Rule compliance in a targeted manner. In contrast, Mr. Kollen's recommendation "to avoid this conundrum" altogether, is not a serious answer when it comes to pipeline safety and Mega Rule compliance.

Q. UNDER THE PROPOSED PM RIDER, WOULD THE COMMISSION STAFF HAVE THE OPPORTUNITY TO REVIEW PROJECTS AND APPROVE OR DISAPPROVE PROJECTS SIMILAR TO THE PRP?

A. Yes. The benefits of the proposed PM Rider are the exact same as the language used by the Commission for projects under the PRP. Through the proposed PM Rider process, the Commission is able to separately review and scrutinize each project and expenditure annually, with the opportunity for the OAG, and potentially others, to intervene in the proposed PM Rider proceedings.[26] The Company does not believe that the Commission's Staff or Pipeline Safety Group wishes to "avoid the conundrum" of navigating federally-mandated PHMSA Mega Rule compliance.

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[26] *See* Case No. 2018-00281, (Ky. PSC May 7, 2019), Order at 14-15.

Q. HAS THE COMMISSION OFFERED GUIDANCE IN THE PAST ON WHEN A CAPITAL RIDER, SUCH AS THE PROPOSED PM RIDER, IS APPROPRIATE?

A. Yes. As noted in my direct testimony, in the Company's most recent general rate case, Case No. 2021-00214, the Commission stated that "the purpose of a rider tied to capital investment in the natural gas industry is to address specific problems such as bare steel or a section of pipe prone to issues and may be tied to specific directives issued by PHMSA."[27] In addition, the Commission approved the Pipeline Modernization Mechanism ("Rider PMM") recently for Duke Energy Kentucky tied to its AM07 line and required Mega Rule compliance.[28] This approval was based on a joint stipulation agreed to between Duke Energy and the Attorney General's office.[29] In the final Order in that case approving Rider PMM the Commission also opined that "the purpose of a rider tied to capital investment in the natural gas industry to address specific problems, such as bare steel or a section of pipe prone to issues, and is often tied to specific directives issued by

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[27] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022), final Order at 60 ("[T]he purpose of a rider tied to capital investment in the natural gas industry is address specific problems such as bare steel or a section of pipe prone to issues and may be tied to specific directives issues by PHMSA"); *see also* Case No. 2021-00183, *Electronic Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates; Approval of Depreciation Study; Approval of Tariff Revisions*, *Issuance of a Certificate of Public Convenience and Necessity; and Other Relief* (Ky. PSC December 28, 2021) final Order at 40.

[28] Case No. 2021-00190, *Electronic Application of Duke Energy Kentucky, Inc. for: 10 An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs, and 3) All Other Required Approvals, Waivers, and Relief* (Ky. PSC Dec. 28, 2021), final Order at 22.

[29] Case No. 2021-00190, (Ky. PSC Dec. 28, 2021), final Order at Exhibit A, Paragraph 16

PHMSA."[30] The Commission also noted another determining factor in the approval of Duke Energy's Pipeline Modernization Mechanism was that most of the expenses related to the Mega Rule compliance associated with AM07 lied outside of the test year.[31] The Company's request in this Case for a PM Rider is tied to specific PHMSA directives on specific sections of pipe for a specific time period, a majority of which is also outside the test year, as identified and discussed in further detail by Company witness T. Ryan Austin. This is a far contrast from Mr. Kollen's assertion that the company has provided a lack of definition for the requirements of the Mega Rule.[32]

Q. DO YOU HAVE ANY OTHER COMMENTS ON MR. KOLLEN'S ANALYSIS REGARDING THE PM RIDER?

A. Yes. The Company provided detailed schedules, definitions, and past Commission precedent on the reasons for a PM Rider. Company witness T. Ryan Austin in his direct testimony extensively lays out the scope of the Mega Rule and path to compliance in Kentucky for Atmos Energy. The Company has cited past Commission precedent on the Commission's favorable approach to accelerated replacement, the purpose of when a capital rider is desirable, and the Commission's approach in similarly-situated situations with Duke Energy. In contrast, Mr.

[30] Case No. 2021-00190, (Ky. PSC Dec. 28, 2021), final Order at 23.
[31] Case No. 2021-00190, (Ky. PSC Dec. 28, 2021), final Order at 23
[32] Kollen at 44.

Kollen's PM Rider analysis attempts to make broad and unsupported assertions regarding transmission assets, Aldyl-A, and bare steel replacement within the Mega Rule[33] rather than focusing on the PHMSA requirements as presented by the Company in the Company's testimony and proposed tariff limiting the costs to compliance with the Mega Rule.

3. <u>TAX RIDER</u>

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION ON THE COMPANY'S PROPOSED TAX RIDER TO ADDRESS TAX CHANGES REQUIRED BY LAW?

A. Mr. Kollen recommends the Commission reject the Company's proposed Tax Rider. Mr. Kollen proposes that any tax changes required by law be dealt with by the Company (or any other utility in Kentucky) and the Commission Staff through the "the existing base ratemaking paradigm."[34]

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION TO REJECT THE COMPANY'S PROPOSED TAX RIDER?

A. I do not agree. This proposal, in effect, results in any tax changes not being reflected within rates for a significant amount of time, while also additionally

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[33] While making these claims in the body of his testimony, Mr. Kollen appears to contradict himself in FN37 of his testimony by noting that "Company witness testimony suggest the request at this time is more limited, i.e. the costs to comply with the Mega Rule. The proposed PM Rider tariff itself appears to limit the request to the costs to comply with the Mega Rule."

[34] Kollen at 41.

incurring the significant expense involved in a base rate proceeding. Mr. Kollen's proposal guarantees the increased frequency of base rate filings, not just by Atmos Energy, but by all utilities in Kentucky as tax rates change in the future. Company witness Joel Multer discusses in detail in his rebuttal testimony the flawed reasoning behind Mr. Kollen's Tax Rider analysis.

4. <u>ANNUAL REVIEW MECHANISM ("ARM")</u>

Q. PLEASE DISCUSS MR. KOLLEN'S RECOMMENDATION REGARDING AN ANNUAL REVIEW MECHANISM.

A. Although the Company does not formally propose an ARM in this case Mr. Kollen nevertheless treats it as a formal proposal and recommends denying an ARM.

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION?

A. I do not. Again, although this is not a formal proposal, I would ask the Commission to consider the benefits of an ARM in future regulatory proceedings. As pipeline safety, regulatory compliance, and tax rates continue to change and remain dynamic the frequency of general base rate case proceeding by all utilities will continue to increase. An ARM allows for increased efficiency, transparency, and adaptability for the Company, Commission Staff, and the OAG to focus on key issues that arise in a timely manner while simultaneously greatly reducing regulatory expenses.

Q. IF THE COMMISSION DOES NOT APPROVE THE COMPANY'S RIDERS COULD IT LEAD TO THE COMPANY FIILNG MORE FREQUENT GENERAL RATE CASES?

A. Almost certainly. Atmos Energy is committed to maintaining compliance, operating a safe and reliable system, following all applicable laws and regulations, and being a continued partner in economic development in Kentucky. The OAG's current recommendation is also that for any tax change or compliance requirement the Company should reflect those changes through the "existing base ratemaking paradigm." For example, one reason for the filing of this Case was to reflect the conclusion of the three-year amortization for the Excess Deferred Income Taxes Regulatory Liability that was established in Case No. 2021-00214.[35] As the Commission noted in the Company's Case No. 2018-00281 regarding proposed PRP projects and the Company's PRP Rider:

> *Through the PRP process, the Commission is able to separately review and scrutinize each project and expenditure annually, with the opportunity for the Attorney General, and potentially others, to intervene in the PRP proceedings. The Commission finds that the already established separately review for the accelerated replacement of bare steel pipelines in Atmos' system to be a more streamlined and efficient process than Atmos's proposal to include the PRP projects in an annual base rate case. During a base rate case, a multitude of issues are examined in detail by the parties and the Commission. If PRP projects are also included in the base rate*

[35] Company Application at 8. *See also* Case No. 2021-00214 (Ky. PSC May 19, 2021), final Order at 27; *see also* Case No. 2021-00214, (Ky. PSC June 24, 2022) Order at 4.

case then the Commission and the intervenors may not have adequate time to review and analyze the proposed projects.[36]

This same logic applies for the Company's proposed riders in this Case. The Company's proposed riders allow for a focused Commission review of the issues presented and ensure timely reflection of tax and compliance requirements.

5. RESEARCH AND DEVELOPMENT ("R&D") RIDER

Q. PLEASE DISCUSS MR. KOLLEN'S RECOMMENDATION REGARDING THE COMPANY'S RESEARCH AND DEVELOPMENT ("R&D") RIDER?

A. Mr. Kollen recommends terminating the R&D Rider to support the research of Gas Technology Institute ("GTI").[37] Mr. Kollen believes this funding should be from suppliers and manufacturers of industry, and that there are no direct benefits associated with these research and development activities.[38] He also states that funding by divisions at Atmos Energy varies, citing a discovery response to an Atmos Energy West Texas Division proceeding.[39]

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION REGARDING THE R&D RIDER?

A. I do not agree, and neither has the Commission in the past. Mr. Kollen also recommended this same adjustment in the Company's Case No. 2017-00349 before

[36] Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), final Order at 14-15.
[37] Kollen direct at 49.
[38] Kollen direct at 49.
[39] Kollen direct at 49.

the Commission. In that Case, the Commission not only affirmed the R&D Rider but approved an increase to the R&D Rider to its current rate today.[40] In its approval, the Order noted;

> *The Commission further finds that the value of benefits received by Atmos's customers and gas consumers, in general, outweighs the bill increase to its customers. While the R&D Riders of both Atmos and Columba were initially approved as a result of rate case settlements in which the Attorney General was a participant, the Commission approved the GTI Rider for Delta Natural Gas Company, Inc. ("Delta") in a contested rate proceeding in Case No. 2004-00067. Despite the opposition of the Attorney General, the Commission stated in its final Order that:*
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>> *"The Commission agrees with Delta's proposal to recover the monies to voluntarily fund GTI research through a tariff rider. The Commission has provided a clear signal to jurisdictional gas utilities in the past that it supports research and development efforts in the gas industry. Allowing recovery via a rider is consistent with Commission decisions for two other gas utilities, Atmos Energy and Columbia Gas of Kentucky"*[41]

The Commission also noted that the decision in support of research and development was consistent with a resolution issued by the National Association of Regulatory Utility Commissioners ("NARUC") in support of research and development funded by gas and electric utilities and performed by institutions such as GTI.[42]

[40] Case No. 2017-00349, *Electronic Application of Atmos Energy Corporation for an Adjustment of rates and Tariff Modifications*, (Ky. PSC May 3, 2018), final Order at 44.
[41] Case No. 2017-00349, (Ky. PSC May 3, 2018), final Order at 44-45.
[42] NARUC Resolution on Public Purpose Research & Development in the Electricity and Natural Gas Industries, adopted November 12, 1997.

Q. DID THE COMMISSION ALSO COMMENT IN CASE NO. 2017-00349 REGARDING MR. KOLLEN'S OTHER CLAIMS REGARDING NO DIRECT BENEFITS FROM R&D FUNDING OR THAT FUNDING LEVELS MAY BE DIFFERENT BY JURISDICTIONS?

A. Yes. Mr. Kollen and the OAG made similar arguments in Case No. 2017-00349, and the Commission also refuted both arguments. Specifically, the Commission stated:

> *The Commission notes that not all states in which Atmos operates have approved ratepayer contributions to research and development. This arguably creates a "free rider" issue because consumers that do not contribute to the efforts of entities such as GTI share in benefits in which they have no investment. The Commission finds, however, that all gas consumers including the customers of Atmos, the utility itself, and the general public, benefit sufficiently from the relatively small investment that it is reasonable for an average residential customer's annual bill to be increased less than a dollar. While private firms may benefit as well, their investment in research and development may not adequately fund science and technology activities that produce important health and safety benefits. With pipeline safety concerns often at the forefront on a national level, R&D Rider funding appears to be a natural accompaniment to pipeline replacement programs approved pursuant to KRS 278.509.*[43]

Mr. Kollen's arguments regarding the R&D Rider in this Case should be dismissed as they have already been well settled by this Commission in Case No. 2017-00349 as well as cases by other utilities within the Commonwealth cited above.

[43] Case No. 2017-00349, (Ky. PSC May 3, 2018), final Order at 45-46.

Q. DID THE COMPANY PROVIDE EXAMPLES OF THE WORK GTI IS PERFORMING THAT HAS BENEFITS?

A. Yes. The Company provided several of the continued benefits of GTI in this case in response to data requests Staff 1-08 and Staff 2-01.

V. RATE OF RETURN IN UPCOMING RIDER FILINGS

Q. DOES OFFICE OF ATTORNEY GENERAL'S WITNESS RICHARD BAUDINO COMMENT ON THE COMPANY'S RATE ON EQUITY USED IN ITS PRP FILINGS?

A. Yes. Mr. Baudino states in his testimony that "[a] lower ROE on capital riders like the PRP is consistent with Commission policy. I recommend that the Commission continue its practice and authorize a lower ROE of 9.30% on its allowed investments collected through the PRP."[44] Mr. Baudino also makes this same recommendation should the Commission approve a form of PM Rider in this Case.[45]

Q. DO YOU AGREE WITH MR. BAUDINO'S RECOMMENDATIONS?

A. I do not. The merits of why the same ROE established for base rates should also be applicable to PRP and other capital riders are more fully discussed in the direct and rebuttal testimony of Company witness Dylan D'Ascendis. I would like to simply make clear that with Mr. Baudino's recommendation in this Case and the current language of the Company's PRP tariff that it is the Company's intention to seek the rate of return established in this proceeding in the Company's next

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[44] Baudino at 37.
[45] Baudino at 37.

applicable PRP (or other capital rider) filing. In other words, the Company believes the intent of both the OAG and its tariff language on file for the PRP is that the rate of return established in this proceeding would then be utilized for submission and review by the Commission in the Company's next applicable PRP.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. Atmos Energy continues to be a good steward in the Commonwealth. The caps that are currently in place for Atmos Energy's capital investment places unnecessary limits on Atmos Energy's ability to invest in the safety and reliability of its system and hinders Atmos Energy's ability to assist the Commonwealth in its economic development endeavors. Atmos Energy has the lowest residential rates for any of the five large LDCs in Kentucky and continues to have an excellent track record for safety and reliability. The proposals made by Atmos Energy in this proceeding are reasonable, supported by the Company and are needed to ensure that Atmos Energy can continue to provide the safe and reliable service its customers have come to expect.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Brannon C. Taylor, 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. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Brannon C. Taylor

STATE OF TENNESSEE
COUNTY OF WILLIAMSON

SUBSCRIBED AND SWORN to before me by Brannon C. Taylor on this the 3rd day of March, 2025.

Pamela Pleasant
Notary Public
My Commission Expires: 01-24-2028

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

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS	**)**	
ENERGY CORPORATION FOR AN	**)**	
ADJUSTMENT OF RATES; APPROVAL OF	**)**	**Case No. 2024-00276**
TARIFF REVISIONS; AND OTHER	**)**	
GENERAL RELIEF	**)**	

<u>REBUTTAL TESTIMONY OF T. RYAN AUSTIN</u>

INDEX TO THE REBUTTAL TESTIMONY
OF T. RYAN AUSTIN, WITNESS FOR
<u>ATMOS ENERGY CORPORATION</u>

EXHIBIT:

Exhibit TRA-R-1 - White Paper on State Infrastructure Replacement Programs

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is T. Ryan Austin. My business address is 3275 Highland Pointe Drive, Owensboro, KY 42303.

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.

Q. WHAT ARE YOUR JOB RESPONSIBILITIES?

A. My current responsibilities for the Company include oversight of engineering, geographic information systems, measurement, compliance, safety, related information technology, damage prevention, and procurement. My department is responsible for execution of Projects within our Pipeline Integrity Plan, Annual DOT filings, Contracting, and Project Management for planned system growth, improvement, and replacement projects. I previously served as the Program Manager for the Kentucky Pipeline Replacement Program from 2015 through 2017.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in Civil Engineering from The University of Evansville in 2000. I am a Registered Professional Engineer in the Commonwealth of Kentucky. I have been employed by Atmos Energy for 15 years. During my time at Atmos Energy I have held engineering positions of increasing responsibility (Engineer 1 – Senior 2009-2015) in Owensboro, Manager of Engineering Services with responsibilities of the Kentucky Bare Steel Pipe Replacement Program (2015-

2017) and VP of Operations for Kentucky (2017-2019) - before moving to my current role as Vice President of Technical Services in June of 2019.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes, I am a member of the American Gas Association and serve on its Transmission Integrity Management Committee. I also serve as a member on the Operations and Engineering Committee of the Kentucky Gas Association.

Q. HAVE YOU SUBMITTED DIRECT TESTIMONY BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION ("COMMISSION") IN THIS PROCEEDING?

A. Yes.

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

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

A. The purpose of my rebuttal testimony is to address the issues raised and the conclusions and recommendations made in the testimony of Office of Attorney General ("OAG") witness Mr. Lane Kollen. Similar to Company witness Brannon Taylor, my rebuttal testimony will rebut Mr. Kollen's recommendation to maintain the caps on capital currently in place for the Company's Pipeline Replacement Program ("PRP") and non-PRP capital spending. I will also rebut Mr. Kollen's recommendation that the PRP mechanism not be utilized for targeted Aldyl-A replacement and his recommendation to deny the Company's proposed Pipeline Modernization ("PM") Rider for federal requirements promulgated by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). My rebuttal testimony will re-emphasize the safety and reliability requirements behind the Company's requests in this Case and reinforce the PHMSA guidance that Mr. Kollen fails to consider throughout his recommendations.

III. REJECTION OF MR. KOLLEN'S RECOMMENDATION TO MAINTAIN CAPS ON CAPITAL

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION RELATED TO CAPS ON CAPITAL

A. Mr. Kollen recommends the Commission deny the Company's requests to remove the PRP and non-PRP caps on capital expenditures.[1] Mr. Kollen claims the caps are not hard caps.[2] Mr. Kollen believes the caps are necessary to impose restraint on the Company's capital expenditures and base revenue requirements.[3]

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION?

A. I do not. Mr. Kollen's recommendation to maintain the caps addresses none of the uncertainty present in the current language of the caps imposed on the Company. For instance, although Mr. Kollen provides the quote regarding non-PRP caps from Case No. 2018-00281,[4] he does not address the different nuances regarding the non-PRP caps.[5] Mr. Kollen does not address the language regarding Distribution Integrity Management Program ("DIMP") or Transmission Integrity Management

[1] Kollen at 35.
[2] Kollen at 35.
[3] Kollen at 35.
[4] Kollen at 34; *see also* Case No. 2018-00281, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 7, 2019), final Order at 25.
[5] Case No. 2018-00281, (Ky. PSC May 7, 2019), final Order at 24-25 ("Moreover, while the Commission is not imposing a specific limit on Atmos's non-PRP capital spending in years after the forecasted test period, the Commission may prohibit a return of and on investments that it finds unreasonable or unlawful. Atmos should ensure that the projects it selects to construct are consistent with its DIMP or TIMP. Moreover, if its total non-PRP capital spending exceeds the 5-year rolling average, Atmos should scrutinize the justification for its projects closely and be prepared to provide supporting documentation showing how each project is consistent with its DIMP or TIMP.").

Program ("TIMP") capital spending compared to non-DIMP or non-TIMP capital spending. Mr. Kollen does not address how the "five-year rolling average" presented within the non-PRP caps language should be analyzed by the Company. Mr. Kollen does not address the points I raised in my direct testimony regarding the necessity of some non-DIMP and non-TIMP capital spending, such as growth and economic development, or public improvement projects required by the Commonwealth to serve such growth. Ultimately, Mr. Kollen's recommendation does not cite to any evidence presented in this Case in making his recommendation.

Q. HAS THE COMMISSION REPEATEDLY EXPLAINED THE PARAMETERS OF THE CAPS AS MR. KOLLEN SUGGESTS?

A. No. Although Mr. Kollen states the Commission has "repeatedly explained the parameters of the caps" that is not the case. Mr. Kollen's only substantive comment in his testimony is that the caps are "not hard caps."[6] The non-PRP caps were not addressed in the Company's PRP filing, Case No. 2023-00231. The non-PRP caps were not addressed in the Company's Case No. 2021-00214 despite the Company raising the issue, leading to continued uncertainty on the exact meaning of those caps. The Commission only discussed the PRP caps in the Company's 2023 PRP filing, Case No. 2023-00231, raising the caps to $30 million. This has been the first case since then for the Company to address the PRP and non-PRP caps and the valid reasons why the Company is seeking a lifting of both of these caps.

[6] Kollen at 35

Q. IS THERE ANY REBUTTAL OF THE POINTS YOU RAISED IN YOUR DIRECT TESTIMONY?

A. No. There is no rebuttal of the various points raised in my direct testimony or the Commission's language establishing the non-PRP caps in Case No. 2018-00281 which has led to continued uncertainty on behalf of the Company. The lack of any analysis in Mr. Kollen's testimony and final recommendation is especially odd as Mr. Kollen certainly seems to be aware of the nuances in the non-PRP caps as he raised these points between DIMP/TIMP capital spending as well as the five-year rolling average multiple times during discovery.[7] However, Mr. Kollen's final recommendation that the caps "are not hard caps" does not ultimately answer the uncertainty that I raised in my direct testimony regarding future capital investment for both PRP and non-PRP capital.

Q. DOES MR. KOLLEN ADDRESS THE NEED FOR ECONOMIC DEVELOPMENT IN KENTUCKY?

A. He does not. Although this spending may not lie within DIMP or TIMP it is still necessary for the Company to be able to provide service. As mentioned in my direct testimony, with growth comes the need to replace, loop, or increase pipe sizes to continue to provide reliable service to existing customers. These projects are not identified through the integrity management process to address safety threats but rather are identified through the system planning process to maintain reliable service. This fact does not make them less necessary for the provision of safe and reliable natural gas service to existing and new customers requesting service.

[7] *See, e.g.*, AG requests and Company responses to AG 1-22, AG 1-42, AG 1-46.

Q. HOW DOES REMOVAL OF THE CAPS AID ECONOMIC DEVELOPMENT IN KENTUCKY?

A. As mentioned in the response to AG 1-24, Atmos Energy's desire and commitment is to be well positioned in the future to continue to support long-term economic development in Kentucky by having available gas capacity in the areas it serves. The removal of the caps grants the Company flexibility in investing in its system from year-to-year for projects in the ordinary course of business and to be appropriately proactive in economic development.

Q. DOES MR. KOLLEN ADDRESS THE RISING CAPITAL COSTS SEEN IN THE INDUSTRY SINCE THE INITIAL CAP LANGUAGE IN CASE NO. 2017-00349 AND CASE NO. 2018-00281?

A. He does not. As mentioned in my direct testimony, the Company has seen substantial increases in capital costs in the last several years due to a variety of factors including but not limited to the COVID-19 pandemic, record inflation, geopolitical issues, and continued industry-wide supply chain constraints that have increased the labor and material costs for the Company on capital projects. These rising costs have meant the Company is able to perform less work each year based on the caps, which have remained static to the levels established in 2017 and 2018, with a minor adjustment to the PRP caps in 2023. While Mr. Kollen claims the caps "are not hard caps" and the Company "must be prepared to justify the additional costs,"[8] he does not address the various details of uncertainty within the caps that were raised in my direct testimony that has led to the Company's request

[8] Kollen at 35.

in this proceeding for the removal of the caps. The Company is always prepared to justify the costs of its capital spending, regardless of if that spending is below or above a cap number, but it is the uncertainty of the language surrounding the caps and the operational flexibility required for why the Company is asking for their removal.

Q. WILL YOU PLEASE REPEAT HOW THE CURRENT NON-PRP CAP LANGUAGE AFFECTS YOUR BUDGETING PROCESS?

A. Yes. When the Company is preparing its budget each year the Company prepares with the consideration of the caps as put in place by the Commission. Planned projects necessary to continue to provide safe, reliable service to existing customers are the first priority. In addition, the Company must continue to operate its day-to-day activities within its functional project budgets that are all part of non-PRP investment. Functional projects are essentially categories of budget dollars reserved for programmatic spending that the Company must incur for its day-to-day operations. These include capital items such as our meter and growth functionals. Based on the long-term system needs of Kentucky, allowing for these two categories of capital expenditures leaves very little flexibility within the space of the caps to serve, if it all, economic development, system improvement, or public improvement projects. Several of these needs fall outside of DIMP or TIMP but are still necessary. Again, these are all points that Mr. Kollen does not address in his recommendation to maintain the caps.

Q. ARE ALL KENTUCKY CAPITAL INVESTMENTS ESTABLISHED AT THE BEGINNING OF EACH FISCAL YEAR?

A. No. The Company knows that there will always be certain investments that will need to be made during the year that cannot be identified in advance. For example, leaks may occur on the system at any time of the year, and the Company budgets and allocates capital accordingly to allow the Company to make operational and investment decisions as necessary throughout the year. Likewise, the Company knows that it will receive requests for facilities to be relocated throughout the year, but it cannot always anticipate the number of requests it will receive in any given year. The projected level of capital expenditures for these items is based on needs known at the time the budget is prepared on the Company's past experience. As I mentioned earlier, the removal of the caps grants the Company flexibility in investing in its system from year-to-year for projects in the ordinary course of business and to be appropriately proactive in the provisioning of safe and reliable service, while still allowing all capital to be subject to justification and review within the appropriate regulatory proceeding.

Q. DOES MR. KOLLEN STATE ANYTHING ABOUT WHICH PARTY IS BEST SITUATED TO ASSESS SYSTEM CONDITION AND RISK?

A. Mr. Kollen, in response to Commission Staff discovery, acknowledges that the replacement and timeline to replace pipelines of any material should be based on the ***utility's*** assessments of condition and risk. (emphasis added).[9] This acknowledgement by the OAG itself recognizes that the Company is in a better

[9] OAG Response to Staff DR 1-02.

position to determine risk and appropriate measures to manage that risk. For Mr. Kollen to suggest a continued policy of caps for PRP and non-PRP when he himself acknowledges the Company is in a better position to determine risk and material replacement for pipeline replacement is misguided.

IV. REJECTION OF MR. KOLLEN'S RECOMMENDATION TO DENY PM RIDER AND PRP RIDER

Q. HAS PHMSA COMMENTED SPECIFICALLY ON THE NEED FOR ACCELERATED REPLACEMENT OF THE MATERIALS THAT ATMOS ENERGY IS SEEKING APPROVAL IN BOTH ITS PRP AND PROPOSED PM RIDER?

A. Yes. In December of 2011, in connection with the publication of a White Paper on State Pipeline Infrastructure Replacement Programs sponsored by 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"). Among other things, PHMSA recommended that State public utility commissions consider accelerating work on the following kinds of high-risk gas infrastructure in the future:

- *Plastic pipe manufactured in the 1960s to the early 1980s, which is susceptible to premature failures as a result of brittle-like cracking;*
- *Pipelines with inadequate construction records or assessment results to verify their integrity*[10]

[10] Exhibit TRA-R-1, White Paper on State Infrastructure Replacement Programs at 2.

These two types of materials are the focus of the Company's requests for its PRP amendment and approval of PM Rider, respectively. I would also note that PHMSA has stated in their White Paper:

> *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 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 establish or improve programs for the repair, rehabilitation, and replacement of high risk pipeline infrastructure. Such assistance could include offering testimony at legislative hearings 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.*[11]

The Company's proposals are in line with existing PHMSA guidance and prior Commission precedent and the Company respectfully requests their approvals from the Commission.

1. <u>PM RIDER</u>

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION TO REJECT THE COMPANY'S PROPOSED PM RIDER FOR PROJECTS REQUIRED BY LAW UNDER THE MEGA RULE BY PHMSA?

A. Mr. Kollen is recommending against the approval of the PM Rider for federally mandated requirements promulgated by PHMSA, specifically the Mega Rule. Mr.

[11] Exhibit TRA-R-1, White Paper on State Infrastructure Replacement Programs at 17.

Kollen simply claims that the PM Rider will provide an incentive for the Company to incur additional capital costs than it would without the PM Rider.[12] Mr. Kollen claims that there will be no brightline for costs that will be recoverable through the PM Rider, and the scope of the projects are difficult to define.[13] Mr. Kollen also claims adoption of the PM Rider would put the Commission in the "untenable" position of navigating through the requirements of the Mega Rule and the better approach is "to avoid this conundrum" altogether.[14]

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION?

A. I do not. The Mega Rule is a federally mandated requirement by PHMSA. For the Company, I mentioned repeatedly in my direct testimony that the portion of the rule that will most directly impact its Kentucky system is regarding Maximum Allowable Operating Pressure ("MAOP") reconfirmation requirements. There is no other option for Atmos Energy but to perform the work required to achieve compliance with federal law. Indeed, as I also noted earlier, Mr. Kollen in response to Commission Staff discovery admitted that he is not aware of a specific time frame for Aldyl-A or any other pipeline material replacement, and that the replacement and timeline to replace pipelines of any material are based on the ***utility's*** (emphasis added) assessments of condition and risk.[15]

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[12] Kollen at 42.
[13] Kollen at 43-44.
[14] Kollen at 44.
[15] OAG Response to Staff Request 1-02.

Q. DO YOU AGREE WITH MR. KOLLEN'S ASSERTION THAT THE SCOPE OF THE MEGA RULE COMPLIANCE FOR THE COMPANY IS BROAD AND SUBJECT TO DEFINITION BY THE COMPANY?

A. I do not. The Company is seeking the PM Rider for Mega Rule compliance, with a specific emphasis for required MAOP reconfirmation between now and 2035. As mentioned in my direct testimony, and in contrast to Mr. Kollen's assertion that the Mega Rule requirements are difficult to navigate, the reconfirmation of MAOP clearly requires:

- Complete MAOP Reconfirmation of 50% of affected pipeline mileage by July 2028 (§192.624);
- Complete MAOP Reconfirmation of 100% of affected pipeline mileage by July 2035 (§192.624);
- Complete integrity assessment of non-HCA Class 3 and 4 Locations, and Piggable Moderate Consequence Areas ("MCAs") by July 2034 (§192.710); and
- Material verification as required to support all activities (§192.607).

Q. DID THE COMPANY PROVIDE A DETAILED LIST OF THE PROPOSED PROJECTS FOR THE PM RIDER BETWEEN NOW AND THE 2035 DEADLINE?

A. Yes. Exhibit TRA-5 in my direct testimony provided the schedule of projects and scope of work necessary to achieve PHMSA compliance for MAOP reconfirmation requirements by the prescribed deadlines. Mr. Kollen erroneously asserted that the Company did not provide an estimate of the costs or a schedule for Mega Rule compliance in his analysis.[16]

[16] Kollen at 44-45.

Q. WILL YOU RESTATE THE OUTLINED WORK NECESSARY FOR PHMSA MEGA RULE COMPLIANCE UNDER THE PM RIDER FROM YOUR DIRECT TESTIMONY?

A. Yes. The Company has outlined its long-term plan for Mega Rule compliance in Exhibit TRA-5 and believes the approval of the proposed PM Rider is the appropriate approach to support compliance with these specific PHMSA regulations, in particular MAOP reconfirmation requirements. The Company has included the estimated costs of compliance projects through fiscal year 2026 based on latest estimates. Since class locations changes could potentially impact the Company's cost of compliance with the Mega Rule, if the PM Rider is approved by the Commission Atmos Energy would make annual filings with the Commission regarding the costs of compliance projects to be included in the PM Rider. This would allow Atmos Energy to continue to present the Commission with the most accurate information regarding the costs of the compliance projects required for the Commission's review, consideration, and approval. Contrary to Mr. Kollen's assertions, the outlined work in Exhibit TRA-5 must be completed by the prescribed timeframes for PHMSA compliance. The scope and timing of this work is not subject to definition by the Company as Mr. Kollen suggests[17] but is rather subject to the definition of the MAOP reconfirmation requirements clearly outlined in the Mega Rule.

[17] Kollen at 44.

Q. IS THERE ANY OTHER OPTION OTHER THAN REPLACEMENT FOR PROJECTS LISTED IN EXHIBIT TRA-5 TO ACHIEVE PHMSA-MANDATED COMPLIANCE?

A. There is not. I provided extensive detail in pages 16-24 of my direct testimony why replacement is the only feasible option for the required MAOP reconfirmation activities. Of the 14.0 miles of transmission pipelines proposed for replacement in Exhibit TRA-5 all are pre-November 12, 1970 lines, which is when 49 CFR Part 192 went into effect. Of those 14.0 miles, 4.7 miles of these transmission lines were installed between 1956-1959, and 5.9 miles were installed in 1955 or prior to that time. Atmos Energy is committed to maintaining compliance to all applicable laws and regulations, including the PHMSA Mega Rule, and the work outlined for replacement is necessary to achieve compliance.

Q. WOULD THE COMMISSION HAVE THE OPPORTUNITY TO REVIEW ALL PROPOSED PM RIDER PROJECTS TO ENSURE MEGA RULE COMPLIANCE?

A. Yes. The PM Rider will allow for an annual review, discovery, and engagement with the Commission on the Company's progress towards Mega Rule compliance for pipeline replacement projects that are necessitated by PHMSA for pipeline integrity. The PM Rider would allow for these capital costs to be tracked separately, similar to the Company's current PRP mechanism. Similar to PRP, the Commission is able to separately review and scrutinize each project and expenditure annually, with the opportunity for the Attorney General, and potentially others, to intervene in the proposed PM Rider proceedings.[18] Having an annual filing also allows the Company and my team to provide up-to-date cost estimates to the Commission on the specific projects proposed for each year and allows the Company to work with the Commission, and the OAG should they intervene, to analyze and review these projects as needed. This does not put the Commission staff in the "untenable position" of navigating Mega Rule requirements but rather allows the Company and the Commission to have a targeted capital rider to collaboratively achieve federally-mandated PHMSA compliance.

Q. DO YOU AGREE THAT MR. KOLLEN'S ASSERTION THAT THE PM RIDER WILL PUT THE COMMISSION IN THE "UNTENABLE POSITION" OF NAVIGATING THROUGH THE REQUIREMENTS OF THE MEGA RULE AND THE BETTER APPROACH IS TO "AVOID THIS CONUNDRUM" ALTOGETHER?

A. I do not. The Company's request in the PM Rider is narrowly defined to the Mega Rule, with an emphasis on MAOP reconfirmation requirements as I have reiterated in this testimony. The scope of the work that I have outlined in Exhibit TRA-5 is a clear requirement from PHMSA. In the Company's experience the Commission's Pipeline Safety group are knowledgeable and proactive partners in advocacy for pipeline safety, and the PM Rider allows a collaborative approach to achieve prescribed PHMSA compliance in a targeted manner. As class locations potentially change and additional mileage may require reconfirmation in the future the PM Rider allows the Company and the Commission to work together in maintaining

[18] *See* Case No. 2018-00281, (Ky. PSC May 7, 2019), Order at 14-15.

PHMSA compliance. Atmos Energy has always maintained a good working relationship with the Commission's Pipeline Safety division and believes the PM Rider would be a proactive approach to continue that relationship and to collaboratively achieve PHMSA compliance.

Q. HAS THE COMMISSION NOTED THAT A RIDER IS APPROPRIATE TO ADDRESS SPECIFIC DIRECTIVES FROM PHMSA?

A. Yes. In Case No. 2021-00214 the Commission reminded Atmos Energy "that the purpose of a rider tied to capital investment in the natural gas industry is address specific problems such as bare steel or a section of pipe prone to issues and may be tied to specific directives issues by PHMSA."[19] The Company's proposed PM Rider is designed to specifically address required investment tied to the Mega Rule directive issued by PHMSA. The Commission also had similar comments in Case No. 2021-00190 in approving Duke Energy's Pipeline Modernization Mechanism ("Rider PMM") for Duke Energy's AM07 project due to Mega Rule compliance. Again in that case the Commission opined in approving Rider PMM that "the purpose of a rider tied to capital investment in the natural gas industry to address specific problems, such as bare steel or a section of pipe prone to issues, and is often tied to specific directives issued by PHMSA."[20] The Commission also noted another determining factor in approving Rider PMM was that most of the expenses related to the Mega Rule compliance associated with AM07 lied outside of the test

[19] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022), final Order at 60.

[20] Case No. 2021-00190, *Electronic Application of Duke Energy Kentucky, Inc. for: 10 An Adjustment of the Natural Gas Rates; 2) Approval of New Tariffs, and 3) All Other Required Approvals, Waivers, and Relief,* final Order at 23 (Ky. PSC Dec. 28, 2021)

year."[21] Similarly, the majority of Atmos Energy's upcoming work for MAOP compliance required by the PHMSA Mega Rule as detailed in TRA-5 lies outside the test year of this Case. As I have noted earlier, and below again for emphasis, the Mega Rule has prescribed 2028 and 2035 compliance deadlines for the Company's affected transmission assets.

Q. IS THE COMPANY ASKING FOR ANY ADDITIONAL ACTIVITIES THROUGH THE PM RIDER OTHER THAN MAOP RECONFIRMATION ACTIVITIES AS OUTLINED BY THE COMPANY?

A. Not at this time. Should any future requirements arise the Company would seek authorization from the Commission. The PM Rider is targeted to achieve Mega Rule compliance, in particular MAOP Reconfirmation requirements prescribed by the Mega Rule by the 2035 timeframe.

2. <u>PRP RIDER – ALDYL-A INCLUSION</u>

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATION ON THE COMPANY'S PRP PROPOSAL FOR INCLUSION OF ALDYL-A PIPE IN THE COMPANY'S PRP?

A. Mr. Kollen recommends the Commission reject the Company's request for approval of an accelerated Aldyl-A replacement program and recovery of the costs through the PRP in this proceeding…".[22]

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION RECOMMENDING AGAINST ALDYL-A IN THE PRP FOLLOWING BARE STEEL REMOVAL?

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[21] Case No. 2021-00190, (Ky. PSC Dec. 28, 2021), final Order at 23.
[22] *See, e.g.*, Kollen at 31-33.

A. I do not. The Company would seek to replace Aldyl-A pipe, an industry-identified material, and prioritize its PRP to replace pipe based on risk, and pipe in high-consequence areas, whether it be bare steel or Aldyl-A pipe. Initially, the Company would target pre-1973 and unknown vintage Aldyl-A, or other Aldyl-A if specific risk factors were involved. As the Company continually monitors its Aldyl-A pipes it will make decisions regarding these pipes to ensure safety and reliability of its system and our customers. However, the request in this Case is simply that the Commission recognize that Aldyl-A material, in particular the pre-1973 and unknown vintage Aldyl-A, does need to be replaced over time based on the materials involved, PHMSA guidance, and past Commission precedent and that the PRP is an appropriate mechanism for that replacement. The Company believes, for reasons that the Commission has stated in prior orders, that the PRP mechanism would allow for a streamlined and targeted approach to achieve this long-term replacement and is in line with the purpose of a mechanism such as PRP.

Q. ARE YOU RECOMMENDING THAT ALL ALDYL-A NEEDS TO BE REPLACED IMMEDIATELY UNDER THE PRP?

A. No. Tables TRA-2 and TRA-3 in my direct testimony differentiate between types of Aldyl-A. The Company would seek to prioritize and replace pre-1973 initially through its PRP program and other higher risk-ranked segments of Aldyl-A. Within the PRP, the Aldyl-A being replaced over time would be targeted based on risk. However, PHMSA guidance is clear that there is a need for the long-term replacement of Aldyl-A materials.[23] The Commission has also been clear that it

[23] *See* PHMSA Advisory Bulletin ADB-07-01, Advisory Bulletins ADB-99-01, ADB-99-02, and ADB-02-07. PHMSA Advisory Bulleting ADB-07-01 is provided in my direct testimony as Exhibit TRA-8.

affirmatively supports the accelerated replacement of facilities that present safety or reliability issues, including Aldyl-A.[24]

Q. DOES MR. KOLLEN COMMENT UPON PHMSA GUIDANCE REGARDING ALDYL-A OR HIS ASSESSMENT OF ALDYL-A PIPE?

A. Mr. Kollen, in response to Commission discovery, acknowledges that he is not aware of a specific time frame for Aldyl-A or any other pipeline material replacement, and that the replacement and timeline to replace pipelines of any material are based on the ***utility's*** (emphasis added) assessments of condition and risk.[25] Mr. Kollen acknowledges, in essence, that he is not an expert on pipeline materials and that it should be up to the utility to assess risk and replacement of pipeline materials, including Aldyl-A.

Q. HAS THE COMMISSION COMMENTED SPECIFICALLY ON ALDYL-A MATERIALS IN THE PAST?

A. Yes. The Commission is also aware of the long-term risks identified in Aldyl-A materials, that it is subject to multiple PHMSA bulletins, and the need for replacement.[26] The Commission has also noted to the Company that it is aware that Aldyl-A presents a long-term safety and reliability issue.[27] The pre-1973 Aldyl-A vintage that Atmos Energy has initially targeted for long-term replacement is similar (or even older) to the oldest Aldyl-A identified and approved for

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[24] *See, e.g.,* Case No. 2018-00281, (Ky. PSC May 7, 2019) at 23.

[25] OAG Response to Staff DR 1-02.

[26] Case No. 2018-00086 *Electronic Adjustment of the Pipe Replacement Program Rider of Delta Natural Gas Company, Inc.*, (Ky. PSC August 21, 2018) final Order at pp. 3-4; *see also* Case No. 2015-00360, *Application of Louisville Gas and Electric Company for Approval of Revised Rates to be Recovered Through its Gas Line Tracker Beginning with the First Billing Cycle for January, 2016*, (Ky. PSC January 28, 2016) Order at 3; *see also* Case No. 2019-00301, *Electronic Application for an Amended Gas Line Tracker* (Ky. PSC March 26, 2020) Order at 7.

[27] Case No. 2018-00281, (Ky. PSC May 7, 2019), Order at 23.

replacement by the Commission for Delta in Case No. 2018-00086.[28] While the Commission noted the amount of pre-1983 Aldyl-A pipe in Delta's system as a determining factor for long-term replacement, the pipe that Atmos Energy is seeking initial replacement of is the pre-1973 Aldyl-A vintage and other high risk-ranked Aldyl-A based on risk prioritization within the PRP.[29] The Company is simply seeking the long-term and targeted replacement of Aldyl-A by prioritized segments and in coordination with the Commission and believes the PRP mechanism provides the best solution to this approach. This approach is in line with past Commission precedent as more fully noted by Company witness Taylor in his testimony.

Q. IS DELTA THE ONLY UTILITY IN KENTUCKY WHERE THE COMMISSION HAS TARGETED THE REPLACEMENT OF ALDYL-A THROUGH A CAPITAL RIDER?

A. No. As Company witness Taylor notes, the Commission also amended Louisville Gas and Electric Company's ("LG&E") Gas Line Tracker ("GLT") Rider in Case No. 2015-00360 to include the replacement of all Aldyl-A pipe within the LG&E gas distribution system.[30] In its Application, LG&E noted that Aldyl-A replacement programs are very similar in nature to replacement programs that target cast iron, wrought iron, and bare steel piping, and that Aldyl-A had been the subject of multiple safety advisories and the primary cause of several significant issues.[31] The

[28] *Id.*
[29] *See id.*; *see also* Table TRA-2 and Table TRA-3 in Austin Direct.
[30] Case No. 2015-00360, *Application of Louisville Gas and Electric Company for Approval of Revised Rates to be Recovered Through its Gas Line Tracker Beginning with the First Billing Cycle for January 2016*, (Ky. PSC January 28, 2016) Order at 3; *see also* Case No. 2015-00360, (Ky. PSC October 30, 2015), Application
[31] Case No. 2015-00360, (Ky. PSC October 30, 2015), Application at 3-4.

Commission approved the inclusion of a comprehensive Aldyl-A replacement program stating that LGE's proposal to include the replacement of Aldyl-A pipe and services in its GLT program is reasonable and should be approved. The Commission reiterated its approval for Aldyl-A inclusion in the GLT Rider in Case No. 2019-00301 and noted that Aldyl-A was **an immediate safety concern** (emphasis added).[32] The Commission stated in that case that it has approved amendments to LGE's GLT program to address immediate safety concerns, citing the replacement of Aldyl-A pipe as a specific example. The Commission noted that Aldyl-A plastic pipe, manufactured between 1965 and 1991, had been the subject of a number of PHMSA safety bulletins and was considered responsible for several incidents involving fatalities, injuries, and property damage.[33] In that case, the Commission reiterated that all Aldyl-A pipe was a specific example of the type of pipe that a capital rider program, such as GLT or PRP, was designed to replace based on the PHMSA bulletins and incident history. Again, Atmos Energy is seeking initial targeted replacement of pre-1973 Aldyl-A vintage and other high risk-ranked Aldyl-A. The Company would replace Aldyl-A pipe, an industry-identified material, and prioritize its PRP to replace pipe based on risk, and pipe in high-consequence areas, whether it be bare steel or Aldyl-A pipe.

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[32] Case No. 2019-00301, *Electronic Application for an Amended Gas Line Tracker* (Ky. PSC March 26, 2020) Order at 7 ("Subsequent amendments to the GLT program that were proposed by LG&E and approved by the Commission also addressed immediate safety concerns. For example, in Case No. 2015-00360, the Commission approved the addition of a program proposed by LG&E to the GLT program to replace Aldyl-A plastic pipe over two years. The Aldyl-A plastic pipe, manufactured between 1965 and 1991, had been the subject of a number of PHMSA safety bulletins and was considered responsible for several incidents involving fatalities, injuries, and property damage.")

[33] Case No. 2019-00301, Electronic Application for an Amended Gas Line Tracker, Order at 7.

Q. DID THE COMMISSION HAVE ANY COMMENT ON THE COMPANY'S ALDYL-A PROPOSAL FOR INCLUSION WITHIN PRP IN ITS MOST RECENT GENERAL RATE CASE?

A. Yes. The Commission stated that although Aldyl-A is a risk, Aldyl-A is considered a sub-threat and represents only 5.00 percent of Atmos Kentucky's total system in denying the inclusion of Aldyl-A into PRP at that time.[34]

Q. DO YOU AGREE WITH THE COMMISSION'S ANALYSIS IN THAT CASE?

A. I respectfully disagree for the reasons I mention above and as indicated in my direct testimony, especially for the pre-1973 and unknown vintage Aldyl-A that the Company would initially target and is the subject of multiple PHMSA bulletins. The guidance given to the Company with denial of Aldyl-A replacement in the Company's PRP in Case No. 2021-00214 appears to be in direct contradiction with the Commission's past guidance and precedent regarding Aldyl-A with respect to Delta's PRP and LGE's GLT. With the targeting of pre-1973 and unknown vintage Aldyl-A in the PRP mechanism the Company and the Commission would be able to work together on an annual basis to replace these prioritized segments under Commission guidance exactly as the Commission prescribed with Delta and approved with LG&E. The Company would 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.

[34] Case No. 2021-00214, (Ky. PSC May 19, 2022), final Order at 59-60.

Q. HOW MANY MILES OF PRE-1973 ALDYL-A IS CURRENTLY PRESENT IN THE COMPANY'S KENTUCKY SYSTEM?

A. As shown on Table TRA-3 in my direct testimony, approximately 115 miles of pre-1973 Aldyl-A is present.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION REGARDING MR. KOLLEN'S TESTIMONY DENYING ALDYL-A IN THE PRP?

A. I recommend that the Commission deny Mr. Kollen's recommendation. The Company requests Commission approval to begin the targeted, long-term replacement of Aldyl-A and allow the Company 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. This recommendation is consistent with PHMSA guidance and past Commission precedent of affirmative support of accelerated replacement of facilities that present safety or reliability issues.

V. <u>CONCLUSION</u>

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 OF RATES; APPROVAL OF	)	**Case No. 2024-00276**
TARIFF REVISIONS; AND OTHER	)	
GENERAL RELIEF	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Timothy (Ryan) Austin, 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. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Timothy Ryan Austin

Timothy R. Austin

STATE OF KENTUCKY

COUNTY OF DAVIESS

SUBSCRIBED AND SWORN to before me by Timothy R. Austin on this the 3rd day of March, 2025.

DANIEL MAYFIELD
NOTARY
ID KYNP41529
MY COMMISSION EXPIRES 12/8/2025
PUBLIC
STATE AT LARGE, KY.

Daniel Mayfield KYNP41529

Notary Public

My Commission Expires: 12/08/2025

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

Administrator

1200 New Jersey Avenue SE
Washington, DC 20590

DEC 19

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

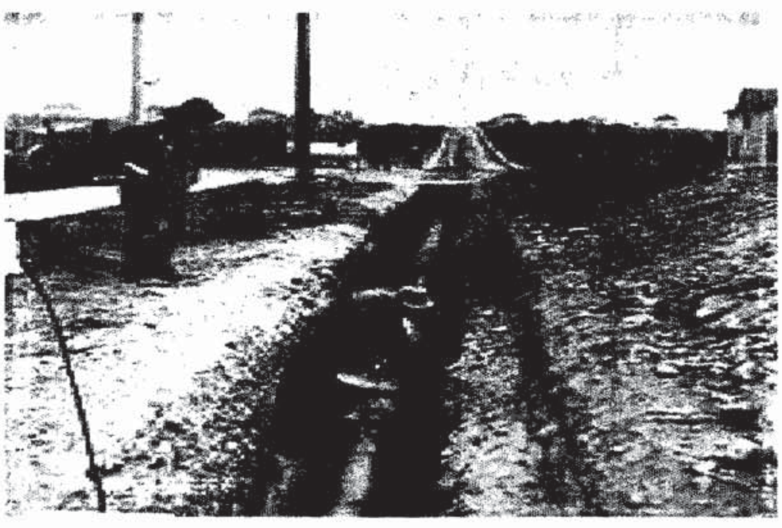
UNITED STATES DEPARTMENT OF TRANSPORTATION
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

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

Texas

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

[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

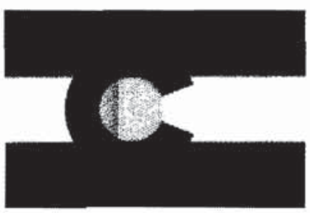
PARTICIPANT: San Diego Gas and Electric

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

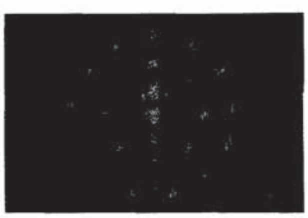
Illinois

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: <u>Missouri Public Service Commission</u>

PROGRAM: Infrastructure System Replacement Surcharge

PARTICIPANTS: <u>Ameren Missouri</u>

<u>Laclede Gas</u>

<u>Missouri Gas Energy</u>

<u>Atmos Energy - MO</u>

LAWS: <u>MO ST 393.1009 *et seq.*</u>

Nebraska

STATE AUTHORITY: <u>Nebraska Public Service Commission</u>

PROGRAM: Infrastructure System Replacement Cost Recovery Charge

PARTICIPANT: <u>Black Hills Energy</u>

LAWS: <u>NE ST 66-1865</u>

<u>NE ST 66-1866</u>

<u>NE ST 66-1867</u>

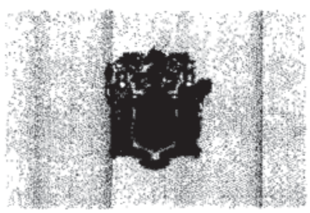
New Hampshire

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

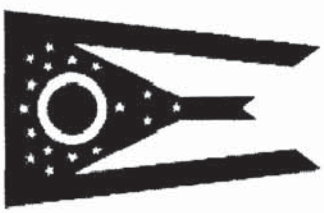
New York

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

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS	**)**	
ENERGY CORPORATION FOR AN	**)**	
ADJUSTMENT OF RATES; APPROVAL OF	**)**	**Case No. 2024-00276**
TARIFF REVISIONS; AND OTHER	**)**	
GENERAL RELIEF	**)**	

REBUTTAL TESTIMONY OF GREGORY K. WALLER

INDEX TO THE REBUTTAL TESTIMONY OF GREGORY K. WALLER, WITNESS FOR ATMOS ENERGY CORPORATION

EXHIBITS:

Exhibit GKW-R-1 – Rebuttal Revenue Requirement Model

Exhibit GKW-R-2 – 2024 Kentucky State Bill

Exhibit GKW-R-3 – Comments of the American Gas Association, FERC Docket No. RM22-5-000

I. INTRODUCTION

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

A. My name is Gregory K. Waller. I am Director, 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.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to rebut certain operating income adjustments proposed by Attorney General's Office of Rate Intervention ("OAG") in the Direct Testimony of Randy Futral. I also summarize the Company's overall revenue requirement deficiency rebuttal position by incorporating the rebuttal positions of other Company witnesses including Mr. Joe Christian, Mr. Joel Multer, and Mr. Dylan D'Ascendis.

III. SUMMARY OF COMPANY'S REBUTTAL POSITION

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

A. Yes. The table GKW-R-1 below, which is adopted from the table that appears in Mr. Futral'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 Commission Staff's First

Request for Information ("Staff's First Request"), Item 1-54 and referenced below as the starting point. By simultaneously incorporating all the adjustments, the proper revenue requirement can be calculated.

Table GKW-R-1
Atmos Energy Corporation - Kentucky Division
Summary of Company Rebuttal Positions
Case No. 2024-00276
Test Year Ended March 31, 2026
$ Millions

	Rebuttal Position	Rebuttal Witness	Deficiency Amount
Atmos Requested Base Revenue Increase			$ 33.001
OAG Rate Base Recommendations			
Reduce Asset NOL ADIT to Reflect Updated Balances though FYE 2024	Accept	Multer	
Reduce Asset NOL ADIT to Reflect Allocated Share of SSU Division Amount	Accept	Multer	
Reduce Asset NOL ADIT to Reflect Only Book/Tax Depreciation Temporary Differences	Reject	Multer	
Subtract Vendor Supplied Portion of Construction Expenditures	Reject	Christian	
CWC - Adjustment 1 - Remove All Non-Cash Expenses	Reject	Christian	
CWC - Adjustment 2 - Correct O&M, Non-Labor Expense Lag Days	Accept	Christian	
OAG Operating Income Recommendations			
Reduce Payroll Expense and Related Payroll Taxes Expense	Reject	Waller	
Reduce Benefits Expense for Filing Error	Accept	Waller	
Reduce Ad Valorem Expense	Modify	Waller	
Remove 50% of Directors and Officers Insurance Expense to Share with Shareholders	Reject	Waller	
Remove 50% of Investor Relations Expense to Share with Shareholders	Reject	Waller	
Remove American Gas Association and Kentucky Chamber of Commerce Dues	Reject	Waller	
OAG Rate of Return Recommendations			
Reflect Changes in Capital Structure (52.5% Equity and 47.5% Debt)	Reject	Christian/D'Ascendis	
Reflect Return on Equity of 9.40%	Reject	D'Ascendis	
OAG Recommended Atmos-KY Composite Allocation Factor Update			
Reduction Due to FYE 2024 Composite Allocation Factor Update	Accept	Waller	
Total Impact of Rebuttal Positions Included in Exhibit GKW-R-1			$ (4.912)
Revenue Requirement Deficiency in Exhibit GKW-R-1			$ 28.089

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.

Q. ARE THERE AREAS OF AGREEMENT BETWEEN THE OAG AND THE COMPANY?

A. Yes. In reviewing the testimony of the OAG's witnesses, I note that there are several areas where the OAG and the Company are aligned and have no disagreement, including:

- **Revenue at Present Rates, Depreciation Rates, Class Cost of Service** - OAG proposed no adjustments to the Company's revenue at present rates (Company witness Troup), depreciation rates (Allis), or class cost of service (Raab).
- **Forecasted Capital Expenditures and Net Plant in Service –** The OAG made no recommendations to change the level of plant investment that the Company included in the forecasted test year ended March 31, 2026 ("Test Period").
- **Operating Income Items Other Than Noted by OAG Witness Futral –** As noted in my direct testimony, the methods that I used to determine the Company's revenue requirement in this Case are consistent with the Company's approach in prior cases before this Commission while recognizing and honoring the Commission's findings in the final Orders of Case Nos. 2017-00349, 2018-00281, and 2021-00214. As a result, Mr. Futral proposed only six operating income adjustments, which is a relatively small number given the

scope and complexity of the Company's forecast. Of his six proposed adjustments, I accept one (which the Company acknowledged in discovery) and rebut five in my testimony, including one for which I will respectfully request the Commission to reconsider its prior ruling.

- **Depreciation Regulatory Liability** - The Company proposed, and the OAG agrees that the remaining Depreciation Regulatory Liability discussed on pages 36-37 of my Direct Testimony should be returned over a three-year period beginning with the implementation of rates in this case.
- **Excess Deferred Income Tax Liability ("EDITL") Balance and Amortization** – Witnesses for the OAG made no adjustments to the Company's proposed updated amortization of the protected portion of its EDITL, the expiration of its unprotected EDITL, nor the proposal to refund the final two months' unprotected EDITL amortization to customers via a one-time bill credit should it be necessary depending on the effective date of new rates resulting from this proceeding. As of the date of this testimony, the Company believes that the proposed refund will likely be unnecessary.
- **Rate Case Expenses** - Witnesses for the OAG made no adjustments to the Company's proposed amount of rate case expense for this proceeding nor the proposed three-year amortization period.
- **Cloud Computing Costs –** Witnesses for the OAG made no arguments in opposition to the Company's proposed treatment of cloud computing costs discussed in the direct testimony of Company witness Ms. Emily Wiebe.

Q. ARE THERE OTHER ADJUSTMENTS THAT THE COMPANY HAS MADE TO ITS CASE THAT ARE MADE AS A RESULT OF THE OAG'S CASE?

A. Yes, as reflected in the summary table above, the Company has updated its revenue requirement and resulting revenue deficiency in agreement with and in response to OAG testimony for the following adjustments proposed by OAG witnesses:

- **NOLC DTA Adjustment 1** proposed by OAG witness Mr. Lane Kollen and discussed in the rebuttal testimony of Mr. Multer.
- **NOLC DTA Adjustment 2** proposed by Mr. Kollen and discussed in the rebuttal testimony of Mr. Multer.
- **CWC Adjustment 2** proposed by Mr. Kollen and discussed in the rebuttal testimony of Mr. Christian.
- **Adjustment to Benefits Expense**- proposed by Mr. Futral, acknowledged by the Company in discovery, and discussed later in my rebuttal testimony.
- **Adjustment to Update to Allocation Factors**- proposed by Mr. Futral and discussed later in my rebuttal testimony.

Q. WHAT IS THE COMPANY'S RESULTING REVENUE REQUIREMENT DEFICIENCY RESULTING FROM THESE AREAS OF AGREEMENT AND THE REBUTTAL POSITIONS OF THE COMPANY'S WITNESSES?

A. As reflected in Exhibit GKW-R-1 and the summary table above, the Company's updated base rate increase request is $28.089 million which is $4.912 million lower than its initial request of $33.001 million.

IV. <u>OPERATING INCOME ADJUSTMENTS</u>

Q. PLEASE SUMMARIZE YOUR REBUTTAL OF MR. FUTRAL'S OPERATING INCOME ADJUSTMENTS.

A. With regards to:

- **Payroll Expense and Related Payroll Taxes**- I recommend that the Commission reject Mr. Futral's recommendation and accept the Company's originally filed level of payroll expense and related payroll taxes.
- **Benefits Expense**- I accept Mr. Futral's recommendation as the Company acknowledged the appropriateness of the adjustment during discovery.
- **Ad Valorem Tax Expense**- I recommend that the Commission reject Mr. Futral's recommendation and accept my revised forecast for ad valorem tax expense as discussed later in my testimony.
- **Disallowance of 50% of D&O Insurance Expense**- I recommend that the Commission reject Mr. Futral's recommendation for three primary reasons: 1) the expense is prudent and necessary to provide natural gas service to customers, 2) the Commission has recently found that the expense is appropriate and reasonable for inclusion in cost of service, and 3) the OAG is inconsistent in its recommendation for inclusion/disallowance across recent cases involving peer utilities in recent proceedings before the Commission.
- **Disallowance of 50% of Investor Relations Expense**- I recommend that the Commission reject Mr. Futral's recommendation for three primary reasons: 1) the expense is prudent and necessary to provide natural gas service to customers, 2) the Commission has recently found that the expense is

appropriate and reasonable for inclusion in cost of service, and 3) the OAG is inconsistent in its recommendation for inclusion/disallowance across recent cases involving peer utilities in recent proceedings before the Commission.

- **American Gas Association ("AGA") and Kentucky Chamber of Commerce Dues-** I recommend that the Commission reject Mr. Futral's recommendation and accept the Company's originally filed level of dues for the two organizations in question. I acknowledge that the Commission removed these expenses from recovery in the Company's most recent general case and respectfully ask the Commission to reconsider those findings in this case in light of the information provided below.

A. Payroll

Q. DO YOU AGREE WITH MR. FUTRAL'S RECOMMENDED ADJUSTMENT FOR PAYROLL EXPENSE AND RELATED PAYROLL TAXES EXPENSE?

A. No.

Q. PLEASE SUMMARIZE MR. FUTRAL'S ADJUSTMENT.

A. Mr. Futral abandons the Company's labor expense forecast and instead depends on actual FY24 results as the basis for his recommendation. He escalates the FY24 actual amount to account for average merit increases that have or will impact labor expense from FY24 through the Test Period and makes a commensurate adjustment to payroll tax expense. No other variables or data points are considered in the formation of his recommendation.

Q. WHY IS MR. FUTRAL'S ADJUSTMENT PROBLEMATIC?

A. Mr. Futral's adjustment fails to consider labor related variances that occurred in FY24 that are not expected to be repeated in FY25. Furthermore, I will demonstrate that, while the Company did budget a full complement of employees for FY25, he failed to acknowledge budgeted attrition in his testimony and the vacancies that he cited are offset with several new positions.

Q. DID THE COMPANY HAVE A LABOR CAPITALIZATION RATE VARIANCE IN FY24?

A. Yes. The actual labor capitalization rate for FY24 for Kentucky direct employees was 59.7% compared to a budgeted capitalization rate of 56.1%. Because of this, the Kentucky division's labor expense was $538,225 lower than it would have been had the labor capitalization rate been on budget as shown in Table GKW-R-2 below.

Q. WHAT ARE SOME REASONS THAT CAPITALIZATION RATE MIGHT BE HIGHER THAN BUDGET?

A. There are many factors that can affect the level of capital work performed relative to expense work. Ultimately, Company labor reacts to the needs of the system over the course of any given year and the labor capitalization rate that results is a function of the actual work performed. Weather, unplanned projects and repairs, and other unpredictable events can and do affect the types of work performed and thus the labor capitalization rate.

Q. ARE THESE TYPES OF ISSUES ANTICIPATED TO RECUR IN 2025 AND BEYOND?

A. No. The budget reflects the best information available at the time it is prepared. Individual cost center owners who have the best knowledge of their systems budget individual employee labor capitalization rates based on anticipated needs. Thus, once the budget is consolidated, it reflects the best information available and the expertise of front-line supervisors who will be held accountable for managing to the budget they prepare. For this reason, the Company's budget is the best indicator of the level of cost that the Company expects to incur and the reason I used it as the basis for formulating the Test Period forecast in this case.

Q. IS THE BUDGETED CAPITALIZATION RATE FOR FY25 SIMILAR TO THE FY24 BUDGET?

A. Yes. The budgeted capitalization rate for Kentucky direct employees is 56.9% for FY25 (which is the basis for the Test Period forecast) versus 56.1% for FY24. Thus, if the capitalization rate for FY25 remains on budget, labor expense will be higher in FY25 as compared to FY24 actuals when the capitalization rate was 59.7%. For this reason, it is appropriate to adjust Mr. Futral's recommended labor expenses to account for this variance.

Q. ARE THERE HEADCOUNT VARIANCES THAT SHOULD BE CONSIDERED IN FORMULATING THE PROPER FORECAST FOR TEST PERIOD LABOR EXPENSE?

A. Yes. As Mr. Futral points out in his testimony, the Company budgeted a full complement of employees despite evidence that it experiences some level of open positions on a regular basis[1]. However, the Company has added new positions (offset by a reduction in contract labor expense as discussed further below) that effectively offset the attrition that Mr. Futral identifies.

Q. PLEASE DESCRIBE THE COMPANY'S INITIATIVE TO CONDUCT AN INCREASING AMOUNT OF LINE LOCATING IN-HOUSE.

A. The Company has hired seven new line locators as full-time employees to conduct line locating tasks and enhance damage prevention efforts. All seven of these positions were filled as of the beginning of FY25. In addition, the Company has hired two new Compliance Technicians to meet the increasing needs of the system in this area and they were also in place at the beginning of the fiscal year.

Q. DID THE COMPANY OFFSET THE EXPENSE OF THESE NEW POSITIONS?

A. Yes. In preparing the FY25 budget, the Company reduced the amount of contracted line locating expense by $600,000, substantially offsetting the cost of the new line locating positions.

Q. DOES MR. FUTRAL'S APPROACH CAPTURE VACANCIES THAT EXISTED IN FY24?

A. Yes. Because Mr. Futral relies on actual FY24 results for the basis of his recommendation, he effectively captures the impact of any vacancies that occurred over the course of FY24. However, as I explained above, the Company effectively offset that identified attrition with new positions.

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[1] As identified in the response to OAG Request 2-02, the Company did budget approximately $204,000 of attrition allocable to Kentucky in the form of negative labor expense which is included in the Company's Test Period forecast.

Q. HOW SHOULD THAT BE VIEWED IN THE CONTEXT OF FORMULATING A PROPER LABOR EXPENSE FORECAST?

A. Even if Mr. Futral's arguments regarding attrition are found to be persuasive, the reality is that the Company's Test Period forecast includes nine new positions that effectively result in headcount levels remaining flat from FY24 if existing attrition identified at the end of FY24 is considered.

Q. CAN YOU RECONCILE MR. FUTRAL'S RECOMMENDATION WITH THE COMPANY'S TEST PERIOD FORECAST?

A. Yes. Table GKW-R-2 below adjusts Mr. Futral's recommendation for the known and measurable items I have discussed in my testimony. As shown, the difference between Mr. Futral's adjusted recommendation and the Company's as-filed Test Period forecast is immaterial.

Table GKW-R-2

Payroll Expense Reconciliation	**Amount**	
OAG proposed labor expense for the Test Period	$ 13,089,963	
Plus value of cap rate variance of FY24 actuals vs budget	538,225	
Plus payroll expense for 7 new Line Locators	335,840	
Plus payroll expense for 2 new Compliance Techs	114,122	
OAG proposal adjusted for known and measurables	$ 14,078,151	(a)
Company's as-filed labor expense	$ 14,070,026	(b)
(a) – (b)	$ 8,125	

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission reject Mr. Futral's recommendation and accept the Company's forecast as originally filed.

B. Benefits

Q. DO YOU AGREE WITH MR. FUTRAL'S RECOMMENDED ADJUSTMENT FOR BENEFITS EXPENSE?

A. Yes. I accept Mr. Futral's recommendation as the Company acknowledged the appropriateness of the adjustment during discovery.

C. Ad Valorem

Q. DO YOU AGREE WITH MR. FUTRAL'S RECOMMENDED ADJUSTMENT FOR AD VALOREM TAX EXPENSE?

A. No.

Q. DOES THE COMPANY HAVE A REVISED ESTIMATE OF 2024 TAX EXPENSE THAT IS APPROPRIATE TO USE AS THE STARTING POINT FOR YOUR ANALYSIS?

A. Yes. Exhibit GKW-R-2 is the 2024 state tax bill received from the Kentucky Department of Revenue on February 18, 2025. The total due is $1,075,778. Using the effective tax rate implied by that amount, the Company has estimated its total ad valorem tax expense for 2024 as follows in Table GKW-R-3:

Table GKW-R-3
Estimated 2024 Kentucky State and Local Taxes

Property Class	Tax Rate Per $100	Noticed Value	State Tax Due
Real Estate	0.109	$ 647,451,382	$ 705,722
Tangible Property	0.45	79,415,375	357,369
Business Inventory	0.05	25,373,751	12,687
Total State Taxes		$ 752,240,508	$ 1,075,778
Local Taxes	Noticed Value	Tax Rate Per $100	Est. Local Taxes
	$ 752,240,508	1.109857369	$ 8,348,797
		Total Est State & Local Taxes	$ 9,424,575

Q. PLEASE EXPLAIN HOW YOU USED THE ESTIMATE IN TABLE GKW-R-3 TO DEVELOP YOUR REVISED FORECAST.

A. I used the estimate of $9,424,575 as the revised starting point for 2024 in WP C.2.3 F in Exhibit GKW-R-1 – the Company's revenue requirement model. I then followed the same approach used in my initial forecast. Specifically, I subtracted $339,931 from the starting point to recognize the amount of ad valorem recovered in Case No. 2023-00231 (the Company's PRP filing covering 2024 PRP investment). I then calculated an effective expense ratio and applied that ratio to the plant forecast for the Test Period. The result is $9,389,824.

Q. DOES MR. FUTRAL'S APPROACH RECOGNIZE GROWTH IN PLANT INVESTMENT OVER THE COURSE OF THE TEST PERIOD?

A. No. Mr. Futral's approach ignores the fact that plant investment is forecasted to grow over the course of the Test Period.

Q. DOES SIGNIFICANT UNCERTAINTY STILL EXIST SURROUNDING THE METHOD OF PROPERTY VALUATION IN KENTUCKY?

A. Yes. While the current Kentucky Department of Revenue methodology is known through 2025, the methodology is scheduled to change again beginning January 1, 2026.[2] Should that change in methodology take place from real property to tangible personal property, the Company's anticipated ad valorem expense would increase by approximately $2 million per year.

Q. GIVEN THE STATUTORY UNCERTAINTY, IS IT APPROPRIATE TO MAKE A FURTHER ADJUSTMENT TO AD VALOREM?

A. Yes. I adjusted the result of my forecast above upward by $500,000 (one-fourth of $2 million) to account for the three months of the Test Period that fall in 2026. The resulting total ad valorem expense for the Test Period is $9,889,824.

Q. WHY IS YOUR FORECAST METHODOLOGY STILL THE BEST APPROACH TO DETERMINING THE AMOUNT OF AD VALOREM EXPENSE FOR THE TEST PERIOD?

A. The approach is sound because it accounts for growing plant investment through the Test Period and properly matches the ad valorem expense with the amount of plant investment that causes the expense to be incurred.

Q. DO YOU HAVE ANY FURTHER COMMENT REGARDING THE FORECAST FOR AD VALOREM EXPENSE?

A. Yes. The statutory uncertainty that gives merit to the additional $500,000 adjustment discussed above is exactly the type of issue that the Company's

[2] *See* KRS § 132.010(3)(b).

proposed Tax Rider Tariff is intended to address. Should the Commission approve the Tax Rider Tariff, it would be appropriate to remove the $500,000 adjustment as the tariff would allow recovery of the statutory impact should it come to fruition.

D. D&O Insurance and Investor Relations

Q. DO YOU AGREE WITH MR. FUTRAL'S RECOMMENDED ADJUSTMENTS FOR D&O INSURANCE AND INVESTOR RELATIONS EXPENSE?

A. No.

Q. PLEASE SUMMARIZE MR. FUTRAL'S ADJUSTMENTS.

A. Mr. Futral recommends that 50% of D&O insurance expense and Investor Relations expense be disallowed, arguing that, because these expenses benefit shareholders, their costs should be shared between customers and shareholders.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. I recommend that the Commission reject Mr. Futral's recommendation for three primary reasons: 1) the expense is prudent and necessary to provide natural gas service to customers, 2) the Commission has recently found that the expense is appropriate and reasonable for inclusion in cost of service, and 3) the OAG is inconsistent in its recommendation for inclusion/disallowance across recent cases involving peer utilities in recent proceedings before the Commission.

Q. IS THE NECESSITY OF THESE FUNCTIONS IN DISPUTE?

A. No. In my experience I have never read a credible argument suggesting that these types of expenses are anything but absolutely necessary for an investor-owned utility to provide service to customers. The argument that certain functions benefit shareholders more than customers and therefore their costs should be borne by shareholders has always been and continues to be a false narrative. All prudent costs incurred by an investor-owned utility exist for the benefit of customers and shareholders alike. A Company's prudent cost of service is collected from its customers to cover the costs of providing utility service to them, including compensating investors for the risk they incur in financing the operation. Mr. Futral does not dispute the necessity of these functions in his testimony.

Q. HAS THE PRUDENCY OF THESE COSTS BEEN CONSIDERED BY THE COMMISSION RECENTLY?

A. Yes. In Case No. 2024-00092 involving Columbia Gas of Kentucky, and for which the Commission issued an Order just 70 days ago, the Commission found the following regarding the prudency of D&O insurance:

> "The Commission agrees with Columbia Kentucky that these expenses are legitimate business expenses that reduce the costs that would be passed on to ratepayers if Columbia Kentucky's executives were involved in litigation related to the operation of the utility. In addition, the Commission agrees with Columbia Kentucky's arguments that this insurance may reduce borrowing costs."[3]

Additionally, the Commission's findings regarding Investor Relations were as follows:

> "These expenses are legitimate business expenses that lower the cost of debt for Columbia Kentucky and the Commission agrees with Columbia Kentucky's reasoning for its inclusion in the revenue requirement."[4]

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[3] Case No, 2024-00092. Order at page 24.
[4] Id. Page 26.

The Order, in which the Commission's above findings were included, approved a settlement amongst the parties in the case that, among other things, included 100% of the costs in question in the utility's cost of service.

Q. HAVE YOU REVIEWED TESTIMONY FILED ON BEHALF OF OAG IN CASE NO. 2024-00346?

A. Yes. The case is a general rate case filed by Delta Natural Gas seeking an update to its base rates.

Q. DID ANY OAG WITNESSES MAKE RECOMMENDATIONS FOR RECOVERY OF D&O INSURANCE OR INVESTOR RELATIONS EXPENSES AT A LEVEL LESS THAN 100%?

A. No. I found no evidence that the OAG made recommendations similar to the recommendations made in this case as it relates to recovery of D&O insurance and Investor Relations expense. I can think no legitimate reason why the recovery of such expenses would be subject to different treatment for peer utilities within a given state.

E. AGA and Kentucky Chamber Dues

Q. DO YOU AGREE WITH MR. FUTRAL'S RECOMMENDED ADJUSTMENTS FOR AMERICAN GAS ASSOCIATION AND KENTUCKY CHAMBER OF COMMERCE DUES?

A. No.

Q. WHAT ADDITIONAL INFORMATION DO YOU HAVE REGARDING THE BENEFITS THAT CUSTOMERS RECEIVE FROM AGA?

A. There appear to be two underlying assumptions that raise skepticism about customer benefits from AGA. The first assumption is that the vast majority of AGA's activities are related to lobbying. The second assumption is that AGA's activities benefit its member utilities somehow to the detriment of those utilities' customers. Neither one of these assumptions is true. To provide an overview of the purpose and organizational structure of AGA, I am attaching to my rebuttal testimony Exhibit GKW-R-3, which are Comments filed by AGA in Docket No. RM22-5-000 entitled *Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses* before the Federal Energy Regulatory Commission ("FERC").

Q. DOES EXHIBIT GKW-R-3 ADDRESS THE DEFINITION OF AND PROPER ACCOUNTING FOR LOBBYING ACTIVITIES?

A. Yes. In Exhibit GKW-R-3, AGA points out that FERC has explained that the Uniform System of Accounts ("USof A") "contains accounts to record the portions of industry association dues paid by regulated entities as either operating or nonoperating in nature"[5] and further defines operating as "above the line" and nonoperating as "below the line". AGA further reiterates that:

> "[FERC] noted that Account 930.2 (Miscellaneous and general expenses), which includes the cost of labor and expenses incurred in connection with the general management of the utility not provided for elsewhere in the USofA, is considered above the line, *i.e.*, generally included in rate recovery, and covers industry association dues for company memberships. Account 426.4 (Expenditures for

[5] Exhibit GKW-R-3, page 5.

> certain civic, political and related activities), which is used for costs for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances or for the purpose of influencing the decisions of public officials, is considered below the line, *i.e.*, generally excluded from rate recovery."[6]

> "[FERC] has noted that a regulated entity can be permitted to obtain the necessary information from the industry association to make a proper allocation of the dues payment to the appropriate operating and non-operating expense accounts."[7]

AGA also points out that the USofA definition of what is included in Account 426.4 (below the line) is generally consistent with how the Internal Revenue Code and Lobbying Disclosure Act define lobbying[8] and confirms that AGA complies with the requirements of both while providing details regarding the methods used to ensure compliance, reporting requirements, and IRS and financial statement audits.[9]

Q. PLEASE SUMMARIZE KEY POINTS REGARDING THE PURPOSE AND STRUCTURE OF AGA FOUND IN EXHIBIT GKW-R-3.

A. AGA exists to fulfill the needs of the local natural gas distribution companies and thereby improve the industry's ability to better serve its customers. The following are some examples of AGA's operations and engineering activities. These activities include hundreds of initiatives to improve the safety, efficiency and productivity of member companies' engineering and operating functions:

- Technical Committees
- Technical Discussion Groups

[6] Exhibit GKW-R-3, pages 5-6
[7] Exhibit GKW-R-3, page 7
[8] Exhibit GKW-R-3, page 9
[9] Exhibit GKW-R-3, pages 10-11

- Leading Practices
- AGA's Mutual Assistance Program and Emergency Planning Resource Center
- Technical Publications
- Operations Conference and Biennial Exhibition
- Plastic Pipe Manual for Gas Services
- Best Practices Program
- SOS Program
- Stakeholder Organizations

AGA member companies benefit from their participation in industry initiatives and programs that serve to highlight practices that enhance public safety and gas system integrity. AGA provides forums that enable utility leadership to exchange information and connect with one another; additionally, committees work on publications that are educational and safety oriented. By making publications available to member companies, AGA's goal is to enable natural gas utilities to have access to the latest information affecting the industry, including lessons learned and/or good practices focused on a wide range of areas related to the provision of natural gas service. AGA also publishes whitepapers and technical notes for member use alone that provide timely and detailed data and analysis on discrete operational issues.

AGA annually conducts a wide range of forums that feature presentations, case studies, lessons learned, and good practices that are intended to advance safety, reliability, and efficiency. AGA's Executive Leadership Safety Summit brings together executives at member companies to focus on worker safety, customer safety and pipeline safety.

AGA's technical committees focus on helping natural gas utilities achieve operational excellence in delivering safe, reliable, and efficient natural gas. Other areas of support received by member companies and their customers include analysis of energy markets, financial and administrative activities (including accounting standards, insurance practices, and participation in Utilities United Against Scams), legal and communications.

For additional discussion of all the benefits supporting safe and reliable operations, please see Exhibit GKW-R-3 at pages 14-32.

Q. WHAT ADDITIONAL INFORMATION DO YOU HAVE REGARDING THE BENEFITS THAT CUSTOMERS RECEIVE FROM ATMOS ENERGY'S MEMBERSHIP IN THE KENTUCKY CHAMBER OF COMMERCE AND OTHER LOCAL CHAMBERS OF COMMERCE IN ITS SERVICE TERRITORY?

A. Chambers of Commerce are the primary organizations within a community to coordinate efforts to strengthen the economy and employment opportunities. The communities we serve are vital stakeholders in Atmos Energy, and providing support, coordination, and education to further the goals of these organizations benefits our individual customers within that community. By way of example, the stated vision of the Kentucky Chamber of Commerce is as follows: "The Kentucky Chamber of Commerce is the major catalyst, consensus builder and advocate for a thriving economic climate in the Commonwealth of Kentucky."[10] On a practical level, the goals of these organizations specifically support natural gas load growth in the area, which provides for additional revenues to offset the cost of service borne by existing Atmos Energy customers. In addition, through educational efforts that

[10] https://www.kychamber.com/about-kentucky-chamber/values-mission-vision-branding-statements

Atmos Energy undertakes with these organizations, we are able to promote safe practices regarding natural gas services and potentially reduce risks to the system such as excavation damage and inform customers regarding how to recognize and respond to a natural gas emergency.

Q. HAS THE COMPANY PROPERLY ACCOUNTED FOR AND REMOVED FROM REVENUE REQUIREMENT COSTS ASSOCIATED WITH LOBBYING ACTIVITIES CONDUCTED BY THESE ORGANIZATIONS?

A. Yes. As explained in my direct testimony,[11] and reiterated by Mr. Futral,[12] the Company properly removed costs associated with lobbying activities in this case.

Q. WHAT ARE YOU REQUESTING AND WHAT IS YOUR RECOMMENDATION?

A. I respectfully request that the Commission reconsider its previous findings on this issue in light of the additional evidence presented in my testimony. Atmos Energy and its customers receive significant benefits from the Company's membership in these organizations while properly accounting for and excluding from revenue requirement costs associated with activities that are not appropriate for recovery. I recommend that the Commission reject Mr. Futral's recommendation and allow the Company's to recover these beneficial costs as originally filed.

[11] Waller direct, page 34 lines 8-12.
[12] Futral page 20 lines 15-20.

F. Allocation Factors

Q. DO YOU AGREE WITH MR. FUTRAL'S RECOMMENDATION TO USE UPDATED ALLOCATION FACTORS?

A. Yes. The Company filed its original case using the most recently available allocation factors at the time of filing. Allocation factors for the current fiscal year are now available. The more recent allocation factors are the ones calculated using data from year-end fiscal 2024 and are currently being used by the Company to record results for fiscal year 2025. It is appropriate to use these factors for the Test Period in this case. These factors are included and used in the Company's rebuttal revenue requirement presented in Exhibit GKW-R-1.

V. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS	)	
ENERGY CORPORATION FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	**Case No. 2024-00276**
TARIFF REVISIONS; AND OTHER	)	
GENERAL RELIEF	)	

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. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Gregory K. Waller

STATE OF TEXAS

COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Gregory K. Waller on this the 5th day of March, 2025.

Notary Public

My Commission Expires: September 1, 2028

Giselle R Heroy
My Commission Expires
9/1/2028
Notary ID130804842

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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)	8.90%	48.90%	4.35%	9.13%	49.97%	4.56%
3	Customer Support (Div 012)	10.86%	48.90%	5.31%	10.90%	49.46%	5.39%
4	**Kentucky/Mid-States**						
5	Mid-States General Office (Div 091)	100%	48.90%	48.90%	100%	49.97%	49.97%
6							
7							
8	**Greenville Avenue Data Center**			1.50%			1.50%
9	**Charles K. Vaughan Center**			2.98%			2.98%
10	**AEAM**			5.59%			5.59%
11	**ALGN**			3.60%			
12							
13	**Kentucky Composite Tax**			24.95%			
14							
15	**Rate of Return on Equity**			10.95%			
16							
17	**STDRATE**			17.14%			
18							
19	**LTDRATE**			4.11%			

Table GKW-R-1
Atmos Energy Corporation - Kentucky Division
Summary of Company Rebuttal Positions
Case No. 2024-00276
Test Year Ended March 31, 2026
$ Millions

	Rebuttal Position	Rebuttal Witness	Deficiency Amount
Atmos Requested Base Revenue Increase			$ 33.001
OAG Rate Base Recommendations			
Reduce Asset NOL ADIT to Reflect Updated Balances though FYE 2024	Accept	Multer	
Reduce Asset NOL ADIT to Reflect Allocated Share of SSU Division Amount	Accept	Multer	
Reduce Asset NOL ADIT to Reflect Only Book/Tax Depreciation Temporary Differei	Reject	Multer	
Subtract Vendor Supplied Portion of Construction Expenditures	Reject	Christian	
CWC - Adjustment 1 - Remove All Non-Cash Expenses	Reject	Christian	
CWC - Adjustment 2 - Correct O&M, Non-Labor Expense Lag Days	Accept	Christian	
OAG Operating Income Recommendations			
Reduce Payroll Expense and Related Payroll Taxes Expense	Reject	Waller	
Reduce Benefits Expense for Filing Error	Accept	Waller	
Reduce Ad Valorem Expense	Modify	Waller	
Remove 50% of Directors and Officers Insurance Expense to Share with Shareholders	Reject	Waller	
Remove 50% of Investor Relations Expense to Share with Shareholders	Reject	Waller	
Remove American Gas Association and Kentucky Chamber of Commerce Dues	Reject	Waller	
OAG Rate of Return Recommendations			
Reflect Changes in Capital Structure (52.5% Equity and 47.5% Debt)	Reject	Christian/D'Ascendis	
Reflect Return on Equity of 9.40%	Reject	D'Ascendis	
OAG Recommended Atmos-KY Composite Allocation Factor Update			
Reduction Due to FYE 2024 Composite Allocation Factor Update	Accept	Waller	
Total Impact of Rebuttal Positions Included in Exhibit GKW-R-1			$ (4.912)
Revenue Requirement Deficiency in Exhibit GKW-R-1			$ 28.089

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Overall Financial Summary
Forecasted Test Period: Twelve Months Ended March 31, 2026

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

FR 16(8)(a)
Schedule A
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	$ 618,389,716	$ 623,012,457
2	Adjusted Operating Income	C-1	$ 29,095,760	$ 29,108,137
3	Earned Rate of Return (line 2 divided by line 1)	J-1.1	4.71%	4.67%
4	Required Rate of Return	J-1	8.24%	8.30%
5	Required Operating Income (line 1 times line 4)	C-1	$ 50,955,313	$ 51,710,034
6	Operating Income Deficiency (line 5 minus line 2)	C-1	$ 21,859,553	$ 22,601,897
7	Gross Revenue Conversion Factor	H	1.34802	1.34802
8	**Revenue Deficiency (line 6 times line 7)**	C-1	**$ 29,467,115**	**$ 30,467,809**
9	Rate Strike Difference			(140)
10	Amortization of Excess ADIT	WP B.5 B1, WP B.5 F1	(8,674,414)	(189,998)
11	**Subtotal (line 8 plus line 9 plus line 10)**		**$ 20,792,701**	**$ 30,277,671**
12	Amortization of COS and Depreciation Reserves	F-12		(2,188,517)
13	**Revenue Increase Requested**	C-1		**$ 28,089,154**
14	Adjusted Operating Revenues	C-1		$ 187,822,013
15	**Revenue Requirements (line 12 plus line 13)**	C-1		**$ 215,911,167**

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

FR 16(8)(b) SCHEDULE B

Rate Base

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Rate Base Summary
Base Period: Twelve Months Ended December 31, 2024

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

Line No.	Rate Base Component	Supporting Schedule Reference	Base Period Ending Balance	Base Period 13 Month Average
1	Plant in Service	B-2 B	$ 931,028,844	$ 913,547,894
2	Construction Work in Progress	B-2 B	-	0
3	Accumulated Depreciation and Amortization	B-3 B	(204,757,751)	(196,963,786)
4	Property Plant and Equipment, Net (Sum line 1 Thru 3)		$ 726,271,093	$ 716,584,108
5	Cash Working Capital Allowance	B-4.2 B	$ (2,306,187)	$ (2,306,187)
6	Other Working Capital Allowances (Inventory)	B-4.1 B	14,639,447	17,822,952
7	Customer Advances For Construction	B-6 B	(736,136)	(736,136)
8	Regulatory Assets / Liabilities*	WP B-5 B1; F-6	(7,387,966)	(11,725,173)
9	Deferred Income Taxes and Investment Tax Credits	B-5 B	(103,958,377)	(101,249,847)
10	Rate Base (Sum line 4 Thru 8)		$ 626,521,874	$ 618,389,716

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Rate Base Summary
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:______Base Period__X___Forecasted Period — FR 16(8)(b)1
Type of Filing:___X____Original________Updated ________Revised — Schedule B-1
Workpaper Reference No(s). — Witness: Waller

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	$ 963,981,103		$ 950,194,538
2	Construction Work in Progress	B-2 F	0		0
3	Accumulated Depreciation and Amortization	B-3 F	(224,697,462)		(216,597,286)
4	Property Plant and Equipment, Net (Sum Line 1 Thru 3)		$ 739,283,641		$ 733,597,252
5	Cash Working Capital Allowance	B-4.2 F	$ (768,634)		$ (768,634)
6	Other Working Capital Allowances (Inventory & Prepaids)	B-4.1 F	(4,275,119)		9,705,173
7	Customer Advances For Construction	B-6 F	(736,136)		(736,136)
8	Regulatory Assets / Liabilities	WP B-5 F1; F-6	(3,625,792)		(3,720,791)
9	Deferred Income Taxes and Investment Tax Credits	B-5 F	(109,322,014)	*	(115,064,407)
10	Rate Base (Sum Line 4 Thru 8)		$ 620,555,945		$ 623,012,457

**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.*

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Plant in Service by Accounts and SubAccounts
Base Period: Twelve Months Ended December 31, 2024

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	12/31/2024 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	$ -	$ 8,330	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	223,508	-	223,508	100%	100%	223,508	201,894	100%	100%	201,894
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	10,922,679	-	10,922,679	100%	100%	10,922,679	9,800,109	100%	100%	9,800,109
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	667,359	-	667,359	100%	100%	667,359	667,359	100%	100%	667,359
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	18,065,905	-	18,065,905	100%	100%	18,065,905	9,788,007	100%	100%	9,788,007
30	35500	Meas & Reg. Equipment	273,084	-	273,084	100%	100%	273,084	273,084	100%	100%	273,084
31	35600	Purification Equipment	1,327,498	-	1,327,498	100%	100%	1,327,498	1,327,498	100%	100%	1,327,498
32												
33		Total Storage Plant	$ 35,936,984	$ -	$ 35,936,984			$ 35,936,984	$ 26,514,902			$ 26,514,902

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Plant in Service by Accounts and SubAccounts
Base Period: Twelve Months Ended December 31, 2024

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	12/31/2024 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	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	397,833	-	397,833	100%	100%	397,833	169,795	100%	100%	169,795
39	36603	Other Structues	60,826	-	60,826	100%	100%	60,826	60,826	100%	100%	60,826
40	36700	Mains Cathodic Protection	47,233	-	47,233	100%	100%	47,233	47,233	100%	100%	47,233
41	36701	Mains - Steel	27,826,921	-	27,826,921	100%	100%	27,826,921	27,826,921	100%	100%	27,826,921
42	36703	Mains - Anodes	11,134	-	11,134	100%	100%	11,134	11,134	100%	100%	11,134
43	36900	Meas. & Reg. Equipment	1,999,587	-	1,999,587	100%	100%	1,999,587	1,999,587	100%	100%	1,999,587
44	36901	Meas. & Reg. Equipment	2,269,499	-	2,269,499	100%	100%	2,269,499	2,269,499	100%	100%	2,269,499
45												
46		Total Transmission Plant	$ 33,507,777	$ -	$ 33,507,777			$ 33,507,777	$ 33,279,738			$ 33,279,738
47												
48		Distribution Plant										
49	37400	Land & Land Rights	$ 613,356	$ -	$ 613,356	100%	100%	$ 613,356	$ 556,456	100%	100%	$ 556,456
50	37401	Land	428,640	-	428,640	100%	100%	428,640	428,640	100%	100%	428,640
51	37402	Land Rights	4,157,536	-	4,157,536	100%	100%	4,157,536	4,157,210	100%	100%	4,157,210
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	3,418,283	-	3,418,283	100%	100%	3,418,283	3,367,097	100%	100%	3,367,097
58	37601	Mains - Steel	227,689,040	-	227,689,040	100%	100%	227,689,040	227,670,623	100%	100%	227,670,623
59	37602	Mains - Plastic	219,036,210	-	219,036,210	100%	100%	219,036,210	216,393,024	100%	100%	216,393,024
60	37603	Mains - Anodes	3,411,519	-	3,411,519	100%	100%	3,411,519	3,312,665	100%	100%	3,312,665
61	37604	Mains - Leak Clamps	6,789,879	-	6,789,879	100%	100%	6,789,879	7,033,995	100%	100%	7,033,995
62	37800	Meas & Reg. Sta. Equip - General	25,444,608	-	25,444,608	100%	100%	25,444,608	25,336,147	100%	100%	25,336,147
63	37900	Meas & Reg. Sta. Equip - City Gate	7,518,545	-	7,518,545	100%	100%	7,518,545	7,518,371	100%	100%	7,518,371
64	37905	Meas & Reg. Sta. Equipment T.b.	1,718,293	-	1,718,293	100%	100%	1,718,293	1,718,293	100%	100%	1,718,293
65	38000	Services	190,318,910	-	190,318,910	100%	100%	190,318,910	187,933,308	100%	100%	187,933,308
66	38100	Meters	52,498,700	-	52,498,700	100%	100%	52,498,700	51,205,440	100%	100%	51,205,440
67	38200	Meter Installaitons	61,444,680	-	61,444,680	100%	100%	61,444,680	61,347,325	100%	100%	61,347,325
68	38300	House Regulators	3,974,497	-	3,974,497	100%	100%	3,974,497	3,862,760	100%	100%	3,862,760
69	38400	House Reg. Installations	378,094	-	378,094	100%	100%	378,094	370,820	100%	100%	370,820
70	38500	Ind. Meas. & Reg. Sta. Equipment	5,725,878	-	5,725,878	100%	100%	5,725,878	5,680,079	100%	100%	5,680,079
71												
72		Total Distribution Plant	$ 815,055,707	$ -	$ 815,055,707			$ 815,055,707	$ 808,381,290			$ 808,381,290

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Plant in Service by Accounts and SubAccounts
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Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	**12/31/2024** 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	100%	100%	$ 1,211,697	$ 1,211,697	100%	100%	$ 1,211,697
76	39000	Structures & Improvements	9,137,528	-	9,137,528	100%	100%	9,137,528	9,106,388	100%	100%	9,106,388
77	39002	Structures-Brick	173,115	-	173,115	100%	100%	173,115	173,115	100%	100%	173,115
78	39003	Improvements	876,634	-	876,634	100%	100%	876,634	876,634	100%	100%	876,634
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	1,267,195	-	1,267,195	100%	100%	1,267,195	1,267,195	100%	100%	1,267,195
81	39100	Office Furniture & Equipment	1,816,939	-	1,816,939	100%	100%	1,816,939	1,814,329	100%	100%	1,814,329
82	39103	Office Machines	-	-	-	100%	100%	-	-	100%	100%	-
83	39200	Transportation Equipment	180,749	-	180,749	100%	100%	180,749	180,749	100%	100%	180,749
84	39202	Trailers	36,588	-	36,588	100%	100%	36,588	36,588	100%	100%	36,588
85	39400	Tools, Shop & Garage Equipment	6,528,040	-	6,528,040	100%	100%	6,528,040	6,403,654	100%	100%	6,403,654
86	39603	Ditchers	-	-	-	100%	100%	-	-	100%	100%	-
87	39604	Backhoes	-	-	-	100%	100%	-	-	100%	100%	-
88	39605	Welders	-	-	-	100%	100%	-	-	100%	100%	-
89	39700	Communication Equipment	433,938	-	433,938	100%	100%	433,938	429,301	100%	100%	429,301
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	2,907,356	-	2,907,356	100%	100%	2,907,356	2,695,722	100%	100%	2,695,722
94	39901	Servers Hardware	21,425	-	21,425	100%	100%	21,425	21,425	100%	100%	21,425
95	39902	Servers Software	-	-	-	100%	100%	-	-	100%	100%	-
96	39903	Other Tangible Property - Network - H/W	-	-	-	100%	100%	-	-	100%	100%	-
97	39906	Other Tang. Property - PC Hardware	530,662	-	530,662	100%	100%	530,662	609,561	100%	100%	609,561
98	39907	Other Tang. Property - PC Software	-	-	-	100%	100%	-	-	100%	100%	-
99	39908	Other Tang. Property - Mainframe S/W	-	-	-	100%	100%	-	-	100%	100%	-
100												
101		Total General Plant	$ 25,134,821	$ -	$ 25,134,821			$ 25,134,821	$ 24,839,314			$ 24,839,314
102												
103		Total Plant (Div 9)	$ 909,763,471	$ -	$ 909,763,471			$ 909,763,471	$ 893,143,427			$ 893,143,427
104												
105												

Atmos Energy Corporation, Kentucky/Mid-States Division
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Workpaper Reference No(s).

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Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	**12/31/2024** 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%	49.97%	$ 92,599	$ 185,309	100%	49.97%	92,599
111	30300	Misc Intangible Plant	1,109,552	-	1,109,552	100%	49.97%	554,443	1,109,552	100%	49.97%	554,443
112												
113		Total Intangible Plant	$ 1,294,861	$ -	$ 1,294,861			$ 647,042	$ 1,294,861			$ 647,042
114												
115		Distribution Plant										
116	37400	Land & Land Rights	$ -	$ -	$ -	100%	49.97%	$ -	$ -	100%	49.97%	$ -
117	35010	Land	-	-	-	100%	49.97%	-	-	100%	49.97%	-
118	37402	Land Rights	-	-	-	100%	49.97%	-	-	100%	49.97%	-
119	37403	Land Other	-	-	-	100%	49.97%	-	-	100%	49.97%	-
120	36602	Structures & Improvements	-	-	-	100%	49.97%	-	-	100%	49.97%	-
121	37402	Land Rights	-	-	-	100%	49.97%	-	-	100%	49.97%	-
122	37501	Structures & Improvements T.B.	-	-	-	100%	49.97%	-	-	100%	49.97%	-
123	37503	Improvements	-	-	-	100%	49.97%	-	-	100%	49.97%	-
124	36700	Mains Cathodic Protection	-	-	-	100%	49.97%	-	-	100%	49.97%	-
125	36701	Mains - Steel	-	-	-	100%	49.97%	-	-	100%	49.97%	-
126	37602	Mains - Plastic	-	-	-	100%	49.97%	-	-	100%	49.97%	-
127	37800	Meas & Reg. Sta. Equip - General	-	-	-	100%	49.97%	-	-	100%	49.97%	-
128	37900	Meas & Reg. Sta. Equip - City Gate	-	-	-	100%	49.97%	-	-	100%	49.97%	-
129	37905	Meas & Reg. Sta. Equipment T.b.	-	-	-	100%	49.97%	-	-	100%	49.97%	-
130	38000	Services	-	-	-	100%	49.97%	-	-	100%	49.97%	-
131	38100	Meters	-	-	-	100%	49.97%	-	-	100%	49.97%	-
132	38200	Meter Installaitons	-	-	-	100%	49.97%	-	-	100%	49.97%	-
133	38300	House Regulators	-	-	-	100%	49.97%	-	-	100%	49.97%	-
134	38400	House Reg. Installations	-	-	-	100%	49.97%	-	-	100%	49.97%	-
135	38500	Ind. Meas. & Reg. Sta. Equipment	-	-	-	100%	49.97%	-	-	100%	49.97%	-
136	38600	Other Prop. On Cust. Prem	-	-	-	100%	49.97%	-	-	100%	49.97%	-
137												
138		Total Distribution Plant	$ -	$ -	$ -			$ -	$ -			$ -

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Workpaper Reference No(s).

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Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12/31/2024 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%	49.97%	89,615	$ 179,339	100%	49.97%	89,615
142	39004	Air Conditioning Equipment	15,384	-	15,384	100%	49.97%	7,687	15,384	100%	49.97%	7,687
143	39009	Improvement to leased Premises	38,834	-	38,834	100%	49.97%	19,405	38,834	100%	49.97%	19,405
144	39100	Office Furniture & Equipment	26,928	-	26,928	100%	49.97%	13,456	26,928	100%	49.97%	13,456
145	39101	Office Furniture And	-	-	-	100%	49.97%	-	-	100%	49.97%	-
146	39103	Office Machines	-	-	-	100%	49.97%	-	-	100%	49.97%	-
147	39200	Transportation Equipment	4,110	-	4,110	100%	49.97%	2,054	9,458	100%	49.97%	4,726
148	39300	Stores Equipment	-	-	-	100%	49.97%	-	-	100%	49.97%	-
149	39400	Tools, Shop & Garage Equipment	110,227	-	110,227	100%	49.97%	55,081	110,227	100%	49.97%	55,081
150	39600	Power Operated Equipment	9,479	-	9,479	100%	49.97%	4,736	9,479	100%	49.97%	4,736
151	39700	Communication Equipment	-	-	-	100%	49.97%	-	-	100%	49.97%	-
152	39701	Communication Equip.	-	-	-	100%	49.97%	-	-	100%	49.97%	-
153	39702	Communication Equip.	-	-	-	100%	49.97%	-	-	100%	49.97%	-
154	39800	Miscellaneous Equipment	-	-	-	100%	49.97%	-	-	100%	49.97%	-
155	39900	Other Tangible Property	-	-	-	100%	49.97%	-	-	100%	49.97%	-
156	39901	Other Tangible Property - Servers - H/W	-	-	-	100%	49.97%	-	-	100%	49.97%	-
157	39902	Other Tangible Property - Servers - S/W	-	-	-	100%	49.97%	-	-	100%	49.97%	-
158	39903	Other Tangible Property - Network - H/W	28,266	-	28,266	100%	49.97%	14,125	28,266	100%	49.97%	14,125
159	39906	Other Tang. Property - PC Hardware	-	-	-	100%	49.97%	-	-	100%	49.97%	-
160	39907	Other Tang. Property - PC Software	43,522	-	43,522	100%	49.97%	21,748	43,522	100%	49.97%	21,748
161	39908	Other Tang. Property - Mainframe S/W	-	-	-	100%	49.97%	-	-	100%	49.97%	-
162												
163		Total General Plant	$ 456,088	$ -	$ 456,088			$ 227,907	$ 461,436			$ 230,580
164												
165		Total Plant (Div 91)	$ 1,750,949	$ -	$ 1,750,949			$ 874,949	$ 1,756,297			$ 877,622
166												
167												

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Line No.	Acct. No.	Account / SubAccount Titles	12/31/2024 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)
168												
169		**Shared Services General Office (Division 002)**										
170												
171		General Plant										
172	39000	Structures & Improvements	$ 5,843,860	$ -	$ 5,843,860	9.13%	49.97%	$ 266,612	$ 5,916,039	9.13%	49.97%	$ 269,905
173	39005	G-Structures & Improvements	14,884,953	-	14,884,953	100.00%	1.50%	223,846	14,884,953	100.00%	1.50%	223,846
174	39009	Improvement to leased Premises	11,855,420	-	11,855,420	9.13%	49.97%	540,875	10,800,026	9.13%	49.97%	492,725
175	39020	Struct & Improv AEAM	24,633	-	24,633	100.00%	5.59%	1,378	24,633	100.00%	5.59%	1,378
176	39029	Improv-Leased AEAM	54,743	-	54,743	100.00%	5.59%	3,061	54,743	100.00%	5.59%	3,061
177	39100	Office Furniture & Equipment	7,012,419	-	7,012,419	9.13%	49.97%	319,925	6,503,800	9.13%	49.97%	296,720
178	39102	Remittance Processing Equip	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
179	39103	Office Machines	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
180	39104	G-Office Furniture & Equip.	71,036	-	71,036	100.00%	1.50%	1,068	71,036	100.00%	1.50%	1,068
181	39120	Off Furn & Equip-AEAM	307,893	-	307,893	100.00%	5.59%	17,219	307,893	100.00%	5.59%	17,219
182	39200	Transportation Equipment	315,397	-	315,397	9.13%	49.97%	14,389	315,397	9.13%	49.97%	14,389
183	39300	Stores Equipment	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
184	39400	Tools, Shop & Garage Equipment	30,134	-	30,134	9.13%	49.97%	1,375	47,606	9.13%	49.97%	2,172
185	39420	Tools And Garage-AEAM	-	-	-	100.00%	5.59%	-	-	100.00%	5.59%	-
186	39500	Laboratory Equipment	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
187	39700	Communication Equipment	616,247	-	616,247	9.13%	49.97%	28,115	586,444	9.13%	49.97%	26,755
188	39720	Commun Equip AEAM	77,436	-	77,436	100.00%	5.59%	4,331	77,436	100.00%	5.59%	4,331
189	39800	Miscellaneous Equipment	107,931	-	107,931	9.13%	49.97%	4,924	107,931	9.13%	49.97%	4,924
190	39820	Misc Equip - AEAM	10,582	-	10,582	100.00%	5.59%	592	10,582	100.00%	5.59%	592
191	39900	Other Tangible Property	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
192	39901	Other Tangible Property - Servers - H/W	38,216,682	-	38,216,682	9.13%	49.97%	1,743,545	38,361,368	9.13%	49.97%	1,750,146
193	39902	Other Tangible Property - Servers - S/W	21,917,085	-	21,917,085	9.13%	49.97%	999,915	12,771,336	9.13%	49.97%	582,662
194	39903	Other Tangible Property - Network - H/W	4,647,457	-	4,647,457	9.13%	49.97%	212,029	4,547,943	9.13%	49.97%	207,489
195	39904	Other Tang. Property - CPU	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
196	39905	Other Tangible Property - MF - Hardware	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
197	39906	Other Tang. Property - PC Hardware	4,540,171	-	4,540,171	9.13%	49.97%	207,134	4,544,444	9.13%	49.97%	207,329
198	39907	Other Tang. Property - PC Software	82,728	-	82,728	9.13%	49.97%	3,774	82,728	9.13%	49.97%	3,774
199	39908	Other Tang. Property - Mainframe S/W	98,869,600	-	98,869,600	9.13%	49.97%	4,510,689	96,201,561	9.13%	49.97%	4,388,966
200	39909	Other Tang. Property - Application Software	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
201	39921	Servers-Hardware-AEAM	8,696,956	-	8,696,956	100.00%	5.59%	486,375	5,331,033	100.00%	5.59%	298,136
202	39922	Servers-Software-AEAM	5,425,529	-	5,425,529	100.00%	5.59%	303,421	5,425,529	100.00%	5.59%	303,421
203	39923	Network Hardware-AEAM	813,640	-	813,640	100.00%	5.59%	45,503	591,813	100.00%	5.59%	33,097
204	39924	39924-Oth Tang Prop - Gen.	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
205	39926	Pc Hardware-AEAM	146,532	-	146,532	100.00%	5.59%	8,195	146,532	100.00%	5.59%	8,195
206	39928	Application SW-AEAM	29,590,572	-	29,590,572	100.00%	5.59%	1,654,844	29,572,964	100.00%	5.59%	1,653,859
207	39931	ALGN-Servers-Hardware	297,267	-	297,267	100.00%	3.60%	10,701	297,267	100.00%	3.60%	10,701
208	39932	ALGN-Servers-Software	783,917	-	783,917	100.00%	3.60%	28,221	783,917	100.00%	3.60%	28,221
209	39938	ALGN-Application SW	21,123,037	-	21,123,037	100.00%	3.60%	760,416	21,123,037	100.00%	3.60%	760,416
210												
211		Total General Plant (Div 2)	$ 276,363,857	$ -	$ 276,363,857			$ 12,402,472	$ 259,489,990			$ 11,595,499
212												
213												
214												

Atmos Energy Corporation, Kentucky/Mid-States Division
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Schedule B-2 B
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	**12/31/2024** 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	10.90%	49.46%	$ 154,954	$ 2,874,240	10.90%	49.46%	$ 154,954
219	38910	CKV-Land & Land Rights	1,886,443	-	1,886,442.92	100.00%	2.98%	56,274	1,886,443	100.00%	2.98%	56,274
220	39000	Structures & Improvements	13,553,450	-	13,553,449.99	10.90%	49.46%	730,685	13,537,284	10.90%	49.46%	729,814
221	39009	Improvement to leased Premises	3,170,598	-	3,170,597.68	10.90%	49.46%	170,931	3,170,598	10.90%	49.46%	170,931
222	39010	CKV-Structures & Improvements	12,590,703	-	12,590,702.67	100.00%	2.98%	375,593	12,590,703	100.00%	2.98%	375,593
223	39100	Office Furniture & Equipment	2,730,258	-	2,730,257.91	10.90%	49.46%	147,192	2,730,258	10.90%	49.46%	147,192
224	39101	Office Furniture And	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
225	39102	Remittance Processing	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
226	39103	39103-Office Furn. - Copiers & Type	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
227	39110	CKV-Office Furn & Eq	810,064	-	810,063.89	100.00%	2.98%	24,165	724,073	100.00%	2.98%	21,600
228	39210	CKV-Transportation Eq	74,994	-	74,993.77	100.00%	2.98%	2,237	79,908	100.00%	2.98%	2,384
229	39410	CKV-Tools Shop Garage	689,747	-	689,746.65	100.00%	2.98%	20,576	729,333	100.00%	2.98%	21,757
230	39510	CKV-Laboratory Equip	-	-	-	100.00%	2.98%	-	-	100.00%	2.98%	-
231	39700	Communication Equipment	1,913,117	-	1,913,117.11	10.90%	49.46%	103,139	1,913,117	10.90%	49.46%	103,139
232	39710	CKV-Communication Equipment	92,838	-	92,838.24	100.00%	2.98%	2,769	92,838	100.00%	2.98%	2,769
233	39800	Miscellaneous Equipment	133,347	-	133,347.03	10.90%	49.46%	7,189	133,347	10.90%	49.46%	7,189
234	39810	CKV-Misc Equipment	652,865	-	652,864.54	100.00%	2.98%	19,476	607,526	100.00%	2.98%	18,123
235	39900	Other Tangible Property	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
236	39901	Other Tangible Property - Servers - H/W	5,650,663	-	5,650,663.14	10.90%	49.46%	304,635	5,650,663	10.90%	49.46%	304,635
237	39902	Other Tangible Property - Servers - S/W	1,824,740	-	1,824,739.91	10.90%	49.46%	98,374	1,824,740	10.90%	49.46%	98,374
238	39903	Other Tangible Property - Network - H/W	659,278	-	659,278.31	10.90%	49.46%	35,543	659,278	10.90%	49.46%	35,543
239	39906	Other Tang. Property - PC Hardware	1,673,780	-	1,673,779.59	10.90%	49.46%	90,236	1,673,780	10.90%	49.46%	90,236
240	39907	Other Tang. Property - PC Software	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
241	39908	Other Tang. Property - Mainframe S/W	104,503,554	-	104,503,554.15	10.90%	49.46%	5,633,933	103,528,616	10.90%	49.46%	5,581,373
242	39910	CKV-Other Tangible Property	217,245	-	217,244.97	100.00%	2.98%	6,481	197,683	100.00%	2.98%	5,897
243	39916	CKV-Oth Tang Prop-PC Hardware	116,342	-	116,342.47	100.00%	2.98%	3,471	116,342	100.00%	2.98%	3,471
244	39917	CKV-Oth Tang Prop-PC Software	3,299	-	3,299.04	100.00%	2.98%	98	3,299	100.00%	2.98%	98
245	39918	CKV-Oth Tang Prop-App	-	-	-	100.00%	2.98%	-	-	100.00%	2.98%	-
246	39924	Oth Tang Prop - Gen.	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
247												
248		Total General Plant (Div 12)	$ 155,821,564	$ -	$ 155,821,564			$ 7,987,952	$ 154,724,070			$ 7,931,346
249												
250												
251												
252		Total Plant (Div 009, 091, 002, 012)	$ 1,343,699,841	$ -	$ 1,343,699,841			$ 931,028,844	$ 1,309,113,784			$ 913,547,894
253												
254												

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Plant in Service by Accounts and SubAccounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	**3/31/2026** 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	$ -	$ 8,330	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	223,508	-	223,508	100%	100%	223,508	223,508	100%	100%	223,508
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	13,339,672	-	13,339,672	100%	100%	13,339,672	12,534,611	100%	100%	12,534,611
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	667,359	-	667,359	100%	100%	667,359	667,359	100%	100%	667,359
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	18,065,905	-	18,065,905	100%	100%	18,065,905	18,065,905	100%	100%	18,065,905
30	35500	Meas & Reg. Equipment	273,084	-	273,084	100%	100%	273,084	273,084	100%	100%	273,084
31	35600	Purification Equipment	1,327,498	-	1,327,498	100%	100%	1,327,498	1,327,498	100%	100%	1,327,498
32												
33		Total Storage Plant	$ 38,353,977	$ -	$ 38,353,977			$ 38,353,977	$ 37,548,916			$ 37,548,916

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Plant in Service by Accounts and SubAccounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	**3/31/2026** 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	397,833	-	397,833	100%	100%	397,833	397,833	100%	100%	397,833
39	36603	Other Structues	60,826	-	60,826	100%	100%	60,826	60,826	100%	100%	60,826
40	36700	Mains Cathodic Protection	47,233	-	47,233	100%	100%	47,233	47,233	100%	100%	47,233
41	36701	Mains - Steel	27,826,921	-	27,826,921	100%	100%	27,826,921	27,826,921	100%	100%	27,826,921
42	36703	Mains - Anodes	11,134	-	11,134	100%	100%	11,134	11,134	100%	100%	11,134
43	36900	Meas. & Reg. Equipment	1,999,587	-	1,999,587	100%	100%	1,999,587	1,999,587	100%	100%	1,999,587
44	36901	Meas. & Reg. Equipment	2,269,499	-	2,269,499	100%	100%	2,269,499	2,269,499	100%	100%	2,269,499
45												
46		Total Transmission Plant	$ 33,507,777	$ -	$ 33,507,777			$ 33,507,777	$ 33,507,777			$ 33,507,777
47												
48		Distribution Plant										
49	37400	Land & Land Rights	$ 613,356	$ -	$ 613,355.87	100%	100%	$ 613,356	$ 613,356	100%	100%	$ 613,355.87
50	37401	Land	428,640	-	428,640	100%	100%	428,640	428,640	100%	100%	428,640
51	37402	Land Rights	4,157,536	-	4,157,536	100%	100%	4,157,536	4,157,536	100%	100%	4,157,536
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	3,418,283	-	3,418,283	100%	100%	3,418,283	3,418,283	100%	100%	3,418,283
58	37601	Mains - Steel	232,921,052	-	232,921,052	100%	100%	232,921,052	230,553,919	100%	100%	230,553,919
59	37602	Mains - Plastic	223,706,553	-	223,706,553	100%	100%	223,706,553	221,659,304	100%	100%	221,659,304
60	37603	Mains - Anodes	3,721,269	-	3,721,269	100%	100%	3,721,269	3,599,610	100%	100%	3,599,610
61	37604	Mains - Leak Clamps	6,789,879	-	6,789,879	100%	100%	6,789,879	6,789,879	100%	100%	6,789,879
62	37800	Meas & Reg. Sta. Equip - General	25,723,807	-	25,723,807	100%	100%	25,723,807	25,594,946	100%	100%	25,594,946
63	37900	Meas & Reg. Sta. Equip - City Gate	11,209,629	-	11,209,629	100%	100%	11,209,629	9,712,761	100%	100%	9,712,761
64	37905	Meas & Reg. Sta. Equipment T.b.	1,718,293	-	1,718,293	100%	100%	1,718,293	1,718,293	100%	100%	1,718,293
65	38000	Services	196,345,885	-	196,345,885	100%	100%	196,345,885	193,916,542	100%	100%	193,916,542
66	38100	Meters	58,392,985	-	58,392,985	100%	100%	58,392,985	55,920,540	100%	100%	55,920,540
67	38200	Meter Installaitons	61,980,837	-	61,980,837	100%	100%	61,980,837	61,761,518	100%	100%	61,761,518
68	38300	House Regulators	3,974,497	-	3,974,497	100%	100%	3,974,497	3,974,497	100%	100%	3,974,497
69	38400	House Reg. Installations	378,094	-	378,094	100%	100%	378,094	378,094	100%	100%	378,094
70	38500	Ind. Meas. & Reg. Sta. Equipment	5,725,878	-	5,725,878	100%	100%	5,725,878	5,725,878	100%	100%	5,725,878
71												
72		Total Distribution Plant	$ 841,695,514	$ -	$ 841,695,514			$ 841,695,514	$ 830,412,635			$ 830,412,635

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Plant in Service by Accounts and SubAccounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	3/31/2026 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	9,359,339	-	9,359,339	100%	100%	9,359,339	9,256,964	100%	100%	9,256,964
77	39002	Structures-Brick	173,115	-	173,115	100%	100%	173,115	173,115	100%	100%	173,115
78	39003	Improvements	876,634	-	876,634	100%	100%	876,634	876,634	100%	100%	876,634
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	1,267,195	-	1,267,195	100%	100%	1,267,195	1,267,195	100%	100%	1,267,195
81	39100	Office Furniture & Equipment	1,816,939	-	1,816,939	100%	100%	1,816,939	1,816,939	100%	100%	1,816,939
82	39103	Office Machines	-	-	-	100%	100%	-	-	100%	100%	-
83	39200	Transportation Equipment	180,749	-	180,749	100%	100%	180,749	180,749	100%	100%	180,749
84	39202	Trailers	36,588	-	36,588	100%	100%	36,588	36,588	100%	100%	36,588
85	39400	Tools, Shop & Garage Equipment	7,670,812	-	7,670,812	100%	100%	7,670,812	7,143,379	100%	100%	7,143,379
86	39603	Ditchers	-	-	-	100%	100%	-	-	100%	100%	-
87	39604	Backhoes	-	-	-	100%	100%	-	-	100%	100%	-
88	39605	Welders	-	-	-	100%	100%	-	-	100%	100%	-
89	39700	Communication Equipment	433,938	-	433,938	100%	100%	433,938	433,938	100%	100%	433,938
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	3,047,675	-	3,047,675	100%	100%	3,047,675	2,982,913	100%	100%	2,982,913
94	39901	Servers Hardware	21,425	-	21,425	100%	100%	21,425	21,425	100%	100%	21,425
95	39902	Servers Software	-	-	-	100%	100%	-	-	100%	100%	-
96	39903	Other Tangible Property - Network - H/W	-	-	-	100%	100%	-	-	100%	100%	-
97	39906	Other Tang. Property - PC Hardware	530,662	-	530,662	100%	100%	530,662	530,662	100%	100%	530,662
98	39907	Other Tang. Property - PC Software	-	-	-	100%	100%	-	-	100%	100%	-
99	39908	Other Tang. Property - Mainframe S/W	-	-	-	100%	100%	-	-	100%	100%	-
100												
101		Total General Plant	$ 26,639,723	$ -	$ 26,639,723			$ 26,639,723	$ 25,945,153			$ 25,945,153
102												
103		Total Plant (Div 9)	$ 940,325,173	$ -	$ 940,325,173			$ 940,325,173	$ 927,542,664			$ 927,542,664
104												
105												

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Plant in Service by Accounts and SubAccounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	3/31/2026 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%	48.90%	$ 90,616	$ 185,309	100%	48.90%	$ 90,616
111	30300	Misc Intangible Plant	1,109,552	-	1,109,552	100%	48.90%	542,571	1,109,552	100%	48.90%	542,571
112												
113		Total Intangible Plant	$ 1,294,861	$ -	$ 1,294,861			$ 633,187	$ 1,294,861			$ 633,187
114												
115		Distribution Plant										
116	37400	Land & Land Rights	$ -	$ -	$ -	100%	48.90%	$ -	$ -	100%	48.90%	$ -
117	35010	Land	-	-	-	100%	48.90%	-	-	100%	48.90%	-
118	37402	Land Rights	-	-	-	100%	48.90%	-	-	100%	48.90%	-
119	37403	Land Other	-	-	-	100%	48.90%	-	-	100%	48.90%	-
120	36602	Structures & Improvements	-	-	-	100%	48.90%	-	-	100%	48.90%	-
121	37402	Land Rights	-	-	-	100%	48.90%	-	-	100%	48.90%	-
122	37501	Structures & Improvements T.B.	-	-	-	100%	48.90%	-	-	100%	48.90%	-
123	37503	Improvements	-	-	-	100%	48.90%	-	-	100%	48.90%	-
124	36700	Mains Cathodic Protection	-	-	-	100%	48.90%	-	-	100%	48.90%	-
125	36701	Mains - Steel	-	-	-	100%	48.90%	-	-	100%	48.90%	-
126	37602	Mains - Plastic	-	-	-	100%	48.90%	-	-	100%	48.90%	-
127	37800	Meas & Reg. Sta. Equip - General	-	-	-	100%	48.90%	-	-	100%	48.90%	-
128	37900	Meas & Reg. Sta. Equip - City Gate	-	-	-	100%	48.90%	-	-	100%	48.90%	-
129	37905	Meas & Reg. Sta. Equipment T.b.	-	-	-	100%	48.90%	-	-	100%	48.90%	-
130	38000	Services	-	-	-	100%	48.90%	-	-	100%	48.90%	-
131	38100	Meters	-	-	-	100%	48.90%	-	-	100%	48.90%	-
132	38200	Meter Installaitons	-	-	-	100%	48.90%	-	-	100%	48.90%	-
133	38300	House Regulators	-	-	-	100%	48.90%	-	-	100%	48.90%	-
134	38400	House Reg. Installations	-	-	-	100%	48.90%	-	-	100%	48.90%	-
135	38500	Ind. Meas. & Reg. Sta. Equipment	-	-	-	100%	48.90%	-	-	100%	48.90%	-
136	38600	Other Prop. On Cust. Prem	-	-	-	100%	48.90%	-	-	100%	48.90%	-
137												
138		Total Distribution Plant	$ -	$ -	$ -			$ -	$ -			$ -

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Plant in Service by Accounts and SubAccounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:______Base Period__X___Forecasted Period | FR 16(8)(b)2
Type of Filing:___X____Original________Updated ________Revised | Schedule B-2 F
Workpaper Reference No(s). | Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	**3/31/2026** 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%	48.90%	$ 87,697	$ 179,339	100%	48.90%	$ 87,697
142	39004	Air Conditioning Equipment	15,384	-	15,384	100%	48.90%	7,523	15,384	100%	48.90%	7,523
143	39009	Improvement to leased Premises	38,834	-	38,834	100%	48.90%	18,990	38,834	100%	48.90%	18,990
144	39100	Office Furniture & Equipment	26,928	-	26,928	100%	48.90%	13,168	26,928	100%	48.90%	13,168
145	39101	Office Furniture And	-	-	-	100%	48.90%	-	-	100%	48.90%	-
146	39103	Office Machines	-	-	-	100%	48.90%	-	-	100%	48.90%	-
147	39200	Transportation Equipment	4,110	-	4,110	100%	48.90%	2,010	4,110	100%	48.90%	2,010
148	39300	Stores Equipment	-	-	-	100%	48.90%	-	-	100%	48.90%	-
149	39400	Tools, Shop & Garage Equipment	110,227	-	110,227	100%	48.90%	53,901	110,227	100%	48.90%	53,901
150	39600	Power Operated Equipment	9,479	-	9,479	100%	48.90%	4,635	9,479	100%	48.90%	4,635
151	39700	Communication Equipment	-	-	-	100%	48.90%	-	-	100%	48.90%	-
152	39701	Communication Equip.	-	-	-	100%	48.90%	-	-	100%	48.90%	-
153	39702	Communication Equip.	-	-	-	100%	48.90%	-	-	100%	48.90%	-
154	39800	Miscellaneous Equipment	-	-	-	100%	48.90%	-	-	100%	48.90%	-
155	39900	Other Tangible Property	-	-	-	100%	48.90%	-	-	100%	48.90%	-
156	39901	Other Tangible Property - Servers - H/W	-	-	-	100%	48.90%	-	-	100%	48.90%	-
157	39902	Other Tangible Property - Servers - S/W	-	-	-	100%	48.90%	-	-	100%	48.90%	-
158	39903	Other Tangible Property - Network - H/W	28,266	-	28,266	100%	48.90%	13,822	28,266	100%	48.90%	13,822
159	39906	Other Tang. Property - PC Hardware	-	-	-	100%	48.90%	-	-	100%	48.90%	-
160	39907	Other Tang. Property - PC Software	43,522	-	43,522	100%	48.90%	21,282	43,522	100%	48.90%	21,282
161	39908	Other Tang. Property - Mainframe S/W	-	-	-	100%	48.90%	-	-	100%	48.90%	-
162												
163		Total General Plant	$ 456,088	$ -	$ 456,088			$ 223,027	$ 456,088			$ 223,027
164												
165		Total Plant (Div 91)	$ 1,750,949	$ -	$ 1,750,949			$ 856,214	$ 1,750,949			$ 856,214
166												
167												

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Plant in Service by Accounts and SubAccounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	3/31/2026 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)
168												
169	**Shared Services General Office (Division 002)**											
170												
171		General Plant										
172	39000	Structures & Improvements	$ 5,543,564	$ -	$ 5,543,564	8.90%	48.90%	$ 241,261	$ 5,655,050	8.90%	48.90%	$ 246,113
173	39005	G-Structures & Improvements	14,884,953	-	14,884,953	100.00%	1.50%	223,846	14,884,953	100.00%	1.50%	223,846
174	39009	Improvement to leased Premises	15,287,156	-	15,287,156	8.90%	48.90%	665,312	14,013,114	8.90%	48.90%	609,865
175	39020	Struct & Improv AEAM	24,633	-	24,633	100.00%	5.59%	1,378	24,633	100.00%	5.59%	1,378
176	39029	Improv-Leased AEAM	54,743	-	54,743	100.00%	5.59%	3,061	54,743	100.00%	5.59%	3,061
177	39100	Office Furniture & Equipment	8,614,801	-	8,614,801	8.90%	48.90%	374,925	8,019,912	8.90%	48.90%	349,035
178	39102	Remittance Processing Equip	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
179	39103	Office Machines	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
180	39104	G-Office Furniture & Equip.	71,036	-	71,036	100.00%	1.50%	1,068	71,036	100.00%	1.50%	1,068
181	39120	Off Furn & Equip-AEAM	307,893	-	307,893	100.00%	5.59%	17,219	307,893	100.00%	5.59%	17,219
182	39200	Transportation Equipment	315,397	-	315,397	8.90%	48.90%	13,726	315,397	8.90%	48.90%	13,726
183	39300	Stores Equipment	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
184	39400	Tools, Shop & Garage Equipment	30,134	-	30,134	8.90%	48.90%	1,311	30,134	8.90%	48.90%	1,311
185	39420	Tools And Garage-AEAM	-	-	-	100.00%	5.59%	-	-	100.00%	5.59%	-
186	39500	Laboratory Equipment	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
187	39700	Communication Equipment	712,329	-	712,329	8.90%	48.90%	31,001	676,658	8.90%	48.90%	29,449
188	39720	Commun Equip AEAM	77,436	-	77,436	100.00%	5.59%	4,331	77,436	100.00%	5.59%	4,331
189	39800	Miscellaneous Equipment	107,931	-	107,931	8.90%	48.90%	4,697	107,931	8.90%	48.90%	4,697
190	39820	Misc Equip - AEAM	10,582	-	10,582	100.00%	5.59%	592	10,582	100.00%	5.59%	592
191	39900	Other Tangible Property	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
192	39901	Other Tangible Property - Servers - H/W	38,222,804	-	38,222,804	8.90%	48.90%	1,663,495	38,220,532	8.90%	48.90%	1,663,396
193	39902	Other Tangible Property - Servers - S/W	50,221,295	-	50,221,295	8.90%	48.90%	2,185,681	39,713,273	8.90%	48.90%	1,728,361
194	39903	Other Tangible Property - Network - H/W	5,009,315	-	5,009,315	8.90%	48.90%	218,010	4,874,974	8.90%	48.90%	212,164
195	39904	Other Tang. Property - CPU	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
196	39905	Other Tangible Property - MF - Hardware	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
197	39906	Other Tang. Property - PC Hardware	4,523,645	-	4,523,645	8.90%	48.90%	196,874	4,529,780	8.90%	48.90%	197,141
198	39907	Other Tang. Property - PC Software	82,728	-	82,728	8.90%	48.90%	3,600	82,728	8.90%	48.90%	3,600
199	39908	Other Tang. Property - Mainframe S/W	111,806,479	-	111,806,479	8.90%	48.90%	4,865,930	108,286,378	8.90%	48.90%	4,712,731
200	39909	Other Tang. Property - Application Software	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
201	39921	Servers-Hardware-AEAM	20,020,796	-	20,020,796	100.00%	5.59%	1,119,657	15,816,787	100.00%	5.59%	884,549
202	39922	Servers-Software-AEAM	5,425,529	-	5,425,529	100.00%	5.59%	303,421	5,425,529	100.00%	5.59%	303,421
203	39923	Network Hardware-AEAM	1,500,129	-	1,500,129	100.00%	5.59%	83,894	1,245,268	100.00%	5.59%	69,641
204	39924	39924-Oth Tang Prop - Gen.	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
205	39926	Pc Hardware-AEAM	146,532	-	146,532	100.00%	5.59%	8,195	146,532	100.00%	5.59%	8,195
206	39928	Application SW-AEAM	29,590,572	-	29,590,572	100.00%	5.59%	1,654,844	29,590,572	100.00%	5.59%	1,654,844
207	39931	ALGN-Servers-Hardware	297,267	-	297,267	100.00%	3.60%	10,701	297,267	100.00%	3.60%	10,701
208	39932	ALGN-Servers-Software	783,917	-	783,917	100.00%	3.60%	28,221	783,917	100.00%	3.60%	28,221
209	39938	ALGN-Application SW	21,123,037	-	21,123,037	100.00%	3.60%	760,416	21,123,037	100.00%	3.60%	760,416
210												
211		Total General Plant (Div 2)	$ 334,796,634	$ -	$ 334,796,634			$ 14,686,669	$ 314,386,046			$ 13,743,073
212												
213												

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Plant in Service by Accounts and SubAccounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	**3/31/2026** 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	10.86%	48.90%	$ 152,638	$ 2,874,240	10.86%	48.90%	$ 152,638
219	38910	CKV-Land & Land Rights	1,886,443	-	1,886,442.92	100.00%	2.98%	56,274	1,886,443	100.00%	2.98%	56,274
220	39000	Structures & Improvements	13,602,813	-	13,602,813.18	10.86%	48.90%	722,383	13,584,463	10.86%	48.90%	721,408
221	39009	Improvement to leased Premises	3,170,598	-	3,170,597.68	10.86%	48.90%	168,376	3,170,598	10.86%	48.90%	168,376
222	39010	CKV-Structures & Improvements	12,590,703	-	12,590,702.67	100.00%	2.98%	375,593	12,590,703	100.00%	2.98%	375,593
223	39100	Office Furniture & Equipment	2,730,258	-	2,730,257.91	10.86%	48.90%	144,991	2,730,258	10.86%	48.90%	144,991
224	39101	Office Furniture And	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
225	39102	Remittance Processing	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
226	39103	39103-Office Furn. - Copiers & Type	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
227	39110	CKV-Office Furn & Eq	1,080,089	-	1,080,088.78	100.00%	2.98%	32,220	979,713	100.00%	2.98%	29,226
228	39210	CKV-Transportation Eq	74,994	-	74,993.77	100.00%	2.98%	2,237	74,994	100.00%	2.98%	2,237
229	39410	CKV-Tools Shop Garage	726,197	-	726,197.35	100.00%	2.98%	21,663	712,648	100.00%	2.98%	21,259
230	39510	CKV-Laboratory Equip	-	-	-	100.00%	2.98%	-	-	100.00%	2.98%	-
231	39700	Communication Equipment	1,913,117	-	1,913,117.11	10.86%	48.90%	101,597	1,913,117	10.86%	48.90%	101,597
232	39710	CKV-Communication Equipment	92,838	-	92,838.24	100.00%	2.98%	2,769	92,838	100.00%	2.98%	2,769
233	39800	Miscellaneous Equipment	133,347	-	133,347.03	10.86%	48.90%	7,081	133,347	10.86%	48.90%	7,081
234	39810	CKV-Misc Equipment	822,381	-	822,381.33	100.00%	2.98%	24,532	759,367	100.00%	2.98%	22,653
235	39900	Other Tangible Property	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
236	39901	Other Tangible Property - Servers - H/W	5,650,663	-	5,650,663.14	10.86%	48.90%	300,081	5,650,663	10.86%	48.90%	300,081
237	39902	Other Tangible Property - Servers - S/W	1,824,740	-	1,824,739.91	10.86%	48.90%	96,904	1,824,740	10.86%	48.90%	96,904
238	39903	Other Tangible Property - Network - H/W	659,278	-	659,278.31	10.86%	48.90%	35,011	659,278	10.86%	48.90%	35,011
239	39906	Other Tang. Property - PC Hardware	1,673,780	-	1,673,779.59	10.86%	48.90%	88,887	1,673,780	10.86%	48.90%	88,887
240	39907	Other Tang. Property - PC Software	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
241	39908	Other Tang. Property - Mainframe S/W	108,594,769	-	108,594,769.09	10.86%	48.90%	5,766,969	107,593,558	10.86%	48.90%	5,713,799
242	39910	CKV-Other Tangible Property	310,800	-	310,800.39	100.00%	2.98%	9,271	276,023	100.00%	2.98%	8,234
243	39916	CKV-Oth Tang Prop-PC Hardware	116,342	-	116,342.47	100.00%	2.98%	3,471	116,342	100.00%	2.98%	3,471
244	39917	CKV-Oth Tang Prop-PC Software	3,299	-	3,299.04	100.00%	2.98%	98	3,299	100.00%	2.98%	98
245	39918	CKV-Oth Tang Prop-App	-	-	-	100.00%	2.98%	-	-	100.00%	2.98%	-
246	39924	Oth Tang Prop - Gen.	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
247												
248		Total General Plant (Div 12)	$ 160,531,690	$ -	$ 160,531,690			$ 8,113,047	$ 159,300,412			$ 8,052,587
249												
250												
251												
252		Total Plant (Div 009, 091, 002, 012)	$ 1,437,404,446	$ -	$ 1,437,404,446			$ 963,981,103	$ 1,402,980,071			$ 950,194,538
253												
254												

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Accumulated Depreciation & Amortization
Base Period: Twelve Months Ended December 31, 2024

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	**12/31/2024 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 Reser	$ -	$ -	$ -			$ -	$ -			$ -
13												
14		Storage Plant										
15	35010	Land	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
16	35020	Rights of Way	4,177	-	4,177	100%	100%	4,177	4,161	100%	100%	4,161
17	35100	Structures and Improvements	7,642	-	7,642	100%	100%	7,642	7,496	100%	100%	7,496
18	35102	Compression Station Equipment	118,143	-	118,143	100%	100%	118,143	116,649	100%	100%	116,649
19	35103	Meas. & Reg. Sta. Structues	20,673	-	20,673	100%	100%	20,673	20,546	100%	100%	20,546
20	35104	Other Structures	104,581	-	104,581	100%	100%	104,581	103,632	100%	100%	103,632
21	35200	Wells \ Rights of Way	2,294,744	-	2,294,744	100%	100%	2,294,744	2,199,315	100%	100%	2,199,315
22	35201	Well Construction	1,482,128	-	1,482,128	100%	100%	1,482,128	1,468,528	100%	100%	1,468,528
23	35202	Well Equipment	467,453	-	467,453	100%	100%	467,453	462,849	100%	100%	462,849
24	35203	Cushion Gas	685,203	-	685,203	100%	100%	685,203	673,339	100%	100%	673,339
25	35210	Leaseholds	166,579	-	166,579	100%	100%	166,579	166,079	100%	100%	166,079
26	35211	Storage Rights	44,273	-	44,273	100%	100%	44,273	43,995	100%	100%	43,995
27	35301	Field Lines	103,909	-	103,909	100%	100%	103,909	102,804	100%	100%	102,804
28	35302	Tributary Lines	151,769	-	151,769	100%	100%	151,769	150,450	100%	100%	150,450
29	35400	Compressor Station Equipment	450,477	-	450,477	100%	100%	450,477	343,290	100%	100%	343,290
30	35500	Meas & Reg. Equipment	163,230	-	163,230	100%	100%	163,230	160,676	100%	100%	160,676
31	35600	Purification Equipment	297,737	-	297,737	100%	100%	297,737	281,143	100%	100%	281,143
32												
33		Total Storage Plant Reserves	$ 6,562,717	$ -	$ 6,562,717			$ 6,562,717	$ 6,304,952			$ 6,304,952

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Accumulated Depreciation & Amortization
Base Period: Twelve Months Ended December 31, 2024

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	**12/31/2024 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	581,881	-	581,881	100%	100%	581,881	578,193	100%	100%	578,193
38	36602	Structures & Improvements	25,750	-	25,750	100%	100%	25,750	24,310	100%	100%	24,310
39	36603	Other Structues	62,894	-	62,894	100%	100%	62,894	62,894	100%	100%	62,894
40	36700	Mains Cathodic Protection	32,055	-	32,055	100%	100%	32,055	31,316	100%	100%	31,316
41	36701	Mains - Steel	17,756,103	-	17,756,103	100%	100%	17,756,103	17,564,098	100%	100%	17,564,098
42	36703	Mains - Anodes	11,041	-	11,041	100%	100%	11,041	10,762	100%	100%	10,762
43	36900	Meas. & Reg. Equipment	593,714	-	593,714	100%	100%	593,714	575,818	100%	100%	575,818
44	36901	Meas. & Reg. Equipment	1,993,279	-	1,993,279	100%	100%	1,993,279	1,972,967	100%	100%	1,972,967
45												
46		Total Production Plant - LPG Reserves	$ 21,056,717	$ -	$ 21,056,717			$ 21,056,717	$ 20,820,358			$ 20,820,358
47												
48		Distribution Plant										
49	37400	Land & Land Rights	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
50	37401	Land	-	-	-	100%	100%	-	-	100%	100%	-
51	37402	Land Rights	603,312	-	603,312	100%	100%	603,312	574,467	100%	100%	574,467
52	37403	Land Other	-	-	-	100%	100%	-	-	100%	100%	-
53	37500	Structures & Improvements	132,744	-	132,744	100%	100%	132,744	130,324	100%	100%	130,324
54	37501	Structures & Improvements T.B.	80,692	-	80,692	100%	100%	80,692	79,974	100%	100%	79,974
55	37502	Land Rights	40,211	-	40,211	100%	100%	40,211	39,878	100%	100%	39,878
56	37503	Improvements	2,161	-	2,161	100%	100%	2,161	2,132	100%	100%	2,132
57	37600	Mains Cathodic Protection	1,672,865	-	1,672,865	100%	100%	1,672,865	1,593,572	100%	100%	1,593,572
58	37601	Mains - Steel	28,631,477	-	28,631,477	100%	100%	28,631,477	27,044,796	100%	100%	27,044,796
59	37602	Mains - Plastic	25,538,587	-	25,538,587	100%	100%	25,538,587	23,833,973	100%	100%	23,833,973
60	37603	Mains - Anodes	1,779,756	-	1,779,756	100%	100%	1,779,756	1,729,472	100%	100%	1,729,472
61	37604	Mains - Leak Clamps	5,360,462	-	5,360,462	100%	100%	5,360,462	5,433,245	100%	100%	5,433,245
62	37800	Meas & Reg. Sta. Equip - General	5,007,226	-	5,007,226	100%	100%	5,007,226	4,733,933	100%	100%	4,733,933
63	37900	Meas & Reg. Sta. Equip - City Gate	1,316,472	-	1,316,472	100%	100%	1,316,472	1,234,909	100%	100%	1,234,909
64	37905	Meas & Reg. Sta. Equipment T.b.	1,040,393	-	1,040,393	100%	100%	1,040,393	1,021,749	100%	100%	1,021,749
65	38000	Services	37,658,454	-	37,658,454	100%	100%	37,658,454	37,126,547	100%	100%	37,126,547
66	38100	Meters	23,104,335	-	23,104,335	100%	100%	23,104,335	22,286,832	100%	100%	22,286,832
67	38200	Meter Installaitons	21,451,840	-	21,451,840	100%	100%	21,451,840	20,641,923	100%	100%	20,641,923
68	38300	House Regulators	375,750	-	375,750	100%	100%	375,750	373,790	100%	100%	373,790
69	38400	House Reg. Installations	120,723	-	120,723	100%	100%	120,723	114,584	100%	100%	114,584
70	38500	Ind. Meas. & Reg. Sta. Equipment	3,017,640	-	3,017,640	100%	100%	3,017,640	2,986,225	100%	100%	2,986,225
71												
72		Total Distribution Plant Reserves	$ 156,935,103	$ -	$ 156,935,103			$ 156,935,103	$ 150,982,326			$ 150,982,326

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Line No.	Acct. No.	Account / SubAccount Titles	**12/31/2024 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	1,800,964	-	1,800,964	100%	100%	1,800,964	1,690,038	100%	100%	1,690,038
77	39002	39002-Structures - Brick	115,662	-	115,662	100%	100%	115,662	113,558	100%	100%	113,558
78	39003	39003-Improvements	319,099	-	319,099	100%	100%	319,099	308,448	100%	100%	308,448
79	39004	39004-Air Conditioning Equipment	8,501	-	8,501	100%	100%	8,501	8,224	100%	100%	8,224
80	39009	39009-Improv. to Leased Premises	1,267,195	-	1,267,195	100%	100%	1,267,195	1,267,195	100%	100%	1,267,195
81	39100	39100-Office Furniture & Equipment	1,405,571	-	1,405,571	100%	100%	1,405,571	1,360,179	100%	100%	1,360,179
82	39103	Office Machines	-	-	-	100%	100%	-	-	100%	100%	-
83	39200	39200-Transportation Equipment	69,784	-	69,784	100%	100%	69,784	65,763	100%	100%	65,763
84	39202	39202-WKG Trailers	7,437	-	7,437	100%	100%	7,437	6,623	100%	100%	6,623
85	39400	39400-Tools, Shop, & Garage Equip.	3,065,860	-	3,065,860	100%	100%	3,065,860	2,872,494	100%	100%	2,872,494
86	39603	39603-Ditchers	-	-	-	100%	100%	-	-	100%	100%	-
87	39604	39604-Backhoes	-	-	-	100%	100%	-	-	100%	100%	-
88	39605	39605-Welders	-	-	-	100%	100%	-	-	100%	100%	-
89	39700	39700-Communication Equipment	344,945	-	344,945	100%	100%	344,945	330,551	100%	100%	330,551
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	1,403,377	-	1,403,377	100%	100%	1,403,377	1,315,747	100%	100%	1,315,747
94	39901	Servers Hardware	21,340	-	21,340	100%	100%	21,340	19,809	100%	100%	19,809
95	39902	Servers Software	-	-	-	100%	100%	-	-	100%	100%	-
96	39903	39903-Oth Tang Prop - Network - H/W	-	-	-	100%	100%	-	-	100%	100%	-
97	39906	39906-Oth Tang Prop - PC Hardware	486,632	-	486,632	100%	100%	486,632	495,078	100%	100%	495,078
98	39907	39907-Oth Tang Prop - PC Software	-	-	-	100%	100%	-	-	100%	100%	-
99	39908	39908-Oth Tang Prop - Appl Software	-	-	-	100%	100%	-	-	100%	100%	-
100	RWIP	Retirement Work in Progress	(1,655,581)	-	(1,655,581)	100%	100%	(1,655,581)	(1,782,539)	100%	100%	(1,782,539)
101												
102		Total General Plant Reserves	$ 8,660,786	$ -	$ 8,660,786			$ 8,660,786	$ 8,071,167			$ 8,071,167
103												
104		Total Depr Reserves (Div 9)	$ 193,343,505	$ -	$ 193,343,505			$ 193,343,505	$ 186,306,986			$ 186,306,986

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Line No.	Acct. No.	Account / SubAccount Titles	12/31/2024 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
105												
106		**Kentucky-Mid-States General Office (Division 091)**										
107												
108		Intangible Plant										
109	30100	Organization	$ -	$ -	$ -	100%	49.97%	$ -	$ -	100%	49.97%	$ -
110	30300	Misc Intangible Plant	-	-	-	100%	49.97%	-	-	100%	49.97%	-
111												
112		Total Intangible Plant	$ -	$ -	$ -			$ -	$ -			$ -
113												
114		Distribution Plant										
115	37400	Land & Land Rights	$ -	$ -	$ -	100%	49.97%	$ -	$ -	100%	49.97%	$ -
116	35010	Land	-	-	-	100%	49.97%	-	-	100%	49.97%	-
117	37402	Land Rights	-	-	-	100%	49.97%	-	-	100%	49.97%	-
118	37403	Land Other	-	-	-	100%	49.97%	-	-	100%	49.97%	-
119	36602	Structures & Improvements	-	-	-	100%	49.97%	-	-	100%	49.97%	-
120	37501	Structures & Improvements T.B.	-	-	-	100%	49.97%	-	-	100%	49.97%	-
121	37402	Land Rights	-	-	-	100%	49.97%	-	-	100%	49.97%	-
122	37503	Improvements	-	-	-	100%	49.97%	-	-	100%	49.97%	-
123	36700	Mains Cathodic Protection	-	-	-	100%	49.97%	-	-	100%	49.97%	-
124	36701	Mains - Steel	-	-	-	100%	49.97%	-	-	100%	49.97%	-
125	37602	Mains - Plastic	-	-	-	100%	49.97%	-	-	100%	49.97%	-
126	37800	Meas & Reg. Sta. Equip - General	-	-	-	100%	49.97%	-	-	100%	49.97%	-
127	37900	Meas & Reg. Sta. Equip - City Gate	-	-	-	100%	49.97%	-	-	100%	49.97%	-
128	37905	Meas & Reg. Sta. Equipment T.b.	-	-	-	100%	49.97%	-	-	100%	49.97%	-
129	38000	Services	-	-	-	100%	49.97%	-	-	100%	49.97%	-
130	38100	Meters	-	-	-	100%	49.97%	-	-	100%	49.97%	-
131	38200	Meter Installaitons	-	-	-	100%	49.97%	-	-	100%	49.97%	-
132	38300	House Regulators	-	-	-	100%	49.97%	-	-	100%	49.97%	-
133	38400	House Reg. Installations	-	-	-	100%	49.97%	-	-	100%	49.97%	-
134	38500	Ind. Meas. & Reg. Sta. Equipment	-	-	-	100%	49.97%	-	-	100%	49.97%	-
135	38600	Other Prop. On Cust. Prem	-	-	-	100%	49.97%	-	-	100%	49.97%	-
136												
137		Total Distribution Plant	$ -	$ -	$ -			$ -	$ -			$ -

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138												
139		General Plant										
140	39001	39001-Structures - Frame	$ 115,083	-	$ 115,083	100.00%	49.97%	57,507	$ 112,402	100.00%	49.97%	$ 56,167
141	39004	39004-Air Conditioning Equipment	14,866	-	14,866	100%	49.97%	7,428	14,420	100%	49.97%	7,206
142	39009	39009-Improv. to Leased Premises	38,834	-	38,834	100%	49.97%	19,405	38,834	100%	49.97%	19,405
143	39100	39100-Office Furniture & Equipment	7,324	-	7,324	100%	49.97%	3,660	6,599	100%	49.97%	3,297
144	39101	Office Furniture And	-	-	-	100%	49.97%	-	-	100%	49.97%	-
145	39103	Office Machines	-	-	-	100%	49.97%	-	-	100%	49.97%	-
146	39200	39200-Trans Equip- Group	(2,224)	-	(2,224)	100%	49.97%	(1,112)	2,917	100%	49.97%	1,458
147	39300	Stores Equipment	-	-	-	100%	49.97%	-	-	100%	49.97%	-
148	39400	39400-Tools, Shop, & Garage Equip.	49,176	-	49,176	100%	49.97%	24,573	46,331	100%	49.97%	23,152
149	39600	39600-Power Operated Equipment	2,383	-	2,383	100%	49.97%	1,191	2,076	100%	49.97%	1,038
150	39700	39700-Communication Equipment	(22,067)	-	(22,067)	100%	49.97%	(11,027)	(22,067)	100%	49.97%	(11,027)
151	39701	Communication Equip.	-	-	-	100%	49.97%	-	-	100%	49.97%	-
152	39702	Communication Equip.	-	-	-	100%	49.97%	-	-	100%	49.97%	-
153	39800	39800-Miscellaneous Equipment	(126,994)	-	(126,994)	100%	49.97%	(63,459)	(126,994)	100%	49.97%	(63,459)
154	39900	39900-Other Tangible Property	-	-	-	100%	49.97%	-	-	100%	49.97%	-
155	39901	39901-Oth Tang Prop - Servers - H/W	-	-	-	100%	49.97%	-	-	100%	49.97%	-
156	39902	39902-Oth Tang Prop - Servers - S/W	-	-	-	100%	49.97%	-	-	100%	49.97%	-
157	39903	39903-Oth Tang Prop - Network - H/W	17,272	-	17,272	100%	49.97%	8,631	15,821	100%	49.97%	7,906
158	39906	39906-Oth Tang Prop - PC Hardware	-	-	-	100%	49.97%	-	-	100%	49.97%	-
159	39907	39907-Oth Tang Prop - PC Software	43,522	-	43,522	100%	49.97%	21,748	42,769	100%	49.97%	21,372
160	39908	39908-Oth Tang Prop - Appl Software	-	-	-	100%	49.97%	-	-	100%	49.97%	-
161	RWIP	Retirement Work in Progress	52,517		52,517	100%	49.97%	26,243	52,517	100%	49.97%	26,243
162												
163		Total General Plant	$ 189,691	$ -	$ 189,691			$ 94,789	$ 185,626			$ 92,757
164												
165		Total Depr Reserves (Div 91)	$ 189,691	$ -	$ 189,691			$ 94,789	$ 185,626			$ 92,757

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166												
167		**Shared Services General Office (Division 002)**										
168												
169		General Plant										
170	39000	39000-Structures & Improvements	$ 1,369,503	-	$ 1,369,503	9.13%	49.97%	62,480	$ 1,294,852	9.13%	49.97%	$ 59,075
171	39005	39005-G-Structures & Improvements	5,789,685	-	5,789,685	100.00%	1.50%	87,068	5,608,832	100.00%	1.50%	84,348
172	39009	39009-Improv. to Leased Premises	10,396,845	-	10,396,845	9.13%	49.97%	474,331	10,149,390	9.13%	49.97%	463,042
173	39020	Struct & Improv AEAM	1,983	-	1,983	100.00%	5.59%	111	1,668	100.00%	5.59%	93
174	39029	Improv-Leased AEAM	16,452	-	16,452	100.00%	5.59%	920	15,104	100.00%	5.59%	845
175	39100	39100-Office Furniture & Equipment	3,598,464	-	3,598,464	9.13%	49.97%	164,171	3,390,686	9.13%	49.97%	154,692
176	39102	39102-Remittance Processing Equipment	1	-	1	9.13%	49.97%	0	1	9.13%	49.97%	0
177	39103	39103-Office Furn. - Copiers & Type	0	-	0	9.13%	49.97%	0	0	9.13%	49.97%	0
178	39104	39104-G-Office Furniture & Equip.	51,906	-	51,906	100.00%	1.50%	781	49,636	100.00%	1.50%	746
179	39120	Off Furn & Equip-AEAM	184,288	-	184,288	100.00%	5.59%	10,306	174,894	100.00%	5.59%	9,781
180	39200	39200-Transportation Equipment	212,447	-	212,447	9.13%	49.97%	9,692	203,447	9.13%	49.97%	9,282
181	39300	39300-Stores Equipment	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
182	39400	39400-Tools, Shop, & Garage Equip.	24,437	-	24,437	9.13%	49.97%	1,115	39,979	9.13%	49.97%	1,824
183	39420	Tools And Garage-AEAM	388	-	388	100.00%	5.59%	22	388	100.00%	5.59%	22
184	39500	39500-Laboratory Equipment	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
185	39700	39700-Communication Equipment	119,245	-	119,245	9.13%	49.97%	5,440	99,916	9.13%	49.97%	4,558
186	39720	Commun Equip AEAM	10,797	-	10,797	100.00%	5.59%	604	8,502	100.00%	5.59%	475
187	39800	39800-Miscellaneous Equipment	45,620	-	45,620	9.13%	49.97%	2,081	42,277	9.13%	49.97%	1,929
188	39820	Misc Equip - AEAM	2,797	-	2,797	100.00%	5.59%	156	2,470	100.00%	5.59%	138
189	39900	39900-Other Tangible Equipm	(0)	-	(0)	9.13%	49.97%	(0)	(0)	9.13%	49.97%	(0)
190	39901	39901-Oth Tang Prop - Servers - H/W	5,498,639	-	5,498,639	9.13%	49.97%	250,862	3,105,505	9.13%	49.97%	141,681
191	39902	39902-Oth Tang Prop - Servers - S/W	8,393,125	-	8,393,125	9.13%	49.97%	382,916	7,588,659	9.13%	49.97%	346,214
192	39903	39903-Oth Tang Prop - Network - H/W	1,415,269	-	1,415,269	9.13%	49.97%	64,568	1,179,912	9.13%	49.97%	53,831
193	39904	39904-Oth Tang Prop - CPU	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
194	39905	39905-Oth Tang Prop - MF Hardware	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
195	39906	39906-Oth Tang Prop - PC Hardware	1,180,410	-	1,180,410	9.13%	49.97%	53,853	800,556	9.13%	49.97%	36,523
196	39907	39907-Oth Tang Prop - PC Software	62,619	-	62,619	9.13%	49.97%	2,857	58,407	9.13%	49.97%	2,665
197	39908	39908-Oth Tang Prop - Appl Software	62,830,179	-	62,830,179	9.13%	49.97%	2,866,477	59,271,506	9.13%	49.97%	2,704,121
198	39909	39909-Oth Tang Prop - Mainframe S/W	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
199	39921	Servers-Hardware-AEAM	1,688,324	-	1,688,324	100.00%	5.59%	94,419	1,273,228	100.00%	5.59%	71,205
200	39922	Servers-Software-AEAM	2,879,313	-	2,879,313	100.00%	5.59%	161,025	2,600,616	100.00%	5.59%	145,439
201	39923	Network Hardware-AEAM	144,654	-	144,654	100.00%	5.59%	8,090	110,464	100.00%	5.59%	6,178
202	39924	39924-Oth Tang Prop - Gen.	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
203	39926	Pc Hardware-AEAM	34,386	-	34,386	100.00%	5.59%	1,923	21,223	100.00%	5.59%	1,187
204	39928	Application SW-AEAM	22,167,805	-	22,167,805	100.00%	5.59%	1,239,728	21,092,569	100.00%	5.59%	1,179,596
205	39931	ALGN-Servers-Hardware	243,549	-	243,549	100.00%	3.60%	8,768	224,672	100.00%	3.60%	8,088
206	39932	ALGN-Servers-Software	450,119	-	450,119	100.00%	3.60%	16,204	409,062	100.00%	3.60%	14,726
207	39938	ALGN-Application SW	12,249,290	-	12,249,290	100.00%	3.60%	440,967	11,469,285	100.00%	3.60%	412,887
208	RWIP	Retirement Work in Progress	-	-	-	9.13%	49.97%	-	-	9.13%	49.97%	-
209	ADJ	WTW Adjustment (1)	340,245	-	340,245	9.13%	49.97%	15,523	433,039	9.13%	49.97%	19,756
210												
211		Total Depr Reserves (Div 2)	$ 141,402,787	$ -	$ 141,402,787			$ 6,427,459	$ 130,720,742			$ 5,934,946
212												

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Accumulated Depreciation & Amortization
Base Period: Twelve Months Ended December 31, 2024

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	12/31/2024 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
213		**Shared Services Customer Support (Division 012)**										
214												
215		General Plant										
216	38900	38900-Land	$ -	$ -	$ -	10.90%	49.46%	$ -	$ -	10.90%	49.46%	$ -
217	38910	38910-CKV-Land & Land Rights	-	-	-	100.00%	2.98%	-	-	100.00%	2.98%	-
218	39000	39000-Structures & Improvements	4,479,651	-	4,479,651	10.90%	49.46%	241,504	4,306,577	10.90%	49.46%	232,174
219	39009	39009-Improv. to Leased Premises	2,428,692	-	2,428,692	10.90%	49.46%	130,934	2,351,868	10.90%	49.46%	126,792
220	39010	39010-CKV-Structures & Improvements	5,346,505	-	5,346,505	100.00%	2.98%	159,491	5,183,396	100.00%	2.98%	154,626
221	39100	39100-Office Furniture & Equipment	1,599,648	-	1,599,648	10.90%	49.46%	86,239	1,516,252	10.90%	49.46%	81,743
222	39101	Office Furniture And	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
223	39102	Remittance Processing	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
224	39103	39103-Office Furn. - Copiers & Type	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
225	39110	CKV-Office Furn & Eq	146,288	-	146,288	100.00%	2.98%	4,364	125,683	100.00%	2.98%	3,749
226	39210	CKV-Transportation Eq	75,449	-	75,449	100.00%	2.98%	2,251	80,359	100.00%	2.98%	2,397
227	39410	CKV-Tools Shop Garage	288,803	-	288,803	100.00%	2.98%	8,615	297,770	100.00%	2.98%	8,883
228	39510	CKV-Laboratory Equip	125	-	125	100.00%	2.98%	4	125	100.00%	2.98%	4
229	39700	39700-Communication Equipment	1,748,633	-	1,748,633	10.90%	49.46%	94,271	1,687,314	10.90%	49.46%	90,965
230	39710	39710-CKV-Communication Equipment	(41,012)	-	(41,012)	100.00%	2.98%	(1,223)	(44,005)	100.00%	2.98%	(1,313)
231	39800	39800-Miscellaneous Equipment	32,298	-	32,298	10.90%	49.46%	1,741	28,200	10.90%	49.46%	1,520
232	39810	CKV-Misc Equipment	228,860	-	228,860	100.00%	2.98%	6,827	209,944	100.00%	2.98%	6,263
233	39900	39900-Other Tangible Property	(154,265)	-	(154,265)	10.90%	49.46%	(8,317)	(154,265)	10.90%	49.46%	(8,317)
234	39901	39901-Oth Tang Prop - Servers - H/W	3,312,894	-	3,312,894	10.90%	49.46%	178,603	2,933,098	10.90%	49.46%	158,127
235	39902	39902-Oth Tang Prop - Servers - S/W	1,836,405	-	1,836,405	10.90%	49.46%	99,003	1,812,647	10.90%	49.46%	97,722
236	39903	39903-Oth Tang Prop - Network - H/W	274,382	-	274,382	10.90%	49.46%	14,792	240,991	10.90%	49.46%	12,992
237	39906	39906-Oth Tang Prop - PC Hardware	338,763	-	338,763	10.90%	49.46%	18,263	205,308	10.90%	49.46%	11,068
238	39907	39907-Oth Tang Prop - PC Software	(57,199)	-	(57,199)	10.90%	49.46%	(3,084)	(57,199)	10.90%	49.46%	(3,084)
239	39908	39908-Oth Tang Prop - Appl Software	71,436,832	-	71,436,832	10.90%	49.46%	3,851,260	67,648,850	10.90%	49.46%	3,647,044
240	39910	39910-CKV-Other Tangible Property	171,688	-	171,688	100.00%	2.98%	5,122	156,968	100.00%	2.98%	4,682
241	39916	39916-CKV-Oth Tang Prop-PC Hardware	81,609	-	81,609	100.00%	2.98%	2,434	72,378	100.00%	2.98%	2,159
242	39917	39917-CKV-Oth Tang Prop-PC Software	(26,854)	-	(26,854)	100.00%	2.98%	(801)	(27,016)	100.00%	2.98%	(806)
243	39918	CKV-Oth Tang Prop-App	(9,966)	-	(9,966)	100.00%	2.98%	(297)	(9,966)	100.00%	2.98%	(297)
244	39924	Oth Tang Prop - Gen.	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
245	RWIP	Retirement Work in Progress	-	-	-	10.90%	49.46%	-	-	10.90%	49.46%	-
246												
247		Total Depr Reserves (Div 12)	$ 93,538,229	$ -	$ 93,538,229			$ 4,891,997	$ 88,565,275			$ 4,629,097
248												
249		Total Accumulated Depreciation & Amortization (Div 009, 091, 002, 012)	$ 428,474,213	$ -	$ 428,474,213			$ 204,757,751	$ 405,778,629			$ 196,963,786

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Accumulated Depreciation & Amortization
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	3/31/2026 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	4,216	-	4,216	100%	100%	4,216	4,200	100%	100%	4,200
17	35100	Structures and Improvements	8,010	-	8,010	100%	100%	8,010	7,863	100%	100%	7,863
18	35102	Compression Station Equipment	121,971	-	121,971	100%	100%	121,971	120,440	100%	100%	120,440
19	35103	Meas. & Reg. Sta. Structues	20,991	-	20,991	100%	100%	20,991	20,864	100%	100%	20,864
20	35104	Other Structures	106,952	-	106,952	100%	100%	106,952	106,003	100%	100%	106,003
21	35200	Wells \ Rights of Way	2,588,877	-	2,588,877	100%	100%	2,588,877	2,463,749	100%	100%	2,463,749
22	35201	Well Construction	1,516,128	-	1,516,128	100%	100%	1,516,128	1,502,528	100%	100%	1,502,528
23	35202	Well Equipment	478,965	-	478,965	100%	100%	478,965	474,361	100%	100%	474,361
24	35203	Cushion Gas	714,863	-	714,863	100%	100%	714,863	702,999	100%	100%	702,999
25	35210	Leaseholds	167,828	-	167,828	100%	100%	167,828	167,328	100%	100%	167,328
26	35211	Storage Rights	44,970	-	44,970	100%	100%	44,970	44,691	100%	100%	44,691
27	35301	Field Lines	106,671	-	106,671	100%	100%	106,671	105,566	100%	100%	105,566
28	35302	Tributary Lines	155,066	-	155,066	100%	100%	155,066	153,747	100%	100%	153,747
29	35400	Compressor Station Equipment	836,635	-	836,635	100%	100%	836,635	682,172	100%	100%	682,172
30	35500	Meas & Reg. Equipment	169,613	-	169,613	100%	100%	169,613	167,060	100%	100%	167,060
31	35600	Purification Equipment	339,221	-	339,221	100%	100%	339,221	322,628	100%	100%	322,628
32												
33		Total Storage Plant Reserves	$ 7,380,976	$ -	$ 7,380,976			$ 7,380,976	$ 7,046,197			$ 7,046,197

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Accumulated Depreciation & Amortization
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:______Base Period__X___Forecasted Period — FR 16(8)(b)3
Type of Filing:___X____Original________Updated ________Revised — Schedule B-3 F
Workpaper Reference No(s). — Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	3/31/2026 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	591,102	-	591,102	100%	100%	591,102	587,414	100%	100%	587,414
38	36602	Structures & Improvements	31,369	-	31,369	100%	100%	31,369	29,122	100%	100%	29,122
39	36603	Other Structues	62,894	-	62,894	100%	100%	62,894	62,894	100%	100%	62,894
40	36700	Mains Cathodic Protection	33,903	-	33,903	100%	100%	33,903	33,163	100%	100%	33,163
41	36701	Mains - Steel	18,236,118	-	18,236,118	100%	100%	18,236,118	18,044,112	100%	100%	18,044,112
42	36703	Mains - Anodes	11,180	-	11,180	100%	100%	11,180	11,180	100%	100%	11,180
43	36900	Meas. & Reg. Equipment	638,455	-	638,455	100%	100%	638,455	620,559	100%	100%	620,559
44	36901	Meas. & Reg. Equipment	2,044,059	-	2,044,059	100%	100%	2,044,059	2,023,747	100%	100%	2,023,747
45												
46		Total Production Plant - LPG Reserves	$ 21,649,079	$ -	$ 21,649,079			$ 21,649,079	$ 21,412,190			$ 21,412,190
47												
48		Distribution Plant										
49	37400	Land & Land Rights	$ -	$ -	$ -	100%	100%	$ -	$ -	100%	100%	$ -
50	37401	Land	-	-	-	100%	100%	-	-	100%	100%	-
51	37402	Land Rights	671,392	-	671,392	100%	100%	671,392	644,160	100%	100%	644,160
52	37403	Land Other	-	-	-	100%	100%	-	-	100%	100%	-
53	37500	Structures & Improvements	138,795	-	138,795	100%	100%	138,795	136,375	100%	100%	136,375
54	37501	Structures & Improvements T.B.	82,489	-	82,489	100%	100%	82,489	81,770	100%	100%	81,770
55	37502	Land Rights	41,044	-	41,044	100%	100%	41,044	40,711	100%	100%	40,711
56	37503	Improvements	2,233	-	2,233	100%	100%	2,233	2,204	100%	100%	2,204
57	37600	Mains Cathodic Protection	1,871,980	-	1,871,980	100%	100%	1,871,980	1,792,334	100%	100%	1,792,334
58	37601	Mains - Steel	32,468,120	-	32,468,120	100%	100%	32,468,120	30,950,942	100%	100%	30,950,942
59	37602	Mains - Plastic	29,741,303	-	29,741,303	100%	100%	29,741,303	28,052,270	100%	100%	28,052,270
60	37603	Mains - Anodes	1,903,475	-	1,903,475	100%	100%	1,903,475	1,851,162	100%	100%	1,851,162
61	37604	Mains - Leak Clamps	5,784,830	-	5,784,830	100%	100%	5,784,830	5,615,083	100%	100%	5,615,083
62	37800	Meas & Reg. Sta. Equip - General	5,449,132	-	5,449,132	100%	100%	5,449,132	5,288,177	100%	100%	5,288,177
63	37900	Meas & Reg. Sta. Equip - City Gate	1,571,995	-	1,571,995	100%	100%	1,571,995	1,456,651	100%	100%	1,456,651
64	37905	Meas & Reg. Sta. Equipment T.b.	1,087,002	-	1,087,002	100%	100%	1,087,002	1,068,358	100%	100%	1,068,358
65	38000	Services	39,616,202	-	39,616,202	100%	100%	39,616,202	38,828,841	100%	100%	38,828,841
66	38100	Meters	24,596,262	-	24,596,262	100%	100%	24,596,262	23,998,006	100%	100%	23,998,006
67	38200	Meter Installaitons	23,561,146	-	23,561,146	100%	100%	23,561,146	22,719,274	100%	100%	22,719,274
68	38300	House Regulators	531,749	-	531,749	100%	100%	531,749	469,350	100%	100%	469,350
69	38400	House Reg. Installations	136,225	-	136,225	100%	100%	136,225	130,024	100%	100%	130,024
70	38500	Ind. Meas. & Reg. Sta. Equipment	3,139,315	-	3,139,315	100%	100%	3,139,315	3,090,645	100%	100%	3,090,645
71												
72		Total Distribution Plant Reserves	$ 172,394,689	$ -	$ 172,394,689			$ 172,394,689	$ 166,216,337			$ 166,216,337

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Accumulated Depreciation & Amortization
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	3/31/2026 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	2,081,660	-	2,081,660	100%	100%	2,081,660	1,968,463	100%	100%	1,968,463
77	39002	39002-Structures - Brick	120,920	-	120,920	100%	100%	120,920	118,817	100%	100%	118,817
78	39003	39003-Improvements	345,727	-	345,727	100%	100%	345,727	335,075	100%	100%	335,075
79	39004	39004-Air Conditioning Equipment	9,192	-	9,192	100%	100%	9,192	8,916	100%	100%	8,916
80	39009	39009-Improv. to Leased Premises	1,267,195	-	1,267,195	100%	100%	1,267,195	1,267,195	100%	100%	1,267,195
81	39100	39100-Office Furniture & Equipment	1,519,129	-	1,519,129	100%	100%	1,519,129	1,473,706	100%	100%	1,473,706
82	39103	Office Machines	-	-	-	100%	100%	-	-	100%	100%	-
83	39200	39200-Transportation Equipment	79,839	-	79,839	100%	100%	79,839	75,817	100%	100%	75,817
84	39202	39202-WKG Trailers	9,472	-	9,472	100%	100%	9,472	8,658	100%	100%	8,658
85	39400	39400-Tools, Shop, & Garage Equip.	3,545,207	-	3,545,207	100%	100%	3,545,207	3,345,740	100%	100%	3,345,740
86	39603	39603-Ditchers	-	-	-	100%	100%	-	-	100%	100%	-
87	39604	39604-Backhoes	-	-	-	100%	100%	-	-	100%	100%	-
88	39605	39605-Welders	-	-	-	100%	100%	-	-	100%	100%	-
89	39700	39700-Communication Equipment	381,125	-	381,125	100%	100%	381,125	366,653	100%	100%	366,653
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	1,648,359	-	1,648,359	100%	100%	1,648,359	1,548,948	100%	100%	1,548,948
94	39901	Servers Hardware	21,595	-	21,595	100%	100%	21,595	21,595	100%	100%	21,595
95	39902	Servers Software	-	-	-	100%	100%	-	-	100%	100%	-
96	39903	39903-Oth Tang Prop - Network - H/W	-	-	-	100%	100%	-	-	100%	100%	-
97	39906	39906-Oth Tang Prop - PC Hardware	530,854	-	530,854	100%	100%	530,854	530,003	100%	100%	530,003
98	39907	39907-Oth Tang Prop - PC Software	-	-	-	100%	100%	-	-	100%	100%	-
99	39908	39908-Oth Tang Prop - Appl Software	-	-	-	100%	100%	-	-	100%	100%	-
100	RWIP	Retirement Work in Progress	(1,655,581)	-	(1,655,581)	100%	100%	(1,655,581)	(1,655,581)	100%	100%	(1,655,581)
101												
102		Total General Plant Reserves	$ 9,904,694	$ -	$ 9,904,694			$ 9,904,694	$ 9,414,005			$ 9,414,005
103												
104		Total Depr Reserves (Div 9)	$ 211,457,621	$ -	$ 211,457,621			$ 211,457,621	$ 204,216,911			$ 204,216,911
105												
106												

Atmos Energy Corporation, Kentucky/Mid-States Division
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FR 16(8)(b)3
Schedule B-3 F
Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	3/31/2026 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%	48.90%	$ -	$ -	100%	48.90%	$ -
112	30300	Misc Intangible Plant	-	-	-	100%	48.90%	-	-	100%	48.90%	-
113												
114		Total Intangible Plant	$ -	$ -	$ -			$ -	$ -			$ -
115												
116		Distribution Plant										
117	37400	Land & Land Rights	$ -	$ -	$ -	100%	48.90%	$ -	$ -	100%	48.90%	$ -
118	35010	Land	-	-	-	100%	48.90%	-	-	100%	48.90%	-
119	37402	Land Rights	-	-	-	100%	48.90%	-	-	100%	48.90%	-
120	37403	Land Other	-	-	-	100%	48.90%	-	-	100%	48.90%	-
121	36602	Structures & Improvements	-	-	-	100%	48.90%	-	-	100%	48.90%	-
122	37501	Structures & Improvements T.B.	-	-	-	100%	48.90%	-	-	100%	48.90%	-
123	37402	Land Rights	-	-	-	100%	48.90%	-	-	100%	48.90%	-
124	37503	Improvements	-	-	-	100%	48.90%	-	-	100%	48.90%	-
125	36700	Mains Cathodic Protection	-	-	-	100%	48.90%	-	-	100%	48.90%	-
126	36701	Mains - Steel	-	-	-	100%	48.90%	-	-	100%	48.90%	-
127	37602	Mains - Plastic	-	-	-	100%	48.90%	-	-	100%	48.90%	-
128	37800	Meas & Reg. Sta. Equip - General	-	-	-	100%	48.90%	-	-	100%	48.90%	-
129	37900	Meas & Reg. Sta. Equip - City Gate	-	-	-	100%	48.90%	-	-	100%	48.90%	-
130	37905	Meas & Reg. Sta. Equipment T.b.	-	-	-	100%	48.90%	-	-	100%	48.90%	-
131	38000	Services	-	-	-	100%	48.90%	-	-	100%	48.90%	-
132	38100	Meters	-	-	-	100%	48.90%	-	-	100%	48.90%	-
133	38200	Meter Installaitons	-	-	-	100%	48.90%	-	-	100%	48.90%	-
134	38300	House Regulators	-	-	-	100%	48.90%	-	-	100%	48.90%	-
135	38400	House Reg. Installations	-	-	-	100%	48.90%	-	-	100%	48.90%	-
136	38500	Ind. Meas. & Reg. Sta. Equipment	-	-	-	100%	48.90%	-	-	100%	48.90%	-
137	38600	Other Prop. On Cust. Prem	-	-	-	100%	48.90%	-	-	100%	48.90%	-
138												
139		Total Distribution Plant	$ -	$ -	$ -			$ -	$ -			$ -

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Accumulated Depreciation & Amortization
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	3/31/2026 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	$ 124,081	$ -	$ 124,081	100.00%	48.90%	$ 60,676	$ 120,136	100.00%	48.90%	$ 58,746
143	39004	39004-Air Conditioning Equipment	15,425	-	15,425	100%	48.90%	7,543	15,341	100%	48.90%	7,502
144	39009	39009-Improv. to Leased Premises	38,834	-	38,834	100%	48.90%	18,990	38,834	100%	48.90%	18,990
145	39100	39100-Office Furniture & Equipment	9,392	-	9,392	100%	48.90%	4,593	8,526	100%	48.90%	4,169
146	39101	Office Furniture And	-	-	-	100%	48.90%	-	-	100%	48.90%	-
147	39103	Office Machines	-	-	-	100%	48.90%	-	-	100%	48.90%	-
148	39200	39200-Trans Equip- Group	(1,795)	-	(1,795)	100%	48.90%	(878)	(1,982)	100%	48.90%	(969)
149	39300	Stores Equipment	-	-	-	100%	48.90%	-	-	100%	48.90%	-
150	39400	39400-Tools, Shop, & Garage Equip.	57,217	-	57,217	100%	48.90%	27,979	53,861	100%	48.90%	26,338
151	39600	39600-Power Operated Equipment	3,488	-	3,488	100%	48.90%	1,705	2,995	100%	48.90%	1,464
152	39700	39700-Communication Equipment	(22,067)	-	(22,067)	100%	48.90%	(10,791)	(22,067)	100%	48.90%	(10,791)
153	39701	Communication Equip.	-	-	-	100%	48.90%	-	-	100%	48.90%	-
154	39702	Communication Equip.	-	-	-	100%	48.90%	-	-	100%	48.90%	-
155	39800	39800-Miscellaneous Equipment	(126,994)	-	(126,994)	100%	48.90%	(62,100)	(126,994)	100%	48.90%	(62,100)
156	39900	39900-Other Tangible Property	-	-	-	100%	48.90%	-	-	100%	48.90%	-
157	39901	39901-Oth Tang Prop - Servers - H/W	-	-	-	100%	48.90%	-	-	100%	48.90%	-
158	39902	39902-Oth Tang Prop - Servers - S/W	-	-	-	100%	48.90%	-	-	100%	48.90%	-
159	39903	39903-Oth Tang Prop - Network - H/W	21,085	-	21,085	100%	48.90%	10,311	19,532	100%	48.90%	9,551
160	39906	39906-Oth Tang Prop - PC Hardware	-	-	-	100%	48.90%	-	-	100%	48.90%	-
161	39907	39907-Oth Tang Prop - PC Software	43,522	-	43,522	100%	48.90%	21,282	43,522	100%	48.90%	21,282
162	39908	39908-Oth Tang Prop - Appl Software	-	-	-	100%	48.90%	-	-	100%	48.90%	-
163	RWIP	Retirement Work in Progress	52,517		52,517	100%	48.90%	25,681	52,517	100%	48.90%	25,681
164												
165		Total General Plant	$ 214,706	$ -	$ 214,706			$ 104,991	$ 204,221			$ 99,864
166												
167		Total Depr Reserves (Div 91)	$ 214,706	$ -	$ 214,706			$ 104,991	$ 204,221			$ 99,864

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Accumulated Depreciation & Amortization
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	3/31/2026 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	$ 1,538,371	$ -	$ 1,538,371	8.90%	48.90%	66,951	$ 1,471,608	8.90%	48.90%	$ 64,046
173	39005	39005-G-Structures & Improvements	6,232,512	-	6,232,512	100.00%	1.50%	93,727	6,055,381	100.00%	1.50%	91,063
174	39009	39009-Improv. to Leased Premises	11,180,975	-	11,180,975	8.90%	48.90%	486,607	10,859,248	8.90%	48.90%	472,605
175	39020	Struct & Improv AEAM	2,716	-	2,716	100.00%	5.59%	152	2,423	100.00%	5.59%	136
176	39029	Improv-Leased AEAM	19,579	-	19,579	100.00%	5.59%	1,095	18,367	100.00%	5.59%	1,027
177	39100	39100-Office Furniture & Equipment	4,231,405	-	4,231,405	8.90%	48.90%	184,155	3,968,772	8.90%	48.90%	172,725
178	39102	39102-Remittance Processing Equipment	1	-	1	8.90%	48.90%	0	1	8.90%	48.90%	0
179	39103	39103-Office Furn. - Copiers & Type	0	-	0	8.90%	48.90%	0	0	8.90%	48.90%	0
180	39104	39104-G-Office Furniture & Equip.	57,596	-	57,596	100.00%	1.50%	866	55,337	100.00%	1.50%	832
181	39120	Off Furn & Equip-AEAM	208,950	-	208,950	100.00%	5.59%	11,685	199,159	100.00%	5.59%	11,138
182	39200	39200-Transportation Equipment	238,192	-	238,192	8.90%	48.90%	10,366	227,799	8.90%	48.90%	9,914
183	39300	39300-Stores Equipment	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
184	39400	39400-Tools, Shop, & Garage Equip.	29,168	-	29,168	8.90%	48.90%	1,269	27,293	8.90%	48.90%	1,188
185	39420	Tools And Garage-AEAM	388	-	388	100.00%	5.59%	22	388	100.00%	5.59%	22
186	39500	39500-Laboratory Equipment	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
187	39700	39700-Communication Equipment	172,931	-	172,931	8.90%	48.90%	7,526	151,027	8.90%	48.90%	6,573
188	39720	Commun Equip AEAM	17,007	-	17,007	100.00%	5.59%	951	14,552	100.00%	5.59%	814
189	39800	39800-Miscellaneous Equipment	55,129	-	55,129	8.90%	48.90%	2,399	51,352	8.90%	48.90%	2,235
190	39820	Misc Equip - AEAM	3,729	-	3,729	100.00%	5.59%	209	3,359	100.00%	5.59%	188
191	39900	39900-Other Tangible Equipm	(0)	-	(0)	8.90%	48.90%	(0)	(0)	8.90%	48.90%	(0)
192	39901	39901-Oth Tang Prop - Servers - H/W	11,608,118	-	11,608,118	8.90%	48.90%	505,197	9,188,701	8.90%	48.90%	399,901
193	39902	39902-Oth Tang Prop - Servers - S/W	13,189,129	-	13,189,129	8.90%	48.90%	574,004	10,970,430	8.90%	48.90%	477,444
194	39903	39903-Oth Tang Prop - Network - H/W	2,088,010	-	2,088,010	8.90%	48.90%	90,872	1,810,018	8.90%	48.90%	78,774
195	39904	39904-Oth Tang Prop - CPU	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
196	39905	39905-Oth Tang Prop - MF Hardware	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
197	39906	39906-Oth Tang Prop - PC Hardware	2,286,379	-	2,286,379	8.90%	48.90%	99,505	1,835,232	8.90%	48.90%	79,871
198	39907	39907-Oth Tang Prop - PC Software	74,489	-	74,489	8.90%	48.90%	3,242	69,666	8.90%	48.90%	3,032
199	39908	39908-Oth Tang Prop - Appl Software	72,269,684	-	72,269,684	8.90%	48.90%	3,145,249	68,468,562	8.90%	48.90%	2,979,820
200	39909	39909-Oth Tang Prop - Mainframe S/W	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
201	39921	Servers-Hardware-AEAM	4,081,370	-	4,081,370	100.00%	5.59%	228,249	2,973,262	100.00%	5.59%	166,279
202	39922	Servers-Software-AEAM	3,571,475	-	3,571,475	100.00%	5.59%	199,734	3,297,486	100.00%	5.59%	184,411
203	39923	Network Hardware-AEAM	311,289	-	311,289	100.00%	5.59%	17,409	235,281	100.00%	5.59%	13,158
204	39924	39924-Oth Tang Prop - Gen.	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
205	39926	Pc Hardware-AEAM	70,154	-	70,154	100.00%	5.59%	3,923	55,552	100.00%	5.59%	3,107
206	39928	Application SW-AEAM	24,776,954	-	24,776,954	100.00%	5.59%	1,385,644	23,751,640	100.00%	5.59%	1,328,304
207	39931	ALGN-Servers-Hardware	291,068	-	291,068	100.00%	3.60%	10,478	272,251	100.00%	3.60%	9,801
208	39932	ALGN-Servers-Software	550,127	-	550,127	100.00%	3.60%	19,804	510,540	100.00%	3.60%	18,379
209	39938	ALGN-Application SW	14,111,813	-	14,111,813	100.00%	3.60%	508,017	13,379,900	100.00%	3.60%	481,668
210	RWIP	Retirement Work in Progress	-	-	-	8.90%	48.90%	-	-	8.90%	48.90%	-
211	ADJ	WTW Adjustment (1)	108,260	-	108,260	8.90%	48.90%	4,712	201,054	8.90%	48.90%	8,750
212												
213		Total Depr Reserves (Div 2)	$ 173,376,968	$ -	$ 173,376,968			$ 7,664,021	$ 160,125,640			$ 7,067,204

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Jurisdictional Accumulated Depreciation & Amortization
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	3/31/2026 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	$ -	$ -	$ -	10.86%	48.90%	$ -	$ -	10.86%	48.90%	$ -
219	38910	38910-CKV-Land & Land Rights	-	-	-	100.00%	2.98%	-	-	100.00%	2.98%	-
220	39000	39000-Structures & Improvements	4,883,687	-	4,883,687	10.86%	48.90%	259,350	4,721,951	10.86%	48.90%	250,761
221	39009	39009-Improv. to Leased Premises	2,609,812	-	2,609,812	10.86%	48.90%	138,595	2,539,584	10.86%	48.90%	134,866
222	39010	39010-CKV-Structures & Improvements	5,721,078	-	5,721,078	100.00%	2.98%	170,665	5,571,249	100.00%	2.98%	166,196
223	39100	39100-Office Furniture & Equipment	1,818,342	-	1,818,342	10.86%	48.90%	96,564	1,731,519	10.86%	48.90%	91,953
224	39101	Office Furniture And	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
225	39102	Remittance Processing	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
226	39103	39103-Office Furn. - Copiers & Type	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
227	39110	CKV-Office Furn & Eq	223,194	-	223,194	100.00%	2.98%	6,658	190,863	100.00%	2.98%	5,694
228	39210	CKV-Transportation Eq	75,449	-	75,449	100.00%	2.98%	2,251	75,449	100.00%	2.98%	2,251
229	39410	CKV-Tools Shop Garage	400,269	-	400,269	100.00%	2.98%	11,940	355,631	100.00%	2.98%	10,609
230	39510	CKV-Laboratory Equip	125	-	125	100.00%	2.98%	4	125	100.00%	2.98%	4
231	39700	39700-Communication Equipment	1,902,065	-	1,902,065	10.86%	48.90%	101,010	1,841,419	10.86%	48.90%	97,789
232	39710	39710-CKV-Communication Equipment	(33,566)	-	(33,566)	100.00%	2.98%	(1,001)	(36,509)	100.00%	2.98%	(1,089)
233	39800	39800-Miscellaneous Equipment	44,046	-	44,046	10.86%	48.90%	2,339	39,379	10.86%	48.90%	2,091
234	39810	CKV-Misc Equipment	294,682	-	294,682	100.00%	2.98%	8,791	267,291	100.00%	2.98%	7,974
235	39900	39900-Other Tangible Property	(154,265)	-	(154,265)	10.86%	48.90%	(8,192)	(154,265)	10.86%	48.90%	(8,192)
236	39901	39901-Oth Tang Prop - Servers - H/W	4,216,153	-	4,216,153	10.86%	48.90%	223,900	3,858,466	10.86%	48.90%	204,905
237	39902	39902-Oth Tang Prop - Servers - S/W	1,836,405	-	1,836,405	10.86%	48.90%	97,523	1,836,405	10.86%	48.90%	97,523
238	39903	39903-Oth Tang Prop - Network - H/W	365,791	-	365,791	10.86%	48.90%	19,425	328,608	10.86%	48.90%	17,451
239	39906	39906-Oth Tang Prop - PC Hardware	747,333	-	747,333	10.86%	48.90%	39,687	580,541	10.86%	48.90%	30,830
240	39907	39907-Oth Tang Prop - PC Software	(57,199)	-	(57,199)	10.86%	48.90%	(3,038)	(57,199)	10.86%	48.90%	(3,038)
241	39908	39908-Oth Tang Prop - Appl Software	80,888,094	-	80,888,094	10.86%	48.90%	4,295,595	77,147,188	10.86%	48.90%	4,096,932
242	39910	39910-CKV-Other Tangible Property	220,079	-	220,079	100.00%	2.98%	6,565	199,513	100.00%	2.98%	5,952
243	39916	39916-CKV-Oth Tang Prop-PC Hardware	110,009	-	110,009	100.00%	2.98%	3,282	98,415	100.00%	2.98%	2,936
244	39917	39917-CKV-Oth Tang Prop-PC Software	(26,381)	-	(26,381)	100.00%	2.98%	(787)	(26,573)	100.00%	2.98%	(793)
245	39918	CKV-Oth Tang Prop-App	(9,966)	-	(9,966)	100.00%	2.98%	(297)	(9,966)	100.00%	2.98%	(297)
246	39924	Oth Tang Prop - Gen.	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
247	RWIP	Retirement Work in Progress	-	-	-	10.86%	48.90%	-	-	10.86%	48.90%	-
248												
249		Total Depr Reserves (Div 12)	$ 106,075,234	$ -	$ 106,075,234			$ 5,470,829	$ 101,099,083			$ 5,213,306
250												
251		Total Accumulated Depreciation & Amortization (Div 009, 091, 002, 012)	$ 491,124,529	$ -	$ 491,124,529			$ 224,697,462	$ 465,645,855			$ 216,597,286

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Depreciation Expense
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:______Base Period__X___Forecasted Period | FR 16(8)(b)3.1
Type of Filing:___X____Original________Updated ________Revised | Schedule B-3.1
Workpaper Reference No(s). | Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12 Months Ending 3/31/2026	O&M Expense Factor	Kentucky- Mid States Division 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 Ways	$ -	100.00%	100%	100%	-
9	33202	Tributary 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	32	100.00%	100%	100%	32
17	35100	Structures and Improvements	294	100.00%	100%	100%	294
18	35102	Compression Station Equipment	3,062	100.00%	100%	100%	3,062
19	35103	Meas. & Reg. Sta. Structures	255	100.00%	100%	100%	255
20	35104	Other Structures	1,897	100.00%	100%	100%	1,897
21	35200	Wells \ Rights of Way	241,977	100.00%	100%	100%	241,977
22	35201	Well Construction	27,200	100.00%	100%	100%	27,200
23	35202	Well Equipment	9,210	100.00%	100%	100%	9,210
24	35203	Cushion Gas	23,728	100.00%	100%	100%	23,728
25	35210	Leaseholds	1,000	100.00%	100%	100%	1,000
26	35211	Storage Rights	557	100.00%	100%	100%	557
27	35301	Field Lines	2,209	100.00%	100%	100%	2,209
28	35302	Tributary Lines	2,637	100.00%	100%	100%	2,637
29	35400	Compressor Station Equipment	308,927	100.00%	100%	100%	308,927
30	35500	Meas & Reg. Equipment	5,107	100.00%	100%	100%	5,107
31	35600	Purification Equipment	33,187	100.00%	100%	100%	33,187
32							
33		Total Storage Plant Depr	$ 661,278				$ 661,278
34							
35		Transmission Plant					
36	36510	Land	$ -	100.00%	100%	100%	$ -
37	36520	Rights of Way	7,376	100.00%	100%	100%	7,376
38	36602	Structures & Improvements	4,496	100.00%	100%	100%	4,496
39	36603	Other Structues	-	100.00%	100%	100%	-
40	36700	Mains Cathodic Protection	1,478	100.00%	100%	100%	1,478
41	36701	Mains - Steel	384,012	100.00%	100%	100%	384,012
42	36703	Mains - Anodes	-	100.00%	100%	100%	-
43	36900	Meas. & Reg. Equipment	35,793	100.00%	100%	100%	35,793
44	36901	Meas. & Reg. Equipment	40,624	100.00%	100%	100%	40,624
45							
46		Total Production Plant - (LPG) Depr	$ 473,778				$ 473,778
47							

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Depreciation Expense
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:______Base Period__X___Forecasted Period | FR 16(8)(b)3.1
Type of Filing:___X____Original________Updated ________Revised | Schedule B-3.1
Workpaper Reference No(s). | Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12 Months Ending 3/31/2026	O&M Expense Factor	Kentucky- Mic States Divisior Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
48		Distribution Plant					
49	37400	Land & Land Rights	$ -	100.00%	100%	100%	$ -
50	37401	Land	-	100.00%	100%	100%	-
51	37402	Land Rights	54,464	100.00%	100%	100%	54,464
52	37403	Land Other	-	100.00%	100%	100%	-
53	37500	Structures & Improvements	4,841	100.00%	100%	100%	4,841
54	37501	Structures & Improvements T.B.	1,437	100.00%	100%	100%	1,437
55	37502	Land Rights	666	100.00%	100%	100%	666
56	37503	Improvements	58	100.00%	100%	100%	58
57	37600	Mains Cathodic Protection	159,292	100.00%	100%	100%	159,292
58	37601	Mains - Steel	3,554,207	100.00%	100%	100%	3,554,207
59	37602	Mains - Plastic	3,416,357	100.00%	100%	100%	3,416,357
60	37603	Mains - Anodes	200,720	100.00%	100%	100%	200,720
61	37604	Mains - Leak Clamps	339,494	100.00%	100%	100%	339,494
62	37800	Meas & Reg. Sta. Equip - General	573,607	100.00%	100%	100%	573,607
63	37900	Meas & Reg. Sta. Equip - City Gate	214,735	100.00%	100%	100%	214,735
64	37905	Meas & Reg. Sta. Equipment T.b.	37,287	100.00%	100%	100%	37,287
65	38000	Services	4,814,131	100.00%	100%	100%	4,814,131
66	38100	Meters	2,722,922	100.00%	100%	100%	2,722,922
67	38200	Meter Installaitons	2,026,363	100.00%	100%	100%	2,026,363
68	38300	House Regulators	124,799	100.00%	100%	100%	124,799
69	38400	House Reg. Installations	12,401	100.00%	100%	100%	12,401
70	38500	Ind. Meas. & Reg. Sta. Equipment	97,340	100.00%	100%	100%	97,340
71							
72		Total Distribution Plant Depr	$ 18,355,122				$ 18,355,122
73							
74		General Plant					
75	38900	38900-Land & Land Rights	$ -	100.00%	100%	100%	$ -
76	39000	39000-Structures & Improvements	225,186	100.00%	100%	100%	225,186
77	39002	39002-Structures - Brick	4,207	100.00%	100%	100%	4,207
78	39003	39003-Improvements	21,302	100.00%	100%	100%	21,302
79	39004	39004-Air Conditioning Equipment	553	100.00%	100%	100%	553
80	39009	39009-Improv. to Leased Premises	-	100.00%	100%	100%	-
81	39100	39100-Office Furniture & Equipment	90,847	100.00%	100%	100%	90,847
82	39103	Office Machines	-	100.00%	100%	100%	-
83	39200	39200-Transportation Equipment	8,043	31.22%	100%	100%	2,511
84	39202	39202-WKG Trailers	1,628	31.22%	100%	100%	508
85	39400	39400-Tools, Shop, & Garage Equip.	449,666	37.66%	100%	100%	169,362
86	39603	39603-Ditchers	-	2.00%	100%	100%	-
87	39604	39604-Backhoes	-	2.00%	100%	100%	-
88	39605	39605-Welders	-	2.00%	100%	100%	-
89	39700	39700-Communication Equipment	28,944	100.00%	100%	100%	28,944
90	39701	Communication Equip.	-	100.00%	100%	100%	-
91	39702	Communication Equip.	-	100.00%	100%	100%	-
92	39705	39705-Comm. Equip. - Telemetering	-	100.00%	100%	100%	-
93	39800	39800-Miscellaneous Equipment	199,380	100.00%	100%	100%	199,380
94	39901	Servers Hardware	-	100.00%	100%	100%	-
95	39902	Servers Software	-	100.00%	100%	100%	-
96	39903	39903-Oth Tang Prop - Network - H/W	-	100.00%	100%	100%	-
97	39906	39906-Oth Tang Prop - PC Hardware	11,055	100.00%	100%	100%	11,055
98	39907	39907-Oth Tang Prop - PC Software	-	100.00%	100%	100%	-
99	39908	39908-Oth Tang Prop - Appl Software	-	100.00%	100%	100%	-
100		RWIP	-	100.00%	100%	100%	-
101							
102		Total General Plant Depr	$ 1,040,812				$ 753,856
103							
104		Total Depreciation Expense (Div 9)	$ 20,530,990				$ 20,244,034
105							
106							

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Depreciation Expense
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:______Base Period__X___Forecasted Period | FR 16(8)(b)3.1
Type of Filing:___X____Original________Updated ________Revised | Schedule B-3.1
Workpaper Reference No(s). | Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12 Months Ending 3/31/2026	O&M Expense Factor	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	$ -	100.00%	100%	48.90%	$ -
112	30300	Misc Intangible Plant	-	100.00%	100%	48.90%	-
113							
114		Total Intangible Plant Depr	$ -				$ -
115							
116		Distribution Plant					
117	37400	Land & Land Rights	$ -	100.00%	100%	48.90%	$ -
118	35010	Land	-	100.00%	100%	48.90%	-
119	37402	Land Rights	-	100.00%	100%	48.90%	-
120	37403	Land Other	-	100.00%	100%	48.90%	-
121	36602	Structures & Improvements	-	100.00%	100%	48.90%	-
122	37501	Structures & Improvements T.B.	-	100.00%	100%	48.90%	-
123	37402	Land Rights	-	100.00%	100%	48.90%	-
124	37503	Improvements	-	100.00%	100%	48.90%	-
125	36700	Mains Cathodic Protection	-	100.00%	100%	48.90%	-
126	36701	Mains - Steel	-	100.00%	100%	48.90%	-
127	37602	Mains - Plastic	-	100.00%	100%	48.90%	-
128	37800	Meas & Reg. Sta. Equip - General	-	100.00%	100%	48.90%	-
129	37900	Meas & Reg. Sta. Equip - City Gate	-	100.00%	100%	48.90%	-
130	37905	Meas & Reg. Sta. Equipment T.b.	-	100.00%	100%	48.90%	-
131	38000	Services	-	100.00%	100%	48.90%	-
132	38100	Meters	-	100.00%	100%	48.90%	-
133	38200	Meter Installaitons	-	100.00%	100%	48.90%	-
134	38300	House Regulators	-	100.00%	100%	48.90%	-
135	38400	House Reg. Installations	-	100.00%	100%	48.90%	-
136	38500	Ind. Meas. & Reg. Sta. Equipment	-	100.00%	100%	48.90%	-
137	38600	Other Prop. On Cust. Prem	-	100.00%	100%	48.90%	-
138							
139		Total Distribution Plant Depr	$ -				$ -
140							
141		General Plant					
142	39001	39001-Structures - Frame	$ 7,891	100.00%	100%	48.90%	$ 3,859
143	39004	39004-Air Conditioning Equipment	312	100.00%	100%	48.90%	153
144	39009	39009-Improv. to Leased Premises	-	100.00%	100%	48.90%	-
145	39100	39100-Office Furniture & Equipment	1,731	100.00%	100%	48.90%	847
146	39101	Office Furniture And	-	100.00%	100%	48.90%	-
147	39103	Office Machines	-	100.00%	100%	48.90%	-
148	39200	39200-Trans Equip- Group	374	33.11%	100%	48.90%	60
149	39300	Stores Equipment	-	100.00%	100%	48.90%	-
150	39400	39400-Tools, Shop, & Garage Equip.	6,713	41.74%	100%	48.90%	1,370
151	39600	39600-Power Operated Equipment	986	2.00%	100%	48.90%	10
152	39700	39700-Communication Equipment	-	100.00%	100%	48.90%	-
153	39701	Communication Equip.	-	100.00%	100%	48.90%	-
154	39702	Communication Equip.	-	100.00%	100%	48.90%	-
155	39800	39800-Miscellaneous Equipment	-	100.00%	100%	48.90%	-
156	39900	39900-Other Tangible Property	-	100.00%	100%	48.90%	-
157	39901	39901-Oth Tang Prop - Servers - H/W	-	100.00%	100%	48.90%	-
158	39902	39902-Oth Tang Prop - Servers - S/W	-	100.00%	100%	48.90%	-
159	39903	39903-Oth Tang Prop - Network - H/W	3,106	100.00%	100%	48.90%	1,519
160	39906	39906-Oth Tang Prop - PC Hardware	-	100.00%	100%	48.90%	-
161	39907	39907-Oth Tang Prop - PC Software	-	100.00%	100%	48.90%	-
162	39908	39908-Oth Tang Prop - Appl Software	-	100.00%	100%	48.90%	-
163							
164							
165		Total General Plant Depr	$ 21,113				$ 7,817
166							
167		Total Depreciation Expense (Div 91)	$ 21,113				$ 7,817

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Depreciation Expense
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:______Base Period__X___Forecasted Period — FR 16(8)(b)3.1
Type of Filing:___X____Original________Updated ________Revised — Schedule B-3.1
Workpaper Reference No(s). — Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12 Months Ending 3/31/2026	O&M Expense Factor	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	$ 134,334	100%	8.90%	48.90%	$ 5,846
173	39005	39005-G-Structures & Improvements	354,262	100%	100.00%	1.50%	5,328
174	39009	39009-Improv. to Leased Premises	626,231	100%	8.90%	48.90%	27,254
175	39020	Struct & Improv AEAM	586	100%	100.00%	5.59%	33
176	39029	Improv-Leased AEAM	2,425	100%	100.00%	5.59%	136
177	39100	39100-Office Furniture & Equipment	513,720	100%	8.90%	48.90%	22,358
178	39102	39102-Remittance Processing Equipment	-	100%	8.90%	48.90%	-
179	39103	39103-Office Furn. - Copiers & Type	-	100%	8.90%	48.90%	-
180	39104	39104-G-Office Furniture & Equip.	4,518	100%	100.00%	1.50%	68
181	39120	Off Furn & Equip-AEAM	19,582	100%	100.00%	5.59%	1,095
182	39200	39200-Transportation Equipment	20,785	100%	8.90%	48.90%	905
183	39300	39300-Stores Equipment	-	100%	8.90%	48.90%	-
184	39400	39400-Tools, Shop, & Garage Equip.	3,749	100%	8.90%	48.90%	163
185	39420	Tools And Garage-AEAM	-	100%	100.00%	5.59%	-
186	39500	39500-Laboratory Equipment	-	100%	8.90%	48.90%	-
187	39700	39700-Communication Equipment	43,119	100%	8.90%	48.90%	1,877
188	39720	Commun Equip AEAM	4,909	100%	100.00%	5.59%	275
189	39800	39800-Miscellaneous Equipment	7,555	100%	8.90%	48.90%	329
190	39820	Misc Equip - AEAM	741	100%	100.00%	5.59%	41
191	39900	39900-Other Tangible Equipm	-	100%	8.90%	48.90%	-
192	39901	39901-Oth Tang Prop - Servers - H/W	4,838,747	100%	8.90%	48.90%	210,587
193	39902	39902-Oth Tang Prop - Servers - S/W	4,113,532	100%	8.90%	48.90%	179,025
194	39903	39903-Oth Tang Prop - Network - H/W	551,361	100%	8.90%	48.90%	23,996
195	39904	39904-Oth Tang Prop - CPU	-	100%	8.90%	48.90%	-
196	39905	39905-Oth Tang Prop - MF Hardware	-	100%	8.90%	48.90%	-
197	39906	39906-Oth Tang Prop - PC Hardware	902,667	100%	8.90%	48.90%	39,285
198	39907	39907-Oth Tang Prop - PC Software	9,646	100%	8.90%	48.90%	420
199	39908	39908-Oth Tang Prop - Appl Software	7,527,804	100%	8.90%	48.90%	327,618
200	39909	39909-Oth Tang Prop - Mainframe S/W	-	100%	8.90%	48.90%	-
201	39921	Servers-Hardware-AEAM	2,053,803	100%	100.00%	5.59%	114,858
202	39922	Servers-Software-AEAM	547,978	100%	100.00%	5.59%	30,646
203	39923	Network Hardware-AEAM	143,242	100%	100.00%	5.59%	8,011
204	39924	39924-Oth Tang Prop - Gen.	-	100%	8.90%	48.90%	-
205	39926	Pc Hardware-AEAM	29,204	100%	100.00%	5.59%	1,633
206	39928	Application SW-AEAM	2,050,627	100%	100.00%	5.59%	114,681
207	39931	ALGN-Servers-Hardware	37,634	100%	100.00%	3.60%	1,355
208	39932	ALGN-Servers-Software	79,176	100%	100.00%	3.60%	2,850
209	39938	ALGN-Application SW	1,463,826	100%	100.00%	3.60%	52,697
210	ADJ	WTW Adjustment[1]	(185,588)	100%	8.90%	48.90%	(8,077)
211							
212		Total Depreciation Expense (Div 2)	$ 25,900,175				$ 1,165,290

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Depreciation Expense
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:______Base Period__X___Forecasted Period | FR 16(8)(b)3.1
Type of Filing:___X____Original________Updated ________Revised | Schedule B-3.1
Workpaper Reference No(s). | Witness: Waller

Line No.	Acct. No.	Account / SubAccount Titles	12 Months Ending 3/31/2026	O&M Expense Factor	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
213							
214	**Shared Services Customer Support (Division 012)**						
215							
216		General Plant					
217	38900	38900-Land	$ -	100%	10.86%	48.90%	$ -
218	38910	38910-CKV-Land & Land Rights	-	100%	100.00%	2.98%	-
219	39000	39000-Structures & Improvements	323,350	100%	10.86%	48.90%	17,172
220	39009	39009-Improv. to Leased Premises	140,457	100%	10.86%	48.90%	7,459
221	39010	39010-CKV-Structures & Improvements	299,659	100%	100.00%	2.98%	8,939
222	39100	39100-Office Furniture & Equipment	173,644	100%	10.86%	48.90%	9,221
223	39101	Office Furniture And	-	100%	10.86%	48.90%	-
224	39102	Remittance Processing	-	100%	10.86%	48.90%	-
225	39103	39103-Office Furn. - Copiers & Type	-	100%	10.86%	48.90%	-
226	39110	CKV-Office Furn & Eq	62,887	100%	100.00%	2.98%	1,876
227	39210	CKV-Transportation Eq	-	100%	100.00%	2.98%	-
228	39410	CKV-Tools Shop Garage	88,806	100%	100.00%	2.98%	2,649
229	39510	CKV-Laboratory Equip	-	100%	100.00%	2.98%	-
230	39700	39700-Communication Equipment	121,292	100%	10.86%	48.90%	6,441
231	39710	39710-CKV-Communication Equipment	5,886	100%	100.00%	2.98%	176
232	39800	39800-Miscellaneous Equipment	9,334	100%	10.86%	48.90%	496
233	39810	CKV-Misc Equipment	53,555	100%	100.00%	2.98%	1,598
234	39900	39900-Other Tangible Property	-	100%	10.86%	48.90%	-
235	39901	39901-Oth Tang Prop - Servers - H/W	715,374	100%	10.86%	48.90%	37,990
236	39902	39902-Oth Tang Prop - Servers - S/W	-	100%	10.86%	48.90%	-
237	39903	39903-Oth Tang Prop - Network - H/W	74,367	100%	10.86%	48.90%	3,949
238	39906	39906-Oth Tang Prop - PC Hardware	333,584	100%	10.86%	48.90%	17,715
239	39907	39907-Oth Tang Prop - PC Software	-	100%	10.86%	48.90%	-
240	39908	39908-Oth Tang Prop - Appl Software	7,462,508	100%	10.86%	48.90%	396,299
241	39910	39910-CKV-Other Tangible Property	39,754	100%	100.00%	2.98%	1,186
242	39916	39916-CKV-Oth Tang Prop-PC Hardware	23,187	100%	100.00%	2.98%	692
243	39917	39917-CKV-Oth Tang Prop-PC Software	385	100%	100.00%	2.98%	11
244	39918	CKV-Oth Tang Prop-App	-	100%	100.00%	2.98%	-
245	39924	Oth Tang Prop - Gen.	-	100%	10.86%	48.90%	-
246							
247							
248		Total Depreciation Expense (Div 12)	$ 9,928,028				$ 513,870
249							
250		Total Accumulated Depreciation & Amortization (Div 009, 091, 002, 012)	$ 56,380,306				$ 21,931,011
251							

252 Note: 1. This amount relates to the reclass of depreciaiton and amortization expense due to the Willis Towers Watson identified
253 adjustment during years 2018-2021. This amount began being amortized in November 2021 and will continue for 5 years.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Allowance For Working Capital
Base Period: Twelve Months Ended December 31, 2024

Data:__X___Base Period______Forecasted Period — FR 16(8)(b)4
Type of Filing:___X____Original________Updated ________Revised — Schedule B-4 B
Workpaper Reference No(s). — Witness: Christian, Waller

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		$ (2,306,187)
2	Material & Supplies	13 Month Average Balance	B-4.1	533,487
3	Gas Stored Underground	13 Month Average Balance	B-4.1	17,289,465
4	Prepayments	13 Month Average Balance	B-4.1	-
5	Total Working Capital Requirements			$ 15,516,765

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Allowance For Working Capital
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:______Base Period__X___Forecasted Period — FR 16(8)(b)4
Type of Filing:___X____Original________Updated ________Revised — Schedule B-4 F
Workpaper Reference No(s). — Witness: Christian, Waller

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		$ (768,634)
2	Material & Supplies	13 Month Average Balance	B-4.1	522,266
3	Gas Stored Underground	13 Month Average Balance	B-4.1	9,182,907
4	Prepayments	13 Month Average Balance	B-4.1	0
5	Total Working Capital Requirements			$ 8,936,539

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Working Capital Components
Base Period: Twelve Months Ended December 31, 2024

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

Line No.	Description	Base Period Ending Balance: 12/31/2024 Ending Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average: 12/31/2024 13 Month Avg	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
1	Material & Supplies (Account 1540 & 1630)								
2	Kentucky Direct (Div 009)	$ (29,510)	100%	100%	$ (29,510)	$ (29,026)	100%	100%	$ (29,026)
3	KY/Mid-States General Office (Div 091)	1,100,525	100%	49.97%	549,932	1,097,860	100%	49.97%	548,601
4	Shared Services General Office (Div 002)	312,923	8.90%	49.97%	13,917	312,804	8.90%	49.97%	13,911
5	Shared Services Customer Support (Div 012)	-	10.86%	49.46%	-	-	10.86%	49.46%	-
6	Total	$ 1,383,939			$ 534,339	$ 1,381,638			$ 533,487
7									
8	Gas Stored Underground (Account 1641)								
9	Kentucky Direct (Div 009)	$ 14,105,108	100%	100%	$ 14,105,108	$ 17,289,465	100%	100%	$ 17,289,465
10	KY/Mid-States General Office (Div 091)	-	100%	49.97%	-	-	100%	49.97%	-
11	Shared Services General Office (Div 002)	-	8.90%	49.97%	-	-	8.90%	49.97%	-
12	Shared Services Customer Support (Div 012)	-	10.86%	49.46%	-	-	10.86%	49.46%	-
13	Total	$ 14,105,108			$ 14,105,108	$ 17,289,465			$ 17,289,465
14									
15	Prepayments (Account 1650)								
16	Kentucky Direct (Div 009)	$ -	100%	100%	$ -	$ -	100%	100%	$ -
17	KY/Mid-States General Office (Div 091)	-	100%	49.97%	-	-	100%	49.97%	-
18	Shared Services General Office (Div 002)	-	8.90%	49.97%	-	-	8.90%	49.97%	-
19	Shared Services Customer Support (Div 012)	-	10.86%	49.46%	-	-	10.86%	49.46%	-
20	Total	$ -			$ -	$ -			$ -
21									
22	Total Other Working Capital Allowances	$ 15,489,047			$ 14,639,447	$ 18,671,103			$ 17,822,952

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Working Capital Components
Forecasted Test Period: Twelve Months Ended March 31, 2026

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

Line No.	Description	Forecasted Period Ending Balance: 3/31/2026 Ending Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount	13 Month Average: 3/31/2026 13 Month Avg	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
1	Material & Supplies (Account 1540 & 1630)								
2	Kentucky Direct (Div 009)	$ (29,510)	100%	100%	$ (29,510)	$ (29,510)	100%	100%	$ (29,510)
3	KY/Mid-States General Office (Div 091)	1,100,525	100%	48.90%	538,157	1,100,525	100%	48.90%	538,157
4	Shared Services General Office (Div 002)	312,923	8.90%	48.90%	13,619	312,923	8.90%	48.90%	13,619
5	Shared Services Customer Support (Div 012)	-	10.86%	48.90%	-	-	10.86%	48.90%	-
6	Total	$ 1,383,939			$ 522,266	$ 1,383,939			$ 522,266
7									
8	Gas Stored Underground (Account 1641)								
9	Kentucky Direct (Div 009)	$ (4,797,385)	100%	100%	$ (4,797,385)	$ 9,182,907	100%	100%	$ 9,182,907
10	KY/Mid-States General Office (Div 091)	-	100%	48.90%	-	-	100%	48.90%	-
11	Shared Services General Office (Div 002)	-	8.90%	48.90%	-	-	8.90%	48.90%	-
12	Shared Services Customer Support (Div 012)	-	10.86%	48.90%	-	-	10.86%	48.90%	-
13	Total	$ (4,797,385)			$ (4,797,385)	$ 9,182,907			$ 9,182,907
14									
15	Prepayments (Account 1650)								
16	Kentucky Direct (Div 009)	$ -	100%	100%	$ -	$ -	100%	100%	$ -
17	KY/Mid-States General Office (Div 091)	-	100%	48.90%	-	-	100%	48.90%	-
18	Shared Services General Office (Div 002)	-	8.90%	48.90%	-	-	8.90%	48.90%	-
19	Shared Services Customer Support (Div 012)	-	10.86%	48.90%	-	-	10.86%	48.90%	-
20	Total	$ -			$ -	$ -			$ -
21									
22	Total Other Working Capital Allowances	$ (3,413,446)			$ (4,275,119)	$ 10,566,846			$ 9,705,173

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Cash Working Capital Components - 1 / 8 O&M Expenses
Base Period: Twelve Months Ended December 31, 2024

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: Christian, Waller

Line No.	Description	Total Company	1 /8 Method Percent	Jurisdictional Amount
		(1)	(2)	(3)
1	Cash Working Capital			
2	Production O&M Expense	$ -	12.50%	$ -
3	Storage O&M Expense	438,182	12.50%	54,773
4	Transmission O&M Expense	163,544	12.50%	20,443
5	Distribution O&M Expense	11,872,519	12.50%	1,484,065
6	Customer Accting. & Collection	3,596,931	12.50%	449,616
7	Customer Service & Information	198,663	12.50%	24,833
8	Sales Expense	304,172	12.50%	38,021
9	Admin. & General Expense	16,962,917	12.50%	2,120,365
10	Total O & M Expenses	$ 33,536,927		$ 4,192,116

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Cash Working Capital Components - 1 / 8 O&M Expenses
Forecasted Test Period: Twelve Months Ended March 31, 2026

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

FR 16(8)(b)4.2
Schedule B-4.2 F
Witness: Christian, Waller

Line No.	Description	Total Company	1 /8 Method Percent	Jurisdictional Amount
		(1)	(2)	(3)
1	Cash Working Capital			
2	Production O&M Expense	$ -	12.50%	$ -
3	Storage O&M Expense	486,338	12.50%	60,792
4	Transmission O&M Expense	180,838	12.50%	22,605
5	Distribution O&M Expense	11,746,231	12.50%	1,468,279
6	Customer Accting. & Collection	2,534,624	12.50%	316,828
7	Customer Service & Information	214,461	12.50%	26,808
8	Sales Expense	84,610	12.50%	10,576
9	Admin. & General Expense	16,260,853	12.50%	2,032,607
10	Total O & M Expenses	$ 31,507,955		$ 3,938,494

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Deferred Credits and Accumulated Deferred Income Taxes
Base Period: Twelve Months Ended December 31, 2024

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, Multer

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)	$ 11,911,634	100%	100%	$ 11,911,634	$ 12,182,286	100%	100%	$ 12,182,286
2									
3	Account 282 - Accumulated Deferred Income Taxes	(135,783,734)	100%	100%	(135,783,734)	(132,356,045)	100%	100%	(132,356,045)
4									
5	Account 283 - Accumulated Deferred Income Taxes - Other	(61,287)	100%	100%	(61,287)	(61,287)	100%	100%	(61,287)
6									
7	Div 09 Accumulated Deferred Income Taxes	$ (123,933,387)			$ (123,933,387)	$ (120,235,046)			$ (120,235,046)
8									
9	**DIVISION 02**								
10	Account 190 - Accumulated Deferred Income Taxes	$ 618,554,240	9.13%	49.97%	$ 28,220,059	$ 597,800,903	9.13%	49.97%	$ 27,273,237
11									
12	Account 282 - Accumulated Deferred Income Taxes	(17,391,076)	9.13%	49.97%	(793,426)	(18,627,684)	9.13%	49.97%	(849,844)
13									
14	Account 283 - Accumulated Deferred Income Taxes - Other	(147,575,369)	9.13%	49.97%	(6,732,774)	(146,120,033)	9.13%	49.97%	(6,666,377)
15									
16	Div 02 Accumulated Deferred Income Taxes	$ 453,587,794			$ 20,693,859	$ 433,053,185			$ 19,757,017
17	**DIVISION 12**								
18	Account 190 - Accumulated Deferred Income Taxes	$ (1,216,417)	10.90%	49.46%	$ (65,579)	$ (1,211,621)	10.90%	49.46%	$ (65,320)
19									
20	Account 282 - Accumulated Deferred Income Taxes	(8,657,131)	10.90%	49.46%	(466,718)	(9,540,989)	10.90%	49.46%	(514,368)
21									
22	Account 283 - Accumulated Deferred Income Taxes - Other	0	10.90%	49.46%	0	0	10.90%	49.46%	0
23									
24	Div 012 Accumulated Deferred Income Taxes	$ (9,873,548)			$ (532,297)	$ (10,752,610)			$ (579,688)
25	**DIVISION 91**								
26									
27	Account 190 - Accumulated Deferred Income Taxes	$ 1,641,942	100%	49.97%	$ 820,478	$ 1,623,979	100%	49.97%	$ 811,502
28									
29	Account 255 - Accumulated Deferred Investment Tax Credits	0	100%	49.97%	0	0	100%	49.97%	0
30									
31	Account 282 - Accumulated Deferred Income Taxes	238,974	100%	49.97%	119,415	(264,373)	100%	49.97%	(132,107)
32									
33	Account 283 - Accumulated Deferred Income Taxes - Other	(2,254,245)	100%	49.97%	(1,126,446)	(1,744,095)	100%	49.97%	(871,524)
34									
35	Div 91 Accumulated Deferred Income Taxes	$ (373,329)			$ (186,552)	$ (384,489)			$ (192,129)
36									
37	**Total Deferred Inc. Taxes and Investment Tax Credits**	$ 319,407,531			$ (103,958,377)	$ 301,681,040			$ (101,249,847)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Deferred Credits and Accumulated Deferred Income Taxes
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Multer

Line No.	Account	Period End	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Jurisdictional Period ending Balance	Test Period Prorated Ending Balance	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Allocated Amount
	DIVISION 09								
1	Account 190 - Accumulated Deferred Income Taxes	$ 11,911,634	100%	100%	$ 11,911,634	$ 11,911,634	100%	100%	$ 11,911,634
2									
3	Account 282 - Accumulated Deferred Income Taxes	(140,238,520)	100%	100%	(140,238,520)	(140,238,520)	100%	100%	(140,238,520)
4									
5	Account 283 - Accumulated Deferred Income Taxes - Other	(61,287)	100%	100%	(61,287)	(61,287)	100%	100%	(61,287)
6									
7	Div 09 Accumulated Deferred Income Taxes	$ (128,388,173)			$ (128,388,173)	$ (128,388,173)			$ (128,388,173)
8									
9	**DIVISION 02**								
10	Account 190 - Accumulated Deferred Income Taxes	$ 618,554,240	8.90%	48.90%	$ 26,920,099	$ 618,554,240	8.90%	48.90%	$ 26,920,099
11									
12	Account 282 - Accumulated Deferred Income Taxes	(17,592,465)	8.90%	48.90%	(765,642)	(17,592,465)	8.90%	48.90%	(765,642)
13									
14	Account 283 - Accumulated Deferred Income Taxes - Other	(147,575,369)	8.90%	48.90%	(6,422,628)	(147,575,369)	8.90%	48.90%	(6,422,628)
15									
16	Div 02 Accumulated Deferred Income Taxes	$ 453,386,406			$ 19,731,830	$ 453,386,406			$ 19,731,830
17	**DIVISION 12**								
18	Account 190 - Accumulated Deferred Income Taxes	$ (1,216,417)	10.86%	48.90%	$ (64,598)	$ (1,216,417)	10.86%	48.90%	$ (64,598)
19									
20	Account 282 - Accumulated Deferred Income Taxes	(7,914,422)	10.86%	48.90%	(420,299)	(7,914,422)	10.86%	48.90%	(420,299)
21									
22	Account 283 - Accumulated Deferred Income Taxes - Other	0	10.86%	48.90%	0	0	10.86%	48.90%	0
23									
24	Div 012 Accumulated Deferred Income Taxes	$ (9,130,839)			$ (484,897)	$ (9,130,839)			$ (484,897)
25	**DIVISION 91**								
26	Account 190 - Accumulated Deferred Income Taxes	$ 1,641,942	100%	48.90%	$ 802,910	$ 1,641,942	100%	48.90%	$ 802,910
27									
28	Account 255 - Accumulated Deferred Investment Tax Credits	0	100%	48.90%	0	0	100%	48.90%	0
29									
30	Account 282 - Accumulated Deferred Income Taxes	242,621	100%	48.90%	118,642	242,621	100%	48.90%	118,642
31									
32	Account 283 - Accumulated Deferred Income Taxes - Other	(2,254,245)	100%	48.90%	(1,102,326)	(2,254,245)	100%	48.90%	(1,102,326)
33									
34	Div 91 Accumulated Deferred Income Taxes	$ (369,682)			$ (180,774)	$ (369,682)			$ (180,774)
35									
36									
37	**Total Deferred Inc. Taxes and Investment Tax Credits**	$ 315,497,713			$ (109,322,014)	$ 315,497,713			$ (109,322,014)
38	*(excluding forecasted change in NOLC)*								
39	**Forecasted Change in NOLC**								(5,742,393)
40									
41	**Forecasted 13-month Average ADIT in Rate Base**								**(115,064,407)**
42									

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Deferred Credits and Accumulated Deferred Income Taxes
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:_____Base Period___X__Forecasted Period — FR 16(8)(b)5
Type of Filing:___X____Original________Updated — Sch. B-5 F
Workpaper Reference No(s). — Witness: Waller, Multer

Line No.	Account	Period End	Kentucky- Mid States Division Allocation	Kentucky Jurisdiction Allocation	Jurisdictional Period ending Balance	Test Period Prorated Ending Balance	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		623,012,457			
49									
50	Required Operating Income			A.1		51,710,034			
51									
52	Interest Deduction			E.1		10,155,615			
53									
54	Return on Equity Portion of Rate Base			line 50 - line 52		41,554,419			
55									
56	Return, grossed up for Income Tax	24.95%		Line 54 / (1-tax rate)		55,368,980			
57									
58	Tax Expense on Return	24.95%		Line 56 x tax rate		13,814,560			
59									
60	Change In ADIT, excluding forecasted change in NOLC			Line 37; B.5 B		(8,072,167)			
61	Required Change in NOLC					(5,742,393)			
62									
63	**Total Required Change in Accumulated Deferred Income Taxes** [1]			**B.1 F; B.1 B**		**(13,814,560)**			
64									
65									
66	**ADIT Reconciliation**								
67	**Avg ADIT, Base Period**			**B.5 B**		**(101,249,847)**			
68									
69	13-Month Average ADIT, Forecasted Period, excl, Change in NOLC			Line 37		(109,322,014)			
70	Change in NOLC			Line 39		(5,742,393)			
71	**Forecasted 13-month Average ADIT in Rate Base**					**(115,064,407)**			
72									
73	**Total Required Change in Accumulated Deferred Income Taxes**			Line 71 - Line 67		**(13,814,560)**			
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*								

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Customer Advances For Construction
Base Period: Twelve Months Ended December 31, 2024

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 Divisior 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	$ (736,136)	100%	100%	$ (736,136)	$ (736,136)	100%	100%	$ (736,136)
2									
3	**DIVISION 02**								
4	15560 Account 252 - Customer Advances For Construction	-	9.13%	49.97%	-	-	9.13%	49.97%	-
5									
6	**DIVISION 12**								
7	15560 Account 252 - Customer Advances For Construction	-	10.90%	49.46%	-	-	10.90%	49.46%	-
8									
9	**DIVISION 91**								
10	15560 Account 252 - Customer Advances For Construction	-	100%	49.97%	-	-	100%	49.97%	-
11									
12	Total Account 252 - Customer Advances For Constructior	$ (736,136)			$ (736,136)	$ (736,136)			$ (736,136)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Customer Advances For Construction
Forecasted Test Period: Twelve Months Ended March 31, 2026

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 Divisior 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	$ (736,136)	100%	100%	$ (736,136)	$ (736,136)	100%	100%	$ (736,136)
2										
3	**DIVISION 02**									
4	15560	Account 252 - Customer Advances For Construction	-	8.90%	48.90%	-	-	8.90%	48.90%	-
5										
6	**DIVISION 12**									
7	15560	Account 252 - Customer Advances For Construction	-	10.86%	48.90%	-	-	10.86%	48.90%	-
8										
9	**DIVISION 91**									
10	15560	Account 252 - Customer Advances For Construction	0	100%	48.90%	0	0	100%	48.90%	0
11										
12		Total Account 252 - Customer Advances For Constructior	$ (736,136)			$ (736,136)	$ (736,136)			$ (736,136)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Working Capital Components

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

FR 16(8)(b)4.1
WP B.4.1 F
Witness: Waller, Multer

Line No.	Description	actual Dec-23	actual Jan-24	actual Feb-24	actual Mar-24	actual Apr-24	actual May-24	actual Jun-24	projected Jul-24	projected Aug-24	projected Sep-24	projected Oct-24	projected Nov-24	projected Dec-24	13 Month Average
1	**Materials & Supplies**														
2															
3	Kentucky Direct (Div 009)														
4	Account 1540- Plant Materials and Operating Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Account 1560- Other Materials and Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
6	Account 1630- Stores Expense Undistributed	$ (23,216)	$ (26,849)	$ (28,789)	$ (27,632)	$ (28,867)	$ (32,568)	$ (32,352)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	
7	Total Materials & Supplies	$ (23,216)	$ (26,849)	$ (28,789)	$ (27,632)	$ (28,867)	$ (32,568)	$ (32,352)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,026)
8															
9	KY/Mid-States General Office (Div 091)														
10	Account 1540- Plant Materials and Operating Supplies	$ 955,500	$ 955,500	$ 878,944	$ 878,944	$ 878,944	$ 842,833	$ 814,631	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	
11	Account 1560- Other Materials and Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
12	Account 1630- Stores Expense Undistributed	110,384	143,620	175,678	210,611	242,357	275,360	305,727	225,559	225,559	225,559	225,559	225,559	225,559	
13	Total Materials & Supplies	$ 1,065,884	$ 1,099,120	$ 1,054,622	$ 1,089,555	$ 1,121,301	$ 1,118,193	$ 1,120,358	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,097,860
14															
15	Shared Services General Office (Div 002)														
16	Account 1540- Plant Materials and Operating Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
17	Account 1560- Other Materials and Supplies	$ 311,365	$ 311,882	$ 312,399	$ 312,399	$ 312,399	$ 312,916	$ 315,546	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	
18	Account 1630- Stores Expense Undistributed	-	(0)	-	-	0	0	-	0	0	0	0	0	0	
19	Total Materials & Supplies	$ 311,365	$ 311,882	$ 312,399	$ 312,399	$ 312,399	$ 312,916	$ 315,546	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,804
20															
21	Shared Services Customer Support (Div 012)														
22	Account 1540- Plant Materials and Operating Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
23	Account 1560- Other Materials and Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
24	Account 1630- Stores Expense Undistributed	-	-	-	-	-	-	-	-	-	-	-	-	-	
25	Total Materials & Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26															
27	**Gas Stored Underground- Account 1641**														
28															
29	Kentucky Direct (Div 009)	$24,055,139	$19,877,503	$15,740,887	$11,948,688	$12,852,493	$14,187,795	$16,572,132	$16,917,150	$18,070,893	$ 19,869,475	$ 21,715,423	$18,850,359	$ 14,105,108	$17,289,465
30															
31	KY/Mid-States General Office (Div 091)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32															
33	Shared Services General Office (Div 002)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34															
35	Shared Services Customer Support (Div 012)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36															
37	**Prepayments- Account 1650**														
38															
39	Kentucky Direct (Div 009)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40															
41	KY/Mid-States General Office (Div 091)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42															
43	Shared Services General Office (Div 002)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44															
45	Shared Services Customer Support (Div 012)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Forecasted Test Period: Twelve Months Ended March 31, 2026
Working Capital Components

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

FR 16(8)(b)4.1
WP B.4.1 F
Witness: Waller, Multer

Line No.	Description	Forecasted Mar-25	Forecasted Apr-25	Forecasted May-25	Forecasted Jun-25	Forecasted Jul-25	Forecasted Aug-25	Forecasted Sep-25	Forecasted Oct-25	Forecasted Nov-25	Forecasted Dec-25	Forecasted Jan-26	Forecasted Feb-26	Forecasted Mar-26	13 Month Average
1	**Materials & Supplies**														
2															
3	Kentucky Direct (Div 009)														
4	Account 1540- Plant Materials and Operating Supplie	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
5	Account 1560- Other Materials and Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
6	Account 1630- Stores Expense Undistributed	(29,510)	(29,510)	(29,510)	(29,510)	(29,510)	(29,510)	(29,510)	(29,510)	(29,510)	(29,510)	(29,510)	(29,510)	(29,510)	
7	Total Materials & Supplies	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)	$ (29,510)
8															
9	KY/Mid-States General Office (Div 091)														
10	Account 1540- Plant Materials and Operating Supplie	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	$ 874,966	
11	Account 1560- Other Materials and Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
12	Account 1630- Stores Expense Undistributed	225,559	225,559	225,559	225,559	225,559	225,559	225,559	225,559	225,559	225,559	225,559	225,559	225,559	
13	Total Materials & Supplies	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525	$ 1,100,525
14															
15	Shared Services General Office (Div 002)														
16	Account 1540- Plant Materials and Operating Supplie	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
17	Account 1560- Other Materials and Supplies	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	
18	Account 1630- Stores Expense Undistributed	0	0	0	0	0	0	0	0	0	0	0	0	0	
19	Total Materials & Supplies	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923	$ 312,923
20															
21	Shared Services Customer Support (Div 012)														
22	Account 1540- Plant Materials and Operating Supplie	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
23	Account 1560- Other Materials and Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
24	Account 1630- Stores Expense Undistributed	-	-	-	-	-	-	-	-	-	-	-	-	-	
25	Total Materials & Supplies	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26															
27	**Gas Stored Underground- Account 1641**														
28															
29	Kentucky Direct (Div 009)	$ (4,613,647)	$ (866,643)	$ 2,940,314	$ 6,942,441	$11,158,870	$ 15,380,402	$19,682,298	$24,334,988	$21,164,722	$15,918,589	$10,013,767	$ 2,119,080	$ (4,797,385)	$ 9,182,907
30															
31	KY/Mid-States General Office (Div 091)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32															
33	Shared Services General Office (Div 002)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34															
35	Shared Services Customer Support (Div 012)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36															
37	**Prepayments- Account 1650**														
38															
39	Kentucky Direct (Div 009)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40															
41	KY/Mid-States General Office (Div 091)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42															
43	Shared Services General Office (Div 002)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44															
45	Shared Services Customer Support (Div 012)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Deferred Credits and Accumulated Deferred Income Taxes
Base Period: Twelve Months Ended December 31, 2024

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
Witness: Waller, Multer

Line No.	Sub Acct	actual Dec-23	actual Jan-24	actual Feb-24	actual Mar-24	actual Apr-24	actual May-24	actual Jun-24	forecast Jul-24	forecast Aug-24	forecast Sep-24	forecast Oct-24	forecast Nov-24	forecast Dec-24	13 month Average
	DIVISION 09														
1	Account 190 - Accumulated Deferred Income Taxes	$ 12,359,437	$ 12,194,500	$ 12,029,563	$ 12,966,529	$ 12,801,592	$ 12,636,655	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 12,182,286
2															
3	Account 282 - Accumulated Deferred Income Taxes	(128,950,664)	(129,499,648)	(130,052,643)	(130,549,784)	(131,191,913)	(131,590,859)	(132,241,437)	(132,696,522)	(133,237,135)	(134,522,934)	(134,942,476)	(135,368,832)	(135,783,734)	(132,356,045)
4															
5	Account 283 - Accumulated Deferred Income Taxes - Other	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)
6															
7	Div 09 Accumulated Deferred Income Taxes	$ (116,652,514)	$ (117,366,435)	$ (118,084,367)	$ (117,644,542)	$ (118,451,608)	$ (119,015,490)	$ (120,391,090)	$ (120,846,175)	$ (121,386,788)	$ (122,672,587)	$ (123,092,129)	$ (123,518,485)	$ (123,933,387)	$ (120,235,046)
8															
9	**DIVISION 02**														
10	Account 190 - Accumulated Deferred Income Taxes	$ 616,356,876	$ 616,356,876	$ 616,356,876	$ 573,743,939	$ 573,743,939	$ 573,743,939	$ 575,630,777	$ 575,630,777	$ 575,630,777	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 597,800,903
11															
12	Account 282 - Accumulated Deferred Income Taxes	(19,368,656)	(19,368,656)	(19,368,656)	(19,466,317)	(19,466,317)	(19,466,317)	(18,808,093)	(18,188,497)	(18,052,020)	(17,908,186)	(17,736,593)	(17,570,513)	(17,391,076)	(18,627,684)
13															
14	Account 283 - Accumulated Deferred Income Taxes - Other	(135,514,035)	(140,905,243)	(143,459,941)	(143,363,712)	(152,938,225)	(150,351,690)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(146,120,033)
15															
16	Div 02 Accumulated Deferred Income Taxes	$ 461,474,185	$ 456,082,977	$ 453,528,279	$ 410,913,910	$ 401,339,397	$ 403,925,932	$ 409,247,315	$ 409,866,911	$ 410,003,387	$ 453,070,685	$ 453,242,278	$ 453,408,357	$ 453,587,794	$ 433,053,185
17	**DIVISION 12**														
18	Account 190 - Accumulated Deferred Income Taxes	$ (1,200,917)	$ (1,200,917)	$ (1,200,917)	$ (1,211,134)	$ (1,211,134)	$ (1,211,134)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,211,621)
19															
20	Account 282 - Accumulated Deferred Income Taxes	(10,315,424)	(10,315,424)	(10,315,424)	(9,939,247)	(9,939,247)	(9,939,247)	(9,405,484)	(9,299,965)	(9,168,263)	(9,040,945)	(8,912,183)	(8,784,872)	(8,657,131)	(9,540,989)
21															
22	Account 283 - Accumulated Deferred Income Taxes - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23															
24	Div 012 Accumulated Deferred Income Taxes	$ (11,516,341)	$ (11,516,341)	$ (11,516,341)	$ (11,150,381)	$ (11,150,381)	$ (11,150,381)	$ (10,621,901)	$ (10,516,382)	$ (10,384,680)	$ (10,257,362)	$ (10,128,600)	$ (10,001,289)	$ (9,873,548)	$ (10,752,610)
25															
26	**DIVISION 91**														
27	Account 190 - Accumulated Deferred Income Taxes	$ 1,587,162	$ 1,587,162	$ 1,587,162	$ 1,618,882	$ 1,618,882	$ 1,618,882	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,623,979
28															
29	Account 282 - Accumulated Deferred Income Taxes	(694,095)	(694,095)	(694,095)	(695,528)	(695,528)	(695,528)	(696,959)	237,352	237,677	238,001	238,325	238,650	238,974	(264,373)
30															
31	Account 283 - Accumulated Deferred Income Taxes - Other	(338,915)	(338,915)	(338,915)	(1,958,925)	(1,958,925)	(1,958,925)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(1,744,095)
32															
33	Account 255 - Accumulated Deferred Investment Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34															
35	Div 91 Accumulated Deferred Income Taxes	$ 554,152	$ 554,152	$ 554,152	$ (1,035,571)	$ (1,035,571)	$ (1,035,571)	$ (1,309,262)	$ (374,951)	$ (374,626)	$ (374,302)	$ (373,978)	$ (373,653)	$ (373,329)	$ (384,489)
36															
37	Total	$ 333,859,482	$ 327,754,353	$ 324,481,723	$ 281,083,416	$ 270,701,837	$ 272,724,489	$ 276,925,062	$ 278,129,403	$ 277,857,293	$ 319,766,434	$ 319,647,571	$ 319,514,930	$ 319,407,531	$ 301,681,040

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
Deferred Liablity Amortization

Base Period

		Regulatory Liability Balance	Amortization Expense
ADIT Excess Deferred Liabilities	Dec-23	(16,062,381)	
Accounts 2530 - 27909, 2420 - 279	Jan-24	(15,339,513)	722,868
	Feb-24	(14,616,645)	722,868
	Mar-24	(13,893,777)	722,868
	Apr-24	(13,170,909)	722,868
	May-24	(12,448,041)	722,868
	Jun-24	(11,725,173)	722,868
	Jul-24	(11,002,306)	722,868
	Aug-24	(10,279,438)	722,868
	Sep-24	(9,556,570)	722,868
	Oct-24	(8,833,702)	722,868
	Nov-24	(8,110,834)	722,868
	Dec-24	(7,387,966)	722,868
	(13 Month Average)	**(11,725,173)**	**8,674,414**

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Deferred Credits and Accumulated Deferred Income Taxes
Forecasted Test Period: Twelve Months Ended March 31, 2026

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
Witness: Waller, Multer

Line No.	Sub Acct		Budgeted Mar-25	Budgeted Apr-25	Budgeted May-25	Budgeted Jun-25	Budgeted Jul-25	Forecast Aug-25	Forecast Sep-25	Forecast Oct-25	Forecast Nov-25	Forecast Dec-25	Forecast Jan-26	Forecast Feb-26	Forecast Mar-26	Test Period Prorated Ending Balance
	DIVISION 09															
1		Account 190 - Accumulated Deferred Income Taxes	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634	$ 11,911,634
2																
3		Account 282 - Accumulated Deferred Income Taxes	(136,887,382)	(137,242,234)	(137,568,292)	(137,996,857)	(138,259,628)	(138,587,024)	(139,638,886)	(139,804,857)	(139,940,087)	(140,047,090)	(140,152,551)	(140,215,744)	(140,238,520)	(140,238,520)
4																
5		Account 283 - Accumulated Deferred Income Taxes - Other	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)	(61,287)
6																
7		Div 09 Accumulated Deferred Income Taxes	$ (125,037,035)	$ (125,391,887)	$ (125,717,945)	$ (126,146,510)	$ (126,409,281)	$ (126,736,677)	$ (127,788,539)	$ (127,954,510)	$ (128,089,740)	$ (128,196,743)	$ (128,302,204)	$ (128,365,397)	$ (128,388,173)	$ (128,388,173)
8																
9	DIVISION 02															
10		Account 190 - Accumulated Deferred Income Taxes	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240	$ 618,554,240
11																
12		Account 282 - Accumulated Deferred Income Taxes	(17,612,875)	(17,689,151)	(17,702,873)	(17,823,130)	(17,826,729)	(17,784,466)	(17,740,077)	(17,670,214)	(17,629,111)	(17,584,864)	(17,590,454)	(17,592,397)	(17,592,465)	(17,592,465)
13																
14		Account 283 - Accumulated Deferred Income Taxes - Other	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)	(147,575,369)
15																
16		Div 02 Accumulated Deferred Income Taxes	$ 453,365,995	$ 453,289,720	$ 453,275,997	$ 453,155,741	$ 453,152,142	$ 453,194,405	$ 453,238,794	$ 453,308,656	$ 453,349,760	$ 453,394,007	$ 453,388,417	$ 453,386,473	$ 453,386,406	$ 453,386,406
17	DIVISION 12															
18		Account 190 - Accumulated Deferred Income Taxes	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)	$ (1,216,417)
19																
20		Account 282 - Accumulated Deferred Income Taxes	(8,475,714)	(8,383,834)	(8,295,078)	(8,212,891)	(8,135,941)	(8,060,497)	(7,998,176)	(7,940,332)	(7,897,228)	(7,863,097)	(7,890,406)	(7,908,061)	(7,914,422)	(7,914,422)
21																
22		Account 283 - Accumulated Deferred Income Taxes - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23																
24		Div 012 Accumulated Deferred Income Taxes	$ (9,692,131)	$ (9,600,251)	$ (9,511,495)	$ (9,429,308)	$ (9,352,358)	$ (9,276,914)	$ (9,214,593)	$ (9,156,749)	$ (9,113,645)	$ (9,079,514)	$ (9,106,823)	$ (9,124,478)	$ (9,130,839)	$ (9,130,839)
25																
26	DIVISION 91															
27		Account 190 - Accumulated Deferred Income Taxes	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942	$ 1,641,942
28																
29		Account 282 - Accumulated Deferred Income Taxes	239,947	240,374	240,766	241,121	241,439	241,719	241,962	242,162	242,325	242,452	242,543	242,600	242,621	242,621
30																
31		Account 283 - Accumulated Deferred Income Taxes - Other	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)	(2,254,245)
32																
33		Account 255 - Accumulated Deferred Investment Tax Credits	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34																
35		Div 91 Accumulated Deferred Income Taxes	$ (372,356)	$ (371,929)	$ (371,537)	$ (371,182)	$ (370,864)	$ (370,584)	$ (370,341)	$ (370,141)	$ (369,978)	$ (369,851)	$ (369,760)	$ (369,703)	$ (369,682)	$ (369,682)
36																
37		Total	$ 318,264,474	$ 317,925,653	$ 317,675,021	$ 317,208,740	$ 317,019,638	$ 316,810,230	$ 315,865,321	$ 315,827,255	$ 315,776,397	$ 315,747,899	$ 315,609,631	$ 315,526,895	$ 315,497,713	$ 315,497,713

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
Deferred Liablity Amortization

ADIT Excess Deferred Liabilities
Accounts 2530 - 27909, 2420 - 27909

Forecasted Test Period

Protected Balance and Amortization Only		
Test Period Ending Balance	Test Period 13-Month Balance	Test Period Amort. Expense
$ (3,625,792)	$ (3,720,791)	$ 189,998

Full Amortization Schedule

		Balance			Amortization		
						Accelerated	
		Protected	Unprotected	Total Reg Liability	Protected	Unprotected	Unprotected	Total
Beginning Regulatory Liability		$ (5,565,573)	$ (30,215,187)	$ (35,780,760)				
	May-18	(5,544,491)	(30,113,666)	(35,658,157)	21,082	101,521		122,603
	Jun-18	(5,523,409)	(30,012,145)	(35,535,555)	21,082	101,521		122,603
	Jul-18	(5,502,327)	(29,910,624)	(35,412,952)	21,082	101,521		122,603
	Aug-18	(5,481,246)	(29,809,103)	(35,290,349)	21,082	101,521		122,603
	Sep-18	(5,460,164)	(29,707,582)	(35,167,746)	21,082	101,521		122,603
	Oct-18	(5,439,082)	(29,606,061)	(35,045,143)	21,082	101,521		122,603
	Nov-18	(5,418,001)	(29,504,540)	(34,922,541)	21,082	101,521		122,603
	Dec-18	(5,396,919)	(29,403,019)	(34,799,938)	21,082	101,521		122,603
	Jan-19	(5,375,837)	(29,301,498)	(34,677,335)	21,082	101,521		122,603
	Feb-19	(5,354,755)	(29,199,977)	(34,554,732)	21,082	101,521		122,603
	Mar-19	(5,333,674)	(29,098,456)	(34,432,130)	21,082	101,521		122,603
First Change in Rates	Apr-19	(5,312,592)	(28,997,557)	(34,310,149)	21,082	100,899		121,981
	May-19	(5,291,510)	(28,896,658)	(34,188,169)	21,082	100,899		121,981
	Jun-19	(5,270,429)	(28,795,760)	(34,066,188)	21,082	100,899		121,981
	Jul-19	(5,249,347)	(28,694,861)	(33,944,208)	21,082	100,899		121,981
	Aug-19	(5,228,265)	(28,593,962)	(33,822,227)	21,082	100,899		121,981
	Sep-19	(5,207,183)	(28,493,063)	(33,700,247)	21,082	100,899		121,981
	Oct-19	(5,186,102)	(28,392,164)	(33,578,266)	21,082	100,899		121,981
	Nov-19	(5,165,020)	(28,291,266)	(33,456,286)	21,082	100,899		121,981
	Dec-19	(5,143,938)	(28,190,367)	(33,334,305)	21,082	100,899		121,981
	Jan-20	(5,122,857)	(28,089,468)	(33,212,324)	21,082	100,899		121,981
	Feb-20	(5,101,775)	(27,988,569)	(33,090,344)	21,082	100,899		121,981
	Mar-20	(5,080,693)	(27,887,670)	(32,968,363)	21,082	100,899		121,981
	Apr-20	(5,059,611)	(27,786,772)	(32,846,383)	21,082	100,899		121,981
	May-20	(5,038,530)	(27,685,873)	(32,724,402)	21,082	100,899		121,981
	Jun-20	(5,017,448)	(27,584,974)	(32,602,422)	21,082	100,899		121,981
	Jul-20	(4,996,366)	(27,484,075)	(32,480,441)	21,082	100,899		121,981
	Aug-20	(4,975,285)	(27,383,176)	(32,358,461)	21,082	100,899		121,981
	Sep-20	(4,954,203)	(27,282,278)	(32,236,480)	21,082	100,899		121,981
	Oct-20	(4,933,121)	(27,181,379)	(32,114,500)	21,082	100,899		121,981
	Nov-20	(4,912,039)	(27,080,480)	(31,992,519)	21,082	100,899		121,981
	Dec-20	(4,890,958)	(26,979,581)	(31,870,539)	21,082	100,899		121,981
	Jan-21	(4,869,876)	(26,878,682)	(31,748,558)	21,082	100,899		121,981
	Feb-21	(4,848,794)	(26,777,784)	(31,626,578)	21,082	100,899		121,981
	Mar-21	(4,827,713)	(26,676,885)	(31,504,597)	21,082	100,899		121,981
	Apr-21	(4,806,631)	(26,575,986)	(31,382,617)	21,082	100,899		121,981
	May-21	(4,785,549)	(26,475,087)	(31,260,636)	21,082	100,899		121,981
	Jun-21	(4,764,467)	(26,374,188)	(31,138,656)	21,082	100,899		121,981
	Jul-21	(4,743,386)	(26,273,290)	(31,016,675)	21,082	100,899		121,981
	Aug-21	(4,722,304)	(26,172,391)	(30,894,695)	21,082	100,899		121,981
	Sep-21	(4,701,222)	(26,071,492)	(30,772,714)	21,082	100,899		121,981
	Oct-21	(4,680,141)	(25,970,593)	(30,650,734)	21,082	100,899		121,981
	Nov-21	(4,659,059)	(25,869,694)	(30,528,753)	21,082	100,899		121,981
	Dec-21	(4,637,977)	(25,768,796)	(30,406,773)	21,082	100,899		121,981
	Jan-22	(4,616,895)	(25,667,897)	(30,284,792)	21,082	100,899		121,981
	Feb-22	(4,595,814)	(25,566,998)	(30,162,812)	21,082	100,899		121,981
	Mar-22	(4,574,732)	(25,466,099)	(30,040,831)	21,082	100,899		121,981
	Apr-22	(4,553,650)	(25,365,200)	(29,918,851)	21,082	100,899		121,981
	May-22	(4,532,569)	(25,264,302)	(29,796,870)	21,082	100,899		121,981
	Jun-22	(4,511,487)	(24,562,515)	(29,074,002)	21,082		701,786	722,868
	Jul-22	(4,490,405)	(23,860,729)	(28,351,134)	21,082		701,786	722,868
	Aug-22	(4,469,323)	(23,158,943)	(27,628,267)	21,082		701,786	722,868
	Sep-22	(4,448,242)	(22,457,157)	(26,905,399)	21,082		701,786	722,868
	Oct-22	(4,427,160)	(21,755,371)	(26,182,531)	21,082		701,786	722,868
	Nov-22	(4,406,078)	(21,053,585)	(25,459,663)	21,082		701,786	722,868
	Dec-22	(4,384,997)	(20,351,799)	(24,736,795)	21,082		701,786	722,868
	Jan-23	(4,363,915)	(19,650,012)	(24,013,927)	21,082		701,786	722,868
	Feb-23	(4,342,833)	(18,948,226)	(23,291,059)	21,082		701,786	722,868

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
Deferred Liablity Amortization

ADIT Excess Deferred Liabilities
Accounts 2530 - 27909, 2420 - 27909

Forecasted Test Period

Protected Balance and Amortization Only		
Test Period Ending Balance	Test Period 13-Month Balance	Test Period Amort. Expense
$ (3,625,792)	$ (3,720,791)	$ 189,998

Full Amortization Schedule

		Balance			Amortization			
		Protected	Unprotected	Total Reg Liability	Protected	Unprotected	Accelerated Unprotected	Total
	Mar-23	(4,321,751)	(18,246,440)	(22,568,191)	21,082		701,786	722,868
	Apr-23	(4,300,670)	(17,544,654)	(21,845,324)	21,082		701,786	722,868
	May-23	(4,279,588)	(16,842,868)	(21,122,456)	21,082		701,786	722,868
	Jun-23	(4,258,506)	(16,141,082)	(20,399,588)	21,082		701,786	722,868
	Jul-23	(4,237,425)	(15,439,295)	(19,676,720)	21,082		701,786	722,868
	Aug-23	(4,216,343)	(14,737,509)	(18,953,852)	21,082		701,786	722,868
	Sep-23	(4,195,261)	(14,035,723)	(18,230,984)	21,082		701,786	722,868
	Oct-23	(4,174,179)	(13,333,937)	(17,508,116)	21,082		701,786	722,868
	Nov-23	(4,153,098)	(12,632,151)	(16,785,249)	21,082		701,786	722,868
	Dec-23	(4,132,016)	(11,930,365)	(16,062,381)	21,082		701,786	722,868
	Jan-24	(4,110,934)	(11,228,578)	(15,339,513)	21,082		701,786	722,868
	Feb-24	(4,089,853)	(10,526,792)	(14,616,645)	21,082		701,786	722,868
	Mar-24	(4,068,771)	(9,825,006)	(13,893,777)	21,082		701,786	722,868
	Apr-24	(4,047,689)	(9,123,220)	(13,170,909)	21,082		701,786	722,868
	May-24	(4,026,607)	(8,421,434)	(12,448,041)	21,082		701,786	722,868
	Jun-24	(4,005,526)	(7,719,648)	(11,725,173)	21,082		701,786	722,868
	Jul-24	(3,984,444)	(7,017,862)	(11,002,306)	21,082		701,786	722,868
	Aug-24	(3,963,362)	(6,316,075)	(10,279,438)	21,082		701,786	722,868
	Sep-24	(3,942,281)	(5,614,289)	(9,556,570)	21,082		701,786	722,868
	Oct-24	(3,921,199)	(4,912,503)	(8,833,702)	21,082		701,786	722,868
	Nov-24	(3,900,117)	(4,210,717)	(8,110,834)	21,082		701,786	722,868
	Dec-24	(3,879,035)	(3,508,931)	(7,387,966)	21,082		701,786	722,868
	Jan-25	(3,857,954)	(2,807,145)	(6,665,098)	21,082		701,786	722,868
	Feb-25	(3,836,872)	(2,105,358)	(5,942,230)	21,082		701,786	722,868
	Mar-25	(3,815,790)	(1,403,572)	(5,219,363)	21,082		701,786	722,868
New Rate Set	Apr-25	(3,799,957)	(701,786)	(4,501,743)	15,833		701,786	717,619
	May-25	(3,784,124)	(0)	(3,784,124)	15,833		701,786	717,619
	Jun-25	(3,768,291)	(0)	(3,768,291)	15,833			15,833
	Jul-25	(3,752,458)	(0)	(3,752,458)	15,833			15,833
	Aug-25	(3,736,625)	(0)	(3,736,625)	15,833			15,833
	Sep-25	(3,720,791)	(0)	(3,720,791)	15,833			15,833
	Oct-25	(3,704,958)	(0)	(3,704,958)	15,833			15,833
	Nov-25	(3,689,125)	(0)	(3,689,125)	15,833			15,833
	Dec-25	(3,673,292)	(0)	(3,673,292)	15,833			15,833
	Jan-26	(3,657,459)	(0)	(3,657,459)	15,833			15,833
	Feb-26	(3,641,626)	(0)	(3,641,626)	15,833			15,833
Forecasted Test Period End	Mar-26	(3,625,792)	(0)	(3,625,792)	15,833			15,833
	Apr-26	(3,609,959)	(0)	(3,609,959)	15,833			15,833
	May-26	(3,594,126)	(0)	(3,594,126)	15,833			15,833
	Jun-26	(3,578,293)	(0)	(3,578,293)	15,833			15,833
	Jul-26	(3,562,460)	(0)	(3,562,460)	15,833			15,833
	Aug-26	(3,546,627)	(0)	(3,546,627)	15,833			15,833
	Sep-26	(3,530,794)	(0)	(3,530,794)	15,833			15,833
	Oct-26	(3,514,960)	(0)	(3,514,960)	15,833			15,833
	Nov-26	(3,499,127)	(0)	(3,499,127)	15,833			15,833
	Dec-26	(3,483,294)	(0)	(3,483,294)	15,833			15,833
	Jan-27	(3,467,461)	(0)	(3,467,461)	15,833			15,833
	Feb-27	(3,451,628)	(0)	(3,451,628)	15,833			15,833
	Mar-27	(3,435,795)	(0)	(3,435,795)	15,833			15,833
	Apr-27	(3,419,961)	(0)	(3,419,961)	15,833			15,833
	May-27	(3,404,128)	(0)	(3,404,128)	15,833			15,833
	Jun-27	(3,388,295)	(0)	(3,388,295)	15,833			15,833
	Jul-27	(3,372,462)	(0)	(3,372,462)	15,833			15,833
	Aug-27	(3,356,629)	(0)	(3,356,629)	15,833			15,833
	Sep-27	(3,340,796)	(0)	(3,340,796)	15,833			15,833
	Oct-27	(3,324,963)	(0)	(3,324,963)	15,833			15,833
	Nov-27	(3,309,129)	(0)	(3,309,129)	15,833			15,833
	Dec-27	(3,293,296)	(0)	(3,293,296)	15,833			15,833
	Jan-28	(3,277,463)	(0)	(3,277,463)	15,833			15,833

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
Deferred Liablity Amortization

ADIT Excess Deferred Liabilities
Accounts 2530 - 27909, 2420 - 27909

Forecasted Test Period

Protected Balance and Amortization Only		
Test Period Ending Balance	Test Period 13-Month Balance	Test Period Amort. Expense
$ (3,625,792)	$ (3,720,791)	$ 189,998

Full Amortization Schedule

	Balance			Amortization			
	Protected	Unprotected	Total Reg Liability	Protected	Unprotected	Accelerated Unprotected	Total
Feb-28	(3,261,630)	(0)	(3,261,630)	15,833			15,833
Mar-28	(3,245,797)	(0)	(3,245,797)	15,833			15,833
Apr-28	(3,229,964)	(0)	(3,229,964)	15,833			15,833
May-28	(3,214,130)	(0)	(3,214,130)	15,833			15,833
Jun-28	(3,198,297)	(0)	(3,198,297)	15,833			15,833
Jul-28	(3,182,464)	(0)	(3,182,464)	15,833			15,833
Aug-28	(3,166,631)	(0)	(3,166,631)	15,833			15,833
Sep-28	(3,150,798)	(0)	(3,150,798)	15,833			15,833
Oct-28	(3,134,965)	(0)	(3,134,965)	15,833			15,833
Nov-28	(3,119,131)	(0)	(3,119,131)	15,833			15,833
Dec-28	(3,103,298)	(0)	(3,103,298)	15,833			15,833
Jan-29	(3,087,465)	(0)	(3,087,465)	15,833			15,833
Feb-29	(3,071,632)	(0)	(3,071,632)	15,833			15,833
Mar-29	(3,055,799)	(0)	(3,055,799)	15,833			15,833
Apr-29	(3,039,966)	(0)	(3,039,966)	15,833			15,833
May-29	(3,024,133)	(0)	(3,024,133)	15,833			15,833
Jun-29	(3,008,299)	(0)	(3,008,299)	15,833			15,833
Jul-29	(2,992,466)	(0)	(2,992,466)	15,833			15,833
Aug-29	(2,976,633)	(0)	(2,976,633)	15,833			15,833
Sep-29	(2,960,800)	(0)	(2,960,800)	15,833			15,833
Oct-29	(2,944,967)	(0)	(2,944,967)	15,833			15,833
Nov-29	(2,929,134)	(0)	(2,929,134)	15,833			15,833
Dec-29	(2,913,300)	(0)	(2,913,300)	15,833			15,833
Jan-30	(2,897,467)	(0)	(2,897,467)	15,833			15,833
Feb-30	(2,881,634)	(0)	(2,881,634)	15,833			15,833
Mar-30	(2,865,801)	(0)	(2,865,801)	15,833			15,833
Apr-30	(2,849,968)	(0)	(2,849,968)	15,833			15,833
May-30	(2,834,135)	(0)	(2,834,135)	15,833			15,833
Jun-30	(2,818,302)	(0)	(2,818,302)	15,833			15,833
Jul-30	(2,802,468)	(0)	(2,802,468)	15,833			15,833
Aug-30	(2,786,635)	(0)	(2,786,635)	15,833			15,833
Sep-30	(2,770,802)	(0)	(2,770,802)	15,833			15,833
Oct-30	(2,754,969)	(0)	(2,754,969)	15,833			15,833
Nov-30	(2,739,136)	(0)	(2,739,136)	15,833			15,833
Dec-30	(2,723,303)	(0)	(2,723,303)	15,833			15,833
Jan-31	(2,707,469)	(0)	(2,707,469)	15,833			15,833
Feb-31	(2,691,636)	(0)	(2,691,636)	15,833			15,833
Mar-31	(2,675,803)	(0)	(2,675,803)	15,833			15,833
Apr-31	(2,659,970)	(0)	(2,659,970)	15,833			15,833
May-31	(2,644,137)	(0)	(2,644,137)	15,833			15,833
Jun-31	(2,628,304)	(0)	(2,628,304)	15,833			15,833
Jul-31	(2,612,471)	(0)	(2,612,471)	15,833			15,833
Aug-31	(2,596,637)	(0)	(2,596,637)	15,833			15,833
Sep-31	(2,580,804)	(0)	(2,580,804)	15,833			15,833
Oct-31	(2,564,971)	(0)	(2,564,971)	15,833			15,833
Nov-31	(2,549,138)	(0)	(2,549,138)	15,833			15,833
Dec-31	(2,533,305)	(0)	(2,533,305)	15,833			15,833
Jan-32	(2,517,472)	(0)	(2,517,472)	15,833			15,833
Feb-32	(2,501,638)	(0)	(2,501,638)	15,833			15,833
Mar-32	(2,485,805)	(0)	(2,485,805)	15,833			15,833
Apr-32	(2,469,972)	(0)	(2,469,972)	15,833			15,833
May-32	(2,454,139)	(0)	(2,454,139)	15,833			15,833
Jun-32	(2,438,306)	(0)	(2,438,306)	15,833			15,833
Jul-32	(2,422,473)	(0)	(2,422,473)	15,833			15,833
Aug-32	(2,406,640)	(0)	(2,406,640)	15,833			15,833
Sep-32	(2,390,806)	(0)	(2,390,806)	15,833			15,833
Oct-32	(2,374,973)	(0)	(2,374,973)	15,833			15,833
Nov-32	(2,359,140)	(0)	(2,359,140)	15,833			15,833
Dec-32	(2,343,307)	(0)	(2,343,307)	15,833			15,833

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
Deferred Liablity Amortization

ADIT Excess Deferred Liabilities
Accounts 2530 - 27909, 2420 - 27909

Forecasted Test Period

Protected Balance and Amortization Only		
Test Period Ending Balance	Test Period 13-Month Balance	Test Period Amort. Expense
$ (3,625,792)	$ (3,720,791)	$ 189,998

Full Amortization Schedule

	Balance			Amortization			
	Protected	Unprotected	Total Reg Liability	Protected	Unprotected	Accelerated Unprotected	Total
Jan-33	(2,327,474)	(0)	(2,327,474)	15,833			15,833
Feb-33	(2,311,641)	(0)	(2,311,641)	15,833			15,833
Mar-33	(2,295,807)	(0)	(2,295,807)	15,833			15,833
Apr-33	(2,279,974)	(0)	(2,279,974)	15,833			15,833
May-33	(2,264,141)	(0)	(2,264,141)	15,833			15,833
Jun-33	(2,248,308)	(0)	(2,248,308)	15,833			15,833
Jul-33	(2,232,475)	(0)	(2,232,475)	15,833			15,833
Aug-33	(2,216,642)	(0)	(2,216,642)	15,833			15,833
Sep-33	(2,200,809)	(0)	(2,200,809)	15,833			15,833
Oct-33	(2,184,975)	(0)	(2,184,975)	15,833			15,833
Nov-33	(2,169,142)	(0)	(2,169,142)	15,833			15,833
Dec-33	(2,153,309)	(0)	(2,153,309)	15,833			15,833
Jan-34	(2,137,476)	(0)	(2,137,476)	15,833			15,833
Feb-34	(2,121,643)	(0)	(2,121,643)	15,833			15,833
Mar-34	(2,105,810)	(0)	(2,105,810)	15,833			15,833
Apr-34	(2,089,976)	(0)	(2,089,976)	15,833			15,833
May-34	(2,074,143)	(0)	(2,074,143)	15,833			15,833
Jun-34	(2,058,310)	(0)	(2,058,310)	15,833			15,833
Jul-34	(2,042,477)	(0)	(2,042,477)	15,833			15,833
Aug-34	(2,026,644)	(0)	(2,026,644)	15,833			15,833
Sep-34	(2,010,811)	(0)	(2,010,811)	15,833			15,833
Oct-34	(1,994,978)	(0)	(1,994,978)	15,833			15,833
Nov-34	(1,979,144)	(0)	(1,979,144)	15,833			15,833
Dec-34	(1,963,311)	(0)	(1,963,311)	15,833			15,833
Jan-35	(1,947,478)	(0)	(1,947,478)	15,833			15,833
Feb-35	(1,931,645)	(0)	(1,931,645)	15,833			15,833
Mar-35	(1,915,812)	(0)	(1,915,812)	15,833			15,833
Apr-35	(1,899,979)	(0)	(1,899,979)	15,833			15,833
May-35	(1,884,145)	(0)	(1,884,145)	15,833			15,833
Jun-35	(1,868,312)	(0)	(1,868,312)	15,833			15,833
Jul-35	(1,852,479)	(0)	(1,852,479)	15,833			15,833
Aug-35	(1,836,646)	(0)	(1,836,646)	15,833			15,833
Sep-35	(1,820,813)	(0)	(1,820,813)	15,833			15,833
Oct-35	(1,804,980)	(0)	(1,804,980)	15,833			15,833
Nov-35	(1,789,146)	(0)	(1,789,146)	15,833			15,833
Dec-35	(1,773,313)	(0)	(1,773,313)	15,833			15,833
Jan-36	(1,757,480)	(0)	(1,757,480)	15,833			15,833
Feb-36	(1,741,647)	(0)	(1,741,647)	15,833			15,833
Mar-36	(1,725,814)	(0)	(1,725,814)	15,833			15,833
Apr-36	(1,709,981)	(0)	(1,709,981)	15,833			15,833
May-36	(1,694,148)	(0)	(1,694,148)	15,833			15,833
Jun-36	(1,678,314)	(0)	(1,678,314)	15,833			15,833
Jul-36	(1,662,481)	(0)	(1,662,481)	15,833			15,833
Aug-36	(1,646,648)	(0)	(1,646,648)	15,833			15,833
Sep-36	(1,630,815)	(0)	(1,630,815)	15,833			15,833
Oct-36	(1,614,982)	(0)	(1,614,982)	15,833			15,833
Nov-36	(1,599,149)	(0)	(1,599,149)	15,833			15,833
Dec-36	(1,583,315)	(0)	(1,583,315)	15,833			15,833
Jan-37	(1,567,482)	(0)	(1,567,482)	15,833			15,833
Feb-37	(1,551,649)	(0)	(1,551,649)	15,833			15,833
Mar-37	(1,535,816)	(0)	(1,535,816)	15,833			15,833
Apr-37	(1,519,983)	(0)	(1,519,983)	15,833			15,833
May-37	(1,504,150)	(0)	(1,504,150)	15,833			15,833
Jun-37	(1,488,317)	(0)	(1,488,317)	15,833			15,833
Jul-37	(1,472,483)	(0)	(1,472,483)	15,833			15,833
Aug-37	(1,456,650)	(0)	(1,456,650)	15,833			15,833
Sep-37	(1,440,817)	(0)	(1,440,817)	15,833			15,833
Oct-37	(1,424,984)	(0)	(1,424,984)	15,833			15,833
Nov-37	(1,409,151)	(0)	(1,409,151)	15,833			15,833

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
Deferred Liablity Amortization

ADIT Excess Deferred Liabilities
Accounts 2530 - 27909, 2420 - 27909

Forecasted Test Period

Protected Balance and Amortization Only		
Test Period Ending Balance	Test Period 13-Month Balance	Test Period Amort. Expense
$ (3,625,792)	$ (3,720,791)	$ 189,998

Full Amortization Schedule

	Balance			Amortization			
	Protected	Unprotected	Total Reg Liability	Protected	Unprotected	Accelerated Unprotected	Total
Dec-37	(1,393,318)	(0)	(1,393,318)	15,833			15,833
Jan-38	(1,377,484)	(0)	(1,377,484)	15,833			15,833
Feb-38	(1,361,651)	(0)	(1,361,651)	15,833			15,833
Mar-38	(1,345,818)	(0)	(1,345,818)	15,833			15,833
Apr-38	(1,329,985)	(0)	(1,329,985)	15,833			15,833
May-38	(1,314,152)	(0)	(1,314,152)	15,833			15,833
Jun-38	(1,298,319)	(0)	(1,298,319)	15,833			15,833
Jul-38	(1,282,486)	(0)	(1,282,486)	15,833			15,833
Aug-38	(1,266,652)	(0)	(1,266,652)	15,833			15,833
Sep-38	(1,250,819)	(0)	(1,250,819)	15,833			15,833
Oct-38	(1,234,986)	(0)	(1,234,986)	15,833			15,833
Nov-38	(1,219,153)	(0)	(1,219,153)	15,833			15,833
Dec-38	(1,203,320)	(0)	(1,203,320)	15,833			15,833
Jan-39	(1,187,487)	(0)	(1,187,487)	15,833			15,833
Feb-39	(1,171,653)	(0)	(1,171,653)	15,833			15,833
Mar-39	(1,155,820)	(0)	(1,155,820)	15,833			15,833
Apr-39	(1,139,987)	(0)	(1,139,987)	15,833			15,833
May-39	(1,124,154)	(0)	(1,124,154)	15,833			15,833
Jun-39	(1,108,321)	(0)	(1,108,321)	15,833			15,833
Jul-39	(1,092,488)	(0)	(1,092,488)	15,833			15,833
Aug-39	(1,076,655)	(0)	(1,076,655)	15,833			15,833
Sep-39	(1,060,821)	(0)	(1,060,821)	15,833			15,833
Oct-39	(1,044,988)	(0)	(1,044,988)	15,833			15,833
Nov-39	(1,029,155)	(0)	(1,029,155)	15,833			15,833
Dec-39	(1,013,322)	(0)	(1,013,322)	15,833			15,833
Jan-40	(997,489)	(0)	(997,489)	15,833			15,833
Feb-40	(981,656)	(0)	(981,656)	15,833			15,833
Mar-40	(965,822)	(0)	(965,822)	15,833			15,833
Apr-40	(949,989)	(0)	(949,989)	15,833			15,833
May-40	(934,156)	(0)	(934,156)	15,833			15,833
Jun-40	(918,323)	(0)	(918,323)	15,833			15,833
Jul-40	(902,490)	(0)	(902,490)	15,833			15,833
Aug-40	(886,657)	(0)	(886,657)	15,833			15,833
Sep-40	(870,824)	(0)	(870,824)	15,833			15,833
Oct-40	(854,990)	(0)	(854,990)	15,833			15,833
Nov-40	(839,157)	(0)	(839,157)	15,833			15,833
Dec-40	(823,324)	(0)	(823,324)	15,833			15,833
Jan-41	(807,491)	(0)	(807,491)	15,833			15,833
Feb-41	(791,658)	(0)	(791,658)	15,833			15,833
Mar-41	(775,825)	(0)	(775,825)	15,833			15,833
Apr-41	(759,991)	(0)	(759,991)	15,833			15,833
May-41	(744,158)	(0)	(744,158)	15,833			15,833
Jun-41	(728,325)	(0)	(728,325)	15,833			15,833
Jul-41	(712,492)	(0)	(712,492)	15,833			15,833
Aug-41	(696,659)	(0)	(696,659)	15,833			15,833
Sep-41	(680,826)	(0)	(680,826)	15,833			15,833
Oct-41	(664,993)	(0)	(664,993)	15,833			15,833
Nov-41	(649,159)	(0)	(649,159)	15,833			15,833
Dec-41	(633,326)	(0)	(633,326)	15,833			15,833
Jan-42	(617,493)	(0)	(617,493)	15,833			15,833
Feb-42	(601,660)	(0)	(601,660)	15,833			15,833
Mar-42	(585,827)	(0)	(585,827)	15,833			15,833
Apr-42	(569,994)	(0)	(569,994)	15,833			15,833
May-42	(554,160)	(0)	(554,160)	15,833			15,833
Jun-42	(538,327)	(0)	(538,327)	15,833			15,833
Jul-42	(522,494)	(0)	(522,494)	15,833			15,833
Aug-42	(506,661)	(0)	(506,661)	15,833			15,833
Sep-42	(490,828)	(0)	(490,828)	15,833			15,833
Oct-42	(474,995)	(0)	(474,995)	15,833			15,833

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
Deferred Liablity Amortization

ADIT Excess Deferred Liabilities
Accounts 2530 - 27909, 2420 - 27909

Forecasted Test Period

Protected Balance and Amortization Only		
Test Period Ending Balance	Test Period 13-Month Balance	Test Period Amort. Expense
$ (3,625,792)	$ (3,720,791)	$ 189,998

Full Amortization Schedule

	Balance			Amortization			
	Protected	Unprotected	Total Reg Liability	Protected	Unprotected	Accelerated Unprotected	Total
Nov-42	(459,161)	(0)	(459,161)	15,833			15,833
Dec-42	(443,328)	(0)	(443,328)	15,833			15,833
Jan-43	(427,495)	(0)	(427,495)	15,833			15,833
Feb-43	(411,662)	(0)	(411,662)	15,833			15,833
Mar-43	(395,829)	(0)	(395,829)	15,833			15,833
Apr-43	(379,996)	(0)	(379,996)	15,833			15,833
May-43	(364,163)	(0)	(364,163)	15,833			15,833
Jun-43	(348,329)	(0)	(348,329)	15,833			15,833
Jul-43	(332,496)	(0)	(332,496)	15,833			15,833
Aug-43	(316,663)	(0)	(316,663)	15,833			15,833
Sep-43	(300,830)	(0)	(300,830)	15,833			15,833
Oct-43	(284,997)	(0)	(284,997)	15,833			15,833
Nov-43	(269,164)	(0)	(269,164)	15,833			15,833
Dec-43	(253,330)	(0)	(253,330)	15,833			15,833
Jan-44	(237,497)	(0)	(237,497)	15,833			15,833
Feb-44	(221,664)	(0)	(221,664)	15,833			15,833
Mar-44	(205,831)	(0)	(205,831)	15,833			15,833
Apr-44	(189,998)	(0)	(189,998)	15,833			15,833
May-44	(174,165)	(0)	(174,165)	15,833			15,833
Jun-44	(158,332)	(0)	(158,332)	15,833			15,833
Jul-44	(142,498)	(0)	(142,498)	15,833			15,833
Aug-44	(126,665)	(0)	(126,665)	15,833			15,833
Sep-44	(110,832)	(0)	(110,832)	15,833			15,833
Oct-44	(94,999)	(0)	(94,999)	15,833			15,833
Nov-44	(79,166)	(0)	(79,166)	15,833			15,833
Dec-44	(63,333)	(0)	(63,333)	15,833			15,833
Jan-45	(47,499)	(0)	(47,499)	15,833			15,833
Feb-45	(31,666)	(0)	(31,666)	15,833			15,833
Mar-45	(15,833)	(0)	(15,833)	15,833			15,833
Apr-45	0	(0)	0	15,833			15,833

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Deferred Credits
Base Period: Twelve Months Ended December 31, 2024

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
Waller

Line No.	Sub Acct		actual Dec-23	actual Jan-24	actual Feb-24	actual Mar-24	actual Apr-24	actual May-24	actual Jun-24	Budgeted Jul-24	Budgeted Aug-24	Budgeted Sep-24	Budgeted Oct-24	Budgeted Nov-24	Budgeted Dec-24	13 month Average
	DIVISION 09															
1	15560	Account 252 - Customer Advances For Construction	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Deferred Credits
Base Period: Twelve Months Ended December 31, 2024

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
Waller

Line No.	Sub Acct		Budgeted Mar-25	Budgeted Apr-25	Budgeted May-25	Budgeted Jun-25	Budgeted Jul-25	Forecasted Aug-25	Forecasted Sep-25	Forecasted Oct-25	Forecasted Nov-25	Forecasted Dec-25	Forecasted Jan-26	Forecasted Feb-26	Forecasted Mar-26	13 month Average
	DIVISION 09															
1	15560	Account 252 - Customer Advances For Construction	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$ (736,136)	$(736,136)
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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

FR 16(8)(c) SCHEDULE C

Operating Income Summary

Schedule	Pages	Description
C-1	1	Operating Income Summary
C-2	1	Adjusted Operating Income
C-2.1	10	Operating Revenue and Expenses by FERC Account
C-2.2	10	Monthly Operating Income by FERC Account
C-2.3	2	Taxes Other than Income Tax by Sub-Account

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Income Summary
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Description	Base Return at Current Rates	Forecasted Return at Current Rates	Proposed Increase	Forecasted Return at Proposed Rates
1	Operating Revenue	$ 154,805,382	$ 187,822,013	$ 30,467,809	$ 218,289,822
2	Operating Expenses				
3	Purchased Gas Cost	52,986,727	87,640,898		87,640,898
4	Other O & M Expenses	33,536,927	31,507,955	304,678	31,812,633
5	Depreciation Expense	19,915,761	22,028,375		22,028,375
6	Taxes Other than Income	12,842,195	11,235,976	47,347	11,283,323
7					
8	State & Federal Income Taxes	6,428,013	6,300,672	7,513,888	13,814,560
9	Total Operating Expenses	$ 125,709,623	$ 158,713,876	$ 7,865,913	$ 166,579,789
10	Operating Income	$ 29,095,760	$ 29,108,137	$ 22,601,896	$ 51,710,033
11	Rate Base	618,389,716	623,012,457		623,012,457
12	Rate of Return	4.71%	4.67%		8.30%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Adjusted Operating Income Statement
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:__X____Base Period___X___Forecasted Period — FR 16(8)(c)2
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2
Workpaper Reference No(s).____________________ — Witness: Waller, Wiebe, Troup

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	$ 154,805,382	$ 33,016,631	D-1			###########			$ 187,822,013
2										
3	Operating Expenses									
4	Purchased Gas Cost	52,986,727	34,654,171	D-1			87,640,898	-		87,640,898
5	Production O&M Expense	-	-	D-1			-	-		-
6	Storage O&M Expense	438,182	48,157	D-1			486,338	-		486,338
7	Transmission O&M Expense	163,544	17,295	D-1			180,838	-		180,838
8	Distribution O&M Expense	11,872,519	(126,287)	D-1		*	11,746,231	-		11,746,231
9	Customer Accting. & Collection	3,596,931	(1,062,307)	D-1		*	2,534,624	-		2,534,624
10	Customer Service & Information	198,663	15,798	D-1		*	214,461	-		214,461
11	Sales Expense	304,172	(31,723)	D-1		*	272,449	(187,839)	F-4	84,610
12	Admin. & General Expense	16,962,917	1,976,600	D-1		*	18,939,517	(2,678,664)	F-1, F-6, F-8, F-9, F-10, F-11	16,260,853
13	Depreciation Expense	19,915,761	2,112,613	D-1			22,028,375	-		22,028,375
14	Taxes - Other	12,842,195	(1,533,900)	D-1			11,308,295	(72,319)	F-10	11,235,976
15	Income Taxes	6,428,013	(127,341)				6,300,672	-		6,300,672
16										
17										
18	Total Operating Expenses	$ 125,709,623	$ 35,943,076		$ -		###########	$(2,938,822)		$ 158,713,876
19										
20	Net Operating Income	$ 29,095,760	$ (2,926,445)		$ -		$ 26,169,315	$ 2,938,822		$ 29,108,137

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
1		OPERATING REVENUE	
2		Sales of Gas	
3	4800	Residential	$ 87,647,010
4	4805	Unbilled Residential	(4,396,720)
5	4811	Commercial	41,998,643
6	4812	Industrial	4,073,459
7	4815	Unbilled Commercial	(1,896,160)
8	4816	Unbilled Industrial	(34,310)
9	4820	Other - Public Authority	5,745,918
10	4825	Unbilled Public Authority	(337,567)
11		Total Sales of Gas	$ 132,800,273
12			
13		Other Operating Income	
14	4870	Forfeited Discounts	$ 197,310
15	4880	Misc. Service Revenues	58,913
16	4893	Revenue From Transportation of Gas of Others	21,748,887
17	4950	Other Gas Revenue	-
	4960	Provision for Rate Refunds	-
18		Total Other Operating Income	$ 22,005,110
19			
20		TOTAL OPERATING REVENUE	$ 154,805,382
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	$ -

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title		Unadjusted Total Utility (1)
30			$	-
31		Natural Gas Storage Expense - Operation		
32	8140	Operation Supervision & Engineering	$	-
33	8150	Maps and Records		-
34	8160	Wells Expense		33,549
35	8170	Lines Expense		21,362
36	8180	Compressor Station Expense		39,827
37	8190	Compressor Station Expense Fuel & Power		-
38	8200	Measuring & Regulating Station Expense		8,836
39	8210	Purification		76,521
40	8240	Other		-
41	8250	Storage Well Royalties		10,111
42		Total Nat. Gas Storage Expense - Operation	$	190,206
43				
44		Natural Gas Storage Expense - Maintenance		
45	8310	Structure & Improvements	$	-
46	8320	Reservoirs & Wells		-
47	8340	Compressor Station Equip.		41,017
48	8350	Measuring & Regulating Station Equip.		-
49	8360	Purification Equipment		-
50	8370	Maintenance of other equipment		-
51	840/847	Other Storage Exp. - LNG		206,958
52		Total Nat. Gas Storage Expense - Maintenance	$	247,976
53				
54		Transmission Expense - Operation		
55	8500	Operation Supervision & Engineering	$	-
56	8520	Communication system expenses		-
57	8550	Other fuel & power for compression		471
58	8560	Mains Expense		131,470
59	8570	Measuring & Regulating Station Exp.		11,353
60	8590	Other Exp.		-
61	8600	Rents		-
62		Total Transmission Expense - Operation	$	143,294
63				
64		Transmission Expense - Maintenance		
65	8620	Structures and Improvements	$	-
66	8630	Mains		20,250
67	8640	Compressor Station Equipment		-
68	8650	Measuring & Reg Station Equip.		-
69	8670	Other Equipment		-
70		Total Transmission Expense - Maintenance	$	20,250

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
71			
72		Purchased Gas Cost - Operation	
73	8001	Intercompany Gas Well-head Purchases	$ -
74	8010	Natural gas field line purchases	78,633
75	8040	Natural Gas City Gate Purchases	32,087,760
76	8045	Transportation to City Gate	-
77	8050	Transmission-Operation supervision and engineering	(18,610)
78	8051	Other Gas Purchases / Gas Cost Adjustments	30,681,358
79	8052	PGA for Commercial	17,566,889
80	8053	PGA for Industrial	2,750,613
81	8054	PGA for Public Authority	2,873,224
82	8057	PGA for Transportation Sales	-
83	8058	Unbilled PGA Costs	(882,038)
84	8059	PGA Offset to Unrecovered Gas Cost	(60,206,554)
85	8060	Exchange Gas	(1,879,958)
86	8081	Gas Withdrawn From Storage - Debit	15,361,966
87	8082	Gas Delivered to Storage	(9,917,320)
88	8110	Gas used for products extraction-Credit	-
89	8120	Gas Used for Other Utility Operations	(3,318)
90	8130	Gas Used for Other Utility Operations	-
91	8580	Transmission and compression of gas by others	24,494,082
92		Total Purchased Gas Cost	$ 52,986,727
93			
94		Distribution Expenses - Operation	
95	8700	Supervision and Engineering	$ 2,267,606
96	8710	Distribution Load Dispatching	(40)
97	8711	Odorization	137,138
98	8720	Compressor Station Labor & Expenses	-
99	8740	Mains & Services	6,959,627
100	8750	Measuring and Regulating Station Exp. - Gen	1,231,731
101	8760	Measuring and Regulating Station Exp. - Ind.	540
102	8770	Measuring and Regulating Sta. Exp. - City Gate	5,298
103	8780	Meters and House Regulator Expense	833,461
104	8790	Customer Installations Expense	266
105	8800	Other Expense	3,157
106	8810	Rents	99,414
107		Total Distribution Expenses - Operation	$ 11,538,198

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title		Unadjusted Total Utility (1)
108				
109		Distribution Expenses - Maintenance		
110	8850	Supervision and Engineering	$	-
111	8860	Structures and Improvements		-
112	8870	Mains		145,970
113	8890	Measuring and Regulating Station Exp. - Gen		188,075
114	8900	Measuring and Regulating Station Exp. - Ind.		-
115	8910	Measuring and Regulating Sta. Exp. - City Gate		119
116	8920	Services		157
117	8930	Meters and House Regulators		-
118	8940	Other Equipment		-
119	8950	Maintenance of Other Plant		-
120		Total Distribution Expenses - Maintenance	$	334,321
121				
122		Customer Accounts Expenses - Operation		
123	9010	Supervision	$	-
124	9020	Meter Reading Expenses		691,928
125	9030	Customer Records & Collections		1,301,395
126	9040	Uncollectible Accounts		1,603,608
127		Total Customer Accounts Expense	$	3,596,931
128				
129		Customer Service & Information - Operation		
130	9070	Supervision	$	-
131	9080	Customer Assistance Expenses		-
132	9090	Informational and Instructional Advertising Expenses		198,663
133	9100	Misc Cust Serv & Informational Exp		-
134		Total Customer Accounts Expenses - Operation	$	198,663
135				
136		Sales Expense		
137	9110	Supervision	$	143,620
138	9120	Demonstrating and Selling Expenses		88,415
139	9130	Advertising Expenses		69,535
140	9160	Miscellaneous Sales Expenses		2,601
141		Total Sales Expenses	$	304,172

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
142			
143		Administrative and General Expenses - Operation	
144	9200	Administrative and General Salaries	$ -
145	9210	Office Supplies and Expenses	49,458
146	9220	Administrative Expense Transferred	15,853,828
147	9230	Outside Services Employed	96,909
148	9240	Property Insurance	5,555
149	9250	Injuries and Damages	58,037
150	9260	Employee Pensions and Benefits	767,059
151	9270	Franchise Requirements	474
152	9280	Regulatory Commission Expense	106,317
153	930.2	Miscellaneous General Expense	25,278
154	9310	A&G-Rents	$ -
155		Total Administrative and General Exp. - Operation	$ 16,962,917
156			
157		Administrative and General Expense - Maintenance	
158	9320	Maintenance of general plant	$ -
159		Total Administrative and Gen. Exp. - Maintenance	$ -
160			
161		Total Operation and Maintenance Expense	$ 86,523,654
162			
163	403	Depreciation	$ 19,915,761
164	406	Amortization	$ 49,305
165	4081	Taxes Other than Income Taxes	12,842,195
166	4091-4101	Provision for Federal & State Income Taxes	6,428,013
167			
168		TOTAL OPERATING EXPENSE (incl Gas Cost)	$ 125,758,928
169			
170		NET OPERATING INCOME	$ 29,046,455

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
1		OPERATING REVENUE	
2		Sales of Gas	
3	4800	Residential	$ 103,051,755
4	4811	Commercial	51,443,822
5	4812	Industrial	5,130,632
6	4820	Other - Public Authority	7,198,509
7		Total Sales of Gas	$ 166,824,719
8			
9		Other Operating Income	
10	4870	Forfeited Discounts	$ 367,462
11	4880	Misc. Service Revenues	58,912
12	4893-4896	Revenue From Transportation of Gas of Others	20,570,921
13	4950	Other Gas Revenue	-
14		Total Other Operating Income	$ 20,997,295
15			
16		TOTAL OPERATING REVENUE	$ 187,822,013
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	$ -

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility
			(1)
26			$ -
27		Natural Gas Storage Expense - Operation	
28	8140	Operation Supervision & Engineering	$ -
29	8150	Maps and Records	-
30	8160	Wells Expense	35,164
31	8170	Lines Expense	22,782
32	8180	Compressor Station Expense	44,776
33	8190	Compressor Station Expense Fuel & Power	-
34	8200	Measuring & Regulating Station Expense	9,536
35	8210	Purification	83,940
36	8240	Other	-
37	8250	Storage Well Royalties	10,482
38		Total Nat. Gas Storage Expense - Operation	$ 206,679
39			
40		Natural Gas Storage Expense - Maintenance	
41	8310	Structure & Improvements	$ -
42	8320	Reservoirs & Wells	-
43	8340	Compressor Station Equip.	46,416
44	8350	Measuring & Regulating Station Equip.	-
45	8360	Purification Equipment	-
46	8370	Maintenance of other equipment	-
47	841/847	Other Storage Exp. - LNG	233,243
48		Total Nat. Gas Storage Expense - Maintenance	$ 279,659
49			
50		Transmission Expense - Operation	
51	8500	Operation Supervision & Engineering	$ -
52	8520	Communication system expenses	-
53	8550	Other Fuel & Power for Compression	488
54	8560	Mains Expense	145,499
55	8570	Measuring & Regulating Station Exp.	11,936
56	8590	Other Exp.	0
57	8600	Rents	0
58		Total Transmission Expense - Operation	$ 157,923

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility
			(1)
59			
60		Transmission Expense - Maintenance	
61	8620	Structures and Improvements	$ -
62	8630	Mains	22,915
63	8640	Compressor Station Equipment	-
64	8650	Measuring & Reg Station Equip.	-
65	8670	Other Equipment	-
66		Total Transmission Expense - Maintenance	$ 22,915
67			
68		Purchased Gas Cost - Operation	
69	8001	Intercompany Gas Well-head Purchases	$ -
70	8010	Natural gas field line purchases	115,617
71	8040	Natural Gas City Gate Purchases	50,226,537
72	8045	Transportation to City Gate	0
73	8050	Transmission-Operation supervision and engineering	(29,531)
74	8051	Other Gas Purchases / Gas Cost Adjustments	53,391,020
75	8052	PGA for Commercial	30,150,016
76	8053	PGA for Industrial	4,872,096
77	8054	PGA for Public Authority	4,999,866
78	8057	PGA for Transportation Sales	0
79	8058	Unbilled PGA Costs	(5,763,929)
80	8059	PGA Offset to Unrecovered Gas Cost	(109,657,357)
81	8060	Exchange Gas	(122,035)
82	8081	Gas Withdrawn From Storage - Debit	30,798,939
83	8082	Gas Delivered to Storage	(14,414,625)
84	8110	Gas used for products extraction-Credit	0
85	8120	Gas Used for Other Utility Operations	(8,172)
86	8130	Other Gas Supply Expenses	0
87	8580	Transmission and compression of gas by others	43,082,454
88		Total Purchased Gas Cost	$ 87,640,898
89			
90		Distribution Expenses - Operation	
91	8700	Supervision and Engineering	$ 2,140,705
92	8710	Distribution Load Dispatching	(41)
93	8711	Odorization	132,819
94	8720	Compressor Station Labor & Expenses	0
95	8740	Mains & Services	6,802,984
96	8750	Measuring and Regulating Station Exp. - Gen	1,361,535
97	8760	Measuring and Regulating Station Exp. - Ind.	523
98	8770	Measuring and Regulating Sta. Exp. - City Gate	5,487
99	8780	Meters and House Regulator Expense	938,471
100	8790	Customer Installations Expense	257
101	8800	Other Expense	3,085
102	8810	Rents	75,023
103		Total Distribution Expenses - Operation	$ 11,460,849

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
104			
105		Distribution Expenses - Maintenance	
106	8850	Supervision and Engineering	$ -
107	8860	Structures and Improvements	0
108	8870	Mains	144,480
109	8890	Measuring and Regulating Station Exp. - Gen	140,590
110	8900	Measuring and Regulating Station Exp. - Ind.	0
111	8910	Measuring and Regulating Sta. Exp. - City Gate	135
112	8920	Services	178
113	8930	Meters and House Regulators	0
114	8940	Other Equipment	0
115	8950	Maintenance of Other Plant	0
116		Total Distribution Expenses - Maintenance	$ 285,382
117			
118		Customer Accounts Expenses - Operation	
119	9010	Supervision	$ -
120	9020	Meter Reading Expenses	735,288
121	9030	Customer Records & Collections	1,067,803
122	9040	Uncollectible Accounts	731,532
123		Total Customer Accounts Expense	$ 2,534,624
124			
125		Customer Service & Information - Operation	
126	9070	Supervision	$ -
127	9080	Customer Assistance Expenses	0
128	9090	Informational and Instructional Advertising Expenses	214,461
129	9100	Misc Cust Serv & Informational Exp	0
130		Total Customer Accounts Expenses - Operation	$ 214,461
131			
132		Sales Expense	
133	9110	Supervision	$ 158,549
134	9120	Demonstrating and Selling Expenses	77,078
135	9130	Advertising Expenses	36,821
136	9160	Miscellaneous Sales Expenses	0
137		Total Sales Expenses	$ 272,449

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Operating Revenue and Expenses by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Account No. (s)	Account Title	Unadjusted Total Utility (1)
138			
139		Administrative and General Expenses - Operation	
140	9200	Administrative and General Salaries	$ -
141	9210	Office Supplies and Expenses	69,069
142	9220	Administrative Expense Transferred	17,714,001
143	9230	Outside Services Employed	69,993
144	9240	Property Insurance	0
145	9250	Injuries and Damages	23,257
146	9260	Employee Pensions and Benefits	872,759
147	9270	Franchise Requirements	635
148	9280	Regulatory Commission Expense	165,392
149	930.2	Miscellaneous General Expense	24,411
150	9310	A&G-Rents	0
151		Total Administrative and General Exp. - Operation	$ 18,939,517
152			
153		Administrative and General Expense - Maintenance	
154	9320	Maintenance of General Plant	0
155		Total Administrative and Gen. Exp. - Maintenance	$ -
156			
157		Total Operation and Maintenance Expense	$ 122,015,356
158			
159	403-406	Depreciation and Amortization	$ 22,028,375
160	4081	Taxes Other than Income Taxes	11,308,295
161	4091	Provision for Federal & State Income Taxes	6,300,672
162			
163		T O T A L O P E R A T I N G E X P E N S E	$ 161,652,698
164			
165		N E T O P E R A T I N G I N C O M E	$ 26,169,315

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line No.	Acct No.	Account Discription	actual Jan-24	actual Feb-24	actual Mar-24	actual Apr-24	actual May-24	actual Jun-24	Budgeted Jul-24	Budgeted Aug-24	Budgeted Sep-24	Budgeted Oct-24	Budgeted Nov-24	Budgeted Dec-24	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4091-4101	Provision for income taxes	(557,931)	(557,931)	2,337,053	(557,931)	(557,931)	888,545	905,690	905,690	905,690	905,690	905,690	905,690	6,428,013
2															
3	4030	Depreciation Expense	1,764,131	1,540,905	1,643,697	1,651,107	1,659,649	1,665,430	1,644,143	1,649,348	1,670,871	1,673,151	1,675,547	1,677,783	19,915,761
4	4060	Amortization of gas plant acquisition adjustments	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	49,305
5	4081	Taxes other than income taxes, utility operating income	1,239,429	220,308	1,220,105	1,279,448	1,279,091	1,206,164	1,287,684	1,213,712	1,213,596	886,590	909,092	886,977	12,842,195
6	4800	Residential sales	(14,522,204)	(13,210,657)	(9,497,697)	(7,469,105)	(4,669,379)	(4,016,962)	(3,801,156)	(3,927,290)	(3,922,583)	(4,749,661)	(7,428,871)	(10,431,445)	(87,647,010)
7	4805	Unbilled Residential Revenue	(941,607)	1,662,235	1,038,979	2,112,813	492,713	31,587							4,396,720
8	4811	Commercial Revenue	(6,903,467)	(6,188,916)	(4,359,660)	(3,450,356)	(2,269,478)	(2,019,915)	(1,887,757)	(2,012,202)	(1,998,651)	(2,367,384)	(3,567,916)	(4,972,941)	(41,998,643)
9	4812	Industrial Revenue	(744,308)	(650,415)	(439,262)	(338,109)	(376,430)	(159,623)	(114,006)	(170,132)	(171,022)	(186,353)	(283,180)	(440,620)	(4,073,459)
10	4815	Unbilled Comm Revenue	(386,848)	747,403	507,331	859,772	136,563	31,939							1,896,160
11	4816	Unbilled Industrial Revenue	9,492	(7,351)	3,459	(21,741)	40,244	10,207							34,310
12	4820	Other Sales to Public Authorities	(993,050)	(903,357)	(625,180)	(473,388)	(325,266)	(235,203)	(212,177)	(233,256)	(236,396)	(298,803)	(491,252)	(718,589)	(5,745,918)
13	4825	Unbilled Public Authority Revenue	(66,618)	121,281	77,501	156,195	45,481	3,727							337,567
14	4870	Forfeited discounts	0	(27,026)	(26,264)	(19,782)	(14,419)	(11,956)	(13,930)	(13,263)	(14,177)	(14,105)	(16,817)	(25,571)	(197,310)
15	4880	Miscellaneous service revenues	(5,587)	(4,026)	(4,332)	(3,439)	(3,844)	(3,004)	(3,387)	(3,698)	(4,212)	(9,928)	(8,550)	(4,906)	(58,913)
16	4893	Revenue-Transportation Distribution	(2,205,449)	(1,919,454)	(2,254,677)	(1,324,758)	(1,662,340)	(1,594,478)	(1,499,946)	(1,747,368)	(1,803,742)	(1,813,304)	(2,093,702)	(1,829,667)	(21,748,887)
17	4950	Other Gas Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
18	4960	Provision for Rate Refunds	0	0	0	0	0	0	0	0	0	0	0	0	0
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	2,336	423	390	881	3,865	3,421	7,415	19,738	17,271	9,911	8,742	4,239	78,633
23	8040	Natural gas city gate purchases	2,946,869	5,393,021	690,605	(1,091,428)	2,886,912	2,323,453	2,234,799	4,266,034	3,996,668	3,052,338	3,157,552	2,230,938	32,087,760
24	8050	Other purchases	(854)	(721)	(1,099)	(538)	(1,110)	(2,865)	(1,076)	(1,465)	(3,647)	(2,367)	(2,519)	(347)	(18,610)
25	8051	PGA for Residential	7,720,128	6,363,458	3,725,218	2,707,263	1,007,186	599,709	554,275	620,489	597,742	584,683	1,792,000	4,409,207	30,681,358
26	8052	PGA for Commercial	3,952,614	3,217,649	1,908,462	1,426,521	693,114	545,420	542,989	598,118	735,692	700,814	1,025,644	2,219,852	17,566,889
27	8053	PGA for Industrial	534,300	453,404	297,282	225,282	257,646	97,110	75,892	141,479	102,867	85,849	159,756	319,746	2,750,613
28	8054	PGA for Public Authorities	622,566	530,933	320,793	240,455	148,658	90,946	86,759	107,808	84,190	99,157	177,014	363,944	2,873,224
29	8058	Unbilled PGA Cost	1,060,326	(2,117,488)	(821,589)	(2,026,664)	(466,261)	(44,546)	(132,910)	(12,425)	(47,359)	911,291	1,866,785	948,802	(882,038)
30	8059	PGA Offset to Unrecovered Gas Cost	(8,676,794)	(13,579,546)	(8,298,361)	(5,458,963)	(4,696,904)	(1,473,753)	(1,261,163)	(2,523,843)	(2,553,649)	(2,304,752)	(2,956,373)	(6,422,453)	(60,206,554)
31	8060	Exchange gas	1,175,391	1,463,290	1,130,452	935,817	(6,733)	(1,205,146)	(1,162,712)	(1,715,525)	(1,539,579)	(742,489)	(465,308)	252,585	(1,879,958)
32	8081	Gas withdrawn from storage-Debit	2,057,298	4,173,242	4,167,729	3,184,081	22,720	0	0	0	0	0	2,939	1,753,956	15,361,966
33	8082	Gas delivered to storage-Credit	(11,970)	(10,539)	(29,777)	(2,200)	(306,312)	(1,390,229)	(1,068,997)	(2,340,891)	(1,865,333)	(1,457,993)	(1,365,058)	(68,019)	(9,917,320)
34	8120	Gas used for other utility operations-Credit	(319)	(4,879)	336	(665)	(853)	1,624	2,283	(174)	(96)	(202)	(856)	481	(3,318)
35	8580	Transmission and compression of gas by others	2,507,724	2,560,829	2,340,062	2,432,350	2,097,562	1,745,119	1,251,734	2,295,952	1,948,270	1,445,352	1,620,027	2,249,102	24,494,082
36	8140	Storage-Operation supervision and engineering	0	0	0	0	0	0	-	-	-	-	-	-	0
37	8160	Wells expenses	3,999	5,969	449	628	3,381	2,917	2,449	2,422	2,484	2,992	2,839	3,021	33,549
38	8170	Lines expenses	1,663	4,025	435	1,121	2,338	987	1,766	1,717	1,658	1,906	1,849	1,896	21,362
39	8180	Compressor station expenses	2,458	879	3,390	6,561	4,609	683	3,492	3,374	3,192	3,829	3,599	3,761	39,827
40	8190	Compressor station fuel and power	0	0	0	0	0	0	-	-	-	-	-	-	0
41	8200	Storage-Measuring and regulating station expenses	585	3,140	519	303	109	114	579	567	570	773	786	791	8,836
42	8210	Storage-Purification expenses	16,665	18,566	(5,791)	(104)	7,297	135	6,510	6,297	6,037	7,088	6,774	7,046	76,521
43	8240	Storage-Other expenses	0	0	0	0	0	0	-	-	-	-	-	-	0
44	8250	Storage well royalties	890	1,443	1,243	762	524	147	865	876	787	926	860	789	10,111
45	8310	Storage-Maintenance of structures and improvements	0	0	0	0	0	0	-	-	-	-	-	-	0
46	8340	Maintenance of compressor station equipment	1,768	3,871	5,684	3,468	3,461	727	3,626	3,503	3,302	3,984	3,726	3,897	41,017
47	8350	Maintenance of measuring and regulating station equipmen	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 expenses	25,709	9,818	15,509	14,706	13,825	16,853	18,085	17,547	16,649	20,023	18,700	19,536	206,958
51	8500	Transmission-Operation supervision and engineering	0	0	0	0	0	0	-	-	-	-	-	-	0
52	8520	Communication system expenses	0	0	0	0	0	0	-	-	-	-	-	-	0
53	8550	Other fuel and power for Compression	40	40	39	37	36	42	40	41	37	43	40	37	471
54	8560	Mains expenses	1,447	14,099	12,412	9,978	12,857	11,275	11,116	10,774	10,311	12,656	12,029	12,515	131,470
55	8570	Transmission-Measuring and regulating station expenses	1,842	675	562	858	820	809	977	981	888	1,049	976	916	11,353
56	8630	Transmission-Maintenance of mains	(500)	1,494	299	1,055	3,311	3,711	1,790	1,729	1,630	1,967	1,840	1,924	20,250
57	8640	Transmission-Maintenance of compressor sta equipment	0	0	0	0	0	0	-	-	-	-	-	-	0
58	8650	Transmission-Maintenance of measuring and regulating sta	0	0	0	0	0	0	-	-	-	-	-	-	0
59	8700	Distribution-Operation supervision and engineering	132,335	274,473	168,645	177,760	152,738	271,467	180,590	177,517	177,948	176,907	181,082	196,145	2,267,606
60	8710	Distribution load dispatching	0	0	0	(20)	0	0	(3)	(3)	(3)	(4)	(3)	(3)	(40)
61	8711	Odorization	0	5,221	28,621	41,115	396	0	9,806	9,449	9,963	10,244	10,946	11,377	137,138
62	8720	Distribution-Compressor station labor and expenses	0	0	0	0	0	0	-	-	-	-	-	-	0
63	8740	Mains and Services Expenses	562,374	554,304	546,432	607,363	637,386	634,107	568,418	563,295	553,979	543,437	571,105	617,427	6,959,627
64	8750	Distribution-Measuring and regulating station expenses	143,268	122,417	85,161	84,217	77,764	70,958	106,088	102,852	98,134	115,869	109,825	115,178	1,231,731
65	8760	Distribution-Measuring and regulating station expenses-Ind	0	0	191	105	0	0	39	37	39	40	43	45	540
66	8770	Distribution-Measuring and regulating station expenses-City	1,159	381	380	269	280	144	450	455	410	491	458	421	5,298

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line No.	Acct No.	Account Discription	actual Jan-24	actual Feb-24	actual Mar-24	actual Apr-24	actual May-24	actual Jun-24	Budgeted Jul-24	Budgeted Aug-24	Budgeted Sep-24	Budgeted Oct-24	Budgeted Nov-24	Budgeted Dec-24	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
67	8780	Meter and house regulator expenses	88,533	56,980	56,159	64,763	54,982	67,012	72,939	70,855	67,001	80,392	75,324	78,520	833,461
68	8790	Customer installations expenses	0	0	146	0	0	0	19	18	19	20	21	22	266
69	8800	Distribution-Other expenses	492	1,098	5	128	0	0	228	220	231	238	254	263	3,157
70	8810	Distribution-Rents	8,255	8,173	8,102	8,706	9,035	12,704	8,631	9,016	5,647	9,480	7,122	4,542	99,414
71	8850	Distribution-Maintenance supervision and engineering	0	0	0	0	0	0	-	-	-	-	-	-	0
72	8860	Distribution-Maintenance of structures and improvements	0	0	0	0	0	0	-	-	-	-	-	-	0
73	8870	Distribution-Maint of mains	18,223	4,297	29,773	4,891	7,366	10,158	11,638	11,802	11,611	11,581	11,848	12,782	145,970
74	8890	Maintenance of measuring and regulating station equipmen	3,507	940	26,754	31,468	9,038	35,564	14,630	14,734	14,663	9,316	12,416	15,044	188,075
75	8900	Maintenance of measuring and regulating station equipmen	0	0	0	0	0	0	-	-	-	-	-	-	0
76	8910	Maintenance of measuring and regulating station equipmen	0	0	0	0	64	(9)	11	10	10	12	11	11	119
77	8920	Maintenance of services	(10)	0	124	(41)	0	0	14	13	13	15	14	15	157
78	8930	Maintenance of meters and house regulators	0	0	0	0	0	0	-	-	-	-	-	-	0
79	8940	Distribution-Maintenance of other equipment	0	0	0	0	0	0	-	-	-	-	-	-	0
80	9010	Customer accounts-Operation supervision	0	0	0	0	0	0	-	-	-	-	-	-	0
81	9020	Customer accounts-Meter reading expenses	53,027	57,748	52,706	46,747	69,879	56,229	59,670	59,159	54,574	63,951	59,755	58,481	691,928
82	9030	Customer accounts-Customer records and collections expe	101,433	105,565	165,198	146,083	105,044	89,105	103,916	104,456	102,644	76,918	92,509	108,523	1,301,395
83	9040	Customer accounts-Uncollectible accounts	209,704	298,981	210,390	(78,230)	122,814	158,813	86,169	92,651	91,815	100,296	137,716	172,488	1,603,608
84	9090	Customer service-Operating informational and instructional	20,821	18,364	12,760	17,702	17,181	13,584	15,255	15,109	14,624	18,152	17,258	17,855	198,663
85	9100	Customer service-Miscellaneous customer service	0	0	0	0	0	0	-	-	-	-	-	-	0
86	9110	Sales-Supervision	10,508	11,396	11,238	12,311	13,315	10,400	11,883	11,864	11,488	13,393	12,674	13,150	143,620
87	9120	Sales-Demonstrating and selling expenses	23,485	762	1,040	27,609	1,642	4,288	10,965	1,810	2,124	6,829	4,625	3,238	88,415
88	9130	Sales-Advertising expenses	3,921	5,380	5,460	28,396	8,608	1,405	2,183	2,183	2,183	3,272	3,272	3,272	69,535
89	9160	Sales-Miscellaneous sales expenses	0	0	1,300	0	689	0	82	82	82	122	122	122	2,601
90	9200	A&G-Administrative & general salaries	0	0	0	0	0	0	-	-	-	-	-	-	0
91	9210	A&G-Office supplies & expense	2,719	26,720	396	814	206	345	309	309	376	5,754	5,755	5,756	49,458
92	9220	A&G-Administrative expense transferred-Credit	1,141,840	1,094,612	956,814	1,109,783	1,751,889	657,969	1,677,084	1,483,046	1,539,461	1,517,291	1,403,417	1,520,622	15,853,828
93	9230	A&G-Outside services employed	3,257	15,174	0	15,238	17,465	4,368	7,608	7,697	7,619	4,519	6,245	7,719	96,909
94	9240	A&G-Property insurance	(44)	931	1,771	940	942	942	25	25	25	-	-	-	5,555
95	9250	A&G-Injuries & damages	3,543	7,186	5,276	5,126	5,603	17,198	2,643	2,673	2,647	1,502	2,075	2,565	58,037
96	9260	A&G-Employee pensions and benefits	69,160	57,612	54,707	53,613	57,867	54,681	65,462	63,268	59,938	79,014	74,173	77,563	767,059
97	9270	A&G-Franchise requirements	0	0	0	85	0	215	5	5	6	53	53	53	474
98	9280	A&G-Regulatory commission expenses	10,061	10,061	10,061	10,157	10,061	12,210	741	744	902	13,707	13,777	13,837	106,317
99	9302	Miscellaneous general expenses	1,544	5,824	699	1,199	2,072	4,790	3,777	442	556	2,162	1,359	853	25,278
100	9310	A&G-Rents	0	0	0	0	0	0	-	-	-	-	-	-	0
101	9320	A&G-Maintenance of general plant	0	0	0	0	0	0	-	-	-	-	-	-	0
102															
103		Operating (Income)Loss*	($7,192,679)	($7,363,265)	($4,806,331)	($2,007,370)	($836,922)	($1,570,671)	($394,566)	($929,125)	($910,898)	($1,571,888)	($3,411,927)	($4,478,825)	($29,046,455)

*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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account, **Div 002 Only**
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line No.	Acct No.	Account Discription	actual Jan-24	actual Mar-24	actual Mar-24	actual Apr-24	actual May-24	actual Jun-24	Budgeted Jul-24	Budgeted Aug-24	Budgeted Sep-24	Budgeted Oct-24	Budgeted Nov-24	Budgeted Dec-24	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4030	Depreciation Expense	(15,466)	(15,466)	(15,466)	(15,466)	(15,466)	(15,466)	0	0	0	0	0	0	(92,794)
2	4081	Taxes other than income taxes, utility operating	(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	8700	Distribution-Operation supervision and engineer	737	578	2,914	3,147	1,202	125	3,828	3,793	4,113	1,248	1,168	1,258	24,111
5	8520	Communication system expenses	3,864	14,234	3,112	1,040	16,645	11,489	10,743	10,746	11,486	8,234	7,998	8,034	107,626
6	8560	Mains Expenses	3,779	128	25,843	284	21,427	(21,427)	6,668	6,652	6,619	5,475	5,389	6,029	66,867
7	8740	Mains and Services Expenses	22,891	28,090	14,060	4,412	14,987	10,745	23,241	23,135	24,339	19,599	19,399	23,288	228,187
8	8780	Meter and house regulator expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
9	8800	Distribution-Other expenses	21,096	11,797	1,612	11,143	23,784	54,919	38,804	38,430	43,731	16,733	16,147	15,421	293,616
10	8810	Distribution-Rents	(2,445)	(2,735)	(2,445)	(713)	64,636	291	8,674	8,674	9,059	8,854	8,776	8,969	109,594
11	8850	Distribution-Maintenance supervision and engin	0	0	0	0	0	0	0	0	0	0	0	0	0
12	8900	Maintenance of measuring and regulating statio	0	0	0	0	0	0	0	0	0	0	0	0	0
13	9010	Customer accounts-Operation supervision	0	0	0	0	0	0	(69)	(55)	(9)	(161)	(173)	(285)	(751)
14	9020	Customer accounts-Meter reading expenses	16,485	7,957	10,971	8,677	10,686	12,176	14,235	13,438	12,934	14,304	13,144	13,824	148,830
15	9030	Customer accounts-Customer records and colle	35,979	37,899	40,030	43,255	46,288	38,622	45,389	43,073	48,441	51,830	42,764	44,285	517,855
16	9040	Customer accounts-Uncollectible accounts	0	0	0	0	0	0	1,488,510	1,488,510	1,488,510	0	0	0	4,465,529
17	9100	Customer service-Miscellaneous customer servi	0	0	0	0	0	0	0	0	0	0	0	0	0
18	9120	Sales-Demonstrating and selling expenses	10,943	10,943	13,519	6,249	10,943	13,011	89,785	90,162	91,569	9,740	6,420	12,835	366,120
19	9130	Sales-Advertising expenses - Contract Labor	0	0	0	0	3,028	0	978	973	1,062	385	389	364	7,179
20	9160	Sales-Miscellaneous sales expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
21	9200	A&G-Administrative & general salaries	(3,648,235)	(4,393,070)	(3,932,316)	(3,531,608)	(3,661,276)	(10,063,608)	(3,892,474)	(2,297,767)	(2,624,979)	(3,161,136)	(4,143,749)	(3,834,805)	(49,185,022)
22	9210	A&G-Office supplies & expense	4,067,102	3,851,892	3,738,665	4,077,436	4,073,809	4,244,110	5,455,488	5,337,953	5,703,987	4,246,589	4,051,580	4,318,074	53,166,684
23	9220	A&G-Administrative expense transferred-Credit	(11,567,347)	(8,838,144)	(10,708,456)	(10,320,165)	(22,798,023)	(3,264,226)	(19,472,282)	(16,319,007)	(17,374,781)	(13,171,166)	(11,632,020)	(12,208,846)	(157,674,463)
24	9230	A&G-Outside services employed	1,811,009	2,683,363	169,560	2,119,421	1,429,956	2,133,367	3,648,601	3,665,165	4,014,826	1,255,448	1,253,090	1,160,320	25,344,126
25	9240	A&G-Property insurance	10,484	10,484	11,291	11,291	11,291	11,291	8,921	8,963	8,921	11,190	11,251	11,251	126,628
26	9250	A&G-Injuries & damages	4,498,331	8,498,263	4,481,043	4,499,439	4,499,395	4,992,750	4,251,729	4,271,309	4,250,743	5,330,481	5,358,605	5,359,121	60,291,208
27	9260	A&G-Employee pensions and benefits	3,226,662	2,979,869	2,896,528	2,449,237	15,585,681	1,475,047	7,437,106	2,753,266	2,599,525	3,829,321	4,124,919	4,249,475	53,606,635
28	9301	A&G-General advertising expense	0	0	0	0	0	0	0	0	0	0	0	0	0
29	9302	Miscellaneous general expenses	880,822	82,116	1,781,273	776,770	232,679	698,027	233,231	254,387	1,053,587	968,064	304,521	249,248	7,514,724
30	9310	A&G-Rents	528,828	668,938	410,944	586,479	620,633	417,245	505,916	505,571	528,494	504,857	500,504	511,275	6,289,685
31	9320	A&G-Maintenance of general plant	42,942	56,650	83,265	65,776	50,744	36,532	92,979	92,628	97,824	50,108	49,879	50,865	770,193
32		Operating (Income)Loss*	($51,539)	$5,693,787	($974,054)	$796,102	$243,050	$785,020	($0)	$0	$0	($0)	$0	($0)	$6,492,366
33															
34	9220	A&G-Administrative expense transferred-Credit	(11,567,347)	(8,838,144)	(10,708,456)	(10,320,165)	(22,798,023)	(3,264,226)	(19,472,282)	(16,319,007)	(17,374,781)	(13,171,166)	(11,632,020)	(12,208,846)	(157,674,463)
35		Allocation Factor to Kentucky	5.14%	5.29%	5.11%	5.26%	4.94%	6.18%	4.56%	4.56%	4.56%	4.56%	4.56%	4.56%	4.82%
36		Total Allocated Amount	(594,342)	(467,154)	(547,335)	(542,551)	(1,127,076)	(201,751)	(888,376)	(744,516)	(792,683)	(600,903)	(530,683)	(556,999)	(7,594,371)

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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account, **Div 012 Only**
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line No.	Acct No.	Account Discription	actual Jan-24	actual Mar-24	actual Mar-24	actual Apr-24	actual May-24	actual Jun-24	Budgeted Jul-24	Budgeted Aug-24	Budgeted Sep-24	Budgeted Oct-24	Budgeted Nov-24	Budgeted Dec-24	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	0	0	0	0	0	0	0	0	0	0	0	0
4	8740	Mains and Services Expenses	612	570	810	918	460	891	1,500	1,500	1,500	1,500	1,500	1,500	13,262
5	8780	Meter and House Regulator Expenses	0	0	26	0	0	0	5	5	5	5	5	5	56
6	8800	Distribution-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
7	8810	Distribution-Rents	0	0	0	3,204	11,058	0	2,180	2,117	2,117	2,223	2,219	2,219	27,339
8	9100	Customer service-Miscellaneous - Building Maintenance	0	(1,539)	1,539	0	0	0	0	0	0	0	0	0	0
9	9010	Customer accounts-Operation supervision	281,690	261,043	264,394	265,276	247,985	210,483	285,853	272,782	260,569	292,759	266,492	285,899	3,195,224
10	9020	Customer accounts-Meter reading expenses	(794)	0	0	0	0	0	(149)	(143)	(136)	(151)	(138)	(149)	(1,660)
11	9030	Customer accounts-Customer records and collections ex	2,730,007	2,218,549	2,139,808	2,253,102	2,179,184	1,904,682	2,538,028	2,390,667	2,285,037	2,589,353	2,323,795	2,495,300	28,047,512
12	9200	A&G-Administrative & general salaries	299,736	227,416	348,266	421,979	632,422	360,486	429,535	412,341	393,883	437,084	399,089	428,925	4,791,164
13	9210	A&G-Office supplies & expense	896,087	1,075,336	958,047	1,100,712	1,148,788	1,159,464	270,933	246,085	244,691	710,380	688,760	709,551	9,208,833
14	9220	A&G-Administrative expense transferred-Credit	(5,518,126)	(4,953,330)	(4,747,446)	(5,206,149)	(5,544,998)	(4,584,405)	(4,551,309)	(4,267,010)	(4,088,246)	(5,205,494)	(4,851,147)	(5,191,293)	(58,708,954)
15	9230	A&G-Outside services employed	60,626	62,466	9,034	82,013	193,636	(96,276)	30,595	30,595	31,253	57,564	57,494	57,516	576,515
16	9240	A&G-Property insurance	6,316	6,316	6,101	6,101	6,101	6,101	0	0	0	0	0	0	37,035
17	9250	A&G-Injuries & damages	48	48	48	38	38	38	0	0	0	0	0	0	258
18	9260	A&G-Employee pensions and benefits	1,128,722	963,227	922,625	940,288	1,106,148	825,980	882,198	803,714	761,982	1,001,868	999,349	1,097,937	11,434,038
19	9302	Miscellaneous general expenses - Misc General Expens	0	0	0	0	0	0	791	666	664	791	666	666	4,244
20	9310	A&G-Rents	115,009	139,627	96,749	132,519	137,848	96,771	109,839	106,680	106,680	112,016	111,816	111,816	1,377,370
21	9320	A&G-Maintenance of general plant	67	271	0	0	206	411	1	0	0	101	100	106	1,264
22															
23		Operating (Income)Loss*	($0)	$0	($0)	($0)	$118,874	($115,374)	($0)	$0	$0	$0	($0)	($0)	$3,500
24															
25	9220	A&G-Administrative expense transferred-Credit	(5,518,126)	(4,953,330)	(4,747,446)	(5,206,149)	(5,544,998)	(4,584,405)	(4,551,309)	(4,267,010)	(4,088,246)	(5,205,494)	(4,851,147)	(5,191,293)	(58,708,954)
26		Allocation Factor to Kentucky	4.06%	3.92%	3.98%	3.92%	3.82%	4.01%	5.39%	5.39%	5.39%	5.39%	5.39%	5.39%	4.64%
27		Total Allocated Amount	(223,769)	(194,152)	(188,962)	(204,061)	(211,670)	(183,690)	(245,367)	(230,041)	(220,403)	(280,635)	(261,532)	(279,870)	(2,724,153)

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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account, **Div 091 Only**
Base Period: Twelve Months Ended December 31, 2024

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, Wiebe, Troup

Line	Acct		actual	actual	actual	actual	actual	actual	Budgeted	Budgeted	Budgeted	Budgeted	Budgeted	Budgeted	
No.	No.	Account Discription	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24	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	0	0	0	0	0	0
3	4081	Taxes other than income taxes, utility operating i	(0)	0	0	0	0	0	0	0	0	0	0	0	0
4	8170	Lines expenses	45	1	71	25	87	47	93	99	102	108	111	114	903
5	8180	Compressor station expenses	57	1	89	31	109	59	118	124	129	136	140	144	1,138
6	8190	Compressor station fuel and power	0	0	0	0	0	0	0	0	0	0	0	0	0
7	8210	Storage-Purification expenses	100	154	115	90	85	80	211	223	231	243	251	258	2,042
8	8240	Storage-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
9	8250	Storage well royalties	735	525	506	650	178	130	921	972	1,007	1,061	1,096	1,127	8,908
10	8500	Transmission-Operation supervision and enginee	0	0	0	0	0	0	0	0	0	0	0	0	0
11	8560	Mains expenses	74	2	115	40	141	76	151	160	165	174	180	185	1,463
12	8570	Transmission-Measuring and regulating station e	91	2	142	50	174	94	187	197	204	215	222	229	1,807
13	8600	Transmission-Measuring and regulating station e	0	0	0	0	555	0	2,529	2,529	2,529	2,420	2,420	2,420	15,400
14	8650	Transmission-Maintenance of me - Non-Inventor	0	0	0	0	0	0	0	0	0	0	0	0	0
15	8700	Distribution-Operation supervision and engineeri	117,489	461,668	246,379	263,989	244,730	189,577	107,159	164,745	170,692	224,460	211,310	234,669	2,636,867
16	8711	Odorization	0	0	0	0	0	0	0	0	0	0	0	0	0
17	8740	Mains and Services Expenses	42,429	22,466	23,206	47,855	28,569	19,727	20,965	20,498	21,210	34,792	32,900	36,344	350,960
18	8750	Distribution-Measuring and regulating station exp	11,712	12,051	8,771	10,428	9,549	10,511	7,071	8,788	7,690	10,696	9,864	10,445	117,576
19	8760	Distribution-Measuring and regulating station exp	0	0	0	0	0	0	0	0	0	0	0	0	0
20	8770	Distribution-Measuring and regulating station exp	0	0	0	0	0	0	0	0	0	0	0	0	0
21	8780	Meter and house regulator expenses	11,616	6,453	6,742	8,200	10,987	11,138	5,427	5,163	4,904	9,224	8,388	8,914	97,158
22	8800	Distribution-Other expenses	36,028	36,795	42,386	40,149	61,569	15,458	131,141	130,452	137,771	135,491	138,516	165,074	1,070,829
23	8810	Distribution-Rents	19,886	16,644	16,151	18,128	17,183	14,391	34,594	36,511	37,844	39,861	41,200	42,331	334,725
24	8870	Distribution-Maint of mains	0	0	0	561	(210)	0	34	33	31	59	53	57	617
25	8890	Maintenance of measuring and regulating station	0	0	0	0	0	0	0	0	0	0	0	0	0
26	8900	Maintenance of measuring and regulating station	0	0	0	0	0	0	0	0	0	0	0	0	0
27	8910	Maintenance of measuring and regulating station	0	0	0	0	0	99	10	9	9	17	15	16	174
28	9010	Customer accounts-Operation supervision	9,993	10,095	9,124	9,627	9,993	9,705	5,798	6,025	5,459	9,753	8,882	9,412	103,864
29	9020	Customer accounts-Meter reading expenses	3,595	3,401	3,938	2,398	4,390	5,251	2,261	2,151	2,043	3,843	3,495	3,714	40,482
30	9030	Customer accounts-Customer records and collec	211,063	208,119	214,605	223,554	218,400	182,797	500,113	496,496	519,258	546,171	549,869	646,399	4,516,844
31	9040	Customer accounts-Uncollectible accounts	0	0	0	0	0	1,358	0	0	0	0	0	0	1,358
32	9090	Customer service-Operating informational and in	16,341	14,688	14,950	14,853	15,743	14,369	9,031	9,438	8,530	15,148	13,801	14,618	161,508
33	9100	Customer service-Miscellaneous customer servic	1,890	33	0	28	3	0	48	44	188	361	361	375	3,331
34	9110	Sales-Supervision	16,069	16,525	16,630	20,453	17,858	15,353	10,332	13,689	11,023	16,518	15,144	15,892	185,487
35	9120	Sales-Demonstrating and selling expenses	1,798	0	570	2,601	0	0	123	111	479	919	919	955	8,475
36	9130	Sales-Advertising expenses	0	0	0	113	0	0	3	3	11	21	21	22	192
37	9200	A&G-Administrative & general salaries	(8,202)	(28,148)	(83,719)	(5,656)	(25,190)	(6,052)	11,770	11,670	11,674	5,375	1,375	1,475	(113,628)
38	9210	A&G-Office supplies & expense	57	(515)	(172,150)	45	3,492	0	(95,867)	(95,298)	(100,654)	(98,947)	(101,156)	(120,769)	(781,763)
39	9220	A&G-Administrative expense transferred-Credit	(647,846)	(867,132)	(441,297)	(726,778)	(826,783)	(545,382)	(1,087,333)	(1,017,590)	(1,053,381)	(1,272,269)	(1,223,137)	(1,368,327)	(11,077,255)
40	9230	A&G-Outside services employed	1,891	22,863	2,195	(3,955)	(90,019)	5,387	(34,790)	(34,607)	(36,548)	(35,945)	(36,748)	(43,794)	(284,070)
41	9240	A&G-Property insurance	(295)	(295)	(292)	(347)	(347)	(347)	(8,761)	(8,761)	(8,761)	(8,384)	(8,384)	(8,384)	(53,357)
42	9250	A&G-Injuries & damages	7,374	7,295	9,251	7,831	8,031	8,432	73,078	71,327	68,471	86,175	81,268	84,618	513,150
43	9260	A&G-Employee pensions and benefits	145,769	55,830	81,522	65,038	283,223	47,510	283,341	164,583	168,154	243,290	237,548	251,203	2,027,010
44	9280	A&G-Regulatory commission expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
45	9302	Miscellaneous general expenses	241	480	0	0	7,500	230	20,244	10,218	19,535	29,016	10,073	10,266	107,803
46	9310	A&G-Rents	0	0	0	(0)	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)
47															
48		Operating (Income)Loss*	($0)	($0)	($0)	$0	$0	$0	($0)	$0	($0)	($0)	($0)	($0)	$0
49															
50	9220	A&G-Administrative expense transferred-Credit	(647,846)	(867,132)	(441,297)	(726,778)	(826,783)	(545,382)	(1,087,333)	(1,017,590)	(1,053,381)	(1,272,269)	(1,223,137)	(1,368,327)	(11,077,255)
51		Allocation Factor to Kentucky	49.97%	49.97%	49.97%	49.97%	49.97%	49.97%	49.97%	49.97%	49.97%	49.97%	49.97%	49.97%	49.97%
52		Total Allocated Amount	(323,729)	(433,306)	(220,516)	(363,171)	(413,143)	(272,528)	(543,340)	(508,490)	(526,375)	(635,753)	(611,201)	(683,753)	(5,535,304)

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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Acct No.	Account Discription	Forecasted Apr-25	Forecasted May-25	Forecasted Jun-25	Forecasted Jul-25	Forecasted Aug-25	Forecasted Sep-25	Forecasted Oct-25	Forecasted Nov-25	Forecasted Dec-25	Forecasted Jan-26	Forecasted Feb-26	Forecasted Mar-26	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4091	Provision for Federal & State Income Taxes	525,056	525,056	525,056	525,056	525,056	525,056	525,056	525,056	525,056	525,056	525,056	525,056	6,300,672
2															
3	4030	Depreciation Expense	1,800,717	1,793,547	1,801,438	1,805,346	1,811,696	1,842,067	1,845,194	1,848,612	1,851,951	1,855,801	1,859,508	1,863,194	21,979,070
4	4060	Amortization of gas plant acquisition adjustment	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	4,109	49,305
5	4081	Taxes other than income taxes, utility operating	945,551	926,320	926,270	1,000,460	926,488	926,372	927,140	949,642	927,527	927,642	927,555	997,332	11,308,295
6	4800	Residential sales	(8,538,618)	(5,934,429)	(4,292,695)	(4,063,744)	(4,114,451)	(4,113,391)	(5,114,451)	(9,311,835)	(13,607,654)	(15,837,597)	(16,032,941)	(12,089,949)	(103,051,755)
7	4805	Unbilled Residential Revenue													
8	4811	Commercial Revenue	(4,271,267)	(3,061,247)	(2,273,715)	(2,150,099)	(2,200,779)	(2,188,344)	(2,638,128)	(4,615,856)	(6,633,460)	(7,709,056)	(7,751,955)	(5,949,916)	(51,443,822)
9	4812	Industrial Revenue	(398,734)	(434,240)	(214,018)	(156,849)	(209,345)	(211,452)	(229,725)	(386,090)	(609,267)	(931,776)	(800,144)	(548,992)	(5,130,632)
10	4815	Unbilled Comm Revenue													
11	4816	Unbilled Industrial Revenue													
12	4820	Other Sales to Public Authorities	(586,216)	(395,283)	(266,073)	(253,301)	(262,665)	(266,256)	(342,380)	(663,241)	(990,426)	(1,156,162)	(1,154,012)	(862,494)	(7,198,509)
13	4825	Unbilled Public Authority Revenue													
14	4870	Forfeited discounts	(41,096)	(30,594)	(21,780)	(16,033)	(15,172)	(15,548)	(15,486)	(18,793)	(33,240)	(47,958)	(55,753)	(56,008)	(367,462)
15	4880	Miscellaneous service revenues	(3,438)	(3,844)	(3,004)	(3,387)	(3,698)	(4,212)	(9,928)	(8,550)	(4,906)	(5,587)	(4,026)	(4,332)	(58,912)
16	4893	Revenue-Transportation Commercial	(1,618,312)	(1,551,715)	(1,480,646)	(1,499,946)	(1,747,368)	(1,803,742)	(1,813,304)	(2,093,702)	(1,829,667)	(1,797,547)	(1,703,649)	(1,631,322)	(20,570,921)
17	4950	Other Gas Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
18	4960	Provision for Rate Refunds													0
19	7560	Field measuring and regulating station expense:	-	-	-	-	-	-	-	-	-	-	-	-	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	2,392	9,696	5,356	11,388	25,712	22,511	12,900	14,315	6,944	2,772	813	819	115,617
23	8040	Natural gas city gate purchases	(2,962,682)	7,241,767	3,637,631	3,432,007	5,557,101	5,209,154	3,972,977	5,170,480	3,654,146	3,496,942	10,365,699	1,451,315	50,226,537
24	8050	Other purchases	(1,461)	(2,783)	(4,486)	(1,653)	(1,909)	(4,754)	(3,080)	(4,125)	(569)	(1,014)	(1,386)	(2,311)	(29,531)
25	8051	PGA for Residential	7,348,869	2,526,507	938,914	851,206	808,273	779,081	761,034	2,934,393	7,222,025	9,161,195	12,230,934	7,828,589	53,391,020
26	8052	PGA for Commercial	3,872,293	1,738,665	853,917	833,875	779,132	958,883	912,191	1,679,488	3,635,988	4,690,424	6,184,507	4,010,654	30,150,016
27	8053	PGA for Industrial	611,528	646,300	152,037	116,548	184,296	134,075	111,743	261,600	523,725	634,034	871,468	624,743	4,872,096
28	8054	PGA for Public Authorities	652,716	372,905	142,387	133,237	140,435	109,731	129,064	289,861	596,120	738,777	1,020,484	674,149	4,999,866
29	8058	Unbilled PGA Cost	(5,501,383)	(1,169,607)	(69,742)	(204,112)	(16,185)	(61,726)	1,186,152	3,056,854	1,554,082	1,258,250	(4,069,934)	(1,726,578)	(5,763,929)
30	8059	PGA Offset to Unrecovered Gas Cost	(14,818,361)	(11,782,099)	(2,307,329)	(1,936,783)	(3,287,656)	(3,328,361)	(2,999,905)	(4,841,051)	(10,519,604)	(10,296,436)	(26,100,673)	(17,439,100)	(109,657,357)
31	8060	Exchange gas	2,540,276	(16,890)	(1,886,794)	(1,785,590)	(2,234,710)	(2,006,648)	(966,437)	(761,941)	413,719	1,394,794	2,812,529	2,375,657	(122,035)
32	8081	Gas withdrawn from storage-Debit	8,643,192	56,993	0	0	0	0	0	4,812	2,872,878	2,441,321	8,021,213	8,758,530	30,798,939
33	8082	Gas delivered to storage-Credit	(5,972)	(768,379)	(2,176,563)	(1,641,671)	(3,049,336)	(2,431,227)	(1,897,750)	(2,235,279)	(111,411)	(14,204)	(20,257)	(62,577)	(14,414,625)
34	8120	Gas used for other utility operations-Credit	(1,804)	(2,140)	2,542	3,506	(226)	(125)	(262)	(1,401)	788	(378)	(9,378)	707	(8,172)
35	8580	Transmission and compression of gas by others	6,602,616	5,261,696	2,732,184	1,922,303	2,990,797	2,539,325	1,881,295	2,652,789	3,683,897	2,975,825	4,922,062	4,917,666	43,082,454
36	8140	Storage-Operation supervision and engineering	-	-	-	-	-	-	-	-	-	-	-	-	0
37	8160	Wells expenses	2,892	2,906	2,931	2,862	2,898	3,077	3,042	2,886	3,070	2,916	2,701	2,983	35,164
38	8170	Lines expenses	1,911	1,926	1,891	1,865	1,798	1,875	1,946	1,885	1,934	2,002	1,819	1,928	22,782
39	8180	Compressor station expenses	3,726	3,854	3,517	3,657	3,419	3,641	3,958	3,719	3,887	4,153	3,525	3,719	44,776
40	8190	Compressor station fuel and power	-	-	-	-	-	-	-	-	-	-	-	-	0
41	8200	Storage-Measuring and regulating station exper	804	785	841	784	785	798	775	787	792	781	781	824	9,536
42	8210	Storage-Purification expenses	7,004	7,154	6,771	6,859	6,491	6,860	7,289	6,962	7,243	7,616	6,654	7,036	83,940
43	8240	Storage-Other expenses	-	-	-	-	-	-	-	-	-	-	-	-	0
44	8250	Storage well royalties	902	915	880	867	896	883	926	860	789	841	837	885	10,482
45	8310	Storage-Maintenance of structures and improve	-	-	-	-	-	-	-	-	-	-	-	-	0
46	8340	Maintenance of compressor station equipment	3,860	4,007	3,619	3,790	3,534	3,770	4,123	3,857	4,033	4,328	3,648	3,846	46,416
47	8350	Maintenance of measuring and regulating statio	-	-	-	-	-	-	-	-	-	-	-	-	0
48	8360	Processing-Maintenance of purification equipme	-	-	-	-	-	-	-	-	-	-	-	-	0
49	8370	Maintenance of other equipment	-	-	-	-	-	-	-	-	-	-	-	-	0
50	8410	Other storage expenses-Operation labor and ex	19,409	20,099	18,227	19,035	17,818	19,087	20,700	19,334	20,198	21,629	18,334	19,373	233,243
51	8500	Transmission-Operation supervision and engine	-	-	-	-	-	-	-	-	-	-	-	-	0
52	8520	Communication system expenses	-	-	-	-	-	-	-	-	-	-	-	-	0
53	8550	Other fuel and power for Compression	42	43	41	40	42	41	43	40	37	39	39	41	488
54	8560	Mains expenses	12,009	12,361	11,524	11,800	11,134	11,812	13,022	12,371	12,873	13,163	11,395	12,035	145,499
55	8570	Transmission-Measuring and regulating station	1,022	1,040	990	985	1,002	1,000	1,055	982	922	983	951	1,004	11,936
56	8630	Transmission-Maintenance of mains	1,906	1,978	1,787	1,871	1,745	1,861	2,036	1,904	1,991	2,137	1,801	1,899	22,915

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Acct No.	Account Discription	Forecasted Apr-25	Forecasted May-25	Forecasted Jun-25	Forecasted Jul-25	Forecasted Aug-25	Forecasted Sep-25	Forecasted Oct-25	Forecasted Nov-25	Forecasted Dec-25	Forecasted Jan-26	Forecasted Feb-26	Forecasted Mar-26	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
57	8640	Transmission-Maintenance of compressor sta e	-	-	-	-	-	-	-	-	-	-	-	-	0
58	8650	Transmission-Maintenance of measuring and re	-	-	-	-	-	-	-	-	-	-	-	-	0
59	8700	Distribution-Operation supervision and engineer	170,816	179,422	184,214	178,404	182,953	179,742	179,513	183,519	198,693	172,171	160,408	170,849	2,140,705
60	8710	Distribution load dispatching	(4)	(4)	(3)	(3)	(4)	(3)	(4)	(3)	(3)	(3)	(3)	(4)	(41)
61	8711	Odorization	11,189	10,582	12,310	10,861	10,791	11,096	10,244	10,946	11,377	10,755	10,938	11,729	132,819
62	8720	Distribution-Compressor station labor and exper	-	-	-	-	-	-	-	-	-	-	-	-	0
63	8740	Mains and Services Expenses	546,046	584,678	591,789	579,023	603,469	564,263	551,149	578,320	624,972	539,049	510,055	530,170	6,802,984
64	8750	Distribution-Measuring and regulating station ex	113,095	116,764	108,081	111,322	105,369	111,283	119,523	113,243	118,753	124,366	106,801	112,935	1,361,535
65	8760	Distribution-Measuring and regulating station ex	44	42	48	43	42	44	40	43	45	42	43	46	523
66	8770	Distribution-Measuring and regulating station ex	470	476	458	451	466	460	491	458	421	438	436	461	5,487
67	8780	Meter and house regulator expenses	78,175	81,050	73,409	76,698	71,872	76,577	83,089	77,847	81,158	86,974	73,850	77,771	938,471
68	8790	Customer installations expenses	22	21	24	21	21	22	20	21	22	21	21	23	257
69	8800	Distribution-Other expenses	259	248	285	254	252	259	238	254	263	249	253	271	3,085
70	8810	Distribution-Rents	8,612	5,950	4,663	4,209	5,270	4,652	9,480	7,122	4,542	6,413	6,287	7,823	75,023
71	8850	Distribution-Maintenance supervision and engin	-	-	-	-	-	-	-	-	-	-	-	-	0
72	8860	Distribution-Maintenance of structures and impr	-	-	-	-	-	-	-	-	-	-	-	-	0
73	8870	Distribution-Maint of mains	11,932	12,496	12,058	12,092	12,409	12,031	11,832	12,083	13,027	12,049	11,020	11,451	144,480
74	8890	Maintenance of measuring and regulating statio	11,005	12,047	13,842	12,525	15,268	11,205	9,318	12,418	15,045	8,819	9,406	9,691	140,590
75	8900	Maintenance of measuring and regulating statio	-	-	-	-	-	-	-	-	-	-	-	-	0
76	8910	Maintenance of measuring and regulating statio	11	12	10	11	10	11	12	11	12	13	11	11	135
77	8920	Maintenance of services	15	15	14	15	14	14	16	15	15	17	14	15	178
78	8930	Maintenance of meters and house regulators	-	-	-	-	-	-	-	-	-	-	-	-	0
79	8940	Distribution-Maintenance of other equipment	-	-	-	-	-	-	-	-	-	-	-	-	0
80	9010	Customer accounts-Operation supervision	-	-	-	-	-	-	-	-	-	-	-	-	0
81	9020	Customer accounts-Meter reading expenses	62,228	63,769	59,667	60,473	59,636	60,930	64,973	60,711	59,481	63,548	58,370	61,503	735,288
82	9030	Customer accounts-Customer records and colle	84,664	92,169	98,438	93,081	107,377	85,621	77,868	93,397	109,452	75,269	74,007	76,459	1,067,803
83	9040	Customer accounts-Uncollectible accounts	15,222	47,529	48,973	46,488	48,501	47,203	62,927	96,872	97,774	101,124	55,030	63,890	731,532
84	9090	Customer service-Operating informational and ir	17,820	18,406	17,560	17,526	16,683	17,793	18,639	17,713	18,331	19,321	16,959	17,710	214,461
85	9100	Customer service-Miscellaneous customer servi	-	-	-	-	-	-	-	-	-	-	-	-	0
86	9110	Sales-Supervision	13,280	13,715	12,541	12,996	12,383	13,220	13,782	13,038	13,530	14,393	12,546	13,124	158,549
87	9120	Sales-Demonstrating and selling expenses	1,773	6,724	3,632	11,525	1,072	10,285	6,829	4,625	3,238	10,142	8,078	9,157	77,078
88	9130	Sales-Advertising expenses	2,621	2,784	5,550	2,621	2,621	2,784	3,272	3,272	3,272	2,784	2,621	2,621	36,821
89	9160	Sales-Miscellaneous sales expe - Customer Rel	0	0	(1)	0	0	0	0	0	0	0	0	0	0
90	9200	A&G-Administrative & General Salaries	-	-	-	-	-	-	-	-	-	-	-	-	0
91	9210	A&G-Office supplies & expense	5,727	5,733	5,851	5,721	5,721	5,795	5,754	5,755	5,756	5,734	5,727	5,795	69,069
92	9220	A&G-Administrative expense transferred-Credit	1,528,202	1,629,476	1,371,531	1,658,823	1,224,356	1,441,221	1,491,959	1,380,406	1,495,682	1,538,726	1,373,589	1,580,028	17,714,001
93	9230	A&G-Outside services employed	5,415	6,059	6,958	6,314	7,896	5,539	4,519	6,245	7,719	4,191	4,519	4,620	69,993
94	9240	A&G-Property insurance	-	-	-	-	-	-	-	-	-	-	-	-	0
95	9250	A&G-Injuries & damages	1,799	2,013	2,312	2,098	2,624	1,840	1,502	2,075	2,565	1,393	1,502	1,535	23,257
96	9260	A&G-Employee pensions and benefits	73,400	76,160	69,055	72,089	67,270	71,898	78,103	73,320	76,671	78,498	66,278	70,016	872,759
97	9270	A&G-Franchise requirements	52	52	57	52	52	53	53	53	53	52	52	53	635
98	9280	A&G-Regulatory commission expenses	13,743	13,769	13,793	13,767	13,831	13,896	13,707	13,777	13,837	13,694	13,707	13,872	165,392
99	9302	Miscellaneous general expenses	385	2,172	770	3,938	129	3,470	2,162	1,359	853	3,418	2,682	3,075	24,411
100	9310	A&G-Rents	-	-	-	-	-	-	-	-	-	-	-	-	0
101	9320	A&G-Maintenance of general plant	-	-	-	-	-	-	-	-	-	-	-	-	0
102															
103		Operating (Income)Loss*	($2,891,581)	($1,533,347)	($1,029,156)	($551,331)	($1,285,545)	($1,102,568)	($1,407,113)	($3,250,406)	($4,357,981)	($5,261,581)	($5,845,535)	($3,953,843)	($26,169,315)

*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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account, **Div 002 Only**
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Acct No.	Account Discription	Forecasted Apr-25	Forecasted Jun-25	Forecasted Jun-25	Forecasted Jul-25	Forecasted Aug-25	Forecasted Sep-25	Forecasted Oct-25	Forecasted Nov-25	Forecasted Dec-25	Forecasted Jan-26	Forecasted Feb-26	Forecasted Mar-26	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	0	0	0	0	0	0	0	0	0	0	0	0	0
3	8210	Storage-Purification expenses	-	-	-	-	-	-	-	-	-	-	-	-	0
4	8520	Communication system expenses	7,997	7,856	8,027	7,838	7,871	8,268	8,234	7,998	8,034	7,967	7,902	8,278	96,270
5	8560	Mains expenses	6,294	5,982	6,148	6,428	6,284	6,426	5,475	5,389	6,029	5,866	5,654	5,683	71,658
6	8700	Distribution-Operation supervision and engineer	1,107	1,133	1,164	1,155	1,099	1,345	1,247	1,167	1,257	1,161	1,119	1,129	14,084
7	8740	Mains and Services Expenses	21,416	19,764	20,357	23,377	20,014	21,852	19,603	19,402	23,292	23,151	18,060	19,828	250,117
8	8780	Meter and house regulator expenses	-	-	-	-	-	-	-	-	-	-	-	-	0
9	8800	Distribution-Other expenses	16,955	14,860	15,976	14,762	14,881	17,485	16,733	16,147	15,421	14,663	14,167	14,867	186,918
10	8810	Distribution-Rents	8,769	8,753	8,895	8,753	8,753	8,890	8,854	8,776	8,969	8,762	8,762	8,893	105,829
11	8850	Maintenance Supervision and Engineering	-	-	-	-	-	-	-	-	-	-	-	-	0
12	8900	Maintenance of measuring and regulating statio	-	-	-	-	-	-	-	-	-	-	-	-	0
13	9010	Customer accounts-Operation supervision	(174)	(182)	(172)	(189)	(176)	(150)	(161)	(173)	(285)	(212)	(179)	(149)	(2,203)
	9020	Customer accounts-Meter readin - Non-project L	13,831	13,835	13,197	14,508	13,204	13,845	14,799	13,598	14,301	14,982	12,965	13,606	166,671
14	9030	Customer accounts-Customer records and colle	49,874	44,230	42,089	52,383	42,443	45,008	53,357	44,165	45,757	53,616	42,288	55,789	571,000
15	9040	Customer accounts-Uncollectible accounts	-	-	-	-	-	-	-	-	-	-	-	-	0
16	9100	Customer service-Miscellaneous customer servi	-	-	-	-	-	-	-	-	-	-	-	-	0
17	9120	Sales-Demonstrating and selling	8,306	7,678	6,420	7,049	6,420	7,829	9,740	6,420	12,835	10,214	7,401	6,697	97,007
18	9130	Sales-Advertising expenses - Contract Labor	333	344	371	334	328	358	385	389	364	347	337	346	4,237
19	9160	Miscellaneous Sales Expenses	-	-	-	-	-	-	-	-	-	-	-	-	0
20	9200	A&G-Administrative & general salaries	(3,829,865)	(3,924,257)	(6,625,554)	(4,141,435)	(5,977,578)	(3,109,333)	(2,946,418)	(3,946,658)	(3,627,895)	(3,575,367)	(4,519,551)	(3,831,556)	(50,055,468)
21	9210	A&G-Office supplies & expense	4,791,713	4,470,149	4,515,318	4,686,270	4,613,471	4,937,599	4,246,589	4,051,580	4,318,074	4,338,527	4,254,626	4,309,157	53,533,073
22	9220	A&G-Administrative expense transferred-Credit	(12,715,975)	(15,396,831)	(9,861,631)	(15,896,566)	(8,224,312)	(11,669,249)	(13,387,955)	(11,831,012)	(12,417,752)	(13,403,638)	(11,260,021)	(13,340,841)	(149,405,782)
23	9230	A&G-Outside services employed	1,033,260	1,102,792	1,094,292	1,041,980	927,299	1,149,296	1,255,451	1,253,093	1,160,323	1,084,807	1,033,090	1,086,774	13,222,457
24	9240	A&G-Property insurance	11,254	11,254	11,254	11,271	11,313	11,271	11,190	11,251	11,251	11,251	11,251	11,254	135,067
25	9250	A&G-Injuries & damages	5,360,231	5,360,211	5,359,759	5,368,863	5,388,092	5,368,388	5,330,481	5,358,605	5,359,121	5,359,624	5,358,201	5,359,648	64,331,223
26	9260	A&G-Employee pensions and benefits	3,785,202	7,473,384	4,626,384	7,263,091	2,364,752	2,357,264	3,829,321	4,124,919	4,249,475	4,529,017	4,141,903	3,985,991	52,730,702
27	9301	A&G-General advertising expense	-	-	-	-	-	-	-	-	-	-	-	-	0
28	9302	Miscellaneous general expenses	878,744	229,665	197,506	979,783	226,175	263,460	968,108	304,562	249,291	967,009	314,538	1,729,259	7,308,099
29	9310	A&G-Rents	499,935	499,202	507,555	499,285	498,929	507,111	504,857	500,504	511,275	499,309	499,135	506,596	6,033,693
30	9320	A&G-Maintenance of general plant	50,795	50,179	52,643	51,059	50,735	53,038	50,108	49,879	50,865	48,943	48,353	48,751	605,348
31	Operating (Income)Loss*		$0	$0	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)
32															
33	9220	A&G-Administrative expense transferred-Credit	(12,715,975)	(15,396,831)	(9,861,631)	(15,896,566)	(8,224,312)	(11,669,249)	(13,387,955)	(11,831,012)	(12,417,752)	(13,403,638)	(11,260,021)	(13,340,841)	
34		Allocation Factor to Kentucky	4.35%	4.35%	4.35%	4.35%	4.35%	4.35%	4.35%	4.35%	4.35%	4.35%	4.35%	4.35%	
35		Total Allocated Amount	(553,412)	(670,085)	(429,188)	(691,834)	(357,930)	(507,857)	(582,657)	(514,897)	(540,433)	(583,340)	(490,047)	(580,607)	(6,502,289)

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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account,**Div 012 Only**
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:________Base Period___X____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, Wiebe, Troup

Line No.	Acct No.	Account Discription	Forecasted Apr-25	Forecasted Jun-25	Forecasted Jun-25	Forecasted Jul-25	Forecasted Aug-25	Forecasted Sep-25	Forecasted Oct-25	Forecasted Nov-25	Forecasted Dec-25	Forecasted Jan-26	Forecasted Feb-26	Forecasted Mar-26	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 incom	0	0	0	0	0	0	0	0	0	0	0	0	0
3	8700	Distribution-Operation supervision and engineering	0	0	0	0	0	0	0	0	0	0	0	0	0
4	8740	Mains and Services Expenses	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500	18,000
5	8780	Meter and House Regulator Expenses	5	5	5	5	5	5	5	5	5	5	5	5	60
6	8800	Distribution-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
7	8810	Distribution-Rents	2,342	2,342	2,342	2,221	2,219	2,219	2,223	2,219	2,219	2,221	2,341	2,342	27,251
8	9100	Customer service-Miscellaneous - Building Maintenan	0	0	0	0	0	0	0	0	0	0	0	0	0
9	9010	Customer accounts-Operation supervision	285,620	281,143	269,018	293,550	265,879	278,000	302,699	275,567	295,653	316,639	273,513	283,427	3,420,708
10	9020	Customer accounts-Meter reading expenses	(148)	(146)	(140)	(152)	(138)	(145)	(157)	(143)	(154)	(164)	(142)	(147)	(1,775)
11	9030	Customer accounts-Customer records and collections	2,526,648	2,453,741	2,347,828	2,593,684	2,320,221	2,427,558	2,676,990	2,403,814	2,581,302	2,799,302	2,386,568	2,474,602	29,992,258
12	9200	A&G-Administrative & general salaries	426,069	421,739	403,226	437,614	398,641	417,297	452,382	413,057	443,938	473,667	410,026	425,326	5,122,982
13	9210	A&G-Office supplies & expense	789,263	738,757	736,324	753,178	768,177	723,245	710,380	688,760	709,551	747,048	726,761	744,280	8,835,724
14	9220	A&G-Administrative expense transferred-Credit	(5,225,416)	(5,186,784)	(4,891,109)	(5,665,227)	(4,663,023)	(4,787,883)	(5,318,364)	(4,954,205)	(5,302,056)	(5,693,376)	(5,008,087)	(5,133,553)	(61,829,082)
15	9230	A&G-Outside services employed	68,938	67,212	66,750	58,122	57,971	58,084	57,564	57,494	57,516	57,719	57,679	66,764	731,813
16	9240	A&G-Property insurance	0	0	0	0	0	0	0	0	0	0	0	0	0
17	9250	A&G-Injuries & damages	0	0	0	0	0	0	0	0	0	0	0	0	0
18	9260	A&G-Employee pensions and benefits	1,006,280	1,101,737	945,504	1,412,710	735,945	767,528	1,001,868	999,349	1,097,937	1,182,647	1,031,144	1,016,702	12,299,350
19	9302	Miscellaneous general expenses - Misc General Expe	791	666	666	791	666	664	791	666	666	791	666	666	8,490
20	9310	A&G-Rents	117,994	117,979	117,979	111,893	111,816	111,818	112,016	111,816	111,816	111,893	117,917	117,979	1,372,917
21	9320	A&G-Maintenance of general plant	113	108	108	110	121	110	101	100	106	109	109	109	1,305
22															
23	Operating (Income)Loss*		$0	($0)	($0)	$0	($0)	$0	$0	($0)	($0)	$0	$0	($0)	($0)
24															
25	9220	A&G-Administrative expense transferred-Credit	(5,225,416)	(5,186,784)	(4,891,109)	(5,665,227)	(4,663,023)	(4,787,883)	(5,318,364)	(4,954,205)	(5,302,056)	(5,693,376)	(5,008,087)	(5,133,553)	(61,829,082)
26		Allocation Factor to Kentucky	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	5.31%	
27		Total Allocated Amount	(277,498)	(275,446)	(259,744)	(300,854)	(247,632)	(254,262)	(282,434)	(263,095)	(281,568)	(302,349)	(265,956)	(272,619)	(3,283,458)

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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Monthly Jurisdictional Operating Income by FERC Account, **Div 091 Only**
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

Line No.	Acct No.	Account Discription	Forecasted Apr-25	Forecasted Jun-25	Forecasted Jun-25	Forecasted Jul-25	Forecasted Aug-25	Forecasted Sep-25	Forecasted Oct-25	Forecasted Nov-25	Forecasted Dec-25	Forecasted Jan-26	Forecasted Feb-26	Forecasted Mar-26	Total
			$	$	$	$	$	$	$	$	$	$	$	$	$
1	4030	Depreciation Expense	-	-	-	-	-	-	-	-	-	-	-	-	-
2	4060	Amortization of gas plant acquisition adjustments													
3	4081	Taxes other than income taxes, utility operating income	-	-	-	-	-	-	-	-	-	-	-	-	-
4	8170	Lines expenses	108	109	126	107	116	118	108	111	114	113	109	115	1,354
5	8180	Compressor station expenses	137	137	159	135	146	148	136	140	144	142	137	145	1,706
6	8190	Compressor station fuel and power	0	0	0	0	0	0	0	0	0	0	0	0	0
7	8210	Storage-Purification expenses	245	245	286	243	262	266	243	251	258	254	246	261	3,061
8	8240	Storage-Other expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
9	8250	Storage well royalties	1,069	1,070	1,247	1,058	1,143	1,161	1,061	1,096	1,127	1,109	1,072	1,138	13,352
10	8500	Transmission-Operation supervision and engineering	0	0	0	0	0	0	0	0	0	0	0	0	0
11	8560	Mains expenses	176	176	205	174	188	191	174	180	185	182	176	187	2,193
12	8570	Transmission-Measuring and regulating station expenses	217	217	253	215	232	235	215	222	229	225	217	231	2,708
13	8600	Transmission-Measuring and regulating station expenses	2,585	2,585	2,585	2,585	2,585	2,585	2,420	2,420	2,420	2,420	2,420	2,537	30,144
14	8650	Transmission-Maintenance of me - Non-Inventory Supplies 8650-02005	0	0	0	0	0	0	0	0	0	0	0	0	0
15	8700	Distribution-Operation supervision and engineering	281,160	207,393	236,468	227,289	279,940	262,643	228,669	215,138	238,736	235,822	204,619	261,708	2,879,585
16	8711	Odorization	0	0	0	0	0	0	0	0	0	0	0	0	0
17	8740	Mains and Services Expenses	34,629	35,780	37,092	36,986	35,075	38,292	35,524	33,566	37,052	36,180	32,870	36,379	429,425
18	8750	Distribution-Measuring and regulating station expenses-Genrl	10,468	10,642	10,442	10,865	12,033	11,308	11,000	10,141	10,739	11,310	9,845	11,713	130,506
19	8760	Distribution-Measuring and regulating station expenses-Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
20	8770	Distribution-Measuring and regulating station expenses-City gate check stations	0	0	0	0	0	0	0	0	0	0	0	0	0
21	8780	Meter and house regulator expenses	8,911	8,881	8,440	9,326	8,422	8,864	9,547	8,682	9,226	9,734	8,357	8,766	107,156
22	8800	Distribution-Other expenses	172,881	172,788	174,435	142,669	141,547	171,041	135,491	138,516	165,074	142,528	153,429	196,056	1,906,454
23	8810	Distribution-Rents	40,177	40,225	46,855	39,751	42,968	43,615	39,861	41,200	42,331	41,690	40,270	42,769	501,714
24	8870	Distribution-Maint of mains	57	56	54	59	54	56	61	55	59	62	53	56	681
25	8890	Maintenance of measuring and regulating station equipment-General	0	0	0	0	0	0	0	0	0	0	0	0	0
26	8900	Maintenance of measuring and regulating station equipment-Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
27	8910	Maintenance of measuring and regulating station equipment-City gate check sta	16	16	15	17	15	16	17	16	17	17	15	16	192
28	9010	Customer accounts-Operation supervision	9,446	9,458	9,031	9,863	9,431	9,573	10,085	9,184	9,732	10,304	8,850	9,584	114,542
29	9020	Customer accounts-Meter reading expenses	3,713	3,700	3,517	3,886	3,509	3,693	3,978	3,617	3,844	4,056	3,482	3,652	44,648
30	9030	Customer accounts-Customer records and collections expenses	673,562	673,077	675,274	571,948	561,630	667,115	548,793	552,253	648,933	574,813	601,429	753,437	7,502,264
31	9040	Customer accounts-Uncollectible accounts	0	0	0	0	0	0	0	0	0	0	0	0	0
32	9090	Customer service-Operating informational and instructional advertising expense	14,866	14,699	14,042	15,318	14,709	14,892	15,661	14,267	15,114	16,002	13,752	14,922	178,243
33	9100	Customer service-Miscellaneous customer service	361	361	375	361	365	383	361	361	375	361	361	380	4,407
34	9110	Sales-Supervision	16,155	16,469	15,979	16,780	19,160	17,434	17,016	15,596	16,373	17,541	15,110	18,193	201,807
35	9120	Sales-Demonstrating and selling expenses	919	919	955	919	928	975	919	919	955	919	919	967	11,214
36	9130	Sales-Advertising expenses	21	21	22	21	21	22	21	21	22	21	21	22	255
37	9200	A&G-Administrative & general salaries	1,475	1,375	1,375	1,475	1,375	1,379	5,375	1,375	1,475	1,375	1,375	1,375	20,802
38	9210	A&G-Office supplies & expense	(126,617)	(126,547)	(127,553)	(104,275)	(103,343)	(125,140)	(98,947)	(101,156)	(120,769)	(104,110)	(112,221)	(143,677)	(1,394,355)
39	9220	A&G-Administrative expense transferred-Credit	(1,425,956)	(1,398,658)	(1,395,907)	(1,362,239)	(1,265,428)	(1,388,756)	(1,281,938)	(1,231,930)	(1,377,671)	(1,335,456)	(1,262,956)	(1,486,303)	(16,213,198)
40	9230	A&G-Outside services employed	(45,865)	(45,841)	(46,278)	(37,850)	(37,552)	(45,377)	(35,945)	(36,748)	(43,794)	(37,812)	(40,704)	(52,013)	(505,779)
41	9240	A&G-Property insurance	(8,955)	(8,955)	(8,955)	(8,955)	(8,955)	(8,955)	(8,384)	(8,384)	(8,384)	(8,384)	(8,384)	(8,791)	(104,439)
42	9250	A&G-Injuries & damages	83,930	85,681	81,419	85,933	80,206	83,250	86,175	81,268	84,618	88,686	76,954	80,481	998,601
43	9260	A&G-Employee pensions and benefits	240,096	275,835	232,862	314,890	188,798	197,830	243,290	237,548	251,203	279,741	238,261	234,351	2,934,705
44	9280	A&G-Regulatory commission expenses	0	0	0	0	0	0	0	0	0	0	0	0	0
45	9302	Miscellaneous general expenses	10,014	18,085	25,180	20,447	10,421	31,142	29,016	10,073	10,266	10,151	9,916	11,344	196,054
46	9310	A&G-Rents	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
47															
48		Operating (Income)Loss*	$0	($0)	($0)	($0)	($0)	$0	($0)	($0)	($0)	($0)	($0)	$0	($0)
49															
50	9220	A&G-Administrative expense transferred-Credit	(1,425,956)	(1,398,658)	(1,395,907)	(1,362,239)	(1,265,428)	(1,388,756)	(1,281,938)	(1,231,930)	(1,377,671)	(1,335,456)	(1,262,956)	(1,486,303)	(16,213,198)
51		Allocation Factor to Kentucky	48.90%	48.90%	48.90%	48.90%	48.90%	48.90%	48.90%	48.90%	48.90%	48.90%	48.90%	48.90%	48.90%
52		Total Allocated Amount	(697,293)	(683,944)	(682,598)	(666,135)	(618,794)	(679,102)	(626,868)	(602,414)	(673,681)	(653,038)	(617,585)	(726,802)	(7,928,254)

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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Account 4081-Taxes Other than Income Tax by Sub-Account
Base Period: Twelve Months Ended December 31, 2024

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-24	actual Feb-24	actual Mar-24	actual Apr-24	actual May-24	actual Jun-24	Budgeted Jul-24	Budgeted Aug-24	Budgeted Sep-24	Budgeted Oct-24	Budgeted Nov-24	Budgeted Dec-24	Total
1	**Div 009**													
2														
3	Payroll	$ 31,158	$ 24,299	$ 25,934	$ 16,417	$ 55,530	$ 24,110	$ 34,521	$ 34,521	$ 34,521	$ 36,713	$ 36,713	$ 36,713	$ 391,151
4	Payroll Tax Projects	-	211	92	(303)	-	-	$ -	$ -	$ -	$ -	$ -	$ -	-
5	Ad Valorem - Accrual	1,107,840	107,840	1,107,840	1,107,840	1,107,840	1,107,840	$1,107,840	$1,107,840	$1,107,840	$ 783,971	$ 783,971	$ 783,971	11,322,473
6	Dot Transmission User Tax	5,654	5,654	5,654	67,477	13,385	13,385	$ 85,810	$ 11,620	$ 11,620	$ 5,810	$ 5,810	$ 5,810	237,690
7	Taxes Property and Other	95	-	82	89	49	-	$ -	$ 218	$ 102	$ -	$ 80	$ 387	1,103
8	Public Service Commission Assessment	25,148	25,148	25,148	25,148	25,148	25,148	$ 25,239	$ 25,239	$ 25,239	$ 25,239	$ 25,239	$ 25,239	302,323
9	Allocation for taxes other CSC	20,767	15,546	15,634	16,311	22,874	7,359	10,540	10,540	10,540	10,843	10,843	10,843	162,641
10	Allocation from taxes other SS	27,331	21,967	21,765	22,787	33,520	10,614	17,446	17,446	17,446	16,170	38,593	16,170	261,256
11	Allocation from taxes other Gen Office	21,435	19,642	17,954	23,682	20,745	17,708	6,288	6,288	6,288	7,842	7,842	7,842	163,558
12														
13	Total	$1,239,429	$ 220,308	$1,220,105	$1,279,448	$1,279,091	$1,206,164	$1,287,684	$1,213,712	$1,213,596	$ 886,590	$ 909,092	$ 886,977	$ 12,842,195
14														
15														
16	**Div 002**													
17														
18	Payroll	$ 537,320	$ 431,153	$ 420,680	$ 442,603	$ 678,464	$ 176,423	$ 375,942	$ 375,942	$ 375,942	$ 388,440	$ 388,440	$ 388,440	$ 4,979,790
19	Ad Valorem	61,461	50,200	55,700	55,700	55,700	55,700	61,300	61,300	61,300	55,800	55,800	55,800	685,761
20	Payroll Tax Projects	282	146	690	730	562	535	-	-	-	-	-	-	2,944
21	Taxes Property And Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22														
23	Total Tax Other Than Income Tax	$ 599,062	$ 481,498	$ 477,070	$ 499,033	$ 734,726	$ 232,657	$ 437,242	$ 437,242	$ 437,242	$ 444,240	$ 444,240	$ 444,240	$ 5,668,494
24														
25	Allocated to Kentucky Jurisdiction (Div 009)	$ 27,331	$ 21,967	$ 21,765	$ 22,787	$ 33,520	$ 10,614	$ 17,446	$ 17,446	$ 17,446	$ 16,170	$ 38,593	$ 16,170	$ 261,256
26														
27														
28	**Div 012**													
29														
30	Payroll	$ 337,006	$ 248,262	$ 245,803	$ 258,346	$ 380,082	$ 92,297	$ 215,959	$ 215,959	$ 215,959	$ 251,798	$ 251,798	$ 251,798	$ 2,965,067
31	Ad Valorem	48,200	40,100	44,200	44,200	44,200	44,200	48,200	48,200	48,200	46,100	46,100	46,100	548,000
32														
33	Total Tax Other Than Income Tax	$ 385,206	$ 288,362	$ 290,003	$ 302,546	$ 424,282	$ 136,497	$ 264,159	$ 264,159	$ 264,159	$ 297,898	$ 297,898	$ 297,898	$ 3,513,067
34														
35	Allocated to Kentucky Jurisdiction (Div 009)	$ 20,767	$ 15,546	$ 15,634	$ 16,311	$ 22,874	$ 7,359	$ 10,540	$ 10,540	$ 10,540	$ 10,843	$ 10,843	$ 10,843	$ 162,641
36														
37														
38	**Div 091**													
39														
40	Payroll	$ 42,797	$ 39,218	$ 35,830	$ 47,292	$ 41,414	$ 35,317	$ 12,230	$ 12,230	$ 12,230	$ 15,898	$ 15,898	$ 15,898	$ 326,252
41	Payroll Tax Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Ad Valorem	100	100	100	100	100	100	100	100	100	-	-	-	900
43	Occupational Licenses	-	-	-	-	-	-	-	-	-	-	-	-	-
44														
45	Total Tax Other Than Income Tax	$ 42,897	$ 39,318	$ 35,930	$ 47,392	$ 41,514	$ 35,417	$ 12,330	$ 12,330	$ 12,330	$ 15,898	$ 15,898	$ 15,898	$ 327,152
46														
47	Total Allocated Amount	$ 21,435	$ 19,642	$ 17,954	$ 23,682	$ 20,745	$ 17,708	$ 6,288	$ 6,288	$ 6,288	$ 7,842	$ 7,842	$ 7,842	$ 163,558

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Account 4081-Taxes Other than Income Tax by Sub-Account
Forecasted Test Period: Twelve Months Ended March 31, 2026

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-25	Forecasted May-25	Forecasted Jun-25	Forecasted Jul-25	Forecasted Aug-25	Forecasted Sep-25	Forecasted Oct-25	Forecasted Nov-25	Forecasted Dec-25	Forecasted Jan-26	Forecasted Feb-26	Forecasted Mar-26	Total
1	**Div 009**													
2														
3	Payroll	$ 36,713	$ 36,713	$ 36,713	$ 36,713	$ 36,713	$ 36,713	$ 37,998	$ 37,998	$ 37,998	$ 37,998	$ 37,998	$ 37,998	$ 448,271
4	Payroll Tax Projects	-	-	-	-	-	-	-	-	-	-	-	-	$ -
5	Ad Valorem - Accrual	824,152	824,152	824,152	824,152	824,152	824,152	824,152	824,152	824,152	824,152	824,152	824,152	9,889,824
6	Dot Transmission User Tax	25,000	5,810	5,810	80,000	5,810	5,810	5,810	5,810	5,810	5,810	5,810	75,500	232,790
7	Taxes Property and Other	91	50	-	-	218	102	-	80	387	87	-	87	1,102
8	Public Service Commission Assessment	24,323	24,323	24,323	24,323	24,323	24,323	24,323	24,323	24,323	24,323	24,323	24,323	291,875
9	Allocation for taxes other CSC	10,989	10,989	10,989	10,989	10,989	10,989	10,843	10,843	10,843	10,989	10,989	10,989	131,432
10	Allocation from taxes other SS	16,440	16,440	16,440	16,440	16,440	16,440	16,170	38,593	16,170	16,440	16,440	16,440	218,891
11	Allocation from taxes other Gen Office	7,842	7,842	7,842	7,842	7,842	7,842	7,842	7,842	7,842	7,842	7,842	7,842	94,109
12														
13	Total	$ 945,551	$ 926,320	$ 926,270	$1,000,460	$ 926,488	$ 926,372	$ 927,140	$ 949,642	$ 927,527	$ 927,642	$ 927,555	$ 997,332	$ 11,308,295
14														
15														
16	**Div 002**													
17														
18	Payroll	$ 388,440	$ 388,440	$ 388,440	$ 388,440	$ 388,440	$ 388,440	$ 402,036	$ 402,036	$ 402,036	$ 402,036	$ 402,036	$ 402,036	$ 4,742,858
19	Ad Valorem	63,200	63,200	63,200	63,200	63,200	63,200	55,800	55,800	55,800	63,200	63,200	63,200	736,200
20	Benefit Load Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Taxes Property And Other	-	-	-	-	-	-	-	-	-	-	-	-	-
22														
23	Total Tax Other Than Income Tax	$ 451,640	$ 451,640	$ 451,640	$ 451,640	$ 451,640	$ 451,640	$ 457,836	$ 457,836	$ 457,836	$ 465,236	$ 465,236	$ 465,236	$ 5,479,058
24														
25	Allocated to Kentucky Jurisdiction (Div 009)	$ 16,440	$ 16,440	$ 16,440	$ 16,440	$ 16,440	$ 16,440	$ 16,170	$ 38,593	$ 16,170	$ 16,440	$ 16,440	$ 16,440	$ 218,891
26														
27														
28	**Div 012**													
29														
30	Payroll	$ 251,798	$ 251,798	$ 251,798	$ 251,798	$ 251,798	$ 251,798	$ 260,611	$ 260,611	$ 260,611	$ 260,611	$ 260,611	$ 260,611	$ 3,074,449
31	Ad Valorem	50,100	50,100	50,100	50,100	50,100	50,100	46,100	46,100	46,100	50,100	50,100	50,100	589,200
32														
33	Total Tax Other Than Income Tax	$ 301,898	$ 301,898	$ 301,898	$ 301,898	$ 301,898	$ 301,898	$ 306,711	$ 306,711	$ 306,711	$ 310,711	$ 310,711	$ 310,711	$ 3,663,649
34														
35	Allocated to Kentucky Jurisdiction (Div 009)	$ 10,989	$ 10,989	$ 10,989	$ 10,989	$ 10,989	$ 10,989	$ 10,843	$ 10,843	$ 10,843	$ 10,989	$ 10,989	$ 10,989	$ 131,432
36														
37														
38	**Div 091**													
39														
40	Payroll	$ 15,898	$ 15,898	$ 15,898	$ 15,898	$ 15,898	$ 15,898	$ 16,454	$ 16,454	$ 16,454	$ 16,454	$ 16,454	$ 16,454	$ 194,113
41	Payroll Tax Projects	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Ad Valorem	-	-	-	-	-	-	-	-	-	-	-	-	-
43	Occupational Licenses	-	-	-	-	-	-	-	-	-	-	-	-	-
44														
45	Total Tax Other Than Income Tax	$ 15,898	$ 15,898	$ 15,898	$ 15,898	$ 15,898	$ 15,898	$ 16,454	$ 16,454	$ 16,454	$ 16,454	$ 16,454	$ 16,454	$ 194,113
46														
47	Total Allocated Amount	$ 7,842	$ 7,842	$ 7,842	$ 7,842	$ 7,842	$ 7,842	$ 7,842	$ 7,842	$ 7,842	$ 7,842	$ 7,842	$ 7,842	$ 94,109

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Ad Valorem Accrual Forecast
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:________Base Period___X____Forecasted Period — FR 16(8)(c)2.3
Type of Filing:___X____Original________Updated ________Revised — Schedule C-2.3 F
Workpaper Reference No(s).____________________ — Witness: Waller

Line No.	Discription	Sched Ref.		Balance
1	**Div 009**			
2				
3	2024 Ad Valorem Expense			9,424,575
4				
5	Ad Valorem Recovered in PRP Rates CASE NO. 2023-00231			(339,931)
6				
7	Adjusted Base Period Ad Valorem		$	9,084,644
8				
9	Ending Base Period Gross Plant	B.2 B	$	909,763,471
10				
11	Ad Valorem Rate			1.00%
12				
13	Ending Forecasted Period Gross Plant	B.2 F	$	940,325,173
14				
15	Test Period Ad Valorem Adjusted for Forecasted Plant		$	9,389,824
16				
17	Adjustment for Pending "Marathon" expiration (1)		$	500,000
18				
19	Total Test Period Ad Valorem Expense		$	9,889,824

Note: 1) $2 million adjustment for 3 months of CY26 - see Waller rebuttal testimony

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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. 2024-00276
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(d)1
Type of Filing:___X___Original________Updated ________Revised — Schedule D-1
Workpaper Reference No(s).____________________ — Witness: Waller, Wiebe, Troup

			Title of Adjustment					
Line No.	Account No. & Title	Base Period	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	87,647,010	15,404,745					15,404,745
2	480 Gas Rev - Commericial	41,998,643	9,445,179					9,445,179
3	480 Gas Rev - Industrial	4,073,459	1,057,173					1,057,173
4	480 Gas Rev - Public Authority & Other	5,745,918	1,452,592					1,452,592
5								
6								
7	Total SALE of Gas	139,465,030	27,359,689	0	0	0	0	27,359,689
8								
9	Other Operating Income							
10	Forfeited discounts	197,310		170,152				170,152
11	488 MISC. Service Revenues	58,913		(1)				(1)
12	489 Revenue From Transporting Gas to Others	21,748,887		(1,177,966)				(1,177,966)
13	495 Other Gas Service Revenue	0		0				0
14								
15	Total Other Operating Income	22,005,110	0	(1,007,815)	0	0	0	(1,007,815)
16								
17	Total Operating Revenue	161,470,140	27,359,689	(1,007,815)	0	0	0	26,351,873
18								
19	Other Gas Supply Expenses - Operation							
20	803/804/812 Gas Purchase Costs	52,986,727			34,654,171			34,654,171
21								
22	Total Other Gas Supply Expenses - Operation	52,986,727	0	0	34,654,171	0	0	34,654,171
23								
24	Total Plant Revenue	108,483,413	27,359,689	(1,007,815)	(34,654,171)	0	0	(8,302,297)
25								
26	Blended Effective Tax Rate	24.95%	6,826,242	(251,450)	(8,646,216)	0	0	(2,071,423)
27								
28	NET Operating Income Impact		20,533,446	(756,365)	(26,007,955)	0	0	(6,230,874)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(d)1
Type of Filing:___X___Original________Updated ________Revised — Schedule D-1
Workpaper Reference No(s).____________________ — Witness: Waller, Wiebe, Troup

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	33,549	1,950	-	(336)	-	-	1,614
33	8170	817 Storage Lines Expense	21,362	1,517	114	(212)	-	-	1,419
34	8180	818 Storage Compressor Station	39,827	4,998	6	(53)	-	-	4,950
35	8190	819 Storage Compressor Station Fuel	-	-	-	-	-	-	-
36	8200	820 Storage Measuring & Regulating	8,836	51	69	580	-	-	700
37	8210	821 Storage Purification	76,521	7,779	101	(462)	-	-	7,419
38	8240	824 Storage Other Expense	-	-	-	-	-	-	-
39	8250	825 Storage Royalties	10,111	-	371	-	-	-	371
40	8310	831 Storage Maintenance Structure	-	-	-	-	-	-	-
41	8320	832 Storage Maintenance Res	-	-	-	-	-	-	-
42	8340	834 Storage Maintenance Compressor	41,017	5,399	-	-	-	-	5,399
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	206,958	26,228	-	57	-	-	26,285
48	8470	847 Storage Maintenance	-	-	-	-	-	-	-
49	8500	850 Trsm Supervision & Engineering	-	-	-	-	-	-	-
50	8520	852 Communication system expenses	-	-	-	-	-	-	-
51	8550	855 Other Fuel & Power Comp	471	-	17	-	-	-	17
52	8560	856 Trsm Mains Expense	131,470	14,167	127	(265)	-	-	14,029
53	8570	857 Trsm Measuring & Regulating	11,353	230	353	-	-	-	583
54	8590	859 Trsm Other Exp	-	-	-	-	-	-	-
55	8600	860 Rents	-	-	-	-	-	-	-
56	8620	862 Trsm Structure & Improvements	-	-	-	-	-	-	-
57	8630	863 Trsm Maint of Mains	20,250	2,665	-	-	-	-	2,665
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	2,267,606	100,874	2,611	(230,385)	-	-	(126,901)
62	8710	871 Dist Load Dispatching	(40)	-	(1)	-	-	-	(1)
63	8711	8711 Odorization	137,138	-	-	(4,319)	-	-	(4,319)
64	8720	872 Dist Comp Sta	-	-	-	-	-	-	-
65	8740	874 Dist Main/Ser Exp	6,959,627	298,627	5,844	(461,113)	-	-	(156,642)
66	8750	875 Dist Meas/Reg Sta-Gen	1,231,731	141,483	232	(11,911)	-	-	129,804
67	8760	876 Dist Meas/Reg Sta-Ind	540	-	-	(17)	-	-	(17)
68	8770	877 Dist Meas/Reg Sta-Cty.	5,298	-	192	(3)	-	-	189
69	8780	878 Dist Mtr/House Reg	833,461	104,428	525	57	-	-	105,010
70	8790	879 Dist Cust Install	266	-	-	(8)	-	-	(8)
71	8800	880 Dist Other Exp	3,157	-	-	(72)	-	-	(72)
72	8810	881 Dist Rents	99,414	-	13,442	(37,833)	-	-	(24,392)
73	8850	885 Dist Maint Super/Eng	-	-	-	-	-	-	-
74	8860	886 Dist Maint Struc/Improv	-	-	-	-	-	-	-

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(d)1
Type of Filing:___X___Original________Updated ________Revised — Schedule D-1
Workpaper Reference No(s).____________________ — Witness: Waller, Wiebe, Troup

				Title of Adjustment					GRAND
Line No.	Account No. & Title		Base Period	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	Total ADJUST.
75	8870	887 Dist Maint of Mains	145,970	9,719	-	(11,209)	-	-	(1,490)
76	8890	889 Dist Maint Meas/Reg Sta-Gen	188,075	70	-	(47,555)	-	-	(47,485)
77	8900	890 Dist Maint Meas/Reg Sta-Ind	-	-	-	-	-	-	-
78	8910	891 Dist Maint Meas/Reg Sta-Cty	119	16	-	-	-	-	16
79	8920	892 Dist Maint of Ser	157	21	-	-	-	-	21
80	8930	893 Dist Maint Mtr/House Reg	-	-	-	-	-	-	-
81	8940	894 Dist Maint Other Eq	-	-	-	-	-	-	-
82	8950	895 Maintenance of Other Plant	-	-	-	-	-	-	-
83	9010	901 Cust Accts Supervision	-	-	-	-	-	-	-
84	9020	902 Cust Accts Mtr Exp	691,928	39,554	13,133	(9,326)	-	-	43,360
85	9030	903 Cust Accts Records/Collections	1,301,395	36,777	-	(270,369)	-	-	(233,591)
86	9040	904 Cust Accts Uncoll Accts	1,603,608	-	-	-	(872,076)	-	(872,076)
87	9070	907 Cust Accts Supervision	-	-	-	-	-	-	-
88	9080	908 Customer Assistance Expenses	-	-	-	-	-	-	-
89	9090	909 Cust Ser Supervision	198,663	18,848	-	(3,051)	-	-	15,798
90	9100	910 Cust Ser Assist Exp	-	-	-	-	-	-	-
91	9110	911 Cust Ser Info Adv Exp	143,620	15,069	-	(140)	-	-	14,929
92	9120	912 Demonstrating and Selling Expenses	88,415	-	-	(11,337)	-	-	(11,337)
93	9130	913 Advertising Expenses	69,535	-	-	(32,714)	-	-	(32,714)
94	9160	916 Sales Promo Demo/Selling	2,601	-	-	(2,601)	-	-	(2,601)
95	9200	920 Administrative and General Salaries	-	-	-	-	-	-	-
96	9210	921 Adm Gen Office Supply	49,458	-	-	19,610	-	-	19,610
97	9220	922 Administrative Expense Transferred	15,853,828	-	-	-	-	1,860,173	1,860,173
98	9230	923 Adm Gen Outside Services Emply	96,909	-	-	(26,916)	-	-	(26,916)
99	9240	924 Property insurance	5,555	-	-	(5,555)	-	-	(5,555)
100	9250	925 Adm Gen Injuries/Damages	58,037	-	-	(34,780)	-	-	(34,780)
101	9260	926 Adm Gen Empl Pen/Ben	767,059	106,722	-	(1,022)	-	-	105,700
102	9270	927 Adm Gen Franchise Req	474	-	-	161	-	-	161
103	9280	928 Adm Gen Reg Comm Exp	106,317	-	-	59,074	-	-	59,074
104	9290	929 Uniforms capitalized	-	-	-	-	-	-	-
105	9301	9301 Adm Gen Goodwill Adv	-	-	-	-	-	-	-
106	9302	9302 Adm Gen Gen Exp	25,278	-	-	(868)	-	-	(868)
107	9310	931 A&G-Rents	-	-	-	-	-	-	-
108	9320	932 Adm Gen Maint Gen Plant	-	-	-	-	-	-	-
109	Total		33,536,927	937,190	37,136	(1,124,892)	(872,076)	1,860,173	837,531
110	Labor and Benefits		7,055,733	937,190					937,190
111	Rent, Maintenance and Utilites		1,011,281		37,136				37,136
112	Other O&M		17,683,099			(1,124,892)			(1,124,892)
113	Bad Debt		1,603,608				(872,076)		(872,076)
114	Costs allocated from SSU and KY-MDS General Office		15,853,828	0	0	0		1,860,173	1,860,173
115	Total		43,207,549	937,190	37,136	(1,124,892)	(872,076)	2,397,488	837,531
116	Blended Effective Tax Rate		24.95%	(233,829)	(9,265)	280,661	217,583	(598,173)	(208,964)
117	NET Operating Income Impact			703,361	27,871	(844,232)	(654,493)	1,799,315	628,567

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Summary of Utility Jurisdictional Adjustments to
Operating Income by Major Accounts
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(d)1
Type of Filing:___X___Original________Updated ________Revised — Schedule D-1
Workpaper Reference No(s).____________________ — Witness: Waller, Wiebe, Troup

Line No.	Account No. & Title	Base Period	Title of Adjustment 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	19,915,761	2,063,309					2,063,309
119	404 Amortization Expense	0						0
120	406 AMORT. - Gas Plant AQUIST.	49,305						0
121								
122	Total DEPRECIATION and Amortization	19,965,066	2,063,309					2,063,309
123								
124	Blended Effective Tax Rate	24.95%	514,796					514,796
125								
126	NET Operating Income Impact		1,548,513					1,548,513
127								
128								
129								
130								
131	408 Taxes, Other than Income	12,842,195		(1,533,900)				(1,533,900)
132								
133	Blended Effective Tax Rate	24.95%		(382,708)				(382,708)
134								
135	NET Operating Income Impact			(1,151,192)				(1,151,192)

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Detailed Adjustments
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

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	$103,051,755
3	due to cold weather in base period, and changes in gas costs between the periods	Base	87,647,010
4		Adjustment	$15,404,745
5			17.6%
6			
7	SALE of Gas-Commercial - the purpose of this Adjustment is to reflect the normalization of volumes	Forecasted	$51,443,822
8	due to cold weather in base period, and changes in gas costs between the periods	Base	41,998,643
9		Adjustment	$9,445,179
10			22.5%
11			
12	SALE of Gas-Industrial - the purpose of this Adjustment is to reflect known and measurable changes,	Forecasted	$5,130,632
13	increases and reductions, shifts from base period to test year and	Base	4,073,459
14	changes in gas costs between the periods.	Adjustment	$1,057,173
15			26.0%
16			
17	SALE of Gas-Public Authority - The purpose of this Adjustment is to reflect the normalization of	Forecasted	$7,198,509
18	volumes due to cold weather in base period, and changes in gas costs between the periods	Base	5,745,918
19		Adjustment	$1,452,592
20			25.3%
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	$367,462
28	payment fees from the base period to the test year.	Base	197,310
29		Adjustment	$170,152
30			86.2%
31			
32	Misc Service Revenues - the purpose of this adjustment is to reflect modest reduction in service charg	Forecasted	$58,912
33	revenues for the base period.	Base	58,913
34		Adjustment	($1)
35			0.0%
36			
37	Revenue from Transportation - the purpose of this Adjustment is to reflect known and measurable	Forecasted	$20,570,921
38	changes in demand for existing industries and account for migration to/from transportation service	Base	21,748,887
39		Adjustment	($1,177,966)
40			-5.4%
41			
42	Other gas service revenues - the purpose of this adjustment is to reflect pro forma adjustments for	Forecasted	$0
43	individual customers and special contract reformations	Base	0
44		Adjustment	$0
45			0.0%
46	**ADJ3**		
47	Gas Purchase Costs - The purpose of this Adjustment is to reflect the purchase quantities	Forecasted	$87,640,898
48	for sales service. The Base Period includes Unbilled Gas Costs that will zero out by the end	Base	52,986,727
49	of the base period when replaced by actuals. Gas costs in the Forecasted Period are higher	Adjustment	$34,654,171
50	primarily due to lower estimated GCA price		65.4%
51			
52			
53			
54	Summary of Revenue Adjustments.		
55	Base Year Revenues		161,470,140
56	Base Year Gas Costs		52,986,727
57	Base Year Gross Profit		108,483,413
58			
59	Test Year Revenues		187,822,013
60	Test Year Gas costs		87,640,898
61	Test Year Gross Profit		100,181,115

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Detailed Adjustments
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(d)2.2
Type of Filing:___X_____Original________Updated — Schedule D-2.2
Workpaper Reference No(s).___________ — Vitness: Waller, Wiebe, Troup

Purpose and Description		Amount
ADJ 1		
Labor and Benefits - The purpose of this adjustment is to account for forecasted labor and benefits expense due primarily to adjustments to labor capitalization rate versus the base period. Benefits are projected as a fixed benefit load percentage of labor expense plus an amount for workers' comp insurance. This adjustment pertains to labor and benefits for Kentucky operations.	Forecasted	$ 7,992,924
	Base	7,055,733
	Adjustment	$ 937,190
		13.3%
ADJ 2		
Rent, Maintenance and Utilities - The purpose of this adjustment is to account for forecasted rent, maintenance and utilities. Unlike other O&M categories that are likely to increase with normal inflation, our building rents are driven by leases already in place and can therefore be projected with a high level of accuracy. The rent portion of this O&M category was projected by reviewing actual lease amounts. This adjustment pertains to expenses for Kentucky operations.	Forecasted	$ 1,048,417
	Base	1,011,281
	Adjustment	$ 37,136
		3.7%
ADJ 3		
Other O&M - The purpose of this adjustment is to account for projected changes in O&M expenses other than labor, benefits, rent, and bad debt. This adjustment pertains to expenses for Kentucky operations.	Forecasted	$ 6,887,584
	Base	8,012,477
	Adjustment	$ (1,124,892)
		-14.0%
ADJ 4		
Bad Debt - The purpose of this adjustment is to account for anticipated bad debt costs due to uncollectible accounts. The projection is made by calculating 0.50% of residential, commercial and public authority margins from the revenues projection.	Forecasted	$ 731,532
	Base	1,603,608
	Adjustment	$ (872,076)
		-54.4%
ADJ 5		
Costs allocated from Shared Services and Kentucky-Mid States General Office - The purpose of this adjustment is to account for the forecasted amount of expenses that are allocated to Kentucky from the Shared Services Unit and Division General Office.	Forecasted	$ 18,251,309
	Base	15,853,822
	Adjustment	$ 2,397,488
		15.1%
Summary of O & M adjustments.	Forecasted	$ 34,911,766
	Base	33,536,921
	Adjustment	$ 1,374,846
		4.1%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Detailed Adjustments
Forecasted Test Period: Twelve Months Ended March 31, 2026

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, Wiebe, Troup

LN NO	Purpose and Description		Amount
1	**ADJ1**		
2	Depreciation Expense - The purpose of this adjustment is to reflect the change in	Forecasted	$21,979,070
3	depreciation expense due to the increased level of depreciable plant investment.	Base	19,915,761
4		Adjustment	$2,063,309
5			10.4%
6	**ADJ2**		
7	Taxes Other - The purpose of this adjustment is to account for anticipated	Forecasted	$11,308,295
8	changes in Taxes, Other than Income Taxes	Base	12,842,195
9		Adjustment	($1,533,900)
10			-11.9%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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. 2024-00276
Computation of State & Federal Income Tax
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(e)
Type of Filing:___X____Original________Updated ________Revised — Schedule E
Workpaper Reference No(s).____________________ — Witness: Waller, Multer

Line No.	Description	Base Period Unadjusted (1)	Adjustments (2)	Test Period Fully Adjusted (3)	Sched. Ref.
1	Operating Income before Income Tax & Interest	$ 35,523,772	$ (114,963)	$ 35,408,809	C-2
2					
3	Interest Deduction	9,760,195	395,420	10,155,615	*
4					
5	Taxable Income	$ 25,763,577	$ (510,383)	$ 25,253,194	
6					
7	Composite Tax Rate (state & federal)	24.950%		24.950%	* *
8					
9	**State & Federal Income Tax**	$ 6,428,013	$ (127,341)	**$ 6,300,672**	
10					
11					
12					
13	* Interest Expense Calculation:				
14	13 Month Average Rate Base	$618,389,716		$623,012,457	B-1
15					
16	Weighted cost of Debt	1.58%		1.63%	J-1
17					
18	Interest Expense	$ 9,760,195		$ 10,155,615	
19					
20					
21	2021 * * Composite Tax Rate Calculation: 5.00% + 21%(100% - 5.00%) = 24.95%				
22	State Tax Rate	5.00%			
23	Federal Tax Rate	21.00%			

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	4	Projected Rate Case Expense
F-7	1	Civic, Political and Related Activities
F-8	1	Expense Reports
F-9	1	SERP Expense
F-10	1	Incentive Compensation Expense
F-11	1	2017-00349 O&M Adjustments
F-12	1	Misc Regulatory Liabilities

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
SOCIAL and Service CLUB DUES
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	34,038	100%	34,038
2	Various	ASME	158		158
3	Various	AUCSC	(200)		(200)
4	Various	B2B PRIME	196		196
5	Various	BEACON / QPUBLIC.NET	105		105
6	Various	BIA OF LOUISVILLE	450		450
7	Various	BUILDERS ASSOCIATION OF SOUTH CENTRAL KY	455		455
8	Various	CADIZ TRIGG COUNTY ECONOMIC DEVELOP COMM	500		500
9	Various	CHAMBER OF COMMERCE	55,630		55,630
10	Various	CHRISTIAN COUNTY PVA	50		50
11	Various	CNA SURETY	61		61
12	Various	COMCAST CABLE	3		3
13	Various	CRITTENDEN COUNTY ECONOMIC	100		100
14	Various	ECONOMIC DEVELOPMENT COUNCIL	18,500		18,500
15	Various	FRANKLIN SIMPSON INDUSTRIAL AUTHORITY	5,000		5,000
16	Various	GRAVES COUNTY	3,000		3,000
17	Various	GREATER OWENSBORO ECONOMIC DEVELOPMENT CORP	10,000		10,000
18	Various	GREATER PADUCAH ECONOMIC DEVELOPMENT COUNCIL INC	10,000		10,000
19	Various	HOME BUILDERS ASSOCIATION	1,570		1,570
20	Various	HOME BUILDERS ASSOCIATION OF OWENSBORO	550		550
21	Various	HOPKINS COUNTY HOME BUILDERS ASSOCIATION	325		325
22	Various	HOPKINS COUNTY PVA	555		555
23	Various	KENTUCKY ASSOCIATION FOR ECONOMIC DEVELOPMENT	25,000		25,000
24	Various	KENTUCKY ASSOCIATION OF MAPPING PROFESSIONALS	25		25
25	Various	KENTUCKY ASSOCIATION OF MASTER CONTRACTORS INC	1,250		1,250
26	Various	KENTUCKY GAS ASSOCIATION	10,436		10,436
27	Various	KENTUCKY LAKE ECONOMIC DEVELOPMENT	1,000		1,000
28	Various	KENTUCKY OIL AND GAS ASSOCIATION	1,520		1,520
29	Various	KENTUCKY PROFESSIONAL ENGINEER	150		150
30	Various	KENTUCKY PROFESSIONAL GEOLGIST LICENSE RENEWAL	180		180
31	Various	KENTUCKY RESTAURANT ASSOCIATION	395		395
32	Various	KENTUCKY SECRETARY OF STATE	10		10
33	Various	LEADERSHIP KENTUCKY	229		229
34	Various	MAD HOP CO BOARD OF REALTORS	100		100
35	Various	MASTERCRAFT PRINTED PRODUCTS AND SERVICES INC	292		292
36	Various	MCCRACKEN COUNTY TAX	23		23
37	Various	NACE INTERNATIONAL	295		295
38	Various	OBION COUNTY INDUSTRIAL DEVELOPMENT CORP	1,500		1,500
39	Various	OBION COUNTY JEDC	1,364		1,364
40	Various	OHIO COUNTY CHAMBER OF COMMERCE	850		850

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
SOCIAL and Service CLUB DUES
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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
41	Various	PADUCAH BOARD OF REALTORS INC	350		350	
42	Various	REALTOR ASSOCIATION	398		398	
43	Various	SAM'S CLUB	285		285	
44	Various	THE MESSENGER	51		51	
45	Various	TNGIC	40		40	
46	Various	TRIGG COUNTY PVA	10		10	
		Total Base Period	186,798		186,798	

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
SOCIAL and Service CLUB DUES
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	Adjustment %	Adjustment	Adjusted Amount
		TEST PERIOD						
1	Various	AGA	34,038	100%	34,038	4.3%	(1,464)	32,574
2	Various	ASME	158		158			158
3	Various	AUCSC	(200)		(200)			(200)
4	Various	B2B PRIME	196		196			196
5	Various	BEACON / QPUBLIC.NET	105		105			105
6	Various	BIA OF LOUISVILLE	450		450			450
7	Various	BUILDERS ASSOCIATION OF SOUTH CENTRAL KY	455		455			455
8	Various	CADIZ TRIGG COUNTY ECONOMIC DEVELOP COMM	500		500			500
9	Various	CHAMBER OF COMMERCE	55,630		55,630	20.0%	(11,126)	44,504
10	Various	CHRISTIAN COUNTY PVA	50		50			50
11	Various	CNA SURETY	61		61			61
12	Various	COMCAST CABLE	3		3			3
13	Various	CRITTENDEN COUNTY ECONOMIC	100		100			100
14	Various	ECONOMIC DEVELOPMENT COUNCIL	18,500		18,500			18,500
15	Various	FRANKLIN SIMPSON INDUSTRIAL AUTHORITY	5,000		5,000			5,000
16	Various	GRAVES COUNTY	3,000		3,000			3,000
17	Various	GREATER OWENSBORO ECONOMIC DEVELOPMENT CORP	10,000		10,000			10,000
18	Various	GREATER PADUCAH ECONOMIC DEVELOPMENT COUNCIL INC	10,000		10,000			10,000
19	Various	HOME BUILDERS ASSOCIATION	1,570		1,570			1,570
20	Various	HOME BUILDERS ASSOCIATION OF OWENSBORO	550		550			550
21	Various	HOPKINS COUNTY HOME BUILDERS ASSOCIATION	325		325			325
22	Various	HOPKINS COUNTY PVA	555		555			555
23	Various	KENTUCKY ASSOCIATION FOR ECONOMIC DEVELOPMENT	25,000		25,000			25,000
24	Various	KENTUCKY ASSOCIATION OF MAPPING PROFESSIONALS	25		25			25
25	Various	KENTUCKY ASSOCIATION OF MASTER CONTRACTORS INC	1,250		1,250			1,250
26	Various	KENTUCKY GAS ASSOCIATION	10,436		10,436			10,436
27	Various	KENTUCKY LAKE ECONOMIC DEVELOPMENT	1,000		1,000			1,000
28	Various	KENTUCKY OIL AND GAS ASSOCIATION	1,520		1,520			1,520
29	Various	KENTUCKY PROFESSIONAL ENGINEER	150		150			150
30	Various	KENTUCKY PROFESSIONAL GEOLGIST LICENSE RENEWAL	180		180			180
31	Various	KENTUCKY RESTAURANT ASSOCIATION	395		395			395
32	Various	KENTUCKY SECRETARY OF STATE	10		10			10
33	Various	LEADERSHIP KENTUCKY	229		229			229
34	Various	MAD HOP CO BOARD OF REALTORS	100		100			100
35	Various	MASTERCRAFT PRINTED PRODUCTS AND SERVICES INC	292		292			292
36	Various	MCCRACKEN COUNTY TAX	23		23			23
37	Various	NACE INTERNATIONAL	295		295			
38	Various	OBION COUNTY INDUSTRIAL DEVELOPMENT CORP	1,500		1,500			
39	Various	OBION COUNTY JEDC	1,364		1,364			
40	Various	OHIO COUNTY CHAMBER OF COMMERCE	850		850			

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
SOCIAL and Service CLUB DUES
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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
41	Various	PADUCAH BOARD OF REALTORS INC	350		350		
42	Various	REALTOR ASSOCIATION	398		398		
43	Various	SAM'S CLUB	285		285		
44	Various	THE MESSENGER	51		51		
45	Various	TNGIC	40		40		
46	Various	TRIGG COUNTY PVA	10		10		
		Total Forecasted Period	186,798		186,798	(12,590)	169,066

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
CHARITABLE CONTRIBUTIONS
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	Community Welfare	$ 289,341	100%	$ 289,341
2	Various	Education	$ 60,018		60,018
3	Various	Health	$ 21,000		21,000
4	Various	Museums & Arts	$ 15,750		15,750
5	Various	United Way Agencies	$ 3,500		3,500
6	Various	Youth Clubs & Centers	$ 13,630		13,630
7	Various	American Red Cross	$ 1,500		1,500
8	Various	Energy Assistance Program	$ 631,940		631,940
		Total	$1,036,679		$ 1,036,679
		TEST PERIOD			
1	Various	Community Welfare	$ 289,341	100%	$ 289,341
2	Various	Education	$ 60,018		60,018
3	Various	Health	$ 21,000		21,000
4	Various	Museums & Arts	$ 15,750		15,750
5	Various	United Way Agencies	$ 3,500		3,500
6	Various	Youth Clubs & Centers	$ 13,630		13,630
7	Various	American Red Cross	$ 1,500		1,500
8	Various	Energy Assistance Program	$ 631,940		631,940
		Total	$1,036,679		$ 1,036,679

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. 2024-00276
Employee PARTY, OUTING, and GIFT EXP.
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X___Base Period___X___Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original_______Updated_______Revised — Schedule F-2.3
Workpaper Reference No(s)._____________________ — Witness: Waller

Line No.	Account No.	Description of Expenses	Base Period Total Utility	Base Period Kentucky Jurisdictional	Base Period Allocated Amount	Forecasted Period Total Utility	Forecasted Period Kentucky Jurisdictional	Forecasted Period 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	$ 41,717	49.97%	$ 20,846	$ 31,754	48.90%	$ 15,528
8								
9		Total	$ 41,717		$ 20,846	$ 31,754		$ 15,528
10								
11		**Div 002**						
12	Various	Sub Account 07421- Service Awards	$ 102,942	4.56%	$ 4,696	$ 86,825	4.35%	$ 3,779
13								
14		Total	$ 102,942		$ 4,696	$ 86,825		$ 3,779
15								
16		**Div 012**						
17	Various	Sub Account 07421- Service Awards	$ 22,952	5.39%	$ 1,237	$ 32,717	5.31%	$ 1,737
18								
19		Total	$ 22,952		$ 1,237	$ 32,717		$ 1,737
20								
21		**Grand Total**	$ 167,611		$ 26,780	$ 151,296		$ 21,044

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Customer Service and Informational SALES and General ADVERTISING Expense
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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)	198,663	100%	198,663	214,461	100%	214,461
7	910	Miscellaneous Customer Service and Informational (1)	-	100%	-	-	100%	-
8		Total	$ 198,663		$ 198,663	$ 214,461		$ 214,461
9								
10		**Div 091**						
11	907	Supervision (1)	$ -	49.97%	$ -	$ -	48.90%	$ -
12	908	Customer Assistance	-	49.97%	-	-	48.90%	-
13	909	Informational Advertising (1)	-	49.97%	-	-	48.90%	-
14	910	Miscellaneous Customer Service and Informational (1)	3,331	49.97%	1,664	4,407	48.90%	2,155
15		Total	$ 3,331		$ 1,664	$ 4,407		$ 2,155
16								
17		**Div 002**						
18	907	Supervision (1)	$ -	4.56%	$ -	$ -	4.35%	$ -
19	908	Customer Assistance	-	4.56%	-	-	4.35%	-
20	909	Informational Advertising (1)	-	4.56%	-	-	4.35%	-
21	910	Miscellaneous Customer Service and Informational (1)	-	4.56%	-	-	4.35%	-
22		Total	$ -		$ -	$ -		$ -
23								
24		**Div 012**						
25	907	Supervision (1)	$ -	5.39%	$ -	$ -	5.31%	$ -
26	908	Customer Assistance	-	5.39%	-	-	5.31%	-
27	909	Informational Advertising (1)	-	5.39%	-	-	5.31%	-
28	910	Miscellaneous Customer Service and Informational (1)	-	5.39%	-	-	5.31%	-
29		Total	$ -		$ -	$ -		$ -
30								
31		**Sales Expense**						
32								
33		**Div 009**						
34	911	Supervision	$ 143,620	100%	$ 143,620	$ 158,549	100%	$ 158,549
35	912	Demonstration and Selling (1)	88,415	100%	88,415	77,078	100%	77,078
36	913	Advertising	69,535	100%	69,535	36,821	100%	36,821
37	916	Miscellaneous Sales Expense	-	100%	-	-	100%	-
38		Total	$ 301,570		$ 301,570	$ 272,449		$ 272,449
39								
40		**Div 091**						
41	911	Supervision	$ 185,487	49.97%	$ 92,688	$ 201,807	48.90%	$ 98,683
42	912	Demonstration and Selling (1)	8,475	49.97%	4,235	11,214	48.90%	5,484
43	913	Advertising	192	49.97%	96	255	48.90%	125
44	916	Miscellaneous Sales Expense	0	49.97%	0	0	48.90%	0
45		Total	$ 194,154		$ 97,019	$ 213,275		$ 104,292
46								
47		**Div 002**						
48	911	Supervision	$ -	4.56%	$ -	$ -	4.35%	$ -
49	912	Demonstration and Selling (1)	366,120	4.56%	16,703	97,007	4.35%	4,222
50	913	Advertising	-	4.56%	-	-	4.35%	-
51	916	Miscellaneous Sales Expense	-	4.56%	-	-	4.35%	-
52		Total	$ 366,120		$ 16,703	$ 97,007		$ 4,222
53								
54		**Div 012**						
55	911	Supervision	$ -	5.39%	$ -	$ -	5.31%	$ -
56	912	Demonstration and Selling (1)	-	5.39%	-	-	5.31%	-
57	913	Advertising	-	5.39%	-	-	5.31%	-
58	916	Miscellaneous Sales Expense	-	5.39%	-	-	5.31%	-
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. 2024-00276
ADVERTISING
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	$ 157,821	$ 55,854	$ 213,675	100%	$ 213,675	$ 157,821	100%	$ 157,821
3									
4	**Div 091**								
5	Newspaper, Magazine,bill stuffer & Other	38,506	414,420	452,926	49.97%	226,327	38,506	48.90%	18,830
6									
7	**Div 002**								
8	Newspaper, Magazine,bill stuffer & Other	208,280	544,793	753,073	4.56%	34,357	208,280	4.35%	9,065
9									
10	**Div 012**								
11	Newspaper, Magazine,bill stuffer & Other	40,005	1,601	41,606	5.39%	2,243	40,005	5.31%	2,124
12									
13	**Grand Total**	$ 444,611	$ 1,016,668	$ 1,461,280		$ 476,602	$ 444,611		$ 187,839

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
PROFESSIONAL Service Expenses
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	$ -	100%	$ -	$ -	100%	$ -
4	06121- Legal	$ 96,909	100%	96,909	$ 69,993	100%	69,993
5	Total	$ 96,909		$ 96,909	$ 69,993		$ 69,993
6							
7	Div 091						
8	06111- Contract Labor	$ 178,426	49.97%	$ 89,159	$ 317,682	48.90%	$ 155,347
9	06121- Legal	$ (462,496)	49.97%	(231,109)	$ (823,461)	48.90%	(402,673)
10	Total	$ (284,070)		$ (141,950)	$ (505,779)		$ (247,326)
11							
12	Div 002						
13	06111- Contract Labor	$ 16,211,762	4.56%	$ 739,623	$ 9,569,728	4.35%	$ 416,484
14	06121- Legal	$ 7,353,348	4.56%	335,479	$ 4,340,647	4.35%	188,909
15	Total	$ 23,565,110		$ 1,075,102	$13,910,375		$ 605,393
16							
17	Div 012						
18	06111- Contract Labor	$ 576,515	5.39%	$ 31,081	$ 731,813	5.31%	$ 38,863
19	06121- Legal	$ -	5.39%	-	$ -	5.31%	-
20	Total	$ 576,515		$ 31,081	$ 731,813		$ 38,863

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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
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	$ 50,000	
3	Depreciation Study - N. Allis	30,000	
4	Cost of Capital - D'Ascendis	120,000	
5	sub-total		$ 200,000
6			
7	**Legal Fees**		
8	(J. Hughes/A. Honaker)		303,000
9			
10	**Employee Expense**		
11	(airfare, lodging, meals, etc.)		31,617
12			
13	**Miscellaneous Expense**		
14	(printing, advertising, etc.)		108,105
15			
16	**Total Projected Rate Case Expense**		$ 642,722
17			
18	**Three (3) Year Amortization of Rate Case Expenses**		$ 214,241

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
CIVIC, POLITICAL and RELATED ACTIVITIES
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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

Line No.	Item (A)	Base Period Total Utility	Base Period Kentucky Jurisdictional	Base Period Allocated Amount	Forecasted Period Total Utility	Forecasted Period Kentucky Jurisdictional	Forecasted Period Allocated Amount
1	**Div 009**						
2	Donations (1)	$ -	100%	$ -	$ -	100%	$ -
3	Civic Duties (2)	-	100%	-	-	100%	-
4	Political Activities (3)	63,927	100%	63,927	63,927	100%	63,927
5	Other	-	100%	-	-	100%	-
6	Total	$ 63,927		$ 63,927	$ 63,927		$ 63,927
7							
8	**Div 091**						
9	Donations (1)	$ -	49.97%	$ -	$ -	48.90%	$ -
10	Civic Duties (2)	-	49.97%	-	-	48.90%	-
11	Political Activities (3)	-	49.97%	-	-	48.90%	-
12	Other	-	49.97%	-	-	48.90%	-
13	Total	$ -		$ -	$ -		$ -
14							
15	**Div 002**						
16	Donations (1)	$ -	4.56%	$ -	$ -	4.35%	$ -
17	Civic Duties (2)	-	4.56%	-	-	4.56%	-
18	Political Activities (3)	359,377	4.56%	16,396	359,377	4.56%	16,396
19	Other	-	4.56%	-	-	4.56%	-
20	Total	$ 359,377		$ 16,396	$ 359,377		$ 16,396
21							
22	**Div 012**						
23	Donations (1)	$ -	5.39%	$ -	$ -	5.39%	$ -
24	Civic Duties (2)	-	5.39%	-	-	5.39%	-
25	Political Activities (3)	-	5.39%	-	-	5.39%	-
26	Other	-	5.39%	-	-	5.39%	-
27	Total	$ -		$ -	$ -		$ -
28							
29	**Grand Total**	$ 423,305		$ 80,323	$ 423,305		$ 80,323

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. 2024-00276
EMPLOYEE EXPENSE REPORT EXCLUSIONS

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

Line No.	Description	Base Period Amount	Base Period Kentucky Jurisdictional	Base Period Allocated Amount	Forecasted Period Amount	Forecasted Period Kentucky Jurisdictional	Forecasted Period Allocated Amount
1	Div 009	$ 33,461	100.00%	$ 33,461	$ 33,461	100%	$ 33,461
2							
3	Div 091	102,874	49.97%	51,406	102,874	48.90%	50,305
4							
5	Div 002	880,463	4.56%	40,169	880,463	4.35%	38,319
6							
7	Div 012	165,584	5.39%	8,927	165,584	5.31%	8,793
8							
9	Total Expense Report Exclusions	$ 1,182,382		$ 133,963	$ 1,182,382		$ 130,879

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. 2024-00276
SERP EXPENSE

Data:______Base Period___X___Forecasted Period FR 16(8)(f)
Type of Filing:___X_____Original________Updated________Revise Schedule F-9
Workpaper Reference No(s).____________________ Witness: Waller

Line No.	Div	Category	Total	Allocation Factor	Allocated Total Amount
1	2	SERP Expense	$ 697,807	4.35%	$ 30,369
2					
3	91	SERP Expense	35,888	48.90%	17,549
4					
5		SERP Expense Adjustment			$ 47,918

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
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
1		Variable Pay & Management Incentive Plans			
2	2	VPP & MIP	10,633,155	4.56%	$ 485,112
3					
4	12	VPP & MIP	1,691,183	5.39%	91,174
5					
6	91	VPP & MIP	518,970	49.97%	259,329
7					
8	9	VPP & MIP	0	100.00%	0
9					
10		Total Allocated VPP & MIP Plans			$ 835,616
11					
12					
13		Restricted Stock Plans			
14	2	RSU-LTIP - Performance Based	5,314,210	4.56%	242,448
15					
16	12	RSU-LTIP - Performance Based	119,488	5.39%	6,442
17					
18	91	RSU-LTIP - Performance Based	56,219	49.97%	28,093
19					
20	9	RSU-LTIP - Performance Based	0	100.00%	0
21					
22		Total Allocated Restricted Stock Plans			$ 276,983
23					
24		Grand Total Allocated Expense			$ 1,112,598
25					
26		Payroll Taxes Expense Adjustment			$ 72,319

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
2017-00349 O&M Adjustments

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.	Division	Budget Sub Account	Amount	Allocation	Total
1	002	Directors Retirement Expenses - 04113	2,947,500	4.35%	128,278
2	002	Removal of Retirement Benefits	893,438	4.56%	40,761
3	012	Removal of Retirement Benefits	410,483	5.39%	22,130
4	009	Removal of Retirement Benefits	80,903	100.00%	80,903
5	091	Removal of Retirement Benefits	62,787	49.97%	31,375
6					
7		Grand Total			303,447

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Regulatory Liabilities
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:__X___Base Period__X___Forecasted Period — FR 16(8)(f)
Type of Filing:___X____Original________Updated ________Revised — Schedule F-12
Workpaper Reference No(s). — Witness: Waller

Line No.	Description	Base Period				Forecast Period			
1	Regulatory Liability			Balance	Amortization			Balance	Amortization
2	Depreciation Reserve 2540-27913	Dec-23	$	(8,620,222)		Mar-25	$	(6,565,552)	$ 136,978
3		Jan-24		(8,620,222)	0	Apr-25		(6,383,176)	182,376
4		Feb-24		(8,346,266)	273,956	May-25		(6,200,799)	182,376
5		Mar-24		(8,209,288)	136,978	Jun-25		(6,018,423)	182,376
6		Apr-24		(8,072,310)	136,978	Jul-25		(5,836,046)	182,376
7		May-24		(7,935,332)	136,978	Aug-25		(5,653,670)	182,376
8		Jun-24		(7,798,354)	136,978	Sep-25		(5,471,294)	182,376
9		Jul-24		(7,661,376)	136,978	Oct-25		(5,288,917)	182,376
10		Aug-24		(7,524,398)	136,978	Nov-25		(5,106,541)	182,376
11		Sep-24		(7,387,420)	136,978	Dec-25		(4,924,164)	182,376
12		Oct-24		(7,250,442)	136,978	Jan-26		(4,741,788)	182,376
13		Nov-24		(7,113,464)	136,978	Feb-26		(4,559,411)	182,376
14		Dec-24		(6,976,486)	136,978	Mar-26		(4,377,035)	182,376
15									
16		Base Period	$	(7,808,891)	$ 1,643,736	Forecast Period	$	(5,471,294)	$ 2,188,517
17				(13-Month Avg)				(13-Month Avg)	
18									
19		Jan-25		(6,839,508)	136,978				
20		Feb-25		(6,702,530)	136,978				
21									
22									
23									
24								Balance (13-Mo.)	Amortization
25	Total Regulatory Liabilities					Forecast Period	$	(5,471,294)	$ 2,188,517

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
PAYROLL Costs
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:__X___Base Period___X___Forecasted Period | FR 16(8)(g)
Type of Filing:___X____Original________Updated | Schedule G-1
Workpaper Reference No(s). | 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		$ 15,732,461	100.00%	$ 15,732,461	$2,070,638	$ 17,803,099
3							
4	Employee Benefits						
5	PENSION & RETIREMENT Income Plan	3.73%	$ 586,896	100.00%	$ 586,896	$ 77,245	$ 664,140
6	FAS 106	1.33%	209,005	100.00%	209,005	27,508	236,514
7	Employee INSURANCE PLANS	19.75%	3,107,931	100.00%	3,107,931	409,052	3,516,984
8	ESOP PLAN Contributions	2.68%	421,952	100.00%	421,952	55,535	477,487
9							
10	Total Employee BENEFITS		$ 1,859,853		$ 1,859,853	$ 266,092	$ 2,125,946
11							
12	Payroll Taxes						
15	Payroll Taxes		$ 975,269	100.00%	975,269	142,419	$ 1,117,688
16	Total Payroll Taxes		$ 975,269		$ 975,269	$ 142,419	$ 1,117,688
17							
18	Total Payroll Costs		$ 18,567,583		$ 18,567,583	$2,479,150	$ 21,046,733

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Payroll Analysis by Employee Classifications/Payroll Distribution/Total Company
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	2019	% Change	2020	% Change	2021	% Change	2022	% Change	2023	% Change	Base Period	% Change	Forecasted Period
		Most Recent Five Years*												
1	Man Hours													
2	Straight Time Hours	428,910	-1.01%	424,588	-5.83%	399,843	-0.75%	396,862	2.92%	408,449	8.47%	443,040	0.00%	443,040
3	OverTime Hours	31,808	-41.08%	18,741	-3.62%	18,062	40.00%	25,288	15.41%	29,186	2.68%	29,969	0.00%	29,969
4	Total Manhours	460,718	-3.77%	443,329	-5.73%	417,905	1.02%	422,150	12.05%	437,635	8.08%	473,009	0.00%	473,009
5	Ratio of OverTime Hours													
6	to Straight-Time Hours	7.416%		4.414%		4.517%		6.372%		7.146%		6.764%		6.764%
7														
8	Labor Dollars													
9	Straight-Time Dollars	11,830,931	2.27%	12,100,004	-1.65%	11,900,925	3.22%	12,284,631	4.73%	12,865,295	9.73%	14,117,366	13.16%	15,975,433
10	OverTime Dollars	1,321,265	-38.17%	816,954	1.11%	826,044	43.59%	1,186,118	17.98%	1,399,361	15.42%	1,615,094	13.16%	1,827,666
11	Total Labor Dollars	13,152,196	-1.79%	12,916,959	-1.47%	12,726,969	5.84%	13,470,748	5.89%	14,264,656	10.29%	15,732,461	13.16%	17,803,099
12	Ratio of OverTime Dollars													
13	to Straight-Time Dollars	11.168%		6.752%		6.941%		9.655%		10.877%		11.440%		11.440%
14														
15	O&M Labor Dollars	5,432,594	-6.04%	5,104,736	1.69%	5,191,175	10.04%	5,712,268	10.46%	5,950,691	6.03%	6,309,802	13.16%	7,140,271
16	Ratio of O&M of Labor Dollars													
17	to Total Labor Dollars	41.306%		39.520%		40.789%		42.405%		41.716%		40.107%		40.107%
18														
19	Employee Benefits													
20	Total Employee Benefits	4,573,154	-6.33%	4,283,537	6.51%	4,562,205	-0.69%	4,530,697	-7.09%	4,209,567	-55.82%	1,859,853	14.31%	2,125,946
21	Employee Benefits Expensed	1,949,162	-9.71%	1,759,955	6.49%	1,874,230	1.07%	1,894,292	-8.30%	1,737,067	-57.06%	745,931	14.31%	852,653
22	Ratio of Employee Benefits													
23	Expensed to Total Employee													
24	Benefits	42.622%		41.086%		41.082%		41.810%		41.265%		40.107%		40.107%
25														
26	Payroll Taxes													
27	Total Payroll Taxes	1,483,580	-16.89%	1,233,011	-3.83%	1,185,815	-12.26%	1,040,392	5.99%	1,102,685	-11.56%	975,269	14.60%	1,117,688
28	Payroll Taxes Expensed	408,463	-17.83%	335,621	9.88%	368,773	0.00%	368,773	5.08%	387,516	0.94%	391,151	14.60%	448,271
29	Ratio of Payroll Taxes													
30	Expensed to Total Payroll													
31	Taxes	27.532%		27.220%		31.099%		35.446%		35.143%		40.107%		40.107%
32														
33	Employee Levels													
34	Average Employee Levels	195	-2.05%	191	13.61%	217	0.00%	217	0.46%	218	-2.29%	213	0.00%	213
35	Year end Employee Levels	195	-4.62%	186	19.89%	223	0.00%	223	-4.48%	213	0.00%	213	0.00%	213

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Executive Compensation
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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			Base Period Company Unallocated	Adjustments	Forecasted Period Company Unallocated
1	Includes 5 Officers						
2							
3	Gross Payroll						
4	Salary				$ 2,980,448	$ 119,218	$ 3,099,666
5	Other Allowances and Compensation				14,994,093	599,764	$ 15,593,857
6	Total Salary and Compensation				$ 17,974,541	$ 718,982	$ 18,693,522
7							
8	Employee Benefits	FY23	FY24	Wtd Avg			
9	Pensions	1.16%	1.22%	1.19%	$ 35,467	$ 1,419	$ 36,886
10	SERP				$ 1,211,906	48,476	1,260,382
11	Other Benefits	22.68%	24.78%	23.73%	707,260	28,290	735,551
12	Total Employee Benefits				$ 1,954,634	$ 78,185	$ 2,032,819
13							
14	Payroll Taxes						
15	FICA/FUTA/SUTA				$ 288,003	$ 11,520	$ 299,523
16	Total Payroll Taxes				$ 288,003	$ 11,520	$ 299,523
17							
18	Total Compensation				$ 20,217,178	$ 808,687	$ 21,025,865

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

Positions included on this schedule are:
President and CEO
SVP, CFO
SVP, Utility Operations
SVP, General Counsel & Corporate Secretary
SVP, Human Resources

These costs are total costs for Atmos Energy Corporation, a portion of which are allocated to Kentucky.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Computation of Gross Revenue Conversion Factor
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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				
3	Less: Uncollectible Accounts Expense		1.000000%	1.000000%
4				
5	Less: PSC Fees		0.155400%	0.155400%
6				
7	Net Revenues		98.844600%	98.844600%
8				
9	SIT Rate	5.00%	4.942230%	4.942230%
10				
11	Income before Federal Income Tax		93.902370%	93.902370%
12				
13	Federal Income Tax @	21%	19.719500%	19.719500%
14				
15	Operating Income Percentage		74.182870%	74.182870%
16				
17	Gross Revenue Conversion Factor			
18	(100 % divided by Income after Income Tax)		1.348020	1.348020

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Comparative Income Statement
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X____Base Period___X____Forecasted Period | FR 16(8)(i)1
Type of Filing:___X____Original________Updated ________Revised | Schedule I
Workpaper Reference No(s).____________________ | Witness: Wiebe, Waller, Troup

	Most Recent Five Calendar Years (000s)					Base Year (000s)	Test Year (000s)	Fiscal Year (000s)		
	2019	2020	2021	2022	2023	12/31/2024	3/31/2026	2026	2027	2028
INCOME STATEMENT	$	$	$	$	$	$	$		$	$
Operating Revenues										
Gas service revenue	157,506	134,242	152,334	209,580	170,002	132,800	166,825	168,083	170,687	170,237
Transportation	18,325	17,180	18,499	20,214	20,703	21,749	20,571	17,453	17,453	17,453
Other revenue	1,878	2,087	136	211	26	256	426	3,550	3,556	3,556
Total Operating Revenues	177,709	153,508	170,969	230,005	190,732	154,805	187,822	189,085	191,696	191,245
Purchase gas	83,689	59,996	75,839	131,387	89,605	52,987	87,641	88,874	91,415	90,903
Gross Profit	94,020	93,513	95,130	98,619	101,126	101,819	100,181	100,212	100,281	100,342
Operating Expenses										
Direct O&M	18,981	15,673	19,495	17,205	17,558	17,683	13,794	21,186	21,882	22,658
Allocated O&M	12,487	12,950	13,806	12,755	13,458	15,854	17,714	15,597	16,110	16,681
Depreciation & amortization	20,423	20,485	21,285	19,950	19,462	19,916	22,028	23,309	26,684	30,972
Taxes - other than income	8,673	9,401	10,421	10,661	10,667	12,842	11,308	14,412	16,062	17,030
Total Operating Expenses	60,563	58,510	65,007	60,571	61,145	66,295	64,845	74,504	80,738	87,341
Operating income(loss)	33,457	35,003	30,123	38,047	39,981	35,524	35,336	25,708	19,543	13,001
Other income										
Interest Income	31	39	55	179	240	240	240	240	240	240
Performance based rates	3,425	3,359	1,485	4,846	3,354	3,354	3,000	3,000	3,000	3,000
Donations	(477)	(817)	(944)	(986)	(1,031)	(1,031)	(1,031)	(1,031)	(1,031)	(1,031)
Other Income	647	(106)	44	332	(183)	(183)	(183)	(183)	(183)	(183)
Total other income	3,627	2,476	641	4,371	2,381	2,381	2,026	2,026	2,026	2,026
Interest Charges										
Total interest charges	9,456	9,366	9,702	10,833	10,253	9,760	10,156	11,222	12,056	12,885
Income Before Taxes	27,628	28,113	21,061	31,586	32,109	28,144	27,207	16,512	9,513	2,142
Provision for income taxes	6,288	3,380	3,870	5,163	607	7,022	6,788	4,120	2,373	535
Net Income	21,340	24,732	17,191	26,424	31,502	21,122	20,419	12,392	7,139	1,608

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Revenue Statistics
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(i)2
Type of Filing:___X_____Original________Updated — Schedule I
Workpaper Reference No(s).____________________ — Witness: Wiebe; Waller

Line No.	Description	Most Recent Five Calendar Years 2019	2020	2021	2022	2023	Base Period 12/31/2024	Forecasted Period 3/31/2026	2027	2028	#REF!
1	Revenue by Customer Class:										
2	Residential	$ 97,529,079	$ 88,021,107	$ 97,682,349	$ 134,142,107	$ 100,075,448	$ 83,250,290	$ 103,051,755	$ 105,137,090	$ 104,815,041	$ 104,295,359
3	Commercial	43,100,803	35,926,642	43,001,906	58,232,724	55,242,802	40,102,483	51,443,822	52,839,457	52,778,411	52,635,221
4	Industrial	9,909,683	4,916,762	5,316,142	8,450,852	6,550,741	4,039,149	5,130,632	5,315,173	5,281,062	5,242,052
5	Public Authority & Other	6,966,725	5,377,006	6,333,612	8,754,196	8,132,819	5,408,351	7,198,509	7,394,870	7,362,028	7,315,728
6	Unbilled										
7											
8	Total	$ 157,506,291	$134,241,517	$ 152,334,010	$ 209,579,879	$ 170,001,810	$132,800,273	$166,824,719	$ 170,686,589	$ 170,236,542	$ 169,488,360
9											
10	Number of Customer by Class:										
11	Residential	158,011	159,525	160,539	160,766	160,394	160,460	160,460	160,460	160,460	160,460
12	Commercial	17,719	18,098	18,160	18,175	18,262	18,314	18,401	18,476	18,526	18,576
13	Industrial	222	224	223	217	217	216	216	216	216	216
14	Public Authority & Other	1,537	1,533	1,529	1,520	1,508	1,502	1,502	1,502	1,502	1,502
15											
16	Total	177,488	179,380	180,451	180,677	180,381	180,492	180,579	180,654	180,704	180,754
17											
18	Average Revenue per Class:										
19	Residential	$ 617	$ 552	$ 608	$ 834	$ 624	$ 519	$ 642	$ 655	$ 653	$ 650
20	Commercial	2,432	1,985	2,368	3,204	3,025	2,190	2,796	2,860	2,849	2,833
21	Industrial	44,722	21,942	23,821	39,004	30,211	18,664	23,707	24,560	24,402	24,222
22	Public Authority & Other	4,534	3,507	4,142	5,760	5,392	3,602	4,794	4,925	4,903	4,872

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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
SALES STATISTICS
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

Data:___X____Base Period___X____Forecasted Period — FR 16(8)(i)3
Type of Filing:___X_____Original________Updated — Schedule I
Workpaper Reference NO(S).____________________ — Witness: Wiebe; Waller

Line No.	Description	2019 Mcf	2020 Mcf	2021 Mcf	2022 Mcf	2023	Base Period 12/31/2024 Mcf	Forecasted Period 3/31/2026 Mcf	2027 Mcf	2028 Mcf	#REF!
		Most Recent Five Calendar Years									
1	Sales by Customer Class:										
2	Residential	9,772,864	9,443,234	9,292,340	10,696,568	7,934,228	9,938,593	9,938,593	9,938,593	9,938,593	9,938,593
3	Commercial	5,129,772	4,677,889	5,253,754	5,199,932	4,873,727	5,586,229	5,614,138	5,633,206	5,648,444	5,663,677
4	Industrial	1,997,154	1,175,062	948,854	1,048,616	823,444	825,382	825,382	825,382	825,382	825,382
5	Public Authority & Other	956,098	838,414	910,621	891,723	818,992	915,391	915,391	915,391	915,391	915,391
6	Unbilled										
7											
8	Total	17,855,887	16,134,599	16,405,570	17,836,839	14,450,392	17,265,595	17,293,505	17,312,572	17,327,810	17,343,043
9											
10	Number of Customer by Class:										
11	Residential	158,011	159,525	160,539	160,766	160,394	160,460	160,460	160,460	160,460	160,460
12	Commercial	17,719	18,098	18,160	18,175	18,262	18,314	18,401	18,476	18,526	18,576
13	Industrial	222	224	223	217	217	216	216	216	216	216
14	Public Authority & Other	1,537	1,533	1,529	1,520	1,508	1,502	1,502	1,502	1,502	1,502
15											
16	Total	177,488	179,380	180,451	180,677	180,381	180,492	180,579	180,654	180,704	180,754
17											
18	Average Volume per Class:										
19	Residential	62	59	58	67	49	62	62	62	62	62
20	Commercial	290	258	289	286	267	305	305	305	305	305
21	Industrial	9,013	5,244	4,252	4,840	3,798	3,814	3,814	3,814	3,814	3,814
22	Public Authority & Other	622	547	596	587	543	610	610	610	610	610

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Cost of Capital Summary
Base Period: Twelve Months Ended December 31, 2024

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	%	%	%
1	**Capital Structure**					
2						
3	SHORT-TERM DEBT	J-3	$ 37,867	0.20%	17.14%	0.03%
4						
5	LONG-TERM DEBT	J-3	7,213,975	38.90%	3.97%	1.54%
6						
7	PREFERRED STOCK	J-4	0	0.000%	0.00%	0.00%
8						
9	COMMON EQUITY		$ 11,296,404	60.90%	10.95%	6.67%
10						
11	Total Capital		$ 18,548,247	100.00%		8.24%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
13 Month Average Capital Structure
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026

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

FR 16(8)(j)
Schedule J-1
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		37,867	0.20%	17.14%	0.03%	37,867	0.19%	17.14%	0.03%
2										
3	LONG-TERM DEBT		7,213,975	38.89%	3.97%	1.54%	7,790,898	38.93%	4.11%	1.60%
4										
5	Total DEBT		7,251,842	39.09%		1.58%	7,828,765	39.12%		1.63%
6										
7	PREFERRED STOCK		0	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%
8										
9	COMMON EQUITY		11,296,404	60.90%	10.95%	6.67%	12,183,077	60.88%	10.95%	6.67%
10										
11	Other Capital		0	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%
12										
13	Total Capital		18,548,247	100.0%		8.25%	20,011,842	100.0%		8.30%

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	%	%	%
14	SHORT-TERM DEBT		37,867	0.20%	17.14%	0.03%	37,867	0.19%	17.14%	0.03%
15										
16	LONG-TERM DEBT		7,213,975	38.89%	3.97%	1.54%	7,790,898	38.93%	4.11%	1.60%
17										
18	Total DEBT		7,251,842	39.09%		1.58%	7,828,765	39.12%		1.63%
19										
20	PREFERRED STOCK		0	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%
21										
22	COMMON EQUITY		11,296,404	60.90%	5.13%	3.13%	12,183,077	60.88%	4.99%	3.04%
23										
24	Other Capital		0	0.00%	0.00%	0.00%	0	0.00%	0.00%	0.00%
25										
26	Total Capital		18,548,247	100.0%		4.71%	20,011,842	100.0%		4.67%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
ANNUALIZED SHORT-TERM DEBT
as of June 30, 2024

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

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

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	$ 37,867	5.508%	$ 2,086	
2					
3	COMMITMENT FEE & BANK ADMIN			$ 4,403	
4					
5	TOTAL SHORT-TERM DEBT	$ 37,867		$ 6,489	17.14%

NOTES:

(1) Interest Rate is the actual average rate for 12 Months Ended June 30, 2024

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
AVERAGE ANNUALIZED LONG-TERM DEBT
Base Period: Twelve Months Ended December 31, 2024

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	6.750%	$10,125,000	
2	6.67% MTN A1 due Dec 2025	10,000,000	6.670%	$667,000	
3	5.95% Sr Note due 10/15/2034	200,000,000	5.950%	$11,900,000	
4	4.3% Sr Note due 10/1/2048	600,000,000	4.300%	$25,800,000	
5	Sr Note 5.50% Due 06/15/2041	400,000,000	5.500%	$22,000,000	
6	4.15% Sr Note due 1/15/2043	500,000,000	4.150%	$20,750,000	
7	4.125% Sr Note due 10/15/2044 (500MM(2014) & 250MM(2017)	750,000,000	4.125%	$30,937,500	
8	3.00% Sr Note due 6/15/2027	500,000,000	3.000%	$15,000,000	
9	4.125% Sr Note due 3/15/49	450,000,000	4.125%	$18,562,500	
10	2.625% Sr Notes Due 2029	500,000,000	2.625%	$13,125,000	
11	3.375% Sr Notes Due 2049	500,000,000	3.375%	$16,875,000	
12	1.500% Sr Notes Due 2031	600,000,000	1.500%	$9,000,000	
13	2.850% Sr Notes Due 2052	600,000,000	2.850%	$17,100,000	
14	5.450% Sr Notes Due 2032	300,000,000	5.450%	$16,350,000	
15	5.750% Sr Notes Due 2052	500,000,000	5.750%	$28,750,000	
16	5.900% Sr Notes Due 2033 400MM(2023)& 325MM(2024)	301,923,077	5.900%	$17,813,462	
17	6.200% Sr Notes Due 2053	346,153,846	6.200%	$21,461,538	
18	Total	$ 7,208,076,923		$296,217,000	
19					
20	Annualized Amortization of Debt Exp. & Debt Dsct.			($10,128,890)	
21	Less Unamortized Debt Discount	$5,898,229			
22	Less Unamortized Debt Expenses	$0			
23					
24					
25					
26	Total LONG-TERM DEBT	$7,213,975,152		286,088,110	**3.97%**

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
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.

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Cost of Capital Summary
Thirteen Month Average as of September 30, 2024

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

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

Line No.	Class of Capital	Workpaper Reference	Amount	Percent of Total	Cost Rate	Weighted Cost
		(A)	(B)	(C)	(D)	(E)
			$000		%	%
	Capital Structure					
1	SHORT-TERM DEBT		$ 37,867	0.19%	17.14%	0.03%
2						
3	LONG-TERM DEBT	J-3	7,790,898	38.93%	4.11%	1.60%
4						
5	PREFERRED STOCK	J-4	0	0.00%	0.00%	0.00%
6						
7	COMMON EQUITY		$ 12,183,077	60.88%	10.95%	6.67%
8						
9	Total Capital		$ 20,011,842	100.00%		8.30%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
AVERAGE ANNUALIZED LONG-TERM DEBT
Forecasted Test Period: Twelve Months Ended March 31, 2026

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	13 Mth Average 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	4.3% Sr Note due 10/1/2048	$ 600,000,000	4.30%	25,800,000	
5	Sr Note 5.50% Due 06/15/2041	$ 400,000,000	5.50%	22,000,000	
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 (500MM(2014) & 250MM(2017)	$ 750,000,000	4.13%	30,937,500	
8	3.00% Sr Note due 6/15/2027	$ 500,000,000	3.00%	15,000,000	
9	4.125% Sr Note due 3/15/49	$ 450,000,000	4.13%	18,562,500	
10	2.625% Sr Notes Due 2029	$ 500,000,000	2.63%	13,125,000	
11	3.375% Sr Notes Due 2049	$ 500,000,000	3.38%	16,875,000	
12	1.500% Sr Notes Due 2031	$ 600,000,000	1.50%	9,000,000	
13	2.850% Sr Notes Due 2052	$ 600,000,000	2.85%	17,100,000	
14	5.450% Sr Notes Due 2032	$ 300,000,000	5.45%	16,350,000	
15	5.750% Sr Notes Due 2052	$ 500,000,000	5.75%	28,750,000	
16	5.900% Sr Notes Due 2033 400MM(2023)& 325MM(2024)	$ 725,000,000	5.90%	42,775,000	
17	6.200% Sr Notes Due 2053	$ 500,000,000	6.20%	31,000,000	
18	Total	$ 7,785,000,000		$ 330,717,000	
19					
20	Annualized Amortization of Debt Exp. & Debt Dsct.			(10,128,890)	
21	Less Unamortized Debt Discount	$5,898,229			
22	Less Unamortized Debt Expenses	$0			
23					
24					
25					
26	Total LONG-TERM DEBT	$ 7,790,898,229		$ 320,588,110	4.11%

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
AVERAGE ANNUALIZED SHORT-TERM DEBT
Forecasted Test Period: Twelve Months Ended March 31, 2026

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)	37,867	5.5083%	2,086	
2					
3	COMMITMENT FEE			4,403	
4					
5	TOTAL SHORT-TERM DEBT	37,867		6,489	17.14%

NOTES:

(1) Interest Rate is the actual average rate for 12 Months Ended March 31, 2021

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Comparative Financial Data
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
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: Wiebe, Christian, Waller

Line No.	Description	Forecasted Period	Base Period	Most Recent Ten Calendar Years - as Reported 2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
1	Plant Data: ($000)												
2	Plant in Service by functional class:												
3	Intangible Plant	761	775	128	128	128	128	128	128	128	128	128	128
4	Production & Gathering Plant	0	0	0	0	0	0	0	0	0	0	0	636
5	Underground Storage	38,354	35,937	20,622	14,924	14,473	14,473	14,471	13,328	13,329	12,454	11,560	10,792
6	Transmission Plant	33,508	33,508	33,159	33,198	33,001	33,149	32,817	31,462	31,784	31,814	31,808	31,877
7	Distribution Plant	841,696	815,056	829,749	771,670	752,511	693,559	666,530	573,567	517,179	472,849	413,302	381,623
8	General Plant	49,662	45,753	24,307	23,484	25,021	24,782	23,892	22,758	21,675	21,271	18,126	16,683
9	Acquisition Adjustments			3,279	3,279	3,279	3,279	3,279	3,279	3,279	3,279	3,279	3,279
10													
11	Gross Plant	963,981	931,029	911,244	846,683	828,413	769,370	741,117	644,522	587,374	541,795	478,203	445,018
12	Less: Accumulated depreciation	224,697	204,758	174,869	153,918	182,190	178,144	176,418	178,946	175,150	167,228	165,298	160,839
13	Net plant in Service	739,284	726,271	736,375	692,765	646,223	591,226	564,699	465,576	412,224	374,567	312,905	284,179
14													
15	Construction Work in Progress	0	0	6,973	9,205	12,491	6,625	6,557	42,150	32,838	10,146	26,310	12,708
16													
17	Total CWIP	0	0	6,973	9,205	12,491	6,625	6,557	42,150	32,838	10,146	26,310	12,708
18													
19	Total	739,284	726,271	743,348	701,970	658,714	597,851	571,256	507,726	445,062	384,713	339,215	296,887
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)	37,867	37,867	241,933	184,967	0	0	464,915	575,780	447,745	829,811	457,927	196,695
27	Long-term debt ($000)	7,790,898	7,213,975	6,555,701	7,962,104	7,330,657	4,531,944	3,529,452	3,068,665	3,067,045	2,438,779	2,437,515	2,455,986
28	Preferred stock ($000)			0	0	0	0	0	0	0	0	0	0
29	Common equity ($000)	12,183,077	11,296,404	10,870,064	9,419,091	7,906,889	6,791,203	5,750,223	4,769,951	3,898,666	3,463,059	3,194,797	3,086,232
30													
31	Total	20,011,842	18,548,247	17,667,698	17,566,162	15,237,546	11,323,147	9,744,590	8,414,396	7,413,456	6,731,649	6,090,239	5,738,913

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Comparative Financial Data
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
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: Wiebe, Christian, Waller

Line No.	Description	Forecasted Period	Base Period	Most Recent Ten Calendar Years - as Reported 2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
32													
33	Condensed Income Statement data: ($000)												
34	Operating Revenues	187,822	154,805	190,732	230,005	170,969	153,508	177,709	180,854	164,102	147,431	170,468	196,882
35	Operating Expenses (excludes Federal												
36	and State Taxes, includes gas cost)	152,486	119,282	150,750	191,958	140,846	118,505	144,252	145,817	124,455	113,447	141,526	166,452
37	State Income Tax (current))												
38	Federal Income Tax (current)												
39	Federal and State Income Tax - net	6,788	7,022	607	5,163	3,870	3,380	6,288	8,861	9,697	9,516	9,884	9,672
40	Investment tax credits												
41	Operating Income	28,548	28,502	39,375	32,885	26,253	31,623	27,168	26,177	29,950	24,468	19,058	20,758
42	AFUDC	0	0	908	1,212	685	615	1,513	1,239	379	179	182	139
43	Other Income net	2,026	2,381	763	2,213	(548)	1,418	867	942	2,135	1,908	1,881	1,880
44	Income available for fixed charges	30,575	30,882	41,046	36,310	26,390	33,656	29,548	28,358	32,464	26,555	21,121	22,777
45	Interest charges	10,156	9,760	9,544	9,886	9,199	8,924	8,208	8,022	8,009	7,377	6,744	6,419
46	Net Income	20,419	21,122	31,502	26,424	17,191	24,732	21,340	20,336	24,455	19,178	14,377	16,358
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	20,419	21,122	31,502	26,424	17,191	24,732	21,340	20,336	24,455	19,178	14,377	16,358
49													
50	AFUDC - % of Net Income	0.00%	0.00%	2.88%	4.59%	3.98%	2.49%	7.09%	6.09%	1.55%	0.93%	1.27%	0.85%
51	AFUDC - % of earnings available for												
52	common equity	0.00%	0.00%	2.88%	4.59%	3.98%	2.49%	7.09%	6.09%	1.55%	0.93%	1.27%	0.85%
53													
54													
55													
56	Costs of Capital: (4)												
57	Embedded cost of short-term debt (%)	17.14%	17.14%	9.35%	29.54%	53.98%	22.46%	8.06%	3.40%	1.68%	1.12%	1.09%	1.49%
58	Embedded cost of long-term debt (%)	4.11%	3.97%	3.61%	3.16%	3.15%	4.26%	4.69%	5.19%	5.45%	5.89%	5.90%	6.03%
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	3.68	3.88	7.45	8.25	9.40	8.90	6.98	6.14	5.85	5.72	5.26	4.69
63	Pre-Tax Interest Coverage (Excluding AFUDC)	3.68	3.88	8.28	9.29	10.81	9.84	7.30	6.73	6.03	5.74	5.28	4.70
64	After Tax Interest Coverage	3.01	3.16	6.71	7.58	7.80	7.34	5.69	6.07	4.06	3.24	3.71	3.24
65	SEC Coverage (3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5.45	5.16	4.77	4.11
66	After Tax Interest Coverage (Excluding AFUDC	3.01	3.16	7.45	8.53	8.97	8.12	5.96	6.65	4.18	4.07	3.73	3.25
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 (3)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	3.81	3.64	3.32	3.02
69													
70	Stock and Bond Ratings: (1)												
71	Moody's Bond Rating	N/A	N/A	A1	A1	A1	A1	A2	A2	A2	A2	A2	A2
72	S&P Bond Rating	N/A	N/A	A-	A-	A-	A1	A	A	A	A	A-	A-
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

Atmos Energy Corporation, Kentucky/Mid-States Division
Kentucky Jurisdiction Case No. 2024-00276
Comparative Financial Data
Base Period: Twelve Months Ended December 31, 2024
Forecasted Test Period: Twelve Months Ended March 31, 2026
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: Wiebe, Christian, Waller

Line No.	Description	Forecasted Period	Base Period	Most Recent Ten Calendar Years - as Reported									
				2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
75													
76	Common Stock Related Data: (1)												
77	Shares Outstanding Year End (000)	N/A	N/A	148,493	140,897	132,420	125,882	119,339	111,274	106,105	103,931	101,479	100,388
78	Shares Outstanding - Weighted	N/A	N/A										
79	Average (Monthly) (000)	N/A	N/A	145,166	138,096	129,834	122,872	117,461	111,012	106,100	103,524	101,892	97,608
80	Earnings Per Share - Weighted Avg. ($)	N/A	N/A	6.10	5.60	5.12	4.89	4.35	5.43	3.73	3.38	3.09	2.96
81	Dividends Paid Per Share ($)	N/A	N/A	2.96	2.72	2.50	2.30	2.10	1.94	1.80	1.68	1.56	1.48
82	Dividends Declared Per Share ($)	N/A	N/A	2.96	2.72	2.50	2.30	2.10	1.94	1.80	1.68	1.56	1.48
83	Dividend Payout Ratio (Declared	N/A	N/A										
84	Basis) (%)	N/A	N/A	49%	49%	49%	47%	48%	36%	48%	50%	50%	50%
85	Market Price - High (Low)	N/A	N/A										
86	1st Quarter - High ($)	N/A	N/A	114.90	110.12	92.04	111.58	99.50	92.29	74.73	64.25	58.08	47.06
87	1st Quarter - Low ($)	N/A	N/A	112.56	107.90	89.98	107.73	89.33	84.41	68.96	57.82	47.35	41.08
88	2nd Quarter - High ($)	N/A	N/A	116.70	115.75	101.02	102.55	103.72	85.89	80.40	74.33	58.81	48.01
89	2nd Quarter - Low ($)	N/A	N/A	114.66	113.43	99.55	99.28	89.85	78.03	73.21	61.74	52.02	44.19
90	3rd Quarter - High ($)	N/A	N/A	117.70	115.62	97.52	100.82	107.93	90.53	85.54	81.32	56.41	53.40
91	3rd Quarter - Low ($)	N/A	N/A	115.87	113.54	95.96	98.97	99.07	82.68	78.90	70.60	51.28	46.94
92	4th Quarter - High ($)	N/A	N/A	112.67	111.01	95.54	97.65	114.65	94.77	88.69	81.16	58.18	52.68
93	4th Quarter - Low ($)	N/A	N/A	110.74	108.70	93.79	95.45	105.27	89.81	82.42	71.88	51.48	47.01
94	Book Amount Per Share (Year-end) ($)	N/A	N/A	74.88	68.21	60.90	55.27	48.95	42.97	36.75	33.45	31.35	31.62
95													
96	(1) Based on fiscal year-end of parent company												
97													
98	Rate of Return Measures (1)												
99	Return On Common Equity (Average)	3.3%	3.6%	8.7%	8.9%	9.1%	9.6%	9.7%	13.9%	10.8%	10.4%	9.7%	10.2%
100	Return On Total Capital (Average)	3.1%	3.4%	5.0%	4.7%	5.0%	5.7%	5.6%	7.6%	5.6%	5.4%	5.2%	5.2%
101	Return On Net Plant in Service (Average)	3.9%	3.9%	4.8%	4.8%	4.7%	4.8%	4.6%	6.1%	4.5%	4.4%	4.3%	4.5%
102													
103	Other Financial and Operating Data:												
104	Mix of Sales: (MMcf)												
105	Residential	9,939	9,939	8,150	10,367	9,461	9,389	9,887	10,416	8,724	9,094	9,826	11,729
106	Commercial	5,614	5,586	4,702	5,466	5,118	4,748	5,105	5,346	4,575	4,538	4,845	5,650
107	Industrial	825	825	812	1,064	949	1,139	1,919	1,286	1,517	1,048	693	810
108	Public authority & Other Sales	915	915	786	940	878	859	945	994	859	916	1,025	1,234
109	Unbilled	0	0										
110	Total Mix of Sales	17,294	17,266	14,450	17,837	16,406	16,135	17,856	18,042	15,675	15,596	16,389	19,423
111													
112	Mix of Fuel: (MMcf)												
113		0	0	0	0	0	0	0	0	0	0	0	0
114	Other	17,622	17,594	15,377	18,507	16,891	16,316	18,979	21,324	18,606	15,417	18,606	21,324
115													
116	Total MIX of Fuel (2)	17,622	17,594	15,377	18,507	16,891	16,316	18,979	21,324	18,606	15,417	18,606	21,324
117													
118	Composite Depreciation Rate	2.18%	2.20%	1.96%	2.18%	2.42%	2.46%	2.60%	3.06%	3.10%	3.31%	3.63%	3.47%

(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.
(3) No longer required to provide Computation of Earnings to Fixed charges in SEC filings.
(4) The high cost of short-term debt for 2020 and more recent years is due to fixed commitment fees and low short-term borrowings.

6344

COMMONWEALTH OF KENTUCKY
DEPARTMENT OF REVENUE
FRANKFORT, KY 40619

NOTICE DATE	PERIOD	CASE	TAX
02/18/2025	01/01/2024-12/31/2024	G70467882	PUBLIC SERVICE COMPANY

NOTICE #	RETURN VAL#	TAXPAYER-ID	TAXPAYER NAME
112420264	000005640	G70467882	ATMOS ENERGY CORPORATION

FOR QUESTIONS REGARDING THIS NOTICE, PLEASE CONTACT:

BRITTANY 4279
DEPARTMENT OF REVENUE
STATION NUMBER 32
501 HIGH STREET
STA32
FRANKFORT KY 40601

TEL: (502) 564-7099
FAX: (502) 782-8192
OFFICE HOURS: 8:00 A.M. TO 5:00 P.M. EASTERN TIME

EXPLANATION OF NOTICE

THE PUBLIC SERVICE COMPANY RETURN WAS RECEIVED AND THE PROPERTY TAX DUE HAS BEEN CALCULATED. LOCAL PROPERTY TAXES WILL BE BILLED SEPARATELY BY LOCAL JURISDICTIONS. KRS 136.180(2)

TAX LIABILITY	TAX LIABILITY 1,075,778.07
TOTAL LIABILITY	TOTAL LIABILITY 1,075,778.07

<<<< EXPLANATION OF NOTICE CONTINUED ON NEXT PAGE >>>>

DETACH VOUCHER AND RETURN WITH PAYMENT. MAKE CHECK PAYABLE TO KENTUCKY STATE TREASURER.

NOTICE OF TAX DUE

	VALIDATING NUMBER	CASE NUMBER
00107577807	000005640	G70467882

#BWNCSLW
#252HJ 5646 883405 5#

ATMOS ENERGY CORPORATION
* PROPERTY TAX DIVISION
ATTN TEVYAN FRIEND
PO BOX 650205
DALLAS TX 75265-0205

****
* **TOTAL DUE AS OF:** *
* **04/19/2025** * **$1,075,778.07**
****

ENTER AMOUNT PAID:

10A5009911 **KENTUCKY DEPARTMENT OF REVENUE**
FRANKFORT, KY 40619

99999 G70467882 5 035 112420264 7 00107577807 20241231 7

The mission of the Kentucky Department of Revenue (DOR) is to provide courteous, accurate and efficient services for the benefit of the Commonwealth and to administer Kentucky tax laws in a fair and impartial manner. As a Kentucky taxpayer, you have the right to expect the DOR to honor its mission and uphold your rights every time you contact or are contacted by the DOR.

The following is a summary of your rights and the DOR's responsibilities to you as a Kentucky taxpayer

RIGHTS OF TAXPAYER

Privacy—You have the right to privacy of information provided to the DOR.

Assistance—You have the right to advice and assistance from the DOR in complying with state tax laws.

Explanation—You have the right to a clear and concise explanation of:

- basis of assessment of additional taxes, interest and penalties, or the denial or reduction of any refund;
- procedure for protest and appeal of a Notice of Tax Due, a reduction or denial of a refund, or a denial of a request for additional time to file a supporting statement; and
- tax laws and changes in the tax laws so that you can comply with the law.

Protest and Appeal—You have the right to file a protest with the DOR if you disagree with a Notice of Tax Due, a reduction or denial of a refund, or a denial of a request for additional time to file a supporting statement. If you file a timely protest, you have a right to a conference to discuss the matter. If you are not satisfied with the Department's final ruling following your protest, you may appeal the final ruling to the Kentucky Board of Tax Appeals pursuant to KRS 131.110(5) and KRS 49.220 et. seq.

Representation—You have the right to representation by your authorized agent (attorney, accountant, or other person) in any hearing or conference with the DOR. You have the right to be informed of this right prior to the conference or hearing. If you intend for your representative to attend the conference or hearing in your place, you will be required to give your representative a power of attorney before the DOR can discuss tax matters with your authorized agent. See Form 20A100.

Recordings—You have the right to make an audio recording of any meeting, conference, or hearing with the DOR. The DOR has the right to make an audio recording, if you are notified in writing in advance or if you make a recording. You have the right to receive a copy of the recording.

Consideration—You have the right to consideration of:

- waiver of penalties or collection fees if "reasonable cause" for reduction or waiver is given ("reasonable cause" is defined in KRS 131.010(9) as: "an event, happening, or circumstance entirely beyond the knowledge or control of the taxpayer who has exercised due care and prudence in the filing of a return or report or the payment of monies due the department pursuant to law or administrative regulation");
- installment payments of delinquent taxes, interest and penalties;
- waiver of interest and penalties, but not taxes, resulting from incorrect written advice from the DOR if all facts were given and the law did not change or the courts did not issue a ruling to the contrary;
- extension of time for filing reports or returns; and
- payment of charges incurred resulting from an erroneous filing of a lien or levy by the DOR.

Guarantee—You have the right to a guarantee that DOR employees are not paid, evaluated, or promoted based on taxes assessed or collected, or a tax assessment or collection quota or goal imposed or suggested.

Damages—You have the right to file a claim for actual and direct monetary damages with the Kentucky Board of Tax Appeals if a DOR employee willfully, recklessly, and intentionally disregards your rights as a Kentucky taxpayer.

Interest—You may have the right to receive interest on an overpayment of tax.

REVENUE DEPARTMENT RESPONSIBILITIES

The DOR has the responsibility to:

- perform audits, conduct conferences and hearings with you at reasonable times and places;
- authorize, require or conduct an investigation or surveillance of you only if it relates to a tax matter;
- make a written request for payment of delinquent taxes which are due and payable at least 30 days prior to seizure and sale of your assets;
- conduct educational and informational programs to help you understand and comply with the laws;
- publish clear and simple statements to explain tax procedures, remedies, your rights and obligations, and the rights and obligations of the DOR;
- notify you in writing when an erroneously filed lien or levy is released and, if requested notify major credit reporting companies in counties where lien was filed;
- advise you of procedures, remedies and your rights and obligations with an original notice of audit, or when an original notice of tax due is issued, a refund or credit is denied or reduced, or a license or permit is denied, revoked or canceled;
- notify you in writing prior to termination or modification of a payment agreement;
- furnish copies of the agent's audit workpapers and a written narrative explaining the reason(s) for the assessment;
- resolve tax controversies on a fair and equitable basis at the administrative level whenever possible; and
- notify you in writing at your last known address at least 60 days prior to publishing your name on a list of delinquent taxpayers for which a tax or judgment lien has been filed.

This information merely summarizes your rights as a Kentucky taxpayer and the responsibilities of the Department of Revenue. The Kentucky Taxpayers' Bill of Rights may be found in the Kentucky Revised Statutes (KRS) at Chapter 131.041—131.083. Additional rights and responsibilities are provided for in KRS 131.020, 131.110, 131.170, 131.1817, 131.183, 131.190, 131.500, 131.654, 133.120, 133.130, 134.580, and 134.590.

WHERE TO GET ASSISTANCE

QUESTIONS regarding this notice should be directed to the telephone number or address shown in the "REPLY TO" area of this notice. General taxpayer assistance can be obtained by contacting the DOR, Frankfort, Kentucky 40620, (502) 564-4581.

The DOR also has a Taxpayer Ombudsman whose job is to serve as an advocate for taxpayers' rights. One of the main functions of the office is to ensure that your rights as a Kentucky taxpayer are protected. An important function of the Taxpayer Ombudsman's Office is to confer with DOR employees when you have a problem or conflict that you have been unable to resolve. However, it is not the role of the Ombudsman's Office to intercede in an audit, handle a protest, waive taxes, penalty or interest, or answer technical tax questions. To file a protest see PROTEST AND APPEAL PROCEDURES. Please do not mail your protest to the Ombudsman.

- Office of Taxpayer Ombudsman, P. O. Box 930, Frankfort, KY 40602, (502) 564-7822. Telecommunication Device for the Deaf (TDD), call (502) 564-3058.

PROTEST AND APPEAL PROCEDURE

(Does not apply to all types of property tax)

PROTEST

You have the right to protest an original notice of tax due and/or a reduction or denial of tax refund or denial of a request for additional time to file a supporting statement. To do so:

- submit a written protest within 60 days from the original notice date (or 45 days if the original notice date is prior to 07/01/2018);
- identify the type of tax involved and give the account number, Social Security number or other identification number;
- explain why you disagree;
- attach any proof or documentation available or request additional time to support your protest;
- sign your statement, include your daytime telephone number and mailing address; and
- mail to the Kentucky Department of Revenue at the address shown in the "REPLY TO" area of the notice.

CONFERENCE

You have the right to a conference to discuss a tax matter.

FINAL RULING

If you do not want to have a conference or if the conference did not resolve your protest, you have the right to request a final ruling of the DOR so that you can appeal your case further.

APPEAL

If you do not agree with the Department of Revenue's final ruling, you can file a written appeal with the Kentucky Board of Tax Appeals. If you do not agree with the decision of the Kentucky Board of Tax Appeals you have the right to appeal the ruling to the Kentucky courts (first to the circuit court in your home county or in Franklin County, then to the Kentucky Court of Appeals, and finally to the Kentucky Supreme Court).

The procedure for protest and appeal of an original notice of tax due does not apply for assessments of all types of property tax.

EXPLANATION OF NOTICE, CONTINUED
TAXPAYER ID: G70467882
NOTICE NUMBER: 112420264

TOTAL DUE:	TOTAL AMOUNT OF TAX 1,075,778.07 TOT	BALANCE DUE 1,075,778.07

ANY PROTEST MUST BE IN WRITING, STATING REASONS, AND BE FILED WITH THE DEPARTMENT OF REVENUE AT THE ADDRESS LISTED ON YOUR NOTICE OF ASSESSMENT BY 04/19/2025 OR YOU WILL LOSE ALL APPEAL RIGHTS.

ONLINE PAYMENT OPTIONS ARE AVAILABLE. THE DEPARTMENT OF REVENUE ACCEPTS PAYMENTS BY CREDIT CARD OR ELECTRONIC CHECK. PAYMENT RULES VARY BY TAX TYPE. YOU MAY GET MORE DETAILS AND MAKE PAYMENTS AT HTTPS://EPAYMENT.KY.GOV/EPAY.

TO PAY BY PHONE, PLEASE CALL (502) 564-4921, EXT. 5357. CARDS ACCEPTED ARE VISA, MASTERCARD, DISCOVER OR AMEX. 2.75% CONVENIENCE FEE FOR CREDIT CARD PAYMENT OR 1.5% CONVENIENCE FEE FOR DEBIT CARD PAYMENT. NO CHARGE FOR ELECTRONIC CHECKS.

IMPORTANT REMINDER: INCLUDE YOUR **TAXPAYER IDENTIFICATION NUMBER, TYPE OF TAX, AND TAX PERIOD** ON ANY PAYMENT OR LETTER SENT TO THE DEPARTMENT OF REVENUE. THIS ENABLES THE DEPARTMENT OF REVENUE TO CORRECTLY CREDIT YOUR ACCOUNT FOR THE TAX PERIOD AND TYPE TAX FOR WHICH YOU INTENDED.

REPLY TO: BRITTANY 4279
DEPARTMENT OF REVENUE
STATION NUMBER 32
501 HIGH STREET
STA32
FRANKFORT KY 40601

TEL: (502) 564-7099
FAX: (502) 782-8192
OFFICE HOURS: 8:00 A.M. TO 5:00 P.M. EASTERN TIME

NOTICE REQUIREMENT FOR INTERNET POSTING

IF YOUR TAX LIABILITY REMAINS UNPAID FOR MORE THAN 90 DAYS AFTER THE DATE OF THIS ORIGINAL NOTICE, THE DEPARTMENT OF REVENUE MAY POST YOUR NAME AND THIS LIABILITY FOR PUBLIC INSPECTION, INCLUDING POSTINGS IN YOUR LOCAL NEWSPAPER AND/OR ON THE INTERNET. HOWEVER, IF YOU NOTIFY THE DEPARTMENT IN WRITING DURING THIS PERIOD OF ANY OF THE FOLLOWING, THE DEPARTMENT MUST EXCLUDE YOUR NAME FROM ANY PUBLIC POSTING:

1. YOU HAVE AN APPEAL PENDING OR INTEND TO FILE AN APPEAL PURSUANT TO KRS 131.110 ET SEQ. WITH RESPECT TO THIS LIABILITY;

2. YOU ARE CURRENTLY PAYING THIS TAX LIABILITY THROUGH A VALID PAY AGREEMENT;

3. THE DEPARTMENT IS REVIEWING OR ADJUSTING THIS TAX LIABILITY;

4. YOU ARE IN BANKRUPTCY AND THE AUTOMATIC STAY IS STILL IN EFFECT.

ADDITIONALLY, A TAXPAYER'S NAME WILL BE EXCLUDED OR REMOVED FROM ANY PUBLIC POSTING IN THE EVENT THE DEPARTMENT IS NOTIFIED IN WRITING THAT THE TAXPAYER IS DECEASED.

PLEASE PROVIDE WRITTEN BASIS FOR EXCLUSION TO THE **DIVISION OF COLLECTIONS, P.O. BOX 491**, **FRANKFORT, KY 40602**, OR E-MAIL IT TO *KRC.WEBRESPONSENOTICEOFTAXDUE@KY.GOV*.

6347

EXPLANATION OF NOTICE, CONTINUED
TAXPAYER ID: G70467882
NOTICE NUMBER: 112420264

NOTICE OF INTENT TO OFFSET

IF ANY PORTION OF YOUR LIABILITY REMAINS UNPAID AFTER 60 DAYS FROM THE DATE OF THIS NOTICE, THE DEPARTMENT MAY SUBMIT YOUR DEBT TO THE TREASURY OFFSET PROGRAM (TOP). ONCE YOUR DEBT IS SUBMITTED TO TOP FOR OFFSET, THE UNITED STATES DEPARTMENT OF TREASURY MAY REDUCE OR WITHHOLD ANY OF YOUR ELIGIBLE FEDERAL TAX REFUNDS OR VENDOR PAYMENTS BY THE AMOUNT OF YOUR DEBT. THESE OFFSET PROCESSES ARE AUTHORIZED BY 31 U.S.C. 3716, 26 U.S.C. 6402, KRS 44.065 AND KRS 44.030.

NOTICE FOR LICENSE AND MOTOR VEHICLE REGISTRATION REVOCATION

KENTUCKY STATUTES ENABLE THE DEPARTMENT OF REVENUE TO REQUEST THE REVOCATION OR SUSPENSION OF ANY PROFESSIONAL LICENSE, LICENSE TO PRACTICE LAW, OR DRIVER'S LICENSE ISSUED BY ANY LICENSING AGENCY OF THE COMMONWEALTH OR THE KENTUCKY SUPREME COURT TO ANY PERSON THAT IS DETERMINED BY THE DEPARTMENT TO BE A "DELINQUENT TAXPAYER" AS DEFINED IN KRS 131.1817. ADDITIONALLY, THE DEPARTMENT MAY NOTIFY THE KENTUCKY TRANSPORTATION CABINET THAT AN OWNER OF A MOTOR VEHICLE IS A "DELINQUENT TAXPAYER," REQUIRING THE TRANSPORTATION CABINET TO PROHIBIT THE DELINQUENT TAXPAYER FROM REGISTERING OR RENEWING THE REGISTRATION OF THE MOTOR VEHICLE.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses	))))	Docket No. RM22-5-000

COMMENTS OF THE
AMERICAN GAS ASSOCIATION

Pursuant to the "Notice of Inquiry" ("NOI")[1] issued by the Federal Energy Regulatory Commission ("Commission") on December 16, 2021 in the above-referenced proceeding, the American Gas Association ("AGA") respectfully submits these comments. In response to the NOI, these comments provide information related to rate recovery, reporting, and accounting treatment of industry association dues and certain civic, political, and related expenses. As discussed in detail below, AGA urges the Commission to maintain the current provisions of the Uniform System of Accounts ("USofA") and its current policies related to industry association dues. The Commission's current regulations, policies and precedents are sufficient to assess the treatment of association dues.

I. PROCEDURAL BACKGROUND

On March 17, 2021, the Center for Biological Diversity ("CBD") filed a Petition requesting that the Commission amend the USofA requirements for payments to industry associations

[1] *Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses*, 177 FERC ¶ 61,180 (2021) ("NOI").

engaged in lobbying or other influence-related activities.[2] According to the Commission, the CBD Petition requested that the Commission amend the USofA to allocate all industry association dues paid by utilities to Account 426.4.[3] In response to the CBD Petition, some commenters recommended that the Commission remove all industry association dues from rates, whereas others suggested that such a move was unnecessary because industry association dues were properly allocated between recoverable and non-recoverable expenses.[4] For example, AGA filed a Protest on April 26, 2021 urging the Commission to deny the CBD Petition and decline to institute a rulemaking proceeding to amend the USofA.[5]

On December 16, 2021, the Commission issued the NOI seeking comments on the rate recovery, reporting, and accounting treatment of industry association dues and certain civic, political, and related expenses. In addition, the Commission seeks comments on the ratemaking implications of potential accounting and reporting changes. The Commission also seeks comments on whether additional transparency or guidance is needed with respect to defining donations for charitable, social, or community welfare purposes. The NOI was published in the *Federal Register* on December 23, 2021.[6]

[2] NOI at P. 9; Center for Biological Diversity, Petition for Rulemaking to Amend the Uniform System of Accounts' Treatment of Industry Association Dues, Docket No. RM21-15- 000 (filed Mar. 17, 2021) ("CBD Petition").

[3] *Id*.; CBD Petition at 8.

[4] NOI at P 9. On April 26, 2021, AGA filed a Protest in response to the CBD Petition and urged the Commission to deny the CBD Petition and decline to institute a rulemaking proceeding to amend the USofA. Specifically, AGA argued that the Commission's current regulations already require the segregation of lobbying costs in the USofA and that the Commission's policy and precedent does not permit the recovery of lobbying related costs in jurisdictional rates, as CBD alleged in its Petition.

[5] Protest of the American Gas Association, Docket No. RM21-15-000, Dated April 26, 2021. In this filing, AGA reiterates several points made in the protest filed in Docket No. RM21-15-000 to ensure a complete record in Docket No. RM22-5-000 and because the information is relevant to the questions posed in the NOI.

[6] The NOI was published in the Federal Register on December 23, 2021, hence initial comments on the NOI are due February 22, 2022, and reply comments are due March 23, 2022. *Rate Recovery, Reporting, and Accounting Treatment of Industry Association Dues and Certain Civic, Political, and Related Expenses,* 86 Fed. Reg. 72958 (Dec. 23, 3021).

II. IDENTITY AND INTERESTS

The American Gas Association, founded in 1918, represents more than 200 local energy companies that deliver clean natural gas throughout the United States. There are more than 77 million residential, commercial and industrial natural gas customers in the U.S., of which 96 percent — more than 73 million customers — receive their gas from AGA members.[7] AGA is an advocate[8] for natural gas utility companies and their customers and provides a broad range of programs and services for member natural gas pipelines, marketers, gatherers, international natural gas companies, and industry associates. Today, natural gas meets more than one-third of the United States' energy needs.[9]

AGA's members are directly affected by the rates, terms and conditions of the transportation and storage services provided by jurisdictional pipelines, including the Commission's accounting policies and the USofA. Furthermore, AGA's members, due to their ownership of various natural gas facilities subject to the jurisdiction of the Commission or because of other corporate structures or activities, maintain their financial records in conformance with the USofA pursuant to the Commission's regulations. Additionally, AGA is also concerned about the precedent that any revision to the USofA would have on state policies. AGA's members are primarily regulated by state utility commissions or other state agencies and several of these regulators have adopted, in whole or in part, the Commission's accounting regulations. Therefore,

[7] This translates to nearly 180 million Americans and 5.5 million businesses that use natural gas. *See* 2021 AGA Playbook, available at https://www.aga.org/news/aga-playbook/ (last visited February 21, 2022). AGA's Annual End Users, available at https://www.aga.org/research/data/end-users/ (last visited February 21, 2022); U.S. Census Bureau, Persons Per Household, available at https://www.census.gov/quickfacts/fact/table/US/HSD310219 (last visited last visited February 21, 2022).

[8] As discussed below in detail, AGA provides a wide range of services to members beyond what could be considered advocacy. *See* Section IV.C., *infra.*

[9] For more information, please visit www.aga.org.

AGA member companies have a direct and substantial interest in the issues raised in this proceeding.[10]

III. COMMUNICATIONS

All pleadings, correspondence and other communications filed in this proceeding should be addressed to:

Matthew J. Agen
Assistant General Counsel
American Gas Association
400 North Capitol Street, NW
Washington, DC 20001
(202) 824-7090
magen@aga.org

Katherine Herrera
Regulatory Policy Analyst
American Gas Association
400 N. Capitol Street, NW
Washington, DC 20001
(202) 824-7311
kherrera@aga.org

IV. COMMENTS

AGA submits these comments from three perspectives.[11] First, AGA's members receive service from virtually every interstate pipeline regulated by the Commission and, hence pay the rates approved by the Commission. Second, AGA's members, due to their ownership of Commission regulated facilities or for other corporate reasons, maintain their financial records in conformance with the USofA. Third, while AGA's members are primarily regulated by state utility commissions or other state agencies, AGA is also concerned about the precedent that any revision to the USofA would have on state policies because several of these regulators have adopted, in whole or in part, the Commission's accounting regulations.[12]

[10] AGA filed a motion to intervene (doc-less) in Docket No. RM22-5-000 on April 2, 2021.

[11] In these comments, AGA provides information in response to certain questions and issues raised in the NOI; however, these comments do not respond to every question in the NOI, notably a few questions relate specifically to the electric industry.

[12] *See, e.g.,* Nev. Admin. Code §§ 704.009 and 704.120; 170 Indiana Admin. Code 5-2-3.

The Commission should decline to modify the USofA and its policies related to industry association dues. While the NOI asks important and pertinent questions, in the end, the Commission's current regulations already require the segregation of lobbying costs in the USofA and the Commission's policy and precedent does not permit the recovery of lobbying related costs in jurisdictional rates. Moreover, the Commission's longstanding policies as to how regulated entities account for and include expenses in the appropriate USofA accounts is well-reasoned and provides transparency related to the appropriate costs. Additionally, trade associations already comply with extensive lobbying disclosure requirements that provide transparency related to lobbying activities. Therefore, the Commission's existing regulations and precedent, and other government required disclosures already address the primary concerns raised in the NOI and a further rulemaking would be redundant and therefore, unnecessary.

A. The Commission's Existing Rules, Regulations, And Precedent Sufficiently Address Trade Association Related Expenses

In the NOI, the Commission explained that the USofA contains accounts to record the portions of industry association dues paid by regulated entities as either operating or nonoperating in nature.[13] The USofA gives instructions on the separation of the expenses paid by utilities that industry associations incur and bill to utilities into the appropriate above the line (operating) and below the line (nonoperating) accounts.[14] For example, the Commission noted that Account 930.2 (Miscellaneous and general expenses), which includes the cost of labor and expenses incurred in connection with the general management of the utility not provided for elsewhere in the USofA,

[13] *See* 18 C.F.R. Parts 101, 201. The NOI states that citations are made only to part 101 of the Commission's regulations, in the NOI, also reflect the same provisions as part 201 and references to the USofA are to both part 101 and part 201 of the Commission's regulations.

[14] NOI at P 4.

is considered above the line, *i.e.*, generally included in rate recovery, and covers industry association dues for company memberships.[15] Account 426.4 (Expenditures for certain civic, political and related activities), which is used for costs for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances or for the purpose of influencing the decisions of public officials, is considered below the line, *i.e.*, generally excluded from rate recovery.[16] In the NOI the Commission also explained that the Office of Enforcement within the scope of an audit through its audit program, evaluates the classification of expenses.[17] Furthermore, parties to an Natural Gas Act ("NGA") Section 4 rate proceeding can challenge a regulated entity's accounting classifications and a complainant may file an NGA Section 5 complaint alleging that the current rate treatment is unjust and unreasonable.[18] While there are multiple methods to examine trade association dues in the context of regulated rates, the Commission notes that there may be a lack of detailed information on the nature of the association's activities for purposes of determining the appropriate classification of costs into above the line and below the line accounts.[19]

In addition to the provisions of the USofA, the Commission recently explained its longstanding practice that "while association membership organizations can conduct lobbying on behalf of their members, the portion of the membership fees associated with the costs of such lobbying activities should be recorded in Account 426.4."[20] The Commission has also clarified

[15] *Id. See also*, 18 C.F.R. Part 201, Account 930.2 - Miscellaneous general expenses.

[16] *Id*. *See also,* 18 C.F.R. Part 201, Account 426.4 - Expenditures for certain civic, political and related activities.

[17] NOI at P 7.

[18] *Id*.

[19] NOI at P 8. As discussed below, information is available, which aids in transparency to stakeholders.

[20] *Ameren Illinois Company*, 170 FERC ¶ 61, 267, P 130 (2020). *See also ISO New England Inc.*, 117 FERC ¶ 61,070, P 45 ("[T]he portion of industry association fees where that association undertakes lobbying activities

that "efforts to secure passage of legislation, including analyzing proposals and contacting members of Congress and their staffs to inform them of the impact of legislation on a project should be recorded in Account 426.4."[21] To effectuate this policy, the Commission has noted that a regulated entity can be permitted to obtain the necessary information from the industry association to make a proper allocation of the dues payment to the appropriate operating and non-operating expense accounts.[22]

AGA submits that the provisions of the USofA and precedent contain appropriate safeguards that address any concerns related to accounting for recoverable and non-recoverable expenses. The current requirements are already part of the jurisdictional ratemaking process and the Commission's record is full of cases where accounting issues are addressed in a rate proceeding before an Administrative Law Judge ("ALJ") or the Commission. One recent example is *Pacific Gas and Electric Company*,[23] in which the Commission addressed concerns raised about trade association membership dues. In the opinion, the Commission affirmed the ALJ's determination, and the position of Commission Trial Staff that allocation of a portion of trade association dues to customers was appropriate. The ALJ, as affirmed by the Commission, noted that pursuant to *Delmarva Power & Light Co.*,[24] regulated entities may allocate trade association contributions to customers to the extent there is a demonstration that the contributions were used for a permissible purpose, and that lobbying is not something that is recoverable.[25] Furthermore, in *Pacific Gas and*

should also be recorded in Account 426.4."); *Eastern Edison Company*, 25 FERC ¶ 61,357, 61,807 (1987) (portion of registered lobbyist's fees associated with lobbying activities should be accounted for in Account 426.4).

[21] *ISO New England Inc.*, 117 FERC ¶ 61,070 at P 45.

[22] *Id.* at n.63.

[23] *Pacific Gas and Electric Company*, Opinion No. 572, 173 FERC ¶ 61,045 (2020).

[24] *Delmarva Power & Light Co.*, 58 FERC ¶ 61,169, 61,509 (1992).

[25] *Pacific Gas and Electric Company*, 173 FERC ¶ 61,045 at PP 221-228 (2020).

Electric Company, the Commission upheld the principle that a regulated entity's trade association dues can and do benefit customers and, therefore, are appropriately recoverable.[26] This example illustrates that the current USofA contains a mechanism for determining whether a rate is just and reasonable, and that the current regulations are sufficient to determine what are recoverable and non-recoverable expenses. Additionally, the case upholds the principles that trade association dues benefit customers and not all trade association activities are lobbying.[27]

Longstanding Commission policies recognize that costs for certain activities, such as lobbying costs, are not recoverable from ratepayers and has established accounts in the USofA for tracking those expenditures. Furthermore, in the NOI the Commission explains that if more information is needed regarding a regulated entity's costs, the Commission, shippers, and stakeholders have various mechanisms to seek information.[28] Importantly, as discussed below, entities such as trade associations make disclosure filings that provide additional transparency.

B. The Commission's Existing Rules Are Consistent With Other Federal Laws Regarding the Treatment of Lobbying Costs

The distinction of lobbying and non-lobbying activities is an important element of the USofA and the rate making process and the Commission should maintain this threshold distinction. As such, it is important to understand the scope of those terms both in how the Commission views lobbying and non-lobbying activities and how other relevant statutes make similar distinctions. As explained in the NOI, Account 426.4 includes "miscellaneous expense

[26] *See Id*. at PP 221, 227, 228.

[27] *See* Section IV.C., *infra*, discussing the benefits AGA provides to members and utility customers.

[28] *See* NOI at P 19 (citing Sections 4 and 5 of the NGA, and the Office of Enforcements audit authority).

items which are *nonoperating* in nature but which are properly deductible before determining total income before interest charges."[29] Specifically, Account 426.4 includes:

> expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials, but shall not include such expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations.[30]

The above is generally consistent with how the U.S. Internal Revenue Code ("IRC") and Lobbying Disclosure Act ("LDA") defines lobbying. The IRC denies a deduction for certain lobbying and political expenditures that are, for any amount paid or incurred in connection with, *inter alia*, "influencing legislation," "participation in, or intervention in, any political campaign, on behalf of (or in opposition to) any candidate for public office," and attempts to influence the general public "with respect to elections, legislative matters, or referendums."[31] Furthermore, the Lobbying Disclosure Act ("LDA") defines lobbying contacts and lobbying activities, in a similar manner, *i.e.*, communications to certain persons about federal legislation, among other things.[32] The LDA also includes various exceptions to the definition of lobbying contacts, such as submitting a "response to a notice in the Federal Register," "a written comment filed in the course of a public proceeding," and "a petition for agency action made in writing."[33]

[29] 18 CFR Part 201, Special Instructions – Accounts 426.1, 426.2, 426.3, 426.4, and 426.5.

[30] 18 CFR Part 201, Account 426.4.

[31] *See* 26 U.S.C. § 162(e).

[32] *See* 2 U.S.C. § 1602 (7) and (8) (defining what is and what is not lobbying activities and lobbying contacts).

[33] *See* 2 U.S.C. § 1602 (8) (exceptions to the term "lobbying contact").

AGA complies with the requirements of the IRC and LDA and such compliance supports the fact that the current USofA is sufficient. Membership organizations like AGA are subject to U.S. IRC Section 162(e), which defines lobbying, as discussed below, and the federal LDA,[34] each of which require organizations to track and disclose the amount spent on such activities.[35] The LDA allows organizations that are subject to 26 U.S.C. § 162(e) to use the IRC definitions in lieu of the definitions of lobbying provided in the LDA. IRC Section 162(e), and the regulations promulgated thereunder, defines "lobbying" broadly to include activities for the purpose of "influencing legislation" at the state or federal level. This definition of lobbying includes any attempt to influence legislation through a communication with (i) any member or employee of Congress; (ii) any member or employee of a state legislature; or (iii) any federal or state government official or employee who may participate in the formulation of legislation.

To comply with the requirements of the IRC and the LDA, AGA uses a method provided in the IRC and which the IRS deems to be reasonable.[36] An accurate calculation typically includes tracking employees' time spent lobbying, allocating overhead costs to the lobbying activity, and factoring actual lobbying expenses, *e.g.*, travel and payments to outside consultants, *etc*., into the total. Once the data is collected, the total lobbying expense is filed with the appropriate federal entities, which includes the Clerk of the U.S. House of Representatives and the Secretary of the U.S. Senate, which are required to receive notices under the LDA, each calendar quarter and semi-annually. The information submitted to the House and the Senate includes expenses and issue areas related to lobbying activities during the relevant reporting period. To aid in transparency the relevant

[34] *See* 2 U.S.C. § 1601, *et seq.*

[35] *See* NOI at Questions 16 and 17. AGA complies with the requirements of the IRC and LDA; however, each member seeks potential recovery of dues based on state and public utility commission policies and regulations.

[36] *See* NOI at Question 3.

information submitted to Congress is publicly available via government databases.[37] This calculation is also subject to IRS audit[38] and reviewed annually by external auditors during the audit of AGA's financial statements.[39]

An estimate of the percentage of dues that will be allocated for lobbying expenses, and therefore not deductible by association members, is required by the IRS to be estimated and included on dues notices for the next calendar year.[40] Because the IRS requires this percentage to be estimated in advance, the percentage of dues that will be attributable for lobbying expenses, and therefore not deductible by association members, is estimated in this way and appropriately included on dues notices for the next calendar year. This estimate is based on AGA's forward-looking estimate of lobbying expenses for the coming year, which is in turn based on a review of the past two years' lobbying expenses, including a true-up of expenses for the prior year, as well as the determination of issues that AGA will be working on in the coming year. By examining AGA's actual historical lobbying expenses, its prior estimates as well as any material lobbying activities, AGA uses a reasonable and prudent methodology to determine the IRS required estimate of lobbying expenses for the year ahead.

AGA is concerned that if the Commission revises the USofA to be inconsistent with the IRC and LDA then there will not be consistency in how the energy industry and regulators define lobbying, and in turn how such costs are addressed in filings and rate making proceedings. Furthermore, the Commission should avoid categorizing all trade association activity as lobbying,

[37] In the NOI, the Commission raises transparency as a potential concern. *See, e.g.*, NOI at Questions 9 and 10. *See* https://lda.senate.gov/system/public/ and https://lobbyingdisclosure.house.gov/ (last visited February 21, 2022).

[38] Organizations subject to 26 U.S. Code § 501(c)(6), generally, file IRS Form 990 which provides additional disclosures.

[39] *See* NOI at Question 8.

[40] *See* NOI at Question 3.

or expanding the concept beyond its current parameters. As described in detail below, AGA engages in various types of activities, most of which are not related to lobbying.

AGA believes that the Commission should maintain the exception in Account 426.4 for "expenditures which are directly related to appearances before regulatory or other governmental bodies in connection with the reporting utility's existing or proposed operations."[41] In short, the Commission currently allows all costs related to regulatory interventions and litigation by both utilities and industry associations to be recorded to above the line accounts.[42] The NOI characterizes these expenditures as "political advocacy activities"[43] and asks if the current scope of the exemption is appropriate and if there are types of appearances before regulatory or governmental bodies for which the related expenditures should be excluded from rates. The NOI appears to express a potential desire to treat activities before federal agencies and litigation as it currently treats lobbying costs, *i.e.*, below the line. AGA disagrees with the contention that participation in a regulatory proceeding by a regulated entity, customers of regulated entities or associations that represent industry groups is political or lobbying activities. An attempt to characterize appearances before regulatory or other governmental bodies as somehow inappropriate to the point that such related costs should not be included in rates is simply not correct, and contradicts this Commission's regulations and other laws.

The simple fact of the matter is that AGA does conduct advocacy to advance its members' interests – interests that overlap significantly with the goals of the NGA, the Natural Gas Policy Act, and other federal statutes, including protecting and advancing the interests of the nation's

[41] *See* NOI at Question 19.

[42] *Id*.

[43] *Id*.

natural gas utilities and consumers in receiving safe, reliable, and cost-effective natural gas supplies. Some of that work is lobbying, as defined by federal law and is accounted for as such; however, many of AGA's activities, advocacy or otherwise, do not involve lobbying. While lobbying may be considered a form of advocacy, not all trade association activities are lobbying. Regulatory filings and advocacy, litigation, publications, and operations and engineering services, *etc*. are not lobbying; and therefore, should not be considered as such.

As discussed below, AGA provides a variety of diverse services to members that benefit both members and customers which are not lobbying. Many of these services have nothing to do with lobbying or political activities and are instead directly related to improving safety, operational efficiencies, security, a company's environmental footprint, and operator knowledge. Attempts by the Commission to redefine and expand the scope of what is below the line to include regulatory activities, litigation, and filings with administrative agencies should be rejected as inconsistent with federal law and Commission policy.

AGA is also concerned that the Commission would attempt to revise the USofA to account for and exclude certain regulatory activities or litigation from above the line accounts. AGA is concerned that this would make the USofA into a mechanism that makes accounting determinations based on types of regulatory activities, *i.e.*, rate and certificate proceedings, or positions taken in litigation. In other words, if you challenge a Commission order at the court of appeals that would be considered below the line, but if you intervene and support the Commission that would be considered above the line. Attempting to make any such distinctions in the USofA is simply inappropriate. As an example, in recent years AGA has intervened in dockets related to certificate matters and dockets related to tariff terms and conditions. AGA is concerned that the Commission would place a value judgment on participation in such proceedings and make a determination as to the appropriateness of such activities in the USofA. AGA does not believe it is appropriate for the Commission to use the USofA or it's accounting policies to make value judgments or appropriateness determinations.

C. The Vast Majority Of AGA's Functions Do Not Include Lobbying Activities

One of the underlying themes of the NOI is that the vast majority of trade association activities are lobbying.[44] In reality this is not the case for AGA. AGA provides benefits to members and customers that are not related to lobbying activities. AGA provides a vast number of services to members that benefit both the natural gas utility industry and customers. It is important for the Commission to understand, and for the record to include an accurate summary of AGA's activities. The following sections include a high-level description of AGA, some of its various departments and committees, and the benefits provided to members and customers. AGA's activities, as discussed herein, provide a sufficient basis for AGA industry association membership dues remaining in Account 930.2, while keeping the lobbying activities expenses, consistent with federal law, in Account 426.4.

1. Purpose And Organization Of AGA

As noted above, AGA is a national trade association comprised of over 200 distribution company members. As such, it exists to fulfill the needs of the local natural gas distribution companies ("LDCs") and thereby improve the industry's ability to better serve its customers. AGA's vision and mission statements are succinct and express AGA's overarching goal of ensuring the safe, reliable and cost-effective delivery of natural gas.[45] The Chairman, First and Second Vice-Chairmen and the Immediate Past-Chairman are top officials of member companies,

[44] *See* NOI at Question 1.

[45] *See* https://www.aga.org/about/mission/ (last visited February 21, 2022).

and, together with our President, are the senior officers of AGA.[46] The Board of Directors, who are top executives of member companies, establishes AGA's policies and actively governs the programs, projects, activities, and budget of the association. Reporting to the Board of Directors are various committees. Each committee is composed of employees of member companies of various sizes and from various parts of the country, and each committee has a "charter" that focuses its efforts on a specific functional area of a gas company's operations. Member company employees serve on 52 committees, councils, and task forces. Task forces work to complete specific projects that benefit the natural gas industry. In addition, through AGA's functional area contact lists, other employees in each natural gas company also regularly receive materials and information of interest to their functional areas. Examples include federal regulatory updates, industry studies, surveys, and technical papers that illuminate good practices to enhance safety. It is through the work and with the guidance of these committees, that many AGA activities are undertaken.

2. Members And Customers Benefit From AGA Membership

A member company and its customers benefit from participation in AGA in two general ways. The first is by helping natural gas utilities improve their local programs, practices, and procedures in all areas of their operation. In this regard, AGA annually provides numerous forums and other vehicles through which a member company's employees can exchange information with their peers in other companies in order to better serve its customers. These face-to-face (now virtual due to the COVID-19 pandemic) exchanges include committee meetings, webcasts, seminars, and other forums. In addition, AGA provides program "clearinghouse" services in a

[46] *See* https://www.aga.org/about/leadership/ (last visited February 21, 2022).

number of areas, enabling member company staff to become more informed in a variety of areas, including customer relations, pipeline safety, cybersecurity protection, and workforce training and development. Through such clearinghouses, AGA maintains information on successful programs conducted by member companies, which is shared with other natural gas utilities, who learn about new tools, technologies or practices that can reduce injuries to workers, reduce methane emissions, enhance customer safety, or improve customer satisfaction.[47]

The second way AGA serves a member company, and its customers is by taking action collectively or at the national level that an individual utility could not practically do in a cost-effective matter on its own. For instance, AGA annually produces a number of new publications and technical notes which represent superior industry practices and factual information.[48] These documents often supplement a company's training curriculum or its technical resource center and serve to educate gas company employees on a variety of topics relevant to the industry. Individual natural gas utilities would not be able to produce such documents independently.

Related to this concept is the power of collaboration that comes from an association where members are continually challenging one another to elevate their performance as public stewards. Indicative of this collaboration is AGA's Best Practices Program, discussed below, which allows companies to benchmark their actions against others and to learn from industry leaders; AGA's Peer Review Program, discussed below, which allows natural gas utilities to review other natural gas company practices to identify areas that are working well or that could be improved; and the various commitments for which AGA membership has spurred development of safety, environmental stewardship, and cybersecurity protection.

[47] Details about AGA's various programs are provided below. *See e.g.*, Sections IV.C. 3 and 4, *infra*.

[48] *See e.g.*, Sections IV.C. 3, 4 and 5, *infra*.

All of these activities are directed at the same goal – to continue and help improve member companies' safety, reliability, and environmentally responsible practices, and to support cost-effective delivery of natural gas to their customers, including doing so efficiently and effectively without the cost burden of an unnecessary "learning curve." If AGA did not exist, solid business practice would call for the creation of such an organization.

3. AGA's Operations And Engineering Services Activities

Safety is a core value to AGA and its member companies, and AGA is dedicated to the continued improvement of the industry's longstanding record of providing natural gas service safely and effectively to approximately 180 million Americans. The extensive pipeline infrastructure that makes this all possible is vital to the services LDCs provide, and keeping customers safe, secure and informed is paramount. To that end, there are various types of operations and engineering activities conducted by AGA, in multiple functional areas that either directly or indirectly benefit members and customers. The following are some examples of AGA's operations and engineering activities. These activities include hundreds of initiatives to improve the safety, efficiency and productivity of member companies' engineering and operating functions.

- **Technical Committees**. AGA's Operations and Engineering section includes 17 technical committees and taskforces: Construction Operations, Customer Field Service & Measurement, Cybersecurity Strategy Task Force, Distribution Integrity Management Program, Engineering, Enterprise Risk Management, Environmental Matters, Field Operations, Gas Control, Natural Gas Security, Pipe Materials, Quality Management, Safety & Occupational Health, Supplemental Gas, Transmission Integrity Management Program, Transmission Measurement, and Underground Storage. These technical committees focus on helping natural gas utilities achieve operational excellence in the safe, reliable, and efficient delivery of natural gas. These committees represent the core functions of gas utilities in the gas delivery supply chain and their work is overseen by the AGA Operations Managing Committee. The Operations Managing Committee is comprised of senior operations executives that review and approve on an annual basis the work of each technical committee.

- **Technical Discussion Groups.** Since 2012, AGA has provided companies the opportunity to participate in a series of discussion groups intended to help members address operational challenges. These discussion groups serve as virtual roundtables where members hear presentations and exchange information, ideas, and practices.[49] The roundtables allow members to network with other utilities that share a particular interest and provide companies the opportunity to include multiple individuals in a discussion group without the burden of extensive travel or time commitments. The 2021 discussion groups are: Asset Management, Corrosion Control, Emergency Management and Public Safety, Emission Reductions, Field Worker Assault Prevention, Hydrogen Blending, Pipeline Safety Management Systems, Renewable Natural Gas, Utilization Pressure Systems, Workforce Development and Training, Work Forecasting and Planning.

- **Leading Practices**. AGA has played a key part in identifying the industry-leading practices and innovative work techniques that have assisted member utilities in strengthening their safety programs.

- **AGA's Mutual Assistance Program and Emergency Planning Resource Center.** AGA's Mutual Assistance Program helps facilitate response, recovery, and restoration of services outside the capacity of a company following a natural or other disaster. This program was on call through hurricanes Harvey, Irene and Maria, the fires in California, and other similar events. AGA's program is intended to supplement local, state, and regional assistance programs where the responding company and company in need of aid are not already covered by an alternate agreement. The Emergency Planning Resource Center is a springboard to the AGA Mutual Assistance Program, Situation Reports and Government resources to support all-hazards response, recovery, and restoration. AGA holds an annual National Mock Drill to test response protocols that are required for a large-scale event that would require assistance from other gas utilities.

- **Technical Publications.** AGA develops and publishes a large number of manuals and technical papers that are essential in the day-to-day operations of gas utilities. Examples of publications of high importance for the safe, reliable and cost-efficient operation of a gas utility system include ANSI B109 standards for diaphragm & rotary meters, ANSI Z223.1/NFPA 54 National Fuel Gas Code, ANSI GPTC Z380.1 Guide for Gas Transmission and Distribution Piping Systems, manuals on Gas Quality Management, Odorization, Gas Measurement, Plastic Pipe, Purging Principles and Practices, Data Governance - Defining Leak Causes for Gas Distribution Systems, Blowdown Emission Reduction, Emerging Technologies to Secure Remote Locations, Leading Practices for Preventing Damages to Meter Sets, Guidelines for Natural Gas Companies Conducting an Internal Incident and Event Investigation for Safety and Performance Analysis, Supporting and Communicating DIMP within Your Natural Gas Organization, Quality Metrics for Natural Gas Operations, Guidelines for Understanding Key Hole Technology Associated with Corrosion Control, Risk Modeling Approaches for Gas Distribution Pipelines, Skills and Experience for

[49] All AGA committee, taskforce, and discussion group activities are conducted in strict compliance with federal and state antitrust laws.

Effectively Designing Natural Gas Systems, Leading Practices to Reduce the Possibility of an Over-Pressurization Event, and annual industry occupational injury statistics. AGA also produces or works with other organizations to produce consumer safety pamphlets and fact sheets such as bill stuffers and customer communications. AGA is also involved in relevant industry publications/standards. Examples include:

- NFPA 59A Standard for the Production Storage and Handling of Liquefied Natural Gas
- ANSI Z21/83 (Gas Appliance Standards)
- ICC International Fuel Gas Code
- API 1185 (a pipeline safety public awareness standard under development)
- API 1164 v3 (Pipeline Cybersecurity Standards)
- Underground Storage Integrity Standards (API 1170/API 1171)

- **Operations Conference and Biennial Exhibition**. The annual AGA Operations Conference is the natural gas industry's premier gathering of natural gas utility and transmission company operations management for the sharing of technical knowledge, ideas, and practices to promote safe, reliable, and cost-effective delivery of natural gas to the end user. The Operations Conference is AGA's largest forum focusing on such topics as gas measurement, environment, storage, engineering, construction and maintenance gas control, supplemental gas, corrosion control and piping materials. The Operations Conference is AGA's largest event featuring over 100 presentations and roundtables. The conference includes safety achievement awards and presentations by safety award recipients. Every other year, an exhibition is held in conjunction with the Operations Conference that attracts vendors exhibiting tools and technologies to improve safety, operations, and efficiencies.

- **Plastic Pipe Manual for Gas Services**. AGA's Pipeline Materials Committee evaluates the use of plastic materials and new fabrication techniques for gas piping systems. This Committee publishes the AGA Plastic Pipe Manual for Gas Services, which includes the latest information on plastic materials, piping components, and design as well as installation procedures covered under today's codes and standards for natural gas distribution piping systems. Through the use of this information, member companies can more quickly, confidently, and safely move to increase the use of plastic materials. AGA also assists the Plastic Pipe Institute in maintaining a plastic materials integrity library. This library provides information on historic plastic pipe, fittings and couplings and any known plastic material issues.

- **Best Practices Program**. The AGA Best Practices Program is an effort to identify effective practices and innovative work procedures that can be used to improve participants' operations and reduce costs. It focuses on improving the safety and efficiency of gas distribution system construction, maintenance, operation, and management. The Best Practices Program features data collection to identify companies that have optimal performance in particular areas. It culminates at roundtables at which companies identified as employing leading practices share their techniques with other program participants. AGA annually features five gas distribution operations topics, such as Emergency Response, New Piping Construction, Damage Prevention, Employee Safety, or Corrosion Prevention. Program participants avoid consultant fees for gathering and analyzing industry data. AGA members have documented millions of dollars in savings from participation in the Best Practices Program. These savings can translate into lower costs for customers.

- **SOS Program.** The SOS Program is a resource for AGA members who have the need to inquire of other companies on a particular operational or engineering subject. The SOS program is a simple and effective way for members to better understand how others are addressing a particular operational challenge. For example, SOS requests include member-initiated surveys on the following topics:
    - Emergency Preparedness Planning
    - Fire Retardant Clothing Requirements
    - Facility Security
    - Training of Public Safety Officials
    - Leak Investigation Practices
    - Testing Plastic Pipe
    - Safety Requirements for Entering Residences
    - Intermittent Voltage Checks
    - Portable Fire Extinguishers
    - Security for Company Collectors
    - Injury Prevention
    - First Responder Natural Gas Safety Training Outreach During COVID-19
    - PPE Requirements
    - Serious Injury or Fatality Investigations/Evaluations

- **Stakeholder Organizations.** Furthermore, AGA works with a wide range of government, industry and stakeholder organizations to improve safety and security, including the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration, U.S. Department of Energy, U.S. Department of Homeland Security, National Transportation Safety Board, the National Association of Pipeline Safety Representatives, National Association of Regulatory Utility Commissioners, Common Ground Alliance, and national and regional trade associations.

These are just a few of the many operations and engineering-related projects that benefit a member company and its customers. While in most areas the benefits to consumers in terms of safety, efficiency and lower costs cannot easily be quantified, taken together they represent very significant benefits to consumers in the form of cost savings and improved service.

4. AGA's Oversight Committees And Safety Programs

AGA has played a key part in identifying the industry-leading practices and innovative work techniques that have assisted member utilities in strengthening their safety programs. To help enhance the safety of the natural gas delivery system, AGA has four (4) safety oversight committees and several safety programs:

- **Safety Committee.** This committee focuses on supporting member companies in their enhancement of their overall safety and security program, including pipeline safety; physical and cybersecurity; employee, utility contractor, and customer safety in the home; and public safety.

- **Pipeline Safety Management Systems ("PSMS") Executive Steering Committee.** Formed in October 2020, the PSMS Executive Steering Committee promotes the sharing of incidents and near misses, assists the industry in advancing PSMS, and provides oversight and guidance on implementation of AGA PSMS initiatives.

- **Operations Section Executive Committee and Managing Committee.** This committee formulates the policies of the operations section and provides oversight of the work of the operations committees, programs, and initiatives.

- **Operations Safety Regulatory Action Committee.** This committee is vested with authority to represent AGA membership advocacy positions on areas that impact pipeline safety.

- **Safety Programs.** AGA provides its members with innovative safety programs:

    - **Peer Review Program.**[50] This voluntary peer-to-peer safety and operational practices review program allows natural gas utilities throughout North America to observe their peers, share leading practices, and identify opportunities to better serve customers and communities. This industry effort helps enhance the safe and reliable delivery of natural gas to homes and businesses across the country. Companies take turns reviewing one another's operating procedures and business protocols that drive pipeline safety, customer safety, workforce training, and safety culture. During a company's review, an AGA staff person and the Subject Matter Expert ("SME") team interview the participating or "host" company employees, which can include senior executives, middle management, crew leaders, field workers, HR personnel, union representatives, contractors, and more. In addition, an executive from a peer company will attend with the purpose of guiding the SME team while making observations. A typical review lasts four days, includes 12 – 17 subject matter experts and 60

[50] *See* AGA, Peer Review Program, https://www.aga.org/events-community/peer-review/ (last visited February 21, 2022).

– 100 interviews, with the final day featuring a written report and verbal presentation that highlights the review team's observations to company leadership. All observations made during the review are confidential and are not shared outside of the review.

- **PSMS Virtual Assessment Pilot Program.** PSMS is a voluntary initiative that industry and government officials believe can enhance pipeline safety, operations, and efficiencies. In late 2020, AGA launched a PSMS Virtual Assessment pilot program to determine if virtual PSMS assessments of a company, by their peers, can be done effectively and is meaningful to both the company receiving the assessment and the companies participating in the assessment. The participating companies are dedicating resources to strengthen their own PSMS and to assist AGA in advancing the PSMS of other participating companies.

- **Executive Leadership Safety Summit.** To help enhance the safety of the natural gas delivery system, AGA annually conducts an Executive Safety Leadership Summit for its members to come together and exchange practices and share lessons learned in four (4) critical areas of safety:

    - Public Safety
    - Gas Company Worker Safety
    - Customer Safety
    - Pipeline Safety

  This annual event for natural gas utility executives and safety officers focuses on the state of the natural gas industry in all aspects of safety, including case studies, roundtable discussions, and presentations provided by government and industry safety leaders. Over 100 senior leaders from AGA members attend this event, and its value lies in the information shared by companies that have either experienced some type of safety incident or have implemented some unique safety initiative that might also benefit other AGA members.

- **Safety Resource Information Center.** A website clearinghouse for safety information including external safety alerts (Department of Transportation's Pipeline and Hazardous Materials Safety Administration, U.S. Chemical Safety Board, Occupational Safety and Health Administration), member generated safety alerts, a Lessons Learned Database, cybersecurity materials, case studies, member safety messages, vehicular safety materials, government safety statistics, AGA Safety Statistics and safety articles from the American Gas Magazine.

- **Gas Field Worker Assault Prevention Program.** This cross-committee effort facilitates information exchange to help deter gas worker assaults. Three (3) areas of focus include:

    - Resources/Technologies (alert devices, heat maps, *etc.*) that can enhance the safety and security of field personnel;

    - Program Development: Tools, business practices, and references to build or enhance a utility's gas worker safety/security program; and
    - Coordination: Identify internal and external coordination opportunities.

- **Operational Risk Data Committee ("ORDC").** The ORDC was established in October 2020 to conduct a deep dive analysis of Pipeline and Hazardous Materials Safety Administration's natural gas distribution and transmission pipeline incident data to determine potential trends and issue reports of its findings. Information from the ORDC reports may assist operators with their integrity management efforts.

- **Voluntary Event and Near Miss Data Collection and Analysis.** In February 2021, the AGA Board approved AGA's collection and analysis of pipeline related events and near misses voluntarily submitted by AGA members. Once a secured data site has been established, operators will have the ability to complete an on-line form to submit information. The voluntarily submitted and anonymized data will be analyzed by the Operational Risk Data Committee for potential trends.

- **The Downstream Natural Gas Information Sharing and Analysis Center ("DNG-ISAC").** This is a platform that was created by AGA for sharing cyber and physical threat intelligence, incident information, analytics, and tools. The DNG-ISAC helps natural gas utilities throughout the nation share and access timely, accurate and relevant threat information as part of their continued commitment to the safe and reliable delivery of clean natural gas to customers throughout the nation. All AGA member companies have full access to the DNG-ISAC.

- **Plastic Pipe Data Collection Initiative.** Since 1999, AGA has collected data on in-service plastic piping system failures and leaks with the objective of identifying possible performance issues. Company participation in the initiative is voluntary and the database is designed to address confidentiality concerns. Several times each year, the database is analyzed by the Plastic Pipe Database Committee, composed of representatives of AGA, American Public Gas Association, Plastics Pipe Institute, National Association of Regulatory Utility Commissioners, National Association of Pipeline Safety Representatives, National Transportation Safety Board, and Pipeline and Hazardous Materials Safety Administration. Information from this analysis is published on the AGA website and various government websites.

5. Energy Markets, Analysis, And Standards Activities

AGA's energy and analysis group identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics, and the environment. The group also supports the development of building energy codes and standards (see above) that help enhance natural gas safety. Furthermore, AGA markets, analysis, and standards activities include providing important and timely information service to a member company. For example:

- **Market Data**. A vast array of data about all aspects of the natural gas industry is collected and compiled in ready-reference form. Among these publications are GAS FACTS, and the LDC Winter Heating Season Performance Survey.

- **Analyses**. AGA also undertakes a wide range of analyses on environmental, financial, gas supply, gas demand, consumer cost, capital requirements, resource efficiency and other issues facing the gas industry. These analyses are of great value in assisting a member company and other decision-makers in addressing current energy challenges and in establishing policies in the best interest of the nation.

6. AGA's Financial And Administrative Activities

AGA conducts financial and administrative activities that benefit members and member company customers. The following are some examples of AGA's financial and administrative activities.

- **Financial Workshops.** AGA sponsors topical workshops on cutting-edge issues facing our member companies. One example is AGA's Financial Forum along with its Finance Committee meeting which brings together Chief Financial Officers, Investor Relations Executives, and key stakeholders in the financial community. Another example is the Accounting for Derivatives Workshop, which is targeted towards member company accounting professionals that work with derivatives.

- **Accounting Standards.** The Accounting Principles Committee works extensively with the Financial Accounting Standards Board and the Securities and Exchange Commission to ensure that new accounting standards or information requests are sound and not unnecessarily burdensome to implement. Over the past two years, numerous responses have been filed with these organizations on their proposals, and have been instrumental in positions adopted.

- **Insurance.** Through AGA's Risk Management Committee, member companies are provided with information that is beneficial in evaluating insurance coverages. AGA also provides members with the opportunity to meet with committees representing insurance companies to resolve mutual challenges. In addition, AGA was instrumental in forming a utility mutual insurance company that provides competition to the commercial insurance markets, resulting in broader coverage and more competitive premiums. Most member companies' insurance coverage is with this mutual insurance company. Premium savings to companies ranges up to 20 percent over insurance from other sources.

- **Data Source.** In the customer activities area, AGA's Data Source is the utility industry's premier tool for analyzing and improving customer service programs. It is an extensive database of performance metrics on customer service functions such as call centers, energy assistance programs, billing, and meter reading. The database compares information submitted electronically by the program participants. A powerful online search engine and analytical tools enable members to retrieve data efficiently, thereby increasing employee productivity. This program saves each participant approximately $35,000 annually compared with hiring a commercial benchmarking firm.

- **Surveys.** AGA conducts an annual survey covering corporate and employee salary and benefit information, which is helpful in identifying trends and implementing changes. This supports cost containment.

- **Utilities United Against Scams.** AGA also participates in Utilities United Against Scams ("UUAS"). UUAS is a consortium of more than 150 U.S. and Canadian electric, water, and natural gas utilities (and their respective trade associations). UUAS is dedicated to combating impostor utility scams by providing a forum for utilities and trade associations to share data and best practices, in addition to working together to implement initiatives to inform and protect customers.[51]

These are just a few examples. Although the cost to a member company for this information is small, if a member company were to develop this information on its own, the cost could be in the tens of thousands of dollars.

7. AGA's Office of General Counsel

The Office of General Counsel provides legal counsel to AGA. A significant responsibility of AGA's legal staff is to assist member company attorneys in more effectively performing their duties, thereby reducing their companies' cost of service. For example, AGA offers litigation alerts, forums, and workshops on a broad range of issues of interest to its member companies. Furthermore, the Antitrust Compliance Programs provide assistance to members in potentially

[51] *See* https://www.utilitiesunited.org/ (last visited February 21, 2022).

precedent-setting litigation, as well as analyses and legal summaries. The AGA Legal Committee sponsors the Legal Forum, the preeminent legal program for attorneys at gas utilities. Continuing legal education credit is available for attorneys that participate in AGA's legal programs at a cost lower than other sources. For the last several years, the Office of General Counsel developed the AGA FERC Manual, an authoritative source of information about how the Commission's rules affect natural gas utilities. The manual provides valuable insights into navigating the Commission's various offices, and developing compliance plans. The manual includes material regarding the history of the Commission's regulation of natural gas utilities, the services of pipeline and storage companies, how to obtain capacity directly from the pipeline, rules regarding capacity release, the Commission's regulation of LDCs as sellers of natural gas, LDCs as transportation and storage service providers, the Commission's rules regarding the prohibition of energy market manipulation and the Commission's reporting requirements. It includes tables, charts, checklists, summaries, and hypothetical scenarios to facilitate members' understanding and compliance with Commission regulations.

Members of the Office of General Counsel also serve as staff executives for the AGA FERC Regulatory Committee, which consists of gas utility in-house attorneys, regulatory compliance officers, gas supply and transportation managers, and regulatory affairs representatives. The Office of General Counsel also sends regular regulatory updates to members summarizing Commission issuances relevant to the gas industry.

8. AGA's Governmental Affairs And Public Policy Program

AGA's Governmental Affairs and Public Policy department and its activities benefits members and member companies' customers as well. AGA has in place a program to monitor federal legislative activities and to discuss with members of Congress and their staff the regulated gas industry's views on these activities.[52] While the subject matter AGA monitors are broad, all of AGA's legislative positions have either a direct or indirect benefit to gas utility customers.

For example, AGA is a leader advocating for increased funding of the Low Income Home Energy Assistance Program ("LIHEAP") by the federal government - a program that is essential in reducing the financial burden of those on low and fixed incomes due to the fundamental need for heating and hot water service. Furthermore, with the increasing help of many other state, local and regional low-income consumer-oriented organizations, AGA continues to work to ensure the maintenance of adequate funding for the program. AGA's efforts contributed to final FY2021 appropriations of $3.75 billion. In addition, AGA successfully led efforts to appropriate an additional $4.5 billion in supplemental LIHEAP funding in the American Rescue Plan Act of 2021 to help offset the economic crisis low-income consumers are experiencing during the COVID-19 pandemic. All told, the $8.25 billion allocated to LIHEAP in FY2021 is the highest funding level in the history of the program for some of the most financially burdened individuals.

One of the most important issues AGA engages in, and will always be so engaged, is pipeline safety. AGA members invest $95 million every day in infrastructure upgrades to enhance, among other things, the safety of natural gas distribution and transmission pipeline systems. Furthermore, safety is a joint effort, a partnership that engages customers, industry, and policymakers at the federal and state level to help ensure the safety, reliability, and resiliency of America's 2.6 million mile underground pipeline system. AGA worked diligently with federal legislators, industry partners, and other non-governmental organizations to help develop federal pipeline safety reauthorization legislation. Passed in December 2020, the Protecting our

[52] The activities of this AGA department include lobbying contacts and activities, as defined by federal law, whereas the vast majority of the activities in the other departments would not include lobbying. As such, activities that constitute lobbying are subject to the accounting, reporting, and identification requirements noted above.

Infrastructure of Pipelines and Enhancing Safety ("PIPES Act") of 2020, reflects 2.5 years of work and negotiation to help develop reasonable, practicable - and bipartisan - pipeline safety legislation that improves many facets of pipeline operations and related management, training, and public accountability procedures.

Another important issue on which AGA has advocated is the budget authorizations and allocations for the U.S. Department of Energy's research and development programs. The Department's research and development budget has been drastically reduced in recent years. AGA believes that gas-related programs have suffered unjustifiably large cutbacks compared with projects for other forms of energy - especially in light of the present and future critical importance of natural gas, renewable gas, and hydrogen to meet the nation's energy needs, and the substantial benefits these programs can provide U.S. gas consumers.

The above are just a few examples. The cornerstone of those examples is that AGA's government relations efforts play a key role in protecting the interests of not only member companies but also their customers from proposed legislation that inadvertently or otherwise could have serious impacts on gas supply and cost of gas service.

9. AGA's Communications Department

AGA's Communications Department focuses on program areas of earned media, paid media and advertising, events, polling and member communications. The Communications Department responds to media on topics related to energy and the natural gas industry, and develops content. AGA's Communications Department oversees and produces content for the AGA website, blog and all social media channels. AGA's Communications Department works across the organization to prepare and release relevant news and materials for key industry constituencies.

10. AGA's Regulatory Programs Are Not Primarily Devoted To Lobbying

As the foregoing discussion demonstrates, AGA's involvement in federal government lobbying is a small part of AGA's overall regulatory efforts and an even smaller part of AGA's overall activities. For example, AGA frequently comments on regulations proposed by various executive branch agencies, such as the Environmental Protection Agency, Department of Energy and Department of Transportation, and independent agencies such as this Commission, Securities and Exchange Commission, and Commodity Futures Trading Commission to communicate the interests of the gas utility industry and its customers, much as companies do individually before the agency in rulemaking proceedings. Notably, AGA is active in proceedings before this Commission as members rely on natural gas pipelines to receive supply in order to serve customer needs.

Reviewing and commenting on the economic and other impacts of the many regulations affecting the gas industry is an important aspect of AGA's regulatory work. Such efforts reduce the operating costs of member companies and help ensure resources are directed towards effective and enhanced processes and thus, are of direct benefit to consumers who must ultimately pay the costs of compliance with government regulations and policies.

The regulatory activities, such as those undertaken by AGA are necessary for, and beneficial to, natural gas distribution companies. Specifically, with government at the federal level continuing to be involved in matters such as safety, clean air and water, funding of energy research, and conservation of energy, there continues to be a need for the regulated natural gas utilities to be aware of proposed actions and their potential economic and other impacts in a timely manner and so that collective industry views and information are made known to the federal decisionmakers. The only way the governmental and regulatory process can arrive at balanced results is for all interested groups to express their views and share information. AGA is the most efficient medium through which collective views and information of member companies on gas industry matters can be communicated, complementing individual companies' own communications. It is important to note, however, that communication between AGA and federal agencies is not just one way. Federal agencies look to AGA when there is a need to provide special notices to gas utilities and other parties quickly. On many occasions, AGA provided this service to the Commission, the Department of Transportation's Pipeline and Hazardous Materials Safety Administration, Commodity Futures Trading Commission, the Consumer Products Safety Commission, the Environmental Protection Agency, and the National Transportation Safety Board.

AGA's regulatory activities and advocacy efforts also benefit executive branch agencies by making proceedings more efficient. For example, AGA's submissions allow the industry to speak with one concise voice. Instead of reviewing several similar comments filed in proceedings or listening to different speakers make the same point, AGA's advocacy efforts allows its members to make important industry positions and opinions on matters more succinctly, reducing the workload of both the agencies and other participants to proceedings**.**

11. COVID-19 Related Activities

Throughout the COVID-19 pandemic, America's natural gas distribution network continues to be safe and reliable. Systems have remained fully operational, and natural gas has continued flowing to our country's over 73 million customers. During the pandemic, half of all Americans have depended on natural gas as energy to fuel their homes and businesses. Businesses depending on natural gas include hospitals, grocery stores and other vital services critical to the nation's well-being during the pandemic. It also includes making sure people have heat, hot water, and cooking when they are sheltered in place, as has been the case to varying degrees across the country since the pandemic began. AGA continues to play a vital role in supporting our member company utilities, in their delivery of natural gas.

For our member companies, the value of AGA membership cannot be fully measured. During the pandemic, AGA's leadership role for the natural gas industry has been magnified and member utilities have relied even more on AGA to provide information and leading practices to help members manage the safety of their employees and customers particularly during an unprecedented and fast changing situation such as one presented by COVID-19. The following are a few examples which demonstrate the leadership role that AGA has played since the start of the pandemic:

- **Essential Workers.** AGA has worked to ensure utility personnel have been designated as essential critical infrastructure workers at the federal level. This designation has afforded AGA members the ability to continue responding to the needs of customers, which includes emergency response activities such as leak investigations, which may require their workers to enter a customer's home. Throughout the pandemic, utility personnel have been provided the appropriate personal protective equipment such as masks, gloves, protective suits and coverings, soap, and hand sanitizer to mitigate the threat of contamination. This level of protective health and safety procedures was greatly assisted by AGA's efforts.

- **Spread Prevention.** AGA member companies have adopted policies and changed operating procedures to prevent the spread of COVID-19 and to provide reassurance to employees and customers that their health and safety are always the most important considerations. They have learned of leading practices from fellow utilities during AGA virtual meetings, which have covered a wide spectrum of topics since March 2020.

- **Meetings.** AGA has held hundreds of meetings since March 15, 2020, where COVID-specific operating practices in gas operations have been spotlighted, and presentations have educated member companies on issues associated with employee management, legal matters, and return to workplace strategies.

In addition, gas distribution utilities have been dedicated to helping their communities since the onset of the pandemic. LDCs recognized early on that many of their customers would face financial difficulty, so the utilities took immediate actions to help by collecting donations and conducting food drives. In addition, utilities across the country suspended late fees and service disconnections for non-payment, reconnected those who had been disconnected, and offered bill payment assistance for those struggling financially.

In summary, the benefits of almost all of AGA's activities either directly or indirectly are realized by the customers of AGA members. Highlighted above are a few AGA activities that illustrate how member company customers (73 million) benefit from such undertakings.[53]

V. CONCLUSION

For the reasons stated above, the American Gas Association respectfully requests that the Commission consider these comments in this proceeding.

Respectfully submitted,

/s/ Matthew J. Agen

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Date: February 22, 2022

[53] AGA's website www.aga.org contains additional information about AGA and its programs to benefit members and their customers.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS	**)**	
ENERGY CORPORATION FOR AN	**)**	
ADJUSTMENT OF RATES; APPROVAL OF	**)**	**Case No. 2024-00276**
TARIFF REVISIONS; AND OTHER	**)**	
GENERAL RELIEF	**)**	

REBUTTAL TESTIMONY OF JOE T. CHRISTIAN

INDEX TO THE REBUTTAL TESTIMONY
OF JOE T. CHRISTIAN, WITNESS FOR
ATMOS ENERGY CORPORATION

I. INTRODUCTON 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 T. 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 Key Financial Indicators
- Exhibit JTC-R-2 Interest Savings
- Exhibit JTC-R-3 Moody's Rating Methodology
- Exhibit JTC-R-4 KY 2024 Cash Working Capital

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut the proposed adjustments to the Company's proposed capital structure. The capital structure adjustment is recommended by Attorney General's Office of Rate Intervention ("OAG") witness Mr. Richard

Baudino. I also rebut the proposed adjustments to the Company's cash working capital which is recommended by OAG witness Kollen.

Q. ARE YOU THE ONLY COMPANY WITNESS FILING REBUTTAL TESTIMONY ON CAPITAL STRUCTURE?

A. No. Company witnesses Dylan D'Ascendis also addresses the capital structure issues raised by Mr. Baudino.

II. <u>SUMMARY OF TESTIMONY</u>

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS

A. With regards to:

- **Capital Structure –** I reject Mr. Baudino proposed adjustments to the Company's capitalization ratio.
- **Rate Base Items –** I reject one of Mr. Mr. Kollen's adjustments to cash working capital and one of his rate base adjustments.

III. <u>CAPITAL STRUCTURE</u>

Q. PLEASE DESCRIBE MR. BAUDINO'S ANALYSIS AND RECOMMENDATIONS REGARDING THE CAPITAL STRUCTURE OF THE COMPANY?

A. Mr. Baudino begins his analysis by first referencing back to the final orders in Case No.'s 2018-00281 and 2021-00214 and noting the Commission's concern in 2018-00281 regarding Atmos Energy's capital structure being higher than the proxy group in that case and then noting the Commission's language in 2021-00214 finding that our proposed capital structure as filed and revised upon rebuttal in that case did not result in a reasonable result nor did it result in fair and just rates for

Kentucky's consumers.[1] He then provides a table comparing the capital structures of his peer group.[2] Mr. Baudino notes the requested equity ratios in a recent Columbia Gas of Kentucky case and a pending Delta Natural Gas before the Commission.[3] Mr. Baudino then recommends that the Commission approve a common equity ratio at 52.5% "…as it continues to move Atmos' common equity ratio toward the average of the proxy group. In addition, a 52.5% common equity ratio is consistent with recent capital structure requests from gas distribution companies as I have just described."[4]

Q. DID YOU PROACTIVELY RESPOND TO THE COMMISSION'S CONCERNS IN CASE NOS. 2018-00281 AND 2021-00214 IN YOUR DIRECT TESTIMONY?

A. Yes.[5] In my direct testimony I did acknowledge the Commission's concerns, however I disagree with the OAG's witnesses' concern that our "…common equity ratio is unreasonable, excessive and should be rejected by the Commission."[6] As I noted in Case Nos. 2018-00281 and 2021-00214, and reiterated in my direct testimony, the capital structure proposed and supported in this Case represents an actual cost, not a hypothetical or subsidiary cost that is part of a larger holding company and can be leveraged at a higher level in the corporate structure. Unlike the other large Kentucky utility companies, Atmos Energy does not have a holding company structure and is therefore not a good direct comparison when determining

[1] In the Matter of: *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief,* Direct Testimony and Exhibits of Richard Baudino, Page 34
[2] Baudino, Page 35
[3] Baudino at 36
[4] Baudino, Page 36
[5] Christian Direct at 12 – 19
[6] Baudino, Page 3

an appropriate capital structure for establishing rates for customers. I also noted that, as the factors used by the credit rating agencies 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 therefore fails to provide the utility a reasonable opportunity to earn a fair return on their investments. Moreover, the Company's capital structure is reflective of what is necessary to maintain its current credit metrics. The Company's current credit metrics enable it to access long-term debt and the capital markets at more favorable terms, which is a benefit to customers.

Q. DOES MR. BAUDINO PROVIDE ANY ANALYTICAL SUPPORT FOR HIS CONCLUSIONS?

A. As in the Company's previous two cases, Mr. Baudino limits his analysis and recommendation to a comparison of the proxy group and other recent cases involving other Kentucky utilities.[7] Mr. Baudino has not performed analysis on the financial impact of their recommendations on the Company's financial metrics. His recommendation relies exclusively, if not entirely, on the Commission's prior orders and there is no acknowledgement given to the overall impact of implementing his recommendations on the Company's ability to continue to raise external financing to continue making investments in its utility operations to provide safe and reliable service.

[7] Company witness D'Ascendis addresses Mr. Baudino's narrow look at the Utility Proxy Group as well as commentary from authoritative literature regarding the appropriate uses of hypothetical capital structure.

Q. HAVE YOU ANALYZED THE IMPACT OF THEIR PROPOSED CHANGES TO THE COMPANY'S CAPITAL STRUCTURE?

A. Yes. Attached to my testimony as Exhibit JTC-R-1 Key Financial Indicators ("KFI") is a comparison of the impact on the KFIs used by Standard & Poor's Global Ratings ("S&P"). The comparison is between the Company's current long-term plan[8] for its Kentucky operations and Mr. Baudino's recommendations for its capital structure and return on equity. While S&P evaluates Atmos Energy on a consolidated basis, the analysis is demonstrative of the impact his recommendations would have if applied to the entire Company.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS?

A. As shown in Exhibit JTC-R-1, the two primary core ratios (FFO/Debt and Debt/EBIDA) of Atmos Energy Corporation are in the Intermediate category which is the analytical basis for the Company's current debt rating.[9] Both KFIs are diminished from Intermediate to Significant/Aggressive when applying the recommendations of Mr. Baudino. In other words, if the Commission fully adopted Mr. Baudino's recommendations the Kentucky operations would not pull the same weight in the generation of funds from operations or coverage of debt obligations as the Company's other utility operations. This decline would lead to a downgrade if Kentucky represented the entire Company, which in the long-term would drive higher financing costs for our utility customers. Although Kentucky represents approximately 5% of the Company, it is inappropriate to use its small size relative

[8] To be conservative, I used the recently authorized return for Columbia Gas of Kentucky in Case No. 2024-00092 on equity of 9.75% to derive the KFIs.
[9] In order to exclude the short-term impact of winter storm Uri, I base exclude gas costs in deriving the KFIs and base my comments using S&P Global Ratings report on Atmos Energy dated October 29, 2020.

to the whole as an excuse to not allow it to contribute ratably to the Company's overall financial performance.

Q. WHAT ELSE DOES EXHIBIT JTC-R-1 DEMONSTRATE?

A. The KFIs demonstrate that the Company's proposed capital structure in this Case produces funds from operations and debt coverage ratios that fall within the range of our consolidated capital structure. In other words, we are not proposing or requesting a capital structure with 60% equity that is, "..significantly higher than its peers for no other reason than for stockholder benefits" as stated in the Commission's final order in Case No. 2021-00214.[10] However, use of a hypothetical capital structure for ratemaking purposes with increased long-term debt as Mr. Baudino suggests would negatively affect the Company's financial integrity and put the Company at risk of a credit rating downgrade and increases to the cost of debt financing, both of which adversely affect all of Atmos Energy's stakeholder groups, including its customers, its shareholders, and its bondholders.

Q. DOES THE COMPANY ALSO HAVE AN ANALYSIS DEMONSTRATING LONG-TERM DEBT SAVINGS AS A RESULT OF ITS BALANCE SHEET MANAGEMENT?

A. Yes. Attached to my testimony as Exhibit JTC-R-2 Interest Savings is a comparison of the savings that have been achieved since 2014 as a result of being 'A' rated by the debt rating agencies as compared to a 'B' rated company. As shown on Line 28, the savings is $21.0 million annually on a corporate wide basis. Recomputing

[10] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022), final Order at 38.

the imbedded long-term cost of debt results in an overall cost of debt of 4.56% compared to the 4.11% supported in this case.

Q. HOW MUCH SAVINGS DOES 4.11% COMPARED TO 4.56% LONG-TERM COST OF DEBT RESULT IN WHEN APPLIED TO THE KENTUCKY RATE BASE REQUESTED IN THIS CASE?

A. The resulting savings is approximately $1.14 million.

Q. IF THE COMMISSION FOLLOWED MR. BAUDINO'S RECOMMENDATION, WOULD UPDATING THE COMPANY'S LONG-TERM DEBT RATE BE APPROPRIATE?

A. Yes. In the last two decisions the Commission has taken the benefits accrued to Kentucky customers as a result of the Company's effective balance sheet management, that is the lower imbedded cost of debt, while penalizing the Company by not allowing full recovery of the equity component of our capital structure. If the Commission continues to ignore the analytical results provided and the sound ratemaking principles articulated by Mr. D'Ascendis regarding the fallacy of Mr. Baudino's Peer Group comparison then the final Commission order should utilize the 4.56% long-term debt rate.

Q. DOES THE COMPANY'S PROPOSED CAPITAL STRUCTURE REPRESENT ITS ACTUAL COST OF DOING BUSINESS?

A. Yes. As noted in my direct testimony, the Company uses its actual capital structure, which represents its actual costs. Mr. Baudino does not acknowledge that the Company has operated with a capital structure in its current range since Case No. 2018-00281, thus further support for my arguments in Case No. 2018-00281 as well as this case that we have an analytical basis for our capital structure and have continued to have a need to access the external capital market to support our capital investment in Kentucky as well as our other utility operations. Mr. Baudino has utilized the analysis of a company's actual historical common equity ratios as an appropriate method in the past in making his capital structure recommendations as well.[11] This continued investment benefits our customers by enabling us to continue to provide safe and reliable service.

Q. HAVE ANY OF THE INDUSTRY RATINGS AGENCY REPORTS ISSUED DRAWN THE CONTRAST BETWEEN ATMOS ENERGY'S STRONG BALANCE SHEET AND UTILITIES WITH WEAKER BALANCE SHEETS?

A. Yes. On January 19, 2018, Moody's Investors Service ("Moody's") revised downward its outlooks of 25 US regulated utilities due to the passage of the Tax Cuts and Jobs Act. Atmos Energy was not one of those 25 companies, primarily due to the Company's strong credit metrics. On April 2, 2020 S&P noted in a comment that they were revising their assessment of the North America regulated utility industry to negative from stable and that many utilities with a stable outlook

[11] Case No. 2024-000392, *Electronic Application of Columbia Gas of Kentucky, Inc. for an Adjustment of Rates; Approval of Depreciation Study; Approval of Tariff Revisions; and Other Relief* (Ky. PSC August 14, 2024), Baudino Direct Testimony at 33 ("Based on my review I conclude the Company's requested capital structure is reasonable. It is consistent with the Company's recent historical capital structures as well and [sic] the capital structure that was adopted in the settlement in Columbia Kentucky's last rate proceeding"); *see also* Case No. 2023-00191, *Electronic Application of Kentucky-American Water Company for an Adjustment of Rates, a Certificate of Public Convenience and Necessity for Installation of Advanced Metering Infrastructure, Approval of Certain Regulatory and Accounting Treatments, and Tariff Revisions* (Ky. PSC September 29, 2023) Direct Testimony of Richard A. Baudino at 3 ("The Company requested a common equity ratio of 52.45% for the test period. This request is significantly higher than KAW's recent historical common equity ratios for the years 2017-2022 and should be rejected by the Commission"); *see also* at 34 ("The Company's requested common equity ratio of 52.45% is excessive when compared to its recent historical common equity percentages")

have minimal financial cushion at the current rating level. However, Atmos Energy's business decisions that led to a healthy balance sheet have enabled it to continue to access the capital markets during the current market stress and continue with a stable outlook.

Q. YOU DISCUSSED KFIs AND THE IMPACT ON ATMOS ENERGY OF MR. BAUDINO'S RECOMMENDATION, DO RATING AGENCIES PUBLISH REPORTS THAT PROVIDE TRANSPARENCY INTO HOW DEBT RATINGS ARE DERIVED AND THE IMPORTANCE OF KFIs ON THE DEBT RATING?

A. Yes, both Moody's and S&P provide insight to investors regarding how debt ratings are assigned. Moody's issued an updated Rating Methodology for Regulated Electric and Gas Utilities on June 23, 2017, and I have attached that to my testimony as Exhibit JTC-R-3 as an example of how Moody's assigns ratings.

Q. HOW DOES MOODY'S EVALUATE THE CREDIT RATING OF A UTILITY?

A. As the opening Summary indicates, the rating methodology document explains Moody's approach to assessing credit risk for regulated electric and gas utilities globally in order to enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in the regulated electric and gas sector.

Q. DOES THE MOODY'S REPORT DISCUSS HOW A REGULATORY DECISION IMPACTS RATING CONSIDERATIONS?

A. Yes. Moody's indicates that an over-arching consideration for regulated utilities is the regulatory environment in which they operate. The report goes on to quantify the four factors that are considered when evaluating a utility's overall credit rating. These include, among others, Regulatory Framework (25%), Ability to Recover Costs and Earn Returns (25%), and Financial Strength, Key Financial Metrics (40%). The report describes all of the factors in detail, including why they are important and how they are evaluated.

Q. WHY DOES MOODY'S SAY REGULATORY FRAMEWORK (25%) IS IMPORTANT?

A. On Page 6 of the report under "Why It Matters" Moody's states in part, "For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations."

Q. ARE THERE ANY KEY PASSAGES IN THIS SECTION THAT YOU WOULD LIKE TO HIGHLIGHT?

A. Yes. Included in its more detailed description of Regulatory Framework, the report states, "A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score."

Q. WHY DOES MOODY'S SAY ABILITY TO RECOVER COSTS AND EARN RETURNS (25%) IS IMPORTANT?

A. On Page 12 of the report under "Why It Matters" Moody's states in part, "The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations."

Q. WHY DOES MOODY'S SAY FINANCIAL STRENGTH METRICS (40%) ARE IMPORTANT?

A. On Page 20 of the report under "Why It Matters" Moody's states, "Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant, and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, *is necessary for a utility to attract capital at a reasonable cost in order to invest* in its generation, transmission, and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers." (emphasis added).

Q. HAS MOODY'S CREDIT OPINION CHANGED SINCE THE PREVIOUS CASE?

A. No, however as I pointed out in my Direct Testimony, on April 10, 2024, Moody's changed the Company's Outlook to "negative", stating that "We had previously expected that the company's financial profile would recover after it exhibited lower than historical metrics in 2022 and 2023. However, due to a sizable capex program and the inherent regulatory lag in some of its jurisdictions, we project that Atmos' cash flow from operations before changes in working capital (CFO pre-WC) to debt ratio will more likely be between 20%-22% over the next several years; still strong but below historical levels in the 25% range." This statement strikes directly at the unfavorable treatment that the Company received in its most recent Kentucky rate case and what is being proposed by Mr. Baudino in this Case.

Q. HAS THE COMPANY BEEN MORE ACTIVE IN THE DEBT CAPITAL MARKETS THE PAST FIVE YEARS?

A. Yes. To fund a portion of our capital investment over the past seven fiscal years[12] we have locked in historically low rates on $7.175 billion, including $6.675 billion incremental of long-term debt. As noted above, in addition to improving the safety and reliability of our gas distribution system, the newer long-term debt being issued within the 'A' range by debt ratings agencies rather than the 'BBB' range has benefited our customers by lowering the weighted average cost of long-term debt or approximately $20.998 million annually and having a supportive regulatory environment is key to maintaining this strong 'A' range debt rating. For instance, Columbia's long-term debt rate in its recently concluded rate case was 4.80%, while the Company's long-term debt rate in this Case is significantly lower at 4.11% due in part to the Company's strong balance sheet.[13] This is a significant savings that Mr. Baudino does not recognize in his testimony for Atmos Energy in comparison to Columbia Gas.

Q. DOES MR. BAUDINO'S COMPARISON TO OTHER KENTUCKY UTILITIES AND ATMOS ENERGY CONSIDER THE IMPACT ON HOW THE BALANCE SHEET IS MANAGED?

[12] We have financed the remainder through issuances of additional equity and through reinvested funds from operations.
[13] *See* Case No. 2024-00092, (Ky. PSC December 30, 2024), final Order at 46-47.

A. No. I pointed out in my direct testimony that our Kentucky utility operations are within the consolidated entity of Atmos Energy Corporation, not a subsidiary under a holding company, and thus no separately issued or rated long-term debt. This is different than the holding company structure/subsidiary legal organization of the utilities cited in his answer. I do not know the specifics of how these utilities manage their balance sheet but am aware that often times there is a marked difference in the publicly traded holding company and the regulatory capital structure at the operating company level, thus introducing another layer of consideration when a holding company is managing its balance sheets (holding company and subsidiary) compared to the transparency of Atmos Energy's one consolidated balance sheet that is focused on maintaining one set of credit metrics while raising external financing and reinvesting over half its earnings back into its business in a balanced fashion.

Q. BASED ON YOUR KNOWLEDGE, EXPERTISE, AND REVIEW OF FINANCIAL TREATISES, IS THERE SUCH A THING AS AN OPTIMAL CAPITAL STRUCTURE?

A. No. See, for example, *New Regulatory Finance* by Roger A. Morin. After conducting a review of the various studies that have been performed and trade-offs involved in having a higher or lower debt ratio the author concludes, "…finance theory provides limited guidance on what a company's capital structure should be precisely. Capital structure decisions must be determined by managerial judgement and market data in contrast to the exact mathematical formulas resulting from the theories presented in this chapter. Financial theory provides benchmarks and useful data to assist management in capital structure decisions. Capital structure decisions depend critically on each company's own situation and level of business risk as well. The higher the business risk, the lower the debt ratio."[14]

Q. HOW DOES THE SETTLED CAPITAL STRUCTURE/ROE AT THE SUBSIDIARY LEVEL COMPARE TO THE HOLDING COMPANY LEVEL OF DECEMBER 31, 2024?[15]

A. The capital structure and cost of capital components of Duke-Kentucky Electric and Columbia Gas with the settled cost components applied to the parent company actual capital structure is:

	Duke-KY	Duke	Columbia	NiSource
Long-Term Debt Capitalization	46.039%	59.593%	45.530%	58.980%
Short-Term Debt Capitalization	2.617%	2.647%	1.830%	2.670%
Equity Capitalization	51.344%	37.760%	52.640%	38.350%
Total Capitalization	100.00%	100.00%	100.00%	100.00%
Applied to Holding Company				
Long-Term Debt Cost	2.017%	2.610%	2.185%	2.831%
Short-Term Debt Cost	0.124%	0.125%	0.096%	0.140%
Equity Rate Cost	5.006%	4.411%	5.132%	4.443%
Weighted Average Cost of Capital-HoldCo	7.147%	7.147%	7.414%	7.414%
Resulting ROE		11.682%		11.585%

Q. WHAT DOES THIS COMPARISON DEMONSTRATE?

A. This comparison demonstrates that by holding the weighted average cost of capital constant, applying the debt cost components derived at the subsidiary level to the consolidated total company debt and then backing into the weighted average equity cost results in an ROE, applied to the holding company equity, of 11.682% and 11.585%. The consequences of the "lower" equity capitalization levels cited by Mr. Baudino actually result in a higher effective ROE at the holding company. I

[14] *New Regulatory Finance*, page 470.
[15] Duke-Kentucky Electric Case No. 2022-00372 and Columbia Gas Case No. 2024-00092.

would argue that on an overall basis these companies are getting exactly what the Company is advocating for in this case – a reasonable opportunity to recovery of our actual cost of our capital financing costs.

IV. RATE BASE & CASH WORKING CAPITAL

Q. PLEASE DESCRIBE MR. KOLLEN'S RECOMMENDATIONS AND ADJUSTMENTS TO RATE BASE & CASH WORKING CAPITAL.

A. Mr. Kollen makes three recommendations, one to rate base and two to cash working capital that I will address. These include a recommendation to reduce rate base for the construction accounts payable[16], a recommendation to exclude all non-cash expenses from CWC calculations, including the growth component of the return on equity expense[17], and a recommendation to correct the third-party vendor O&M expense lag days.[18] Mr. Kollen also explained certain other changes related to the flow-through impact of other OAG witnesses.[19]

Q. DO YOU AGREE WITH MR. KOLLEN'S RATIONALE FOR MAKING AN ADDITION OF ACCOUNTS PAYABLE RELATED TO CONSTRUCTION TO CASH WORKING CAPITAL?

A. No. As noted in my direct testimony, the Commission made several material changes to the Company's lead-lag study in Case No. 2021-00214, including the associated reduction to reduce rate base for construction accounts payable, that resulted in a poor outcome for the Company and which do not accurately reflect the

[16] Kollen, Page 21-22
[17] Kollen, Page 26.
[18] Kollen, Page 28.
[19] Kollen, Page 26-27.

sources and uses of working capital of a utility in its daily operations.[20] In light of the Commission's more reasonably balanced orders in Case Nos. 2017-00349 and 2018-00281 the Company utilized a lead-lag study following the same methodology accepted in calculating lead-lag in Case No. 2017-00349 and Case No. 2018-00218 for this case and did not incorporate Mr. Kollen's *ad hoc* adjustments recommended and incorporated in the final order in Case No. 2021-00214.

Q. YOU CHARACTERIZE MR. KOLLEN'S ADJUSTMENT AS "*AD HOC*", IS MR. KOLLEN'S CONSTRUCTION ACCOUNTS PAYABLE CONSISTENT WITH SOUND RATEMAKING PRINCIPLES?

A. No. Regulatory working capital is routinely calculated based on the results of a lead-lag study. In this case, my lead-lag study measures "…other rate base items that is required to bridge the gap between when cash is paid for expenses necessary to provide service and when cash is received from customers for that service."[21] Mr. Kollen proposes to improperly expand the lead-lag analysis to include expenditures recorded to capital investment and recovered through the subsequent recording of depreciation expense.

Q. IN WHAT WAY IS MR. KOLLEN'S RECOMMENDATION INCONSISTENT WITH REGULATORY PRINCIPLES RELATED TO WORKING CAPITAL?

A. In *Accounting for Public Utilities,* Robert L. Hahne describes differences between financial measures of working capital versus the regulatory perspective, stating:

[20] Christian Direct, Page 31.
[21] Christian Direct, Page 31.

"[f]or ***ratemaking purposes***, working capital is a measure of the amount of funding needed to satisfy the level of ***daily operating expenditures*** and a variety of ***non-plant investments*** that are necessary to sustain ongoing operations of the utility."[22] (emphasis added). Absent from this definition is plant-related investments, i.e. construction accounts payable.

Q. WHY IS THE INCLUSION OF CAPITAL EXPENDITURES IN THE WORKING CAPITAL ANALYSIS INAPPROPRIATE?

A. The inclusion of cash working capital impacts related to capital expenditures is a non-operating item that is not part of the lead lag analysis, but rather are properly captured and recovered through depreciation expense. The introduction of an additional element into the working capital calculation results in a hybrid working capital methodology that no longer accurately reflects the daily regulatory cash working capital needs. To further compound his error, Mr. Kollen's supplemental hybrid working capital methodology is also incomplete.

Q. WHY IS MR. KOLLEN'S UNCONVENTIONAL ANALYSIS INCOMPLETE?

A. Mr. Kollen's analysis is incomplete because he recommends reducing rate base related to the 13-month average capital expenditures for both non-PRP and PRP despite the fact that the Company does not include any construction work in progress in our rate base calculations. Thus, not only does he introduce rate base items to the measure of daily operating items (gas supply, O&M, taxes), he does so for an item is not included in the Company's rate base.

[22] Robert L. Hahne and Gregory E. Aliff, Accounting for Public Utilities § 5.01.

Q. ARE THERE ANY OTHER FLAWS IN HIS TESTIMONY REGARDING WHAT THE COMPANY INCLUDES/EXCLUDES IN ITS RATE BASE?

A. Yes. In Case No. 2017-00349 Mr. Kollen recommended removing prepaids from rate base (page 36 of his testimony) and we agreed in rebuttal to remove prepaids (page 15 of my rebuttal); however on page 22 of his testimony in this Case Mr. Kollen says that the accounts payable amounts related to capital expenditures must be considered separately and subtracted directly from rate base in the same manner that the materials and supplies and the prepayments are considered separately and added directly to rate base as components of the other working capital allowances.

Q. DID THE COMPANY INCLUDE PREPAYMENTS AS A SEPARATE RATE BASE ITEM IN THIS CASE?

A. No. As shown on FR 16(8)(b)4.1, Schedule B-4.1 F we have not changed methodologies since 2017-00349 regarding our rebuttal position and prepayments.

Q. DO YOU AGREE WITH MR. KOLLEN'S RATIONALE FOR EXCLUDING NON-CASH EXPENSES FROM THE CASH WORKING CAPITAL STUDY?

A. I do not agree. I addressed the rationale for inclusion of depreciation expense and return on equity in my direct testimony.[23] The inclusion of these items in the study and assigning a zero payment lag, recognizes that the investor funding has occurred, but that it has not been recovered from the customer. Mr. Kollen conflates the recording of depreciation expense, for which no cash is incurred at the time of recording, with the need to exclude the delay associated with the collection from

[23] Christian, Page 41, 42.

the customer associated with the payment of their bill. The cumulative amount of depreciation expense (accumulated depreciation) is a measure of the total consumption of capital investment to date. As the expense is recorded, equal revenues are recoverable from customers as payment to investors and the accumulated provision is deducted from rate base. The recording of expense presumes recovery, but in fact it is offset with an entry to accounts receivable from customers. The expense is recorded in one period and the receipt of funds, the recovery, occurs in the subsequent month.

Q. DO YOU AGREE WITH MR. KOLLEN'S RATIONALE FOR MAKING A CORRECTION RELATED TO DEPRECIATION EXPENSE LAG TO CASH WORKING CAPITAL?

A. No. As illustrated in the previous response, Mr. Kollen's timing, as explained beginning on page 24 of his testimony, confuses the timing of the recordation of expense and the subsequent collection from the customer. His suggestion that the Company earns a return on depreciation expense is a very novel concept. The recording may occur at the end of the month, but the provision of service received by the customer is throughout the month and payment is made subsequent to month end. His proposed solution of modifying the expense lag is incorrect and should be rejected.

Q. IS THE RETURN OF NON-CASH EXPENSE BEST HANDLED THROUGH LAG AND RETAINAGE OF THE CARRYING CHARGE VALUE OF NON-CASH EXPENSES BETWEEN RATE CASES AS MR. KOLLEN SUGGESTS ON PAGE 23 OF THIS TESTIMONY?

A. No. The test period the Company utilizes is a forward-looking rate base and therefore subtracted throughout the test period to arrive at an average investment therefore no lag on depreciated investment achieves this “retainage of the carrying charge value of non-cash expenses” 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, net of changes in accumulated deferred income taxes, more than off-sets any lag that occurs due to depreciating investment and increases in deferred tax liabilities.

Q. IS MR. KOLLEN CORRECT IN BIFURCATING THE RETURN ON EQUITY INTO TWO COMPONENTS AND ARGUE THAT A PORTION SHOULD BE EXCLUDED AND A 114.4 DAY PAYMENT LAG IS APPROPRIATE FOR A DIVIDEND PORTION OF RETURN AS HE SUGGESTS ON PAGE 25 OF HIS TESTIMONY?

A. No. 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 34.63 days from the time service is provided by the Company until revenue related to that service is available to the Company. His attempt to distract and point to dividends in order to suggest that shareholders should have rate base reduced to reflect a payment to the shareholder is puzzling.

Q. DOES MR. KOLLEN'S PROPOSAL TO REMOVE ONLY THE RETURN PORTION OF THE LEAD-LAG ANALYSIS INTRODUCE ANY OTHER INCONSISTANCIES?

A. Yes. As presented, the Company's cash working capital requirement includes all of the Company's operating income associated with the 34.73 day revenue lag. However, Mr. Kollen's proposed adjustments do not include any adjustment to interest expense for short-term or long-term debt. To correct this inconsistency in the OAG's recommendations Lines 36 – 40, column (g) of the cash working capital model would need to have a value of $0. A value of $0 in the CWC model would recognize that that the lead-lag, as recommended by the OAG in this case, should only reflect the amount of funding needed to satisfy the level of daily operating expenditures and a variety of non-plant investments that are necessary to sustain ongoing operations of the utility, exclusive of the operating income revenue lag associated with financing the utility.

Q. MR. KOLLEN HAS IDENTIFIED A CORRECTION TO THE NON-LABOR O&M EXPENSE LAG DAYS, DO YOU AGREE WITH HIS CHANGE?

A. Yes. In updating the format of WP 5-1, I did have an incorrect formula reference that resulted in an understatement of the lag associated with the accounts payable sample. Correcting the formula changes the lag from 23.74 days to the 26.64 days identified by Mr. Kollen in his testimony.

Q. SHOULD ADJUSTMENTS TO THE REVENUE REQUIREMENT MODEL BE FLOWED THROUGH THE CASH WORKING CAPITAL MODEL?

A. Yes. I agree with OAG Witness Futral's suggestion that it be synchronized through the cash working capital model. However, I disagree with his assertion that "[s]ome of the adjustments recommended by the AG could also have a minimal effect on the computation of cash working capital included in rate base."[24] Mr. Waller addresses our rebuttal on the topic of these O&M and Ad Valorum items, however 'as filed' the OAG's position is an overstated reduction to rate base of approximately $1.7 million. I have included an updated cash working capital model to reflect the changes discussed by Mr. Waller in his rebuttal testimony as Exhibit JTC-R-4.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

[24] Futral at 6.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

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. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, 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 10th day of March, 2025.

Notary Public
My Commission Expires: September 1, 2028

Giselle R Heroy
My Commission Expires
9/1/2028
Notary ID130804842

Standard & Poors Report Corporate Methodology
Table 18 - Core ratios and Supplementary coverage ratios
Cash Flow/Leverage Analysis Ratios--Medial Volatility

	--Core ratios--		--Supplementary coverage ratios-	
	FFO/debt (%)	**Debt/EBITDA (x)**	**FFO/cash interest (x)**	**EBITDA/interest (x)**
Minimal	50+	less than 1.75	10.5+	14+
Modest	35-50	1.75-2.5	7.5-10.5	9-14
Intermediate	**23-35**	2.5-3.5	5-7.5	5-9
Significant	13-23	**3.5-4.5**	3-5	2.75-5
Aggressive	9-13	4.5-5.5	1.75-3	1.75-2.75
Highly leveraged	Less than 9	Greater than 5.5	Less than 1.75	Less than 1.75

	FFO/debt (%)	Debt/EBITDA (x)	FFO/cash interest (x)	EBITDA/interest (x)
Actual / Projected Capital Structure				
	Intermediate	Significant/ Intermediate	Significant/ Intermediate	Intermediate
Year 1 - Actual	17%	4.8	4.0	5.0
Year 2 - Actual	16%	4.9	3.8	4.8
Year 3 - Test Period	19%	4.3	4.5	5.5
Year 4	26%	3.3	5.8	6.8
Year 5	24%	3.5	5.2	6.2
Year 6	24%	3.5	4.9	5.9
Year 7	27%	3.2	5.2	6.2
Hypothetical Capital Structure 52.5 D / 47.5 E				
	Significant	Significant / Aggressive	Significant	Significant
Year 1	13%	5.8	3.1	4.1
Year 2	11%	6.4	2.7	3.7
Year 3	13%	5.8	3.0	4.0
Year 4	18%	4.4	4.1	5.1
Year 5	17%	4.7	3.7	4.7
Year 6	17%	4.6	3.5	4.5
Year 7	19%	4.1	3.8	4.8

Standard & Poors, October 29, 2020:
Under our base-case scenario, we expect that Atmos will continue to effectively manage regulatory risk, resulting in funds from operations (FFO) to debt in the 22%-24% range through 2022. The stable outlook reflects our expectation that the company will continue to execute on its strategy focused around safety and reliability of its regulated utility operations.

Large equity issuances in 2018 and 2019 demonstrate commitment to credit quality
We consider this balanced financing as positive for credit quality, as lower leverage benefits credit health.

Atmos Energy Corp.
Long Term Debt Ratings Impact
Case No. 2024-00276

Line #	Issuance Name	Date Issued	Amount	Issued after Upgrade?	Total	A+ A A- Rate	BBB+ BBB BBB- Rate	Spread	Savings
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**10 Year Issuances**								
2	3.00% Sr Notes due 2027	6/8/2017	500,000,000	Y	500,000,000	3.220%	3.520%	0.003000	1,500,000
3	2.625% Sr Notes due 2029	10/2/2019	300,000,000	Y	300,000,000	2.602%	2.857%	0.002550	765,000
4	1.500% Sr Notes due 2031	10/1/2020	600,000,000	Y	600,000,000	1.750%	1.991%	0.002410	1,446,000
5	2.625% Sr Notes due 2029	1/14/2022	200,000,000	Y	200,000,000	2.728%	2.953%	0.002250	450,000
6	5.450% Sr Notes due 2032	10/3/2022	300,000,000	Y	300,000,000	5.231%	5.611%	0.003800	1,140,000
7	5.90% Sr Notes Due 2033	10/10/2023	400,000,000	Y	400,000,000	5.820%	6.211%	0.003910	1,564,000
8	5.90% Sr Notes Due 2033 (Tap)	6/18/2024	325,000,000	Y	325,000,000	5.225%	5.528%	0.003030	984,750
9	**Total 10 Year Issuances**		**2,625,000,000**		**2,625,000,000**				**7,849,750**
10	**30 Year Issuances**								
11	6.67% MTN Due 2025	12/12/1995	10,000,000	N	-			-	-
12	6.75% Debentures due 2028	7/27/1998	150,000,000	N	-			-	-
13	5.95% Sr Notes due 2034	10/22/2004	200,000,000	N	-			-	-
14	5.500% Sr Notes due 2041	6/10/2011	400,000,000	N	-			-	-
15	4.150% Sr Notes due 2043	1/11/2013	500,000,000	N	-			-	-
16	4.125% Sr Notes due 2044	10/15/2014	500,000,000	Y	500,000,000	2.886%	3.283%	0.003970	1,985,000
17	4.125% Sr Notes due 2044	6/8/2017	250,000,000	Y	250,000,000	4.018%	4.319%	0.003010	752,500
18	4.300% Sr Notes due 2048	10/4/2018	600,000,000	Y	600,000,000	4.486%	4.814%	0.003280	1,968,000
19	4.125% Sr. Notes due 2049	3/4/2019	450,000,000	Y	450,000,000	4.336%	4.641%	0.003050	1,372,500
20	3.375% Sr Notes due 2049	10/2/2019	500,000,000	Y	500,000,000	3.329%	3.621%	0.002920	1,460,000
21	2.850% Sr Notes due 2052	10/1/2021	600,000,000	Y	600,000,000	3.038%	3.257%	0.002190	1,314,000
22	5.75% Sr Notes Due 2052	10/3/2022	500,000,000	Y	500,000,000	5.427%	5.759%	0.003320	1,660,000
23	6.20% Sr Notes Due 2053	10/10/2023	500,000,000	Y	500,000,000	6.157%	6.384%	0.002270	1,135,000
24	5.00% Sr. Notes Due 2054	10/1/2024	650,000,000	Y	650,000,000	5.127%	5.358%	0.002310	1,501,500
25	**Total 30 Year Issuances**		**5,810,000,000**		**4,550,000,000**				**13,148,500**
26	Net Total Issuances		8,435,000,000		7,175,000,000				20,998,250
27									
28								% Issued Since Oct. 2013	85%

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

Regulated Electric and Gas Utilities

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This rating methodology replaces "Regulated Electric and Gas Utilities" last revised on December 23, 2013. We have updated some outdated links and removed certain issuer-specific information.

Summary

This rating methodology explains our approach to assessing credit risk for regulated electric and gas utilities globally. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.[1]

This report includes a detailed rating grid which is a reference tool that can be used to approximate credit profiles within the regulated electric and gas utility sector in most cases. The grid provides summarized guidance for the factors that are generally most important in assigning ratings to companies in the regulated electric and gas utility industry. However, the grid is a summary that does not include every rating consideration. The weights shown for each factor in the grid represent an approximation of their importance for rating decisions but actual importance may vary substantially. In addition, the grid in this document uses historical results while ratings are based on our forward-looking expectations. As a result, the grid-indicated rating is not expected to match the actual rating of each company.

THIS RATING METHODOLOGY WAS UPDATED ON SEPTEMBER 27, 2017. WE REMOVED A DUPLICATE FOOTNOTE THAT WAS PLACED IN THE MIDDLE OF THE TEXT ON PAGE 7.

[1] This update may not be effective in some jurisdictions until certain requirements are met.

The grid contains four key factors that are important in our assessment for ratings in the regulated electric and gas utility sector:

1. Regulatory Framework
2. Ability to Recover Costs and Earn Returns
3. Diversification
4. Financial Strength

Some of these factors also encompass a number of sub-factors. There is also a notching factor for holding company structural subordination.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, corporate legal structure, governance and country related risks which are not explained in detail in this document, as well as factors that can be meaningful on a company-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a grid format. The grid used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex grid that might map grid-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe

» A summary of the rating methodology

» A discussion of the key rating factors that drive ratings

» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the grid

The Appendices show the full grid (Appendix A), our approach to ratings within a utility family (Appendix B), a description of the various types of companies rated under this methodology (Appendix C), key industry issues over the intermediate term (Appendix D), regional and other considerations (Appendix E), and treatment of power purchase agreements (Appendix F).

This methodology describes the analytical framework used in determining credit ratings. In some instances our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities. A link to documents that describe our approach to such cross-sector credit rating methodological considerations can be found in the Related Research section of this report.

About the Rated Universe

The Regulated Electric and Gas Utilities rating methodology applies to rate-regulated[2] electric and gas utilities that are not Networks[3]. Regulated Electric and Gas Utilities are companies whose predominant[4][5] business is the sale of electricity and/or gas or related services under a rate-regulated framework, in most cases to retail customers. Also included under this methodology are rate-regulated utilities that own generating assets as any material part of their business, utilities whose charges or bills to customers include a meaningful component related to the electric or gas commodity, utilities whose rates are regulated at a sub-sovereign level (e.g. by provinces, states or municipalities), and companies providing an independent system operator function to an electric grid. Companies rated under this methodology are primarily rate-regulated monopolies or, in certain circumstances, companies that may not be outright monopolies but where government regulation effectively sets prices and limits competition.

This rating methodology covers regulated electric and gas utilities worldwide. These companies are engaged in the production, transmission, coordination, distribution and/or sale of electricity and/or natural gas, and they are either investor owned companies, commercially oriented government owned companies or, in the case of independent system operators, not-for-profit or similar entities. As detailed in Appendix C, this methodology covers a wide variety of companies active in the sector, including vertically integrated utilities, transmission and distribution utilities with retail customers and/or sub-sovereign regulation, local gas distribution utility companies (LDCs), independent system operators, and regulated generation companies. These companies may be operating companies or holding companies.

An over-arching consideration for regulated utilities is the regulatory environment in which they operate. While regulation is also a key consideration for networks, a utility's regulatory environment is in comparison often more dynamic and more subject to political intervention. The direct relationship that a regulated utility has with the retail customer, including billing for electric or gas supply that has substantial price volatility, can lead to a more politically charged rate-setting environment. Similarly, regulation at the sub-sovereign level is often more accessible for participation by interveners, including disaffected customers and the politicians who want their votes. Our views of regulatory environments evolve over time in accordance with our observations of regulatory, political, and judicial events that affect issuers in the sector.

This methodology pertains to regulated electric and gas utilities and excludes the following types of issuers, which are covered by separate rating methodologies: Regulated Networks, Unregulated Utilities and Power Companies, Public Power Utilities, Municipal Joint Action Agencies, Electric Cooperatives, Regulated Water Companies and Natural Gas Pipelines.[5]

The Regulated Electric and Gas Utility sector is predominantly investment grade, reflecting the stability generally conferred by regulation that typically sets prices and also limits competition, such that defaults have been lower than in many other non-financial corporate sectors. However, the nature of regulation can

2 Companies in many industries are regulated. We use the term rate-regulated to distinguish companies whose rates (by which we also mean tariffs or revenues in general) are set by regulators.

3 Regulated Electric and Gas Networks are companies whose predominant business is purely the transmission and/or distribution of electricity and/or natural gas without involvement in the procurement or sale of electricity and/or gas; whose charges to customers thus do not include a meaningful commodity cost component; which sell mainly (or in many cases exclusively) to non-retail customers; and which are rate-regulated under a national framework.

4 We generally consider a company to be predominantly a regulated electric and gas utility when a majority of its cash flows, prospectively and on a sustained basis, are derived from regulated electric and gas utility businesses. Since cash flows can be volatile (such that a company might have a majority of utility cash flows simply due to a cyclical downturn in its non-utility businesses), we may also consider the breakdown of assets and/or debt of a company to determine which business is predominant.

5 A link to credit rating methodologies covering these and other sectors can be found in the Related Research section of this report.

vary significantly from jurisdiction to jurisdiction. Most issuers at the lower end of the ratings spectrum operate in challenging regulatory environments.

About this Rating Methodology

This report explains the rating methodology for regulated electric and gas utilities in six sections, which are summarized as follows:

1. Identification and Discussion of the Rating Factors in the Grid

The grid in this rating methodology focuses on four rating factors. The four factors are comprised of sub-factors that provide further detail:

Factor / Sub-Factor Weighting - Regulated Utilities

Broad Rating Factors	Broad Rating Factor Weighting	Rating Sub-Factor	Sub-Factor Weighting
Regulatory Framework	25%	Legislative and Judicial Underpinnings of the Regulatory Framework	12.5%
		Consistency and Predictability of Regulation	12.5%
Ability to Recover Costs and Earn Returns	25%	Timeliness of Recovery of Operating and Capital Costs	12.5%
		Sufficiency of Rates and Returns	12.5%
Diversification	10%	Market Position	5%*
		Generation and Fuel Diversity	5%**
Financial Strength, Key Financial Metrics	40%		
		CFO pre-WC + Interest/ Interest	7.5%
		CFO pre-WC / Debt	15.0%
		CFO pre-WC – Dividends / Debt	10.0%
		Debt/Capitalization	7.5%
Total	100%		100%
Notching Adjustment			
Holding Company Structural Subordination			0 to -3

*10% weight for issuers that lack generation; **0% weight for issuers that lack generation

2. Measurement or Estimation of Factors in the Grid

We explain our general approach for scoring each grid factor and show the weights used in the grid. We also provide a rationale for why each of these grid components is meaningful as a credit indicator. The information used in assessing the sub-factors is generally found in or calculated from information in company financial statements, derived from other observations or estimated by our analysts.[6] All of the quantitative credit metrics incorporate Moody's standard adjustments to income statement, cash flow statement and balance sheet amounts for restructuring, impairment, off-balance sheet accounts, receivable securitization programs, under-funded pension obligations, and recurring operating leases.[7]

[6] For definitions of our most common ratio terms, please see "Moody's Basic Definitions for Credit Statistics, User's Guide," a link to which may be found in the Related Research section of this report.

[7] Our standard adjustments are described in "Financial Statement Adjustments in the Analysis of Non-Financial Corporations". A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of a company's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) in the rating grid. However, the factors in the grid can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of several years or more, or for individual twelve month periods.

3. Mapping Factors to the Rating Categories

After estimating or calculating each sub-factor, the outcomes for each of the sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, B, or Caa).

4. Assumptions, Limitations and Rating Considerations Not Included in the Grid

This section discusses limitations in the use of the grid to map against actual ratings, some of the additional factors that are not included in the grid but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Grid-Indicated Rating[8]

To determine the overall grid-indicated rating, we convert each of the sub-factor ratings into a numeric value based upon the scale below.

Aaa	Aa	A	Baa	Ba	B	Caa	Ca
1	3	6	9	12	15	18	20

The numerical score for each sub-factor is multiplied by the weight for that sub-factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5

8 In general, the grid-indicated rating is oriented to the Corporate Family Rating (CFR) for speculative-grade issuers and the senior unsecured rating for investment-grade issuers. For issuers that benefit from ratings uplift due to parental support, government ownership or other institutional support, the grid-indicated rating is oriented to the baseline credit assessment. For an explanation of baseline credit assessment, please refer to our rating methodology on government-related issuers. Individual debt instrument ratings also factor in decisions on notching for seniority level and collateral. The documents that provide broad guidance for these notching decisions are our rating methodologies on loss given default for speculative grade non-financial companies and for aligning corporate instrument ratings based on differences in security and priority of claim. The link to these and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Grid-Indicated Rating

Grid-Indicated Rating	Aggregate Weighted Total Factor Score
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 grid-indicated rating.

6. Appendices

The Appendices present a full grid and provide additional commentary and insights on our view of credit risks in this industry.

Discussion of the Grid Factors

Our analysis of electric and gas utilities focuses on four broad factors:

» Regulatory Framework

» Ability to Recover Costs and Earn Returns

» Diversification

» Financial Strength

There is also a notching factor for holding company structural subordination.

Factor 1: Regulatory Framework (25%)

Why It Matters

For rate-regulated utilities, which typically operate as a monopoly, the regulatory environment and how the utility adapts to that environment are the most important credit considerations. The regulatory environment is comprised of two rating factors - the Regulatory Framework and its corollary factor, the Ability to Recover Costs and Earn Returns. Broadly speaking, the Regulatory Framework is the foundation for how all the decisions that affect utilities are made (including the setting of rates), as well as the predictability and consistency of decision-making provided by that foundation. The Ability to Recover Costs and Earn Returns relates more directly to the actual decisions, including their timeliness and the rate-setting outcomes.

Utility rates[9] are set in a political/regulatory process rather than a competitive or free-market process; thus, the Regulatory Framework is a key determinant of the success of utility. The Regulatory Framework has many components: the governing body and the utility legislation or decrees it enacts, the manner in which regulators are appointed or elected, the rules and procedures promulgated by those regulators, the judiciary that interprets the laws and rules and that arbitrates disagreements, and the manner in which the utility manages the political and regulatory process. In many cases, utilities have experienced credit stress or default primarily or at least secondarily because of a break-down or obstacle in the Regulatory Framework – for instance, laws that prohibited regulators from including investments in uncompleted power plants or plants not deemed "used and useful" in rates, or a disagreement about rate-making that could not be resolved until after the utility had defaulted on its debts.

How We Assess Legislative and Judicial Underpinnings of the Regulatory Framework for the Grid

For this sub-factor, we consider the scope, clarity, transparency, supportiveness and granularity of utility legislation, decrees, and rules as they apply to the issuer. We also consider the strength of the regulator's authority over rate-making and other regulatory issues affecting the utility, the effectiveness of the judiciary or other independent body in arbitrating disputes in a disinterested manner, and whether the utility's monopoly has meaningful or growing carve-outs. In addition, we look at how well developed the framework is – both how fully fleshed out the rules and regulations are and how well tested it is – the extent to which regulatory or judicial decisions have created a body of precedent that will help determine future rate-making. Since the focus of our scoring is on each issuer, we consider how effective the utility is in navigating the regulatory framework – both the utility's ability to shape the framework and adapt to it.

A utility operating in a regulatory framework that is characterized by legislation that is credit supportive of utilities and eliminates doubt by prescribing many of the procedures that the regulators will use in determining fair rates (which legislation may show evidence of being responsive to the needs of the utility in general or specific ways), a long history of transparent rate-setting, and a judiciary that has provided ample precedent by impartially adjudicating disagreements in a manner that addresses ambiguities in the laws and rules will receive higher scores in the Legislative and Judicial Underpinnings sub-factor. A utility operating in a regulatory framework that, by statute or practice, allows the regulator to arbitrarily prevent the utility from recovering its costs or earning a reasonable return on prudently incurred investments, or where regulatory decisions may be reversed by politicians seeking to enhance their populist appeal will receive a much lower score.

In general, we view national utility regulation as being less liable to political intervention than regulation by state, provincial or municipal entities, so the very highest scoring in this sub-factor is reserved for this category. However, we acknowledge that states and provinces in some countries may be larger than small nations, such that their regulators may be equally "above-the-fray" in terms of impartial and technically-oriented rate setting, and very high scoring may be appropriate.

[9] In jurisdictions where utility revenues include material government subsidy payments, we consider utility rates to be inclusive of these payments, and we thus evaluate sub-factors 1a, 1b, 2a and 2b in light of both rates and material subsidy payments. For example, we would consider the legal and judicial underpinnings and consistency and predictability of subsidies as well as rates.

The relevant judicial system can be a major factor in the regulatory framework. This is particularly true in litigious societies like the United States, where disagreements between the utility and its state or municipal regulator may eventually be adjudicated in federal district courts or even by the US Supreme Court. In addition, bankruptcy proceedings in the US take place in federal courts, which have at times been able to impose rate settlement agreements on state or municipal regulators. As a result, the range of decisions available to state regulators may be effectively circumscribed by court precedent at the state or federal level, which we generally view as favorable for the credit- supportiveness of the regulatory framework.

Electric and gas utilities are generally presumed to have a strong monopoly that will continue into the foreseeable future, and this expectation has allowed these companies to have greater leverage than companies in other sectors with similar ratings. Thus, the existence of a monopoly in itself is unlikely to be a driver of strong scoring in this sub-factor. On the other hand, a strong challenge to the monopoly could cause lower scoring, because the utility can only recover its costs and investments and service its debt if customers purchase its services. There have some instances of incursions into utilities' monopoly, including municipalization, self-generation, distributed generation with net metering, or unauthorized use (beyond the level for which the utility receives compensation in rates). Incursions that are growing significantly or having a meaningful impact on rates for customers that remain with the utility could have a negative impact on scoring of this sub-factor and on factor 2 - Ability to Recover Costs and Earn Returns.

The scoring of this sub-factor may not be the same for every utility in a particular jurisdiction. We have observed that some utilities appear to have greater sway over the relevant utility legislation and promulgation of rules than other utilities – even those in the same jurisdiction. The content and tone of publicly filed documents and regulatory decisions sometimes indicates that the management team at one utility has better responsiveness to and credibility with its regulators or legislators than the management at another utility.

While the underpinnings to the regulatory framework tend to change relatively slowly, they do evolve, and our factor scoring will seek to reflect that evolution. For instance, a new framework will typically become tested over time as regulatory decisions are issued, or perhaps litigated, thereby setting a body of precedent. Utilities may seek changes to laws in order to permit them to securitize certain costs or collect interim rates, or a jurisdiction in which rates were previously recovered primarily in base rate proceedings may institute riders and trackers. These changes would likely impact scoring of sub-factor 2b - Timeliness of Recovery of Operating and Capital Costs, but they may also be sufficiently significant to indicate a change in the regulatory underpinnings. On the negative side, a judiciary that had formerly been independent may start to issue decisions that indicate it is conforming its decisions to the expectations of an executive branch that wants to mandate lower rates.

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1) within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor-unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

How We Assess Consistency and Predictability of Regulation for the Grid

For the Consistency and Predictability sub-factor, we consider the track record of regulatory decisions in terms of consistency, predictability and supportiveness. We evaluate the utility's interactions in the regulatory process as well as the overall stance of the regulator toward the utility.

In most jurisdictions, the laws and rules seek to make rate-setting a primarily technical process that examines costs the utility incurs and the returns on investments the utility needs to earn so it can make investments that are required to build and maintain the utility infrastructure - power plants, electric transmission and distribution systems, and/or natural gas distribution systems. When the process remains technical and transparent such that regulators can support the financial health of the utility while balancing their public duty to assure that reliable service is provided at a reasonable cost, and when the utility is able to align itself with the policy initiatives of the governing jurisdiction, the utility will receive higher scores in this sub-factor. When the process includes substantial political intervention, which could take the form of legislators or other government officials publically second- guessing regulators, dismissing regulators who have approved unpopular rate increases, or preventing the implementation of rate increases, or when regulators ignore the laws/rules to deliver an outcome that appears more politically motivated, the utility will receive lower scores in this sub-factor.

As with the prior sub-factor, we may score different utilities in the same jurisdiction differently, based on outcomes that are more or less supportive of credit quality over a period of time. We have observed that some utilities are better able to meet the expectations of their customers and regulators, whether through better service, greater reliability, more stable rates or simply more effective regulatory outreach and communication. These utilities typically receive more consistent and credit supportive outcomes, so they will score higher in this sub-factor. Conversely, if a utility has multiple rapid rate increases, chooses to submit major rate increase requests during a sensitive election cycle or a severe economic downturn, has chronic customer service issues, is viewed as frequently providing incomplete information to regulators, or is tone deaf to the priorities of regulators and politicians, it may receive less consistent and supportive outcomes and thus score lower in this sub-factor.

In scoring this sub-factor, we will primarily evaluate the actions of regulators, politicians and jurists rather than their words. Nonetheless, words matter when they are an indication of future action. We seek to differentiate between political rhetoric that is perhaps oriented toward gaining attention for the viewpoint of the speaker and rhetoric that is indicative of future actions and trends in decision- making.

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these conditions to continue.	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to continue.

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for some material decisions.	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2: Ability to Recover Costs and Earn Returns (25%)

Why It Matters

This rating factor examines the ability of a utility to recover its costs and earn a return over a period of time, including during differing market and economic conditions. While the Regulatory Framework looks at the transparency and predictability of the rules that govern the decision-making process with respect to utilities, the Ability to Recover Costs and Earn Returns evaluates the regulatory elements that directly impact the ability of the utility to generate cash flow and service its debt over time. The ability to recover prudently incurred costs on a timely basis and to attract debt and equity capital are crucial credit considerations. The inability to recover costs, for instance if fuel or purchased power costs ballooned during a rate freeze period, has been one of the greatest drivers of financial stress in this sector, as well as the cause of some utility defaults. In a sector that is typically free cash flow negative (due to large capital expenditures and dividends) and that routinely needs to refinance very large maturities of long-term debt, investor concerns about a lack of timely cost recovery or the sufficiency of rates can, in an extreme scenario, strain access to capital markets and potentially lead to insolvency of the utility (as was the case when "used and useful" requirements threatened some utilities that experienced years of delay in completing nuclear power plants in the 1980s). While our scoring for the Ability to Recover Costs and Earn Returns may primarily be influenced by our assessment of the regulatory relationship, it can also be highly impacted by the management and business decisions of the utility.

How We Assess Ability to Recover Costs and Earn Returns

The timeliness and sufficiency of rates are scored as separate sub-factors; however, they are interrelated. Timeliness can have an impact on our view of what constitutes sufficient returns, because a strong assurance of timely cost recovery reduces risk. Conversely, utilities may have a strong assurance that they will earn a full return on certain deferred costs until they are able to collect them, or their generally strong returns may allow them to weather some rate lag on recovery of construction-related capital expenditures. The timeliness of cost recovery is particularly important in a period of rapidly rising costs. During the past five years, utilities have benefitted from low interest rates and generally decreasing fuel costs and purchased power costs, but these market conditions could easily reverse. For example, fuel is a large component of total costs for vertically integrated utilities and for natural gas utilities, and fuel prices are highly volatile, so the timeliness of fuel and purchased power cost recovery is especially important.

While Factors 1 and 2 are closely inter-related, scoring of these factors will not necessarily be the same. We have observed jurisdictions where the Regulatory Framework caused considerable credit concerns – perhaps it was untested or going through a transition to de-regulation, but where the track record of rate case outcomes was quite positive, leading to a higher score in the Ability to Recover Costs and Earn Returns. Conversely, there have been instances of strong Legislative and Judicial Underpinnings of the Regulatory Framework where the commission has ignored the framework (which would affect Consistency and Predictability of Regulation as well as Ability to Recover Costs and Earn Returns) or has used extraordinary measures to prevent or defer an increase that might have been justifiable from a cost perspective but would have caused rate shock.

One might surmise that Factors 2 and 4 should be strongly correlated, since a good Ability to Recover Costs and Earn Returns would normally lead to good financial metrics. However, the scoring for the Ability to Recover Costs and Earn Returns sub-factor places more emphasis on our expectation of timeliness and sufficiency of rates over time; whereas financial metrics may be impacted by one-time events, market conditions or construction cycles - trends that we believe could normalize or even reverse.

How We Assess Timeliness of Recovery of Operating and Capital Costs for the Grid

The criteria we consider include provisions and cost recovery mechanisms for operating costs, mechanisms that allow actual operating and/or capital expenditures to be trued-up periodically into rates without having to file a rate case (this may include formula rates, rider and trackers, or the ability to periodically adjust rates for construction work in progress) as well as the process and timeframe of general tariff/base rate cases – those that are fully reviewed by the regulator, generally in a public format that includes testimony of the utility and other stakeholders and interest groups. We also look at the track record of the utility and regulator for timeliness. For instance, having a formula rate plan is positive, but if the actual process has included reviews that are delayed for long periods, it may dampen the benefit to the utility. In addition, we seek to estimate the lag between the time that a utility incurs a major construction expenditures and the time that the utility will start to recover and/or earn a return on that expenditure.

How We Assess Sufficiency of Rates and Returns for the Grid

The criteria we consider include statutory protections that assure full cost recovery and a reasonable return for the utility on its investments, the regulatory mechanisms used to determine what a reasonable return should be, and the track record of the utility in actually recovering costs and earning returns. We examine outcomes of rate cases/tariff reviews and compare them to the request submitted by the utility, to prior rate cases/tariff reviews for the same utility and to recent rate/tariff decisions for a peer group of comparable utilities. In this context, comparable utilities are typically utilities in the same or similar jurisdiction. In cases where the utility is unique or nearly unique in its jurisdiction, comparison will be made to other peers with an adjustment for local differences, including prevailing rates of interest and returns on capital, as well as the timeliness of rate-setting. We look at regulatory disallowances of costs or investments, with a focus on their financial severity and also on the reasons given by the regulator, in order to assess the likelihood that such disallowances will be repeated in the future.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward-looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward-looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non-refundable interim rates) can be collected, and permit inclusion of important forward-looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.
Ba	**B**	**Caa**	
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.	

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

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Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa	
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.	

Factor 3: Diversification (10%)

Why It Matters

Diversification of overall business operations helps to mitigate the risk that economic cycles, material changes in a single regulatory regime or commodity price movements will have a severe impact on cash flow and credit quality of a utility. While utilities' sales volumes have lower exposure to economic recessions than many non-financial corporate issuers, some sales components, including industrial sales, are directly affected by economic trends that cause lower production and/or plant closures. In addition, economic activity plays a role in the rate of customer growth in the service territory and (absent energy efficiency and conservation) can often impact usage per customer. The economic strength or weakness of the service territory can affect the political and regulatory environment for rate increase requests by the utility. For utilities in areas prone to severe storms and other natural disasters, the utility's geographic diversity or concentration can be a key determinant for creditworthiness.

Diversity among regulatory regimes can mitigate the impact of a single unfavorable decision affecting one part of the utility's footprint.

For utilities with electric generation, fuel source diversity can mitigate the impact (to the utility and to its rate-payers) of changes in commodity prices, hydrology and water flow, and environmental or other regulations affecting plant operations and economics. We have observed that utilities' regulatory environments are most likely to become unfavorable during periods of rapid rate increases (which are more important than absolute rate levels) and that fuel diversity leads to more stable rates over time.

For that reason, fuel diversity can be important even if fuel and purchased power expenses are an automatic pass-through to the utility's ratepayers. Changes in environmental, safety and other regulations have caused vulnerabilities for certain technologies and fuel sources during the past five years. These vulnerabilities have varied widely in different countries and have changed over time.

How We Assess Market Position for the Grid

Market position is comprised primarily of the economic diversity of the utility's service territory and the diversity of its regulatory regimes. We also consider the diversity of utility operations (e.g., regulated electric, gas, water, steam) when there are material operations in more than one area.

Economic diversity is a typically a function of the population, size and breadth of the territory and the businesses that drive its GDP and employment. For the size of the territory, we typically consider the number of customers and the volumes of generation and/or throughput. For breadth, we consider the number of sizeable metropolitan areas served, the economic diversity and vitality in those metropolitan areas, and any concentration in a particular area or industry. In our assessment, we may consider various information sources. For example, in the US, information sources on the diversity and vitality of economies of individual states and metropolitan areas may include Moody's Economy.com. We also look at the mix of the utility's sales volumes among customer types, as well as the track record of volume sales and any notable payment patterns during economic cycles. For diversity of regulatory regimes, we typically look at the number of regulators and the percentages of revenues and utility assets that are under the purview of each. While the highest scores in the Market Position sub-factor are reserved for issuers regulated in multiple jurisdictions, when there is only one regulator, we make a differentiation of regimes perceived as having lower or higher volatility.

Issuers with multiple supportive regulatory jurisdictions, a balanced sales mix among residential, commercial, industrial and governmental customers in a large service territory with a robust and diverse economy will generally score higher in this sub-factor. An issuer with a small service territory economy that has a high dependence on one or two sectors, especially highly cyclical industries, will generally score lower in this sub-factor, as will issuers with meaningful exposure to economic dislocations caused by natural disasters.

For issuers that are vertically integrated utilities having a meaningful amount of generation, this sub- factor has a weighting of 5%. For electric transmission and distribution utilities without meaningful generation and for natural gas local distribution companies, this sub-factor has a weighting of 10%.

How We Assess Generation and Fuel Diversity for the Grid

Criteria include the fuel type of the issuer's generation and important power purchase agreements, the ability of the issuer economically to shift its generation and power purchases when there are changes in fuel prices, the degree to which the utility and its rate-payers are exposed to or insulated from changes in commodity prices, and exposure to Challenged Source and Threatened Sources (see the explanations for how we generally characterize these generation sources in the table below). A regulated utility's capacity mix may not in itself be an indication of fuel diversity or the ability to shift fuels, since utilities may keep old and inefficient plants (e.g., natural gas boilers) to serve peak load. For this reason, we do not incorporate set percentages reflecting an "ideal" or "sub-par" mix for capacity or even generation. In addition to looking at a utility's generation mix to evaluate fuel diversity, we consider the efficiency of the utility's plants, their placement on the regional dispatch curve, and the demonstrated ability/inability of the utility to shift its generation mix in accordance with changing commodity prices.

Issuers having a balanced mix of hydro, coal, natural gas, nuclear and renewable energy as well as low exposure to challenged and threatened sources of generation will score more highly in this sub-factor. Issuers that have concentration in one or two sources of generation, especially if they are threatened or challenged sources, will incur lower scores.

In evaluating an issuer's degree of exposure to challenged and threatened sources, we will consider not only the existence of those plants in the utility's portfolio, but also the relevant factors that will determine the impact on the utility and on its rate-payers. For instance, an issuer that has a fairly high percentage of its generation from challenged sources could be evaluated very differently if its peer utilities face the same magnitude of those issues than if its peers have no exposure to challenged or threatened sources. In evaluating threatened sources, we consider the utility's progress in its plan to replace those sources, its reserve margin, the availability of purchased power capacity in the region, and the overall impact of the replacement plan on the issuer's rates relative to its peer group. Especially if there are no peers in the same jurisdiction, we also examine the extent to which the utility's generation resources plan is aligned with the relevant government's fuel/energy policy.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5.00% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5.00% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definiitons
Market Position	5.00% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.

Generation and Fuel Diversity	5.00% **	Modest diversification in generation and/or fuel sources such that the utility or rate-payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de-activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength (40%)

Why It Matters

Electric and gas utilities are regulated, asset-based businesses characterized by large investments in long-lived property, plant and equipment. Financial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers.

How We Assess It for the Grid

In comparison to companies in other non-financial corporate sectors, the financial statements of regulated electric and gas utilities have certain unique aspects that impact financial analysis, which is further complicated by disparate treatment of certain elements under US Generally Accepted Accounting Principles (GAAP) versus International Financial Reporting Standards (IFRS). Regulatory accounting may permit utilities to defer certain costs (thereby creating regulatory assets) that a non- utility corporate entity would have to expense. For instance, a regulated utility may be able to defer a substantial portion of costs related to recovery from a storm based on the general regulatory framework for those expenses, even if the utility does not have a specific order to collect the expenses from ratepayers over a set period of time. A regulated utility may be able to accrue and defer a return on equity (in addition to capitalizing interest) for construction-work-in-progress for an approved project based on the assumption that it will be able to collect that deferred equity return once the asset comes into service. For this reason, we focus more on a utility's cash flow than on its reported net income.

Conversely, utilities may collect certain costs in rates well ahead of the time they must be paid (for instance, pension costs), thereby creating regulatory liabilities. Many of our metrics focus on Cash Flow from Operations Before Changes in Working Capital (CFO Pre-WC) because, unlike Funds from Operations (FFO), it captures the changes in long-term regulatory assets and liabilities.

However, under IFRS the two measures are essentially the same. In general, we view changes in working capital as less important in utility financial analysis because they are often either seasonal (for example, power demand is generally greatest in the summer) or caused by changes in fuel prices that are typically a relatively automatic pass-through to the customer. We will nonetheless examine the impact of working capital changes in analyzing a utility's liquidity (see Other Rating Considerations– Liquidity).

Given the long-term nature of utility assets and the often lumpy nature of their capital expenditures, it is important to analyze both a utility's historical financial performance as well as its prospective future performance, which may be different from backward-looking measures. Scores under this factor may be higher or lower than what might be expected from historical results, depending on our view of expected future performance. Multi-year periods are usually more representative of credit quality because utilities can experience swings in cash flows from one-time events, including such items as rate refunds, storm cost deferrals that create a regulatory asset, or securitization proceeds that reduce a regulatory asset. Nonetheless, we also look at trends in metrics for individual periods, which may influence our view of future performance and ratings.

For this scoring grid, we have identified four key ratios that we consider the most consistently useful in the analysis of regulated electric and gas utilities. However, no single financial ratio can adequately convey the relative credit strength of these highly diverse companies. Our ratings consider the overall financial strength of a company, and in individual cases other financial indicators may also play an important role.

CFO Pre-Working Capital Plus Interest/Interest or Cash Flow Interest Coverage

The cash flow interest coverage ratio is an indicator for a utility's ability to cover the cost of its borrowed capital. The numerator in the ratio calculation is the sum of CFO Pre-WC and interest expense, and the denominator is interest expense.

CFO Pre-Working Capital / Debt

This important metric is an indicator for the cash generating ability of a utility compared to its total debt. The numerator in the ratio calculation is CFO Pre-WC, and the denominator is total debt.

CFO Pre-Working Capital Minus Dividends / Debt

This ratio is an indicator for financial leverage as well as an indicator of the strength of a utility's cash flow after dividend payments are made. Dividend obligations of utilities are often substantial, quasi- permanent outflows that can affect the ability of a utility to cover its debt obligations, and this ratio can also provide insight into the financial policies of a utility or utility holding company. The higher the level of retained cash flow relative to a utility's debt, the more cash the utility has to support its capital expenditure program. The numerator of this ratio is CFO Pre-WC minus dividends, and the denominator is total debt.

Debt/Capitalization

This ratio is a traditional measure of balance sheet leverage. The numerator is total debt and the denominator is total capitalization. All of our ratios are calculated in accordance with our standard adjustments[10], but we note that our definition of total capitalization includes deferred taxes in addition to total debt, preferred stock, other hybrid securities, and common equity. Since the presence or absence of deferred taxes is a function of national tax policy, comparing utilities using this ratio may be more meaningful among utilities in the same country or in countries with similar tax policies. High debt levels in comparison to capitalization can indicate higher interest obligations, can limit the ability of a utility to raise additional financing if needed, and can lead to leverage covenant violations in bank credit facilities or other financing agreements[11]. A high ratio may result from a regulatory framework that does not permit a robust cushion of equity in the capital structure, or from a material write-off of an asset, which may not have impacted current period cash flows but could affect future period cash flows relative to debt.

There are two sets of thresholds for three of these ratios based on the level of the issuer's business risk – the Standard Grid and the Lower Business Risk (LBR) Grid. In our view, the different types of utility entities covered under this methodology (as described in Appendix E) have different levels of business risk.

Generation utilities and vertically integrated utilities generally have a higher level of business risk because they are engaged in power generation, so we apply the Standard Grid. We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation, including the risk that incurred costs will either not be recovered in rates or recovered with material delays.

Other types of utilities may have lower business risk, such that we believe that they are most appropriately assessed using the LBR Grid, due to factors that could include a generally greater transfer of risk to customers, very strong insulation from exposure to commodity price movements, good protection from volumetric risks, fairly limited capex needs and low exposure to storms, major accidents and natural

10 In certain circumstances, analysts may also apply specific adjustments.

11 We also examine debt/capitalization ratios as defined in applicable covenants (which typically exclude deferred taxes from capitalization) relative to the covenant threshold level.

disasters. For instance, we tend to view many US natural gas local distribution companies (LDCs) and certain US electric transmission and distribution companies (T&Ds, which lack generation but generally retain some procurement responsibilities for customers), as typically having a lower business risk profile than their vertically integrated peers. In cases of T&Ds that we do not view as having materially lower risk than their vertically integrated peers, we will apply the Standard grid. This could result from a regulatory framework that exposes them to energy supply risk, large capital expenditures for required maintenance or upgrades, a heightened degree of exposure to catastrophic storm damage, or increased regulatory scrutiny due to poor reliability, or other considerations. The Standard Grid will also apply to LDCs that in our view do not have materially lower risk; for instance, due to their ownership of high pressure pipes or older systems requiring extensive gas main replacements, where gas commodity costs are not fully recovered in a reasonably contemporaneous manner, or where the LDC is not well insulated from declining volumes.

The four key ratios, their weighting in the grid, and the Standard and LBR scoring thresholds are detailed in the following table.

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.50%		≥ 8.0x	6.0x - 8.0x	4.5x - 6.0x	3.0x - 4.5x	2.0x - 3.0x	1.0x - 2.0x	< 1.0x
CFO pre-WC / Debt	15.00%	Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
CFO pre-WC - Dividends / Debt	10.00%	Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
Debt / Capitalization	7.50%	Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Notching for Structural Subordination of Holding Companies

Why It Matters

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries that are structured as advances, debt, or even hybrid securities.

Most HoldCos present their financial statements on a consolidated basis that blurs legal considerations about priority of creditors based on the legal structure of the family, and grid scoring is thus based on consolidated ratios. However, HoldCo creditors typically have a secondary claim on the group's cash flows and assets after OpCo creditors. We refer to this as structural subordination, because it is the corporate legal structure, rather than specific subordination provisions, that causes creditors at each of the utility and non-utility subsidiaries to have a more direct claim on the cash flows and assets of their respective OpCo obligors. By contrast, the debt of the HoldCo is typically serviced primarily by dividends that are upstreamed by the OpCos[12]. Under normal circumstances, these dividends are made from net income, after payment of the OpCo's interest and preferred dividends. In most non- financial corporate sectors where cash often moves freely between the entities in a single issuer family, this distinction may have less of an impact. However, in the regulated utility sector, barriers to movement of cash among companies in the corporate family can be much more restrictive, depending on the regulatory framework. These barriers can lead to significantly different probabilities of default for HoldCos and OpCos. Structural subordination also affects loss given default. Under most default[1310] scenarios, an OpCo's creditors will be satisfied from the value residing at that OpCo before any of the OpCo's assets can be used to satisfy claims of the HoldCo's creditors. The prevalence of debt issuance at the OpCo level is another reason that structural subordination is usually a more serious concern in the utility sector than for investment grade issuers in other non-financial corporate sectors.

The grids for factors 1-4 are primarily oriented to OpCos (and to some degree for HoldCos with minimal current structural subordination; for example, there is no current structural subordination to debt at the operating company if all of the utility family's debt and preferred stock is issued at the HoldCo level, although there is structural subordination to other liabilities at the OpCo level). The additional risk from structural subordination is addressed via a notching adjustment to bring grid outcomes (on average) closer to the actual ratings of HoldCos.

How We Assess It

Grid-indicated ratings of holding companies may be notched down based on structural subordination. The risk factors and mitigants that impact structural subordination are varied and can be present in different combinations, such that a formulaic approach is not practical and case-by-case analyst judgment of the interaction of all pertinent factors that may increase or decrease its importance to the credit risk of an issuer are essential.

Some of the potentially pertinent factors that could increase the degree and/or impact of structural subordination include the following:

» Regulatory or other barriers to cash movement from OpCos to HoldCo

» Specific ring-fencing provisions

» Strict financial covenants at the OpCo level

» Higher leverage at the OpCo level

» Higher leverage at the HoldCo level[14]

» Significant dividend limitations or potential limitations at an important OpCo

» HoldCo exposure to subsidiaries with high business risk or volatile cash flows

Strained liquidity at the HoldCo level

» The group's investment program is primarily in businesses that are higher risk or new to the group

Some of the potentially mitigating factors that could decrease the degree and/or impact of structural subordination include the following:

[12] The HoldCo and OpCo may also have intercompany agreements, including tax sharing agreements, that can be another source of cash to the HoldCo.

[13] Actual priority in a default scenario will be determined by many factors, including the corporate and bankruptcy laws of the jurisdiction, the asset value of each OpCo, specific financing terms, inter-relationships among members of the family, etc.

[14] While higher leverage at the HoldCo does not increase structural subordination per se, it exacerbates the impact of any structural subordination that exists

- Substantial diversity in cash flows from a variety of utility OpCos
- Meaningful dividends to HoldCo from unlevered utility OpCos
- Dependable, meaningful dividends to HoldCo from non-utility OpCos
- The group's investment program is primarily in strong utility businesses
- Inter-company guarantees - however, in many jurisdictions the value of an upstream guarantee may be limited by certain factors, including by the value that the OpCo received in exchange for granting the guarantee

Notching for structural subordination within the grid may range from 0 to negative 3 notches. Instances of extreme structural subordination are relatively rare, so the grid convention does not accommodate wider differences, although in the instances where we believe it is present, actual ratings do reflect the full impact of structural subordination.

A related issue is the relationship of ratings within a utility family with multiple operating companies, and sometimes intermediate holding companies. Some of the key issues are the same, such as the relative amounts of debt at the holding company level compared to the operating company level (or at one OpCo relative to another), and the degree to which operating companies have credit insulation due to regulation or other protective factors. Appendix B has additional insights on ratings within a utility family.

Rating Methodology Assumptions, Limitations, and Other Rating Considerations

The grid in this rating methodology represents a decision to favor simplicity that enhances transparency and to avoid greater complexity that might enable the grid to map more closely to actual ratings. Accordingly, the four rating factors and the notching factor in the grid do not constitute an exhaustive treatment of all of the considerations that are important for ratings of companies in the regulated electric and gas utility sector. In addition, our ratings incorporate expectations for future performance, while the financial information that is used in the grid in this document is mainly historical. In some cases, our expectations for future performance may be informed by confidential information that we can't disclose. In other cases, we estimate future results based upon past performance, industry trends, competitor actions or other factors. In either case, predicting the future is subject to the risk of substantial inaccuracy.

Assumptions that may cause our forward-looking expectations to be incorrect include unanticipated changes in any of the following factors: the macroeconomic environment and general financial market conditions, industry competition, disruptive technology, regulatory and legal actions.

Key rating assumptions that apply in this sector include our view that sovereign credit risk is strongly correlated with that of other domestic issuers, that legal priority of claim affects average recovery on different classes of debt, sufficiently to generally warrant differences in ratings for different debt classes of the same issuer, and the assumption that lack of access to liquidity is a strong driver of credit risk.

In choosing metrics for this rating methodology grid, we did not explicitly include certain important factors that are common to all companies in any industry such as the quality and experience of management, assessments of corporate governance and the quality of financial reporting and information disclosure. Therefore ranking these factors by rating category in a grid would in some cases suggest too much precision in the relative ranking of particular issuers against all other issuers that are rated in various industry sectors.

Ratings may include additional factors that are difficult to quantify or that have a meaningful effect in differentiating credit quality only in some cases, but not all. Such factors include financial controls, exposure to uncertain licensing regimes and possible government interference in some countries.

Regulatory, litigation, liquidity, technology and reputational risk as well as changes to consumer and business spending patterns, competitor strategies and macroeconomic trends also affect ratings. While these are important considerations, it is not possible precisely to express these in the rating methodology grid without making the grid excessively complex and significantly less transparent.

Ratings may also reflect circumstances in which the weighting of a particular factor will be substantially different from the weighting suggested by the grid.

This variation in weighting rating considerations can also apply to factors that we choose not to represent in the grid. For example, liquidity is a consideration frequently critical to ratings and which may not, in other circumstances, have a substantial impact in discriminating between two issuers with a similar credit profile. As an example of the limitations, ratings can be heavily affected by extremely weak liquidity that magnifies default risk. However, two identical companies might be rated the same if their only differentiating feature is that one has a good liquidity position while the other has an extremely good liquidity position.

Other Rating Considerations

We consider other factors in addition to those discussed in this report, but in most cases understanding the considerations discussed herein should enable a good approximation of our view on the credit quality of companies in the regulated electric and gas utilities sector. Ratings consider our assessment of the quality of management, corporate governance, financial controls, liquidity management, event risk and seasonality. The analysis of these factors remains an integral part of our rating process.

Liquidity and Access to Capital Markets

Liquidity analysis is a key element in the financial analysis of electric and gas utilities, and it encompasses a company's ability to generate cash from internal sources as well as the availability of external sources of financing to supplement these internal sources. Liquidity and access to financing are of particular importance in this sector. Utility assets can often have a very long useful life- 30, 40 or even 60 years is not uncommon, as well as high price tags. Partly as a result of construction cycles, the utility sector has experienced prolonged periods of negative free cash flow – essentially, the sum of its dividends and its capital expenditures for maintenance and growth of its infrastructure frequently exceeds cash from operations, such that a portion of capital expenditures must routinely be debt financed. Utilities are among the largest debt issuers in the corporate universe and typically require consistent access to the capital markets to assure adequate sources of funding and to maintain financial flexibility. Substantial portions of capex are non-discretionary (for example, maintenance, adding customers to the network, or meeting environmental mandates); however, utilities were swift to cut or defer discretionary spending during the 2007-2009 recession. Dividends represent a quasi-permanent outlay, since utilities typically only rarely will cut their dividend. Liquidity is also important to meet maturing obligations, which often occur in large chunks, and to meet collateral calls under any hedging agreements.

Due to the importance of liquidity, incorporating it as a factor with a fixed weighting in the grid would suggest an importance level that is often far different from the actual weight in the rating. In normal circumstances most companies in the sector have good access to liquidity. The industry generally requires, and for the most part has, large, syndicated, multi-year committed credit facilities. In addition, utilities have demonstrated strong access to capital markets, even under difficult conditions. As a result, liquidity generally has not been an issue for most utilities and a utility with very strong liquidity may not warrant a rating distinction compared to a utility with strong liquidity. However, when there is weakness in liquidity or liquidity management, it can be the dominant consideration for ratings.

Our assessment of liquidity for regulated utilities involves an analysis of total sources and uses of cash over the next 12 months or more, as is done for all corporates. Using our financial projections of the utility and our analysis of its available sources of liquidity (including an assessment of the quality and reliability of alternate liquidity such as committed credit facilities), we evaluate how its projected sources of cash (cash from operations, cash on hand and existing committed multi-year credit facilities) compare to its projected uses (including all or most capital expenditures, dividends, maturities of short and long-term debt, our projection of potential liquidity calls on financial hedges, and important issuer-specific items such as special tax payments). We assume no access to capital markets or additional liquidity sources, no renewal of existing credit facilities, and no cut to dividends. We examine a company's liquidity profile under this scenario, its ability to make adjustments to improve its liquidity position, and any dependence on liquidity sources with lower quality and reliability.

Management Quality and Financial Policy

The quality of management is an important factor supporting the credit strength of a regulated utility or utility holding company. Assessing the execution of business plans over time can be helpful in assessing management's business strategies, policies, and philosophies and in evaluating management performance relative to performance of competitors and our projections. A record of consistency provides us with insight into management's likely future performance in stressed situations and can be an indicator of management's tendency to depart significantly from its stated plans and guidelines.

We also assess financial policy (including dividend policy and planned capital expenditures) and how management balances the potentially competing interests of shareholders, fixed income investors and other stakeholders. Dividends and discretionary capital expenditures are the two primary components over which management has the greatest control in the short term. For holding companies, we consider the extent to which management is willing stretch its payout ratio (through aggressive increases or delays in needed decreases) in order to satisfy common shareholders. For a utility that is a subsidiary of a parent company with several utility subsidiaries, dividends to the parent may be more volatile depending on the cash generation and cash needs of that utility, because parents typically want to assure that each utility maintains the regulatory debt/equity ratio on which its rates have been set. The effect we have observed is that utility subsidiaries often pay higher dividends when they have lower capital needs and lower dividends when they have higher capital expenditures or other cash needs. Any dividend policy that cuts into the regulatory debt/equity ratio is a material credit negative.

Size – Natural Disasters, Customer Concentration and Construction Risks

The size and scale of a regulated utility has generally not been a major determinant of its credit strength in the same way that it has been for most other industrial sectors. While size brings certain economies of scale that can somewhat affect the utility's cost structure and competitiveness, rates are more heavily impacted by costs related to fuel and fixed assets. Particularly in the US, we have not observed material differences in the success of utilities' regulatory outreach based on their size. Smaller utilities have sometimes been better able to focus their attention on meeting the expectations of a single regulator than their multi-state peers.

However, size can be a very important factor in our assessment of certain risks that impact ratings, including exposure to natural disasters, customer concentration (primarily to industrial customers in a single sector) and construction risks associated with large projects. While the grid attempts to incorporate the first two of these into Factor 3, for some issuers these considerations may be sufficiently important that the rating reflects a greater weight for these risks. While construction projects always carry the risk of cost over-runs and delays, these risks are materially heightened for projects that are very large relative to the size of the utility.

Interaction of Utility Ratings with Government Policies and Sovereign Ratings

Compared to most industrial sectors, regulated utilities are more likely to be impacted by government actions. Credit impacts can occur directly through rate regulation, and indirectly through energy, environmental and tax policies. Government actions affect fuel prices, the mix of generating plants, the certainty and timing of revenues and costs, and the likelihood that regulated utilities will experience financial stress. While our evolving view of the impact of such policies and the general economic and financial climate is reflected in ratings for each utility, some considerations do not lend themselves to incorporation in a simple ratings grid.[15]

Diversified Operations at the Utility

A small number of regulated utilities have diversified operations that are segments within the utility company, as opposed to the more common practice of housing such operations in one or more separate affiliates. In general, we will seek to evaluate the other businesses that are material in accordance with the appropriate methodology and the rating will reflect considerations from such methodologies. There may be analytical limitations in evaluating the utility and non-utility businesses when segment financial results are not fully broken out and these may be addressed through estimation based on available information. Since regulated utilities are a relatively low risk business compared to other corporate sectors, in most cases diversified non-utility operations increase the business risk profile of a utility. Reflecting this tendency, we note that assigned ratings are typically lower than grid- indicated ratings for such companies.

Event Risk

We also recognize the possibility that an unexpected event could cause a sudden and sharp decline in an issuer's fundamental creditworthiness. Typical special events include mergers and acquisitions, asset sales, spin-offs, capital restructuring programs, litigation and shareholder distributions.

Corporate Governance

Among the areas of focus in corporate governance are audit committee financial expertise, the incentives created by executive compensation packages, related party transactions, interactions with outside auditors, and ownership structure.

Investment and Acquisition Strategy

In our credit assessment we take into consideration management's investment strategy. Investment strategy is benchmarked with that of the other companies in the rated universe to further verify its consistency. Acquisitions can strengthen a company's business. Our assessment of a company's tolerance for acquisitions at a given rating level takes into consideration (1) management's risk appetite, including the likelihood of further acquisitions over the medium term; (2) share buy-back activity; (3) the company's commitment to specific leverage targets; and (4) the volatility of the underlying businesses, as well as that of the business acquired. Ratings can often hold after acquisitions even if leverage temporarily climbs above normally acceptable ranges. However, this depends on (1) the strategic fit; (2) pro-forma capitalization/leverage

15 See also the cross-sector methodology "How Sovereign Credit Quality May Affect Other Ratings." A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

following an acquisition; and (3) our confidence that credit metrics will be restored in a relatively short timeframe.

Financial Controls

We rely on the accuracy of audited financial statements to assign and monitor ratings in this sector. Such accuracy is only possible when companies have sufficient internal controls, including centralized operations, the proper tone at the top and consistency in accounting policies and procedures.

Weaknesses in the overall financial reporting processes, financial statement restatements or delays in regulatory filings can be indications of a potential breakdown in internal controls.

Appendix A: Regulated Electric and Gas Utilities Methodology Factor Grid

Factor 1a: Legislative and Judicial Underpinnings of the Regulatory Framework (12.5%)

Aaa	Aa	A	Baa
Utility regulation occurs under a fully developed framework that is national in scope based on legislation that provides the utility a nearly absolute monopoly (see note 1_ within its service territory, an unquestioned assurance that rates will be set in a manner that will permit the utility to make and recover all necessary investments, an extremely high degree of clarity as to the manner in which utilities will be regulated and prescriptive methods and procedures for setting rates. Existing utility law is comprehensive and supportive such that changes in legislation are not expected to be necessary; or any changes that have occurred have been strongly supportive of utilities credit quality in general and sufficiently forward-looking so as to address problems before they occurred. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility should they occur, including access to national courts, very strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a fully developed national, state or provincial framework based on legislation that provides the utility an extremely strong monopoly (see note 1) within its service territory, a strong assurance, subject to limited review, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a very high degree of clarity as to the manner in which utilities will be regulated and reasonably prescriptive methods and procedures for setting rates. If there have been changes in utility legislation, they have been timely and clearly credit supportive of the issuer in a manner that shows the utility has had a strong voice in the process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur including access to national courts, strong judicial precedent in the interpretation of utility laws, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs under a well developed national, state or provincial framework based on legislation that provides the utility a very strong monopoly (see note 1) within its service territory, an assurance, subject to reasonable prudency requirements, that rates will be set in a manner that will permit the utility to make and recover all necessary investments, a high degree of clarity as to the manner in which utilities will be regulated, and overall guidance for methods and procedures for setting rates. If there have been changes in utility legislation, they have been mostly timely and on the whole credit supportive for the issuer, and the utility has had a clear voice in the legislative process. There is an independent judiciary that can arbitrate disagreements between the regulator and the utility, should they occur, including access to national courts, clear judicial precedent in the interpretation of utility law, and a strong rule of law. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation that provides the utility a strong monopoly within its service territory that may have some exceptions such as greater self-generation (see note 1), a general assurance that, subject to prudency requirements that are mostly reasonable, rates will be set will be set in a manner that will permit the utility to make and recover all necessary investments, reasonable clarity as to the manner in which utilities will be regulated and overall guidance for methods and procedures for setting rates; or (ii) under a new framework where independent and transparent regulation exists in other sectors. If there have been changes in utility legislation, they have been credit supportive or at least balanced for the issuer but potentially less timely, and the utility had a voice in the legislative process. There is either (i) an independent judiciary that can arbitrate disagreements between the regulator and the utility, including access to courts at least at the state or provincial level, reasonably clear judicial precedent in the interpretation of utility laws, and a generally strong rule of law; or (ii) regulation has been applied (under a well developed framework) in a manner such that redress to an independent arbiter has not been required. We expect these conditions to continue.

Ba	B	Caa
Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory that is generally strong but may have a greater level of exceptions (see note 1), and that, subject to prudency requirements which may be stringent, provides a general assurance (with somewhat less certainty) that rates will be set will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where the jurisdiction has a history of less independent and transparent regulation in other sectors. Either: (i) the judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law; or (ii) where there is no independent arbiter, the regulation has mostly been applied in a manner such redress has not been required. We expect these conditions to continue.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility monopoly within its service territory that is reasonably strong but may have important exceptions, and that, subject to prudency requirements which may be stringent or at times arbitrary, provides more limited or less certain assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect less independent and transparent regulation, based either on the regulator's history in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or may not be fully independent of the regulator or other political pressure, but there is a reasonably strong rule of law. Alternately, where there is no independent arbiter, the regulation has been applied in a manner that often requires some redress adding more uncertainty to the regulatory framework. There may be a periodic risk of creditor-unfriendly government intervention in utility markets or rate-setting.	Utility regulation occurs (i) under a national, state, provincial or municipal framework based on legislation or government decree that provides the utility a monopoly within its service territory, but with little assurance that rates will be set in a manner that will permit the utility to make and recover necessary investments; or (ii) under a new framework where we would expect unpredictable or adverse regulation, based either on the jurisdiction's history of in other sectors or other factors. The judiciary that can arbitrate disagreements between the regulator and the utility may not have clear authority or is viewed as not being fully independent of the regulator or other political pressure. Alternately, there may be no redress to an effective independent arbiter. The ability of the utility to enforce its monopoly or prevent uncompensated usage of its system may be limited. There may be a risk of creditor- unfriendly nationalization or other significant intervention in utility markets or rate-setting.

Note 1: The strength of the monopoly refers to the legal, regulatory and practical obstacles for customers in the utility's territory to obtain service from another provider. Examples of a weakening of the monopoly would include the ability of a city or large user to leave the utility system to set up their own system, the extent to which self-generation is permitted (e.g. cogeneration) and/or encouraged (e.g., net metering, DSM generation). At the lower end of the ratings spectrum, the utility's monopoly may be challenged by pervasive theft and unauthorized use. Since utilities are generally presumed to be monopolies, a strong monopoly position in itself is not sufficient for a strong score in this sub-factor, but a weakening of the monopoly can lower the score.

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 1b: Consistency and Predictability of Regulation (12.5%)

Aaa	Aa	A	Baa
The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue.	The issuer's interaction with the regulator has a led to a considerable track record of predominantly predictable and consistent decisions. The regulator is mostly credit supportive of utilities in general and in almost all instances has been highly credit supportive of the issuer. We expect these conditions to continue.	The issuer's interaction with the regulator has led to a track record of largely predictable and consistent decisions. The regulator may be somewhat less credit supportive of utilities in general, but has been quite credit supportive of the issuer in most circumstances. We expect these	The issuer's interaction with the regulator has led to an adequate track record. The regulator is generally consistent and predictable, but there may some evidence of inconsistency or unpredictability from time to time, or decisions may at times be politically charged. However, instances of less credit supportive decisions are based on reasonable application of existing rules and statutes and are not overly punitive. We expect these conditions to

Ba	B	Caa
We expect that regulatory decisions will demonstrate considerable inconsistency or unpredictability or that decisions will be politically charged, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. The regulator may have a history of less credit supportive regulatory decisions with respect to the issuer, but we expect that the issuer will be able to obtain support when it encounters financial stress, with some potentially material delays. The regulator's authority may be eroded at times by legislative or political action. The regulator may not follow the framework for	We expect that regulatory decisions will be largely unpredictable or even somewhat arbitrary, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. However, we expect that the issuer will ultimately be able to obtain support when it encounters financial stress, albeit with material or more extended delays. Alternately, the regulator is untested, lacks a consistent track record, or is undergoing substantial change. The regulator's authority may be eroded on frequent occasions by legislative or political action. The regulator may more frequently ignore the framework in a manner detrimental to the issuer.	We expect that regulatory decisions will be highly unpredictable and frequently adverse, based either on the issuer's track record of interaction with regulators or other governing bodies, or our view that decisions will move in this direction. Alternately, decisions may have credit supportive aspects, but may often be unenforceable. The regulator's authority may have been seriously eroded by legislative or political action. The regulator may consistently ignore the framework to the detriment of the issuer.

Factor 2a: Timeliness of Recovery of Operating and Capital Costs (12.5%)

Aaa	Aa	A	Baa
Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous return on all incremental capital investments, with statutory provisions in place to preclude the possibility of challenges to rate increases or cost recovery mechanisms. By statute and by practice, general rate cases are efficient, focused on an impartial review, quick, and permit inclusion of fully forward -looking costs.	Tariff formulas and automatic cost recovery mechanisms provide full and highly timely recovery of all operating costs and essentially contemporaneous or near-contemporaneous return on most incremental capital investments, with minimal challenges by regulators to companies' cost assumptions. By statute and by practice, general rate cases are efficient, focused on an impartial review, of a very reasonable duration before non-appealable interim rates can be collected, and primarily permit inclusion of forward- looking costs.	Automatic cost recovery mechanisms provide full and reasonably timely recovery of fuel, purchased power and all other highly variable operating expenses. Material capital investments may be made under tariff formulas or other rate-making permitting reasonably contemporaneous returns, or may be submitted under other types of filings that provide recovery of cost of capital with minimal delays. Instances of regulatory challenges that delay rate increases or cost recovery are generally related to large, unexpected increases in sizeable construction projects. By statute or by practice, general rate cases are reasonably efficient, primarily focused on an impartial review, of a reasonable duration before rates (either permanent or non- refundable interim rates) can be collected, and permit inclusion of important forward -looking costs.	Fuel, purchased power and all other highly variable expenses are generally recovered through mechanisms incorporating delays of less than one year, although some rapid increases in costs may be delayed longer where such deferrals do not place financial stress on the utility. Incremental capital investments may be recovered primarily through general rate cases with moderate lag, with some through tariff formulas. Alternately, there may be formula rates that are untested or unclear. Potentially greater tendency for delays due to regulatory intervention, although this will generally be limited to rates related to large capital projects or rapid increases in operating costs.

Ba	B	Caa
There is an expectation that fuel, purchased power or other highly variable expenses will eventually be recovered with delays that will not place material financial stress on the utility, but there may be some evidence of an unwillingness by regulators to make timely rate changes to address volatility in fuel, or purchased power, or other market-sensitive expenses. Recovery of costs related to capital investments may be subject to delays that are somewhat lengthy, but not so pervasive as to be expected to discourage important investments.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to material delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be subject to delays that are material to the issuer, or may be likely to discourage some important investment.	The expectation that fuel, purchased power or other highly variable expenses will be recovered may be subject to extensive delays due to second-guessing of spending decisions by regulators or due to political intervention. Recovery of costs related to capital investments may be uncertain, subject to delays that are extensive, or that may be likely to discourage even necessary investment.

Note: Tariff formulas include formula rate plans as well as trackers and riders related to capital investment.

Factor 2b: Sufficiency of Rates and Returns (12.5%)

Aaa	Aa	A	Baa
Sufficiency of rates to cover costs and attract capital is (and will continue to be) unquestioned.	Rates are (and we expect will continue to be) set at a level that permits full cost recovery and a fair return on all investments, with minimal challenges by regulators to companies' cost assumptions. This will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are strong relative to global peers.	Rates are (and we expect will continue to be) set at a level that generally provides full cost recovery and a fair return on investments, with limited instances of regulatory challenges and disallowances. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally above average relative to global peers, but may at times be average.	Rates are (and we expect will continue to be) set at a level that generally provides full operating cost recovery and a mostly fair return on investments, but there may be somewhat more instances of regulatory challenges and disallowances, although ultimate rate outcomes are sufficient to attract capital without difficulty. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are average relative to global peers, but may at times be somewhat below average.

Ba	B	Caa
Rates are (and we expect will continue to be) set at a level that generally provides recovery of most operating costs but return on investments may be less predictable, and there may be decidedly more instances of regulatory challenges and disallowances, but ultimate rate outcomes are generally sufficient to attract capital. In general, this will translate to returns (measured in relation to equity, total assets, rate base or regulatory asset value, as applicable) that are generally below average relative to global peers, or where allowed returns are average but difficult to earn. Alternately, the tariff formula may not take into account all cost components and/or remuneration of investments may be unclear or at times unfavorable.	We expect rates will be set at a level that at times fails to provide recovery of costs other than cash costs, and regulators may engage in somewhat arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based much more on politics than on prudency reviews. Return on investments may be set at levels that discourage investment. We expect that rate outcomes may be difficult or uncertain, negatively affecting continued access to capital. Alternately, the tariff formula may fail to take into account significant cost components other than cash costs, and/or remuneration of investments may be generally unfavorable.	We expect rates will be set at a level that often fails to provide recovery of material costs, and recovery of cash costs may also be at risk. Regulators may engage in more arbitrary second-guessing of spending decisions or deny rate increases related to funding ongoing operations based primarily on politics. Return on investments may be set at levels that discourage necessary maintenance investment. We expect that rate outcomes may often be punitive or highly uncertain, with a markedly negative impact on access to capital. Alternately, the tariff formula may fail to take into account significant cash cost components, and/or remuneration of investments may be primarily unfavorable.

Factor 3: Diversification (10%)

Weighting 10%	Sub-Factor Weighting	Aaa	Aa	A	Baa
Market Position	5% *	A very high degree of multinational and regional diversity in terms of regulatory regimes and/or service territory economies.	Material operations in three or more nations or substantial geographic regions providing very good diversity of regulatory regimes and/or service territory economies.	Material operations in two to three nations, states, provinces or regions that provide good diversity of regulatory regimes and service territory economies. Alternately, operates within a single regulatory regime with low volatility, and the service territory economy is robust, has a very high degree of diversity and has demonstrated resilience in economic cycles.	May operate under a single regulatory regime viewed as having low volatility, or where multiple regulatory regimes are not viewed as providing much diversity. The service territory economy may have some concentration and cyclicality, but is sufficiently resilient that it can absorb reasonably foreseeable increases in utility rates.
Generation and Fuel Diversity	5% **	A high degree of diversity in terms of generation and/or fuel sources such that the utility and rate-payers are well insulated from commodity price changes, no generation concentration, and very low exposures to Challenged or Threatened Sources (see definitions below).	Very good diversification in terms of generation and/or fuel sources such that the utility and rate-payers are affected only minimally by commodity price changes, little generation concentration, and low exposures to Challenged or Threatened Sources.	Good diversification in terms of generation and/or fuel sources such that the utility and rate-payers have only modest exposure to commodity price changes; however, may have some concentration in a source that is neither Challenged nor Threatened. Exposure to Threatened Sources is low. While there may be some exposure to Challenged Sources, it is not a cause for concern.	Adequate diversification in terms of generation and/or fuel sources such that the utility and rate-payers have moderate exposure to commodity price changes; however, may have some concentration in a source that is Challenged. Exposure to Threatened Sources is moderate, while exposure to Challenged Sources is manageable.

	Sub-Factor Weighting	Ba	B	Caa	Definitions
Market Position	5% *	Operates in a market area with somewhat greater concentration and cyclicality in the service territory economy and/or exposure to storms and other natural disasters, and thus less resilience to absorbing reasonably foreseeable increases in utility rates. May show somewhat greater volatility in the regulatory regime(s).	Operates in a limited market area with material concentration and more severe cyclicality in service territory economy such that cycles are of materially longer duration or reasonably foreseeable increases in utility rates could present a material challenge to the economy. Service territory may have geographic concentration that limits its resilience to storms and other natural disasters, or may be an emerging market. May show decided volatility in the regulatory regime(s).	Operates in a concentrated economic service territory with pronounced concentration, macroeconomic risk factors, and/or exposure to natural disasters.	Challenged Sources are generation plants that face higher but not insurmountable economic hurdles resulting from penalties or taxes on their operation, or from environmental upgrades that are required or likely to be required. Some examples are carbon-emitting plants that incur carbon taxes, plants that must buy emissions credits to operate, and plants that must install environmental equipment to continue to operate, in each where the taxes/credits/upgrades are sufficient to have a material impact on those plants' competitiveness relative to other generation types or on the utility's rates, but where the impact is not so severe as to be likely require plant closure.
Generation and Fuel Diversity	5% **	Modest diversification in generation and/or fuel sources such that the utility or rate- payers have greater exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be more pronounced, but the utility will be able to access alternative sources without undue financial stress.	Operates with little diversification in generation and/or fuel sources such that the utility or rate-payers have high exposure to commodity price changes. Exposure to Challenged and Threatened Sources may be high, and accessing alternate sources may be challenging and cause more financial stress, but ultimately feasible.	Operates with high concentration in generation and/or fuel sources such that the utility or rate-payers have exposure to commodity price shocks. Exposure to Challenged and Threatened Sources may be very high, and accessing alternate sources may be highly uncertain.	Threatened Sources are generation plants that are not currently able to operate due to major unplanned outages or issues with licensing or other regulatory compliance, and plants that are highly likely to be required to de- activate, whether due to the effectiveness of currently existing or expected rules and regulations or due to economic challenges. Some recent examples would include coal fired plants in the US that are not economic to retro-fit to meet mercury and air toxics standards, plants that cannot meet the effective date of those standards, nuclear plants in Japan that have not been licensed to re-start after the Fukushima Dai-ichi accident, and nuclear plants that are required to be phased out within 10 years (as is the case in some European countries).

* 10% weight for issuers that lack generation **0% weight for issuers that lack generation

Factor 4: Financial Strength

Weighting 40%	Sub-Factor Weighting		Aaa	Aa	A	Baa	Ba	B	Caa
CFO pre-WC + Interest / Interest	7.5%		≥ 8x	6x - 8x	4.5x - 6x	3x - 4.5x	2x - 3x	1x - 2x	< 1x
		Standard Grid	≥ 40%	30% - 40%	22% - 30%	13% - 22%	5% - 13%	1% - 5%	< 1%
CFO pre-WC / Debt	15%								
		Low Business Risk Grid	≥ 38%	27% - 38%	19% - 27%	11% - 19%	5% - 11%	1% - 5%	< 1%
		Standard Grid	≥ 35%	25% - 35%	17% - 25%	9% - 17%	0% - 9%	(5%) - 0%	< (5%)
CFO pre-WC - Dividends / Debt	10%								
		Low Business Risk Grid	≥ 34%	23% - 34%	15% - 23%	7% - 15%	0% - 7%	(5%) - 0%	< (5%)
		Standard Grid	< 25%	25% - 35%	35% - 45%	45% - 55%	55% - 65%	65% - 75%	≥ 75%
Debt / Capitalization	7.5%								
		Low Business Risk Grid	< 29%	29% - 40%	40% - 50%	50% - 59%	59% - 67%	67% - 75%	≥ 75%

Appendix B: Approach to Ratings within a Utility Family

Typical Composition of a Utility Family

A typical utility company structure consists of a holding company ("HoldCo") that owns one or more operating subsidiaries (each an "OpCo"). OpCos may be regulated utilities or non-utility companies. Financing of these entities varies by region, in part due to the regulatory framework. A HoldCo typically has no operations – its assets are mostly limited to its equity interests in subsidiaries, and potentially other investments in subsidiaries or minority interests in other companies. However, in certain cases there may be material operations at the HoldCo level. Financing can occur primarily at the OpCo level, primarily at the HoldCo level, or at both HoldCo and OpCos in varying proportions. When a HoldCo has multiple utility OpCos, they will often be located in different regulatory jurisdictions. A HoldCo may have both levered and unlevered OpCos.

General Approach to a Utility Family

In our analysis, we generally consider the stand-alone credit profile of an OpCo and the credit profile of its ultimate parent HoldCo (and any intermediate HoldCos), as well as the profile of the family as a whole, while acknowledging that these elements can have cross-family credit implications in varying degrees, principally based on the regulatory framework of the OpCos and the financing model (which has often developed in response to the regulatory framework).

In addition to considering individual OpCos under this (or another applicable) methodology, we typically[1614] approach a HoldCo rating by assessing the qualitative and quantitative factors in this methodology for the consolidated entity and each of its utility subsidiaries. Ratings of individual entities in the issuer family may be pulled up or down based on the interrelationships among the companies in the family and their relative credit strength.

In considering how closely aligned or how differentiated ratings should be among members of a utility family, we assess a variety of factors, including:

» Regulatory or other barriers to cash movement among OpCos and from OpCos to HoldCo

» Differentiation of the regulatory frameworks of the various OpCos

» Specific ring-fencing provisions at particular OpCos

» Financing arrangements – for instance, each OpCo may have its own financing arrangements, or the sole liquidity facility may be at the parent; there may be a liquidity pool among certain but not all members of the family; certain members of the family may better be able to withstand a temporary hiatus of external liquidity or access to capital markets

» Financial covenants and the extent to which an Event of Default by one OpCo limits availability of liquidity to another member of the family

» The extent to which higher leverage at one entity increases default risk for other members of the family

» An entity's exposure to or insulation from an affiliate with high business risk

» Structural features or other limitations in financing agreements that restrict movements of funds, investments, provision of guarantees or collateral, etc.

[16] See paragraph at the end of this section for approaches to Hybrid HoldCos.

» The relative size and financial significance of any particular OpCo to the HoldCo and the family

See also those factors noted in Notching for Structural Subordination of Holding Companies.

Our approach to a Hybrid HoldCo (see definition in Appendix C) depends in part on the importance of its non-utility operations and the availability of information on individual businesses. If the businesses are material and their individual results are fully broken out in financial disclosures, we may be able to assess each material business individually by reference to the relevant Moody's methodologies to arrive at a composite assessment for the combined businesses. If non-utility operations are material but are not broken out in financial disclosures, we may look at the consolidated entity under more than one methodology. When non-utility operations are less material but could still impact the overall credit profile, the difference in business risks and our estimation of their impact on financial performance will be qualitatively incorporated in the rating.

Higher Barriers to Cash Movement with Financing Predominantly at the OpCos

Where higher barriers to cash movement exist on an OpCo or OpCos due the regulatory framework or debt structural features, ratings among family members are likely to be more differentiated. For instance, for utility families with OpCos in the US, where regulatory barriers to free cash movement are relatively high, greater importance is generally placed on the stand-alone credit profile of the OpCo.

Our observation of major defaults and bankruptcies in the US sector generally corroborates a view that regulation creates a degree of separateness of default probability. For instance, Portland General Electric (Baa1 RUR-up) did not default on its securities, even though its then-parent Enron Corp. entered bankruptcy proceedings. When Entergy New Orleans (Ba2 stable) entered into bankruptcy, the ratings of its affiliates and parent Entergy Corporation (Baa3 stable) were unaffected. PG&E Corporation (Baa1 stable) did not enter bankruptcy proceedings despite bankruptcies of two major subsidiaries - Pacific Gas & Electric Company (A3 stable) in 2001 and National Energy Group in 2003.

The degree of separateness may be greater or smaller and is assessed on a case by case basis, because situational considerations are important. One area we consider is financing arrangements. For instance, there will tend to be greater differentiation if each member of a family has its own bank credit facilities and difficulties experienced by one entity would not trigger events of default for other entities. While the existence of a money pool might appear to reduce separateness between the participants, there may be regulatory barriers within money pools that preserve separateness. For instance, non-utility entities may have access to the pool only as a borrower, only as a lender, and even the utility entities may have regulatory limits on their borrowings from the pool or their credit exposures to other pool members. If the only source of external liquidity for a money pool is borrowings by the HoldCo under its bank credit facilities, there would be less separateness, especially if the utilities were expected to depend on that liquidity source. However, the ability of an OpCo to finance itself by accessing capital markets must also be considered. Inter-company tax agreements can also have an impact on our view of how separate the risks of default are.

For a HoldCo, the greater the regulatory, economic, and geographic diversity of its OpCos, the greater its potential separation from the default probability of any individual subsidiary. Conversely, if a HoldCo's actions have made it clear that the HoldCo will provide support for an OpCo encountering some financial stress (for instance, due to delays and/or cost over-runs on a major construction project), we would be likely to perceive less separateness.

Even where high barriers to cash movement exist, onerous leverage at a parent company may not only give rise to greater notching for structural subordination at the parent, it may also pressure an OpCo's rating, especially when there is a clear dependence on an OpCo's cash flow to service parent debt.

While most of the regulatory barriers to cash movement are very real, they are not absolute. Furthermore, while it is not usually in the interest of an insolvent parent or its creditors to bring an operating utility into a bankruptcy proceeding, such an occurrence is not impossible.

The greatest separateness occurs where strong regulatory insulation is supplemented by effective ring-fencing provisions that fully separate the management and operations of the OpCo from the rest of the family and limit the parent's ability to cause the OpCo to commence bankruptcy proceedings as well as limiting dividends and cash transfers. Typically, most entities in US utility families (including HoldCos and OpCos) are rated within 3 notches of each other. However, it is possible for the HoldCo and OpCos in a family to have much wider notching due to the combination of regulatory imperatives and strong ring-fencing that includes a significant minority shareholder who must agree to important corporate decisions, including a voluntary bankruptcy filing.

Lower Barriers to Cash Movement with Financing Predominantly at the OpCos

Our approach to rating issuers within a family where there are lower regulatory barriers to movement of cash from OpCos to HoldCos (e.g., many parts of Asia and Europe) places greater emphasis on the credit profile of the consolidated group. Individual OpCos are considered based on their individual characteristics and their importance to the family, and their assigned ratings are typically banded closely around the consolidated credit profile of the group due to the expectation that cash will transit relatively freely among family entities.

Some utilities may have OpCos in jurisdictions where cash movement among certain family members is more restricted by the regulatory framework, while cash movement from and/or among OpCos in other jurisdictions is less restricted. In these situations, OpCos with more restrictions may vary more widely from the consolidated credit profile while those with fewer restrictions may be more tightly banded around the other entities in the corporate family group.

Appendix C: Brief Descriptions of the Types of Companies Rated Under This Methodology

The following describes the principal categories of companies rated under this methodology:

Vertically Integrated Utility: Vertically integrated utilities are regulated electric or combination utilities (see below) that own generation, distribution and (in most cases) electric transmission assets. Vertically integrated utilities are generally engaged in all aspects of the electricity business. They build power plants, procure fuel, generate power, build and maintain the electric grid that delivers power from a group of power plants to end-users (including high and low voltage lines, transformers and substations), and generally meet all of the electric needs of the customers in a specific geographic area (also called a service territory). The rates or tariffs for all of these monopolistic activities are set by the relevant regulatory authority.

Transmission & Distribution Utility: Transmission & Distribution utilities (T&Ds) typically operate in deregulated markets where generation is provided under a competitive framework. T&Ds own and operate the electric grid that transmits and/or distributes electricity within a specific state or region.

T&Ds provide electrical transportation and distribution services to carry electricity from power plants and transmission lines to retail, commercial, and industrial customers. T&Ds are typically responsible for billing customers for electric delivery and/or supply, and most have an obligation to provide a standard supply or provider-of-last-resort (POLR) service to customers that have not switched to a competitive supplier. These factors distinguish T&Ds from Networks, whose customers are retail electric suppliers and/or other electricity companies. In a smaller number of cases, T&Ds rated under this methodology may not have an obligation to provide POLR services, but are regulated in sub- sovereign jurisdictions. The rates or tariffs for these monopolistic T&D activities are set by the relevant regulatory authority.

Local Gas Distribution Company: Distribution is the final step in delivering natural gas to customers. While some large industrial, commercial, and electric generation customers receive natural gas directly from high capacity pipelines that carry gas from gas producing basins to areas where gas is consumed, most other users receive natural gas from their local gas utility, also called a local distribution company (LDC). LDCs are regulated utilities involved in the delivery of natural gas to consumers within a specific geographic area. Specifically, LDCs typically transport natural gas from delivery points located on large-diameter pipelines (that usually operate at fairly high pressure) to households and businesses through thousands of miles of small-diameter distribution pipe (that usually operate at fairly low pressure). LDCs are typically responsible for billing customers for gas delivery and/or supply, and most also have the responsibility to procure gas for at least some of their customers, although in some markets gas supply to all customers is on a competitive basis. These factors distinguish LDCs from gas networks, whose customers are retail gas suppliers and/or other natural gas companies. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Integrated Gas Utility: Integrated gas regulated utilities are regulated utilities that deliver gas to all end users in a particular service territory by sourcing the commodity; operating transport infrastructure that often combines high pressure pipelines with low pressure distribution systems and, in some cases, gas storage, re-gasification or other related facilities; and performing other supply-related activities, such as customer billing and metering. The rates or tariffs for the totality of these activities are set by the relevant regulatory authority. Many integrated gas utilities are national in scope.

Combination Utility: Combination utilities are those that combine an LDC or Integrated Gas Utility with either a vertically integrated utility or a T&D utility. The rates or tariffs for these monopolistic activities are set by the relevant regulatory authority.

Regulated Generation Utility: Regulated generation utilities (Regulated Gencos) are utilities that almost exclusively have generation assets, but their activities are generally regulated like those of vertically integrated utilities. In the US, this means that the purchasers of their output (typically other investor-owned, municipal or cooperative utilities) pay a regulated rate based on the total allowed costs of the Regulated Genco, including a return on equity based on a capital structure designated by the regulator (primarily FERC). Companies that have been included in this group include certain generation companies (including in Korea and China) that are not rate regulated in the usual sense of recovering costs plus a regulated rate of return on either equity or asset value. Instead, we have looked at a combination of governmental action with respect to setting feed-in tariffs and directives on how much generation will be built (or not built) in combination with a generally high degree of government ownership, and we have concluded that these companies are currently best rated under this methodology. Future evolution in our view of the operating and/or regulatory environment of these companies could lead us to conclude that they may be more appropriately rated under a related methodology (for example, Unregulated Utilities and Power Companies).

Independent System Operator: An Independent System Operator (ISO) is an organization formed in certain regional electricity markets to act as the sole chief coordinator of an electric grid. In the areas where an ISO is established, it coordinates, controls and monitors the operation of the electrical power system to assure that electric supply and demand are balanced at all times, and, to the extent possible, that electric demand is met with the lowest-cost sources. ISOs seek to assure adequate transmission and generation resources, usually by identifying new transmission needs and planning for a generation reserve margin above expected peak demand. In regions where generation is competitive, they also seek to establish rules that foster a fair and open marketplace, and they may conduct price-setting auctions for energy and/or capacity. The generation resources that an ISO coordinates may belong to vertically integrated utilities or to independent power producers. ISOs may not be rate-regulated in the traditional sense, but fall under governmental oversight. All participants in the regional grid are required to pay a fee or tariff (often volumetric) to the ISO that is designed to recover its costs, including costs of investment in systems and equipment needed to fulfill their function. ISOs may be for profit or not-for-profit entities.

In the US, most ISOs were formed at the direction or recommendation of the Federal Energy Regulatory Commission (FERC), but the ISO that operates solely in Texas falls under state jurisdiction. Some US ISOs also perform certain additional functions such that they are designated as Regional Transmission Organizations (or RTOs).

Transmission-Only Utility: Transmission-only utilities are solely focused on owning and operating transmission assets. The transmission lines these utilities own are typically high-voltage and allow energy producers to transport electric power over long distances from where it is generated (or received) to the transmission or distribution system of a T&D or vertically integrated utility. Unlike most of the other utilities rated under this methodology, transmission-only utilities primarily provide services to other utilities and ISOs. Transmission-only utilities in most parts of the world other than the US have been rated under the Regulated Networks methodology.

Utility Holding Company (Utility HoldCo): As detailed in Appendix B, regulated electric and gas utilities are often part of corporate families under a parent holding company. The operating subsidiaries of Utility Holdcos are overwhelmingly regulated electric and gas utilities.

Hybrid Holding Company (Hybrid HoldCo): Some utility families contain a mix of regulated electric and gas utilities and other types of companies, but the regulated electric and gas utilities represent the majority of the consolidated cash flows, assets and debt. The parent company is thus a Hybrid HoldCo.

Appendix D: Key Industry Issues Over the Intermediate Term

Political and Regulatory Issues

As highly regulated monopolistic entities, regulated utilities continually face political and regulatory risk, and managing these risks through effective outreach to key customers as well as key political and regulatory decision-makers is, or at least should be, a core competency of companies in this sector. However, largerwaves of change in the political, regulatory or economic environment have the potential to cause substantial changes in the level of risk experienced by utilities and their investors in somewhat unpredictable ways.

One of the more universal risks faced by utilities currently is the compression of allowed returns. A longperiod of globally low interest rates, held down by monetary stimulus policies, has generally benefittedutilities, since reductions in allowed returns have been slower than reductions in incurred capital costs.Essentially all regulated utilities face a ratcheting down of allowed and/or earned returns. More difficult topredict is how regulators will respond when monetary stimulus reverses, and how well utilities will farewhen fixed income investors require higher interest rates and equity investors require higher total returnsand growth prospects.

The following global snapshot highlights that regulatory frameworks evolve over time. On an overall basis in the US over the past several years, we have noted some incremental positive regulatory trends, including greater use of formula rates, trackers and riders, and (primarily for natural gas utilities) de-coupling of returns from volumetric sales. In Canada, the framework has historically been viewed as predictable and stable, which has helped offset somewhat lower levels of equity in the capital structure, but the compressionof returns has been relatively steep in recent years. In Japan, the regulatory authorities are working throughthe challenges presented by the decision to shut down virtually all of the country's nuclear generationcapacity, leading to uncertainty regarding the extent to which increased costs will be reflected in rate increases sufficient to permit returns on capital to return to prior levels. China's regulatory framework has continued to evolve, with fairly low transparency and some time-to-time shifts in favored versus less-favoredgeneration sources balanced by an overall state policy of assuring sustainability of the sector, adequate supply of electricity and affordability to the general public. Singapore and Hong Kong have fairly well developed and supportive regulatory frameworks despite a trend towards lower returns, whereas Malaysia, Korea andThailand have been moving towards a more transparent regulatory framework. The Philippines is in theprocess of deregulating its power market, while Indian power utilities continue to grapple with structuralchallenges. In Latin America, there is a wide dispersion among frameworks, ranging from the more stable,long established and predictable framework in Chile to the decidedly unpredictable framework in Argentina. Generally, as Latin American economies have evolved to more stable economic policies, regulatory frameworks for utilities have also shown greater stability and predictability.

All of the other issues discussed in this section have a regulatory/political component, either as the driver of change or in reaction to changes in economic environments and market factors.

Economic and Financial Market Conditions

As regulated monopolies, electric and gas utilities have generally been quite resistant to unsettled economic and financial market conditions for several reasons. Unlike many companies that face direct market-based competition, their rates do not decrease when demand decreases. The elasticity of demand for electricity and gas is much lower than for most products in the consumer economy.

When financial markets are volatile, utilities often have greater capital market access than industrial companies in competitive sectors, as was the case in the 2007-2009 recession. However, regulated electric and gas utilities are by no means immune to a protracted or severe recession.

Severe economic malaise can negatively affect utility credit profiles in several ways. Falling demand for electricity or natural gas may negatively impact margins and debt service protection measures, especially when rates are designed such that a substantial portion of fixed costs is in theory recovered through volumetric charges. The decrease in demand in the 2007-2009 recession was notable in comparison to prior recessions, especially in the residential sector. Poor economic conditions can make it more difficult for regulators to approve needed rate increases or provide timely cost recovery for utilities, resulting in higher cost deferrals and longer regulatory lag. Finally, recessions can coincide with a lack of confidence in the utility sector that impacts access to capital markets for a period of time. For instance, in the Great Depression and (to a lesser extent) in the 2001 recession, access for some issuers was curtailed due to the sector's generally higher leverage than other corporate sectors, combined with a concerns over a lack of transparency in financial reporting.

Fuel Price Volatility and the Global Impact of Shale Gas

The ability of most utilities to pass through their fuel costs to end users may insulate a utility from exposure to price volatility of these fuels, but it does not insulate consumers. Consumers and regulators complained vociferously about utility rates during the run-up in hydro-carbon prices in 2005-2008 (oil, natural gas and, to a lesser extent, coal). The steep decline in US natural gas prices since 2009, caused in large part by the development of shale gas and shale oil resources, has been a material benefit to US utilities, because many have been able to pass through substantial base rate increases during a period when all-in rates were declining. Shale hydro-carbons have also had a positive impact, albeit one that is less immediate and direct, on non-US utilities. In much of the eastern hemisphere, natural gas prices under long-term contracts have generally been tied to oil prices, but utilities and other industrial users have started to have some success in negotiating to de-link natural gas from oil. In addition, increasing US production of oil has had a noticeable impact on world oil prices, generally benefitting oil and gas users.

Not all utilities will benefit equally. Utilities that have locked in natural gas under high-priced long- term contracts that they cannot re-negotiate are negatively impacted if they cannot pass through their full contracted cost of gas, or if the high costs cause customer dissatisfaction and regulatory backlash. Utilities with large coal fleets or utilities constructing nuclear power plants may also face negative impacts on their regulatory environment, since their customers will benefit less from lower natural gas prices.

Distributed Generation Versus the Central Station Paradigm

The regulation and the financing of electric utilities are based on the premise that the current model under which electricity is generated and distributed to customers will continue essentially unchanged for many decades to come. This model, called the central station paradigm (because electricity is generated in large, centrally located plants and distributed to a large number of customers, who may in fact be hundreds of miles away), has been in place since the early part of the 20th century. The model has worked because the economies of scale inherent to very large power plants has more than offset the cost and inefficiency (through power losses) inherent to maintaining a grid for transmitting and distributing electricity to end users.

Despite rate structures that only allow recovery of invested capital over many decades (up to 60 years), utilities can attract capital because investors assume that rates will continue to be collected for at least that long a period. Regulators and politicians assume that taxes and regulatory charges levied on electricity usage will be paid by a broad swath of residences and businesses and will not materially discourage usage of electricity in a way that would decrease the amount of taxes collected. A corollary assumption is that the number of customers taking electricity from the system during that period will continue to be high enough such that rates will be reasonable and generally more attractive than other alternatives. In the event that consumers were to switch en masse to alternate sources of generating or receiving power (for instance distributed generation), rates for remaining customers would either not cover the utility's costs, or rates would need to be increased so much that more customers may be incentivized to leave the system. This scenario has been experienced in the regulated US copper wire telephone business, where rates have increased quite dramatically for users who have not switched to digital or wireless telephone service. While this scenario continues to be unlikely for the electricity sector, distributed generation, especially from solar panels, has made inroads in certain regions.

Distributed generation is any retail-scale generation, differentiated from self-generation, which generally describes a large industrial plant that builds its own reasonably large conventional power plant to meet its own needs. While some residential property owners that install distributed generation may choose to sever their connection to the local utility, most choose to remain connected, generating power into the grid when it is both feasible and economic to do so, and taking power from the grid at other times. Distributed generation is currently concentrated in roof-top photovoltaic solar panels, which have benefitted from varying levels of tax incentives in different jurisdictions.

Regulatory treatment has also varied, but some rate structures that seek to incentivize distributed renewable energy are decidedly credit negative for utilities, in particular net metering.

Under net metering, a customer receives a credit from the utility for all of its generation at the full (or nearly full) retail rate and pays only for power taken, also at the retail rate, resulting in a materially reduced monthly bill relative to a customer with no distributed generation. The distributed generation customer has no obligation to generate any particular amount of power, so the utility must stand ready to generate and deliver that customer's full power needs at all times. Since most utility costs, including the fixed costs of financing and maintaining generation and delivery systems, are currently collected through volumetric rates, a customer owning distributed generation effectively transfers a portion of the utility's costs of serving that customer to other customers with higher net usage, notably to customers that do not own distributed generation. The higher costs may incentivize more customers to install solar panels, thereby shifting the utility's fixed costs to an even smaller group of rate-payers. California is an example of a state employing net solar metering in its rate structure, whereas in New Jersey, which has the second largest residential solar program in the US, utilities buy power at a price closer to their blended cost of generation, which is much lower than the retail rate.

To date, solar generation and net metering have not had a material credit impact on any utilities, but ratings could be negatively impacted if the programs were to grow and if rate structures were not amended so that each customer's monthly bill more closely approximated the cost of serving that customer.

In our current view, the possibility that there will be a widespread movement of electric utility customers to sever themselves from the grid is remote. However, we acknowledge that new technologies, such as the development of commercially viable fuel cells and/or distributed electric storage, could disrupt materially the central station paradigm and the credit quality of the utility sector.

Nuclear Issues

Utilities with nuclear generation face unique safety, regulatory, and operational issues. The nuclear disaster at Fukushima Daiichi had a severely negative credit impact on its owner, Tokyo Electric Power Company, Incorporated, as well as all the nuclear utilities in the country. Japan previously generated about 30% of its power from 50 reactors, but all are currently either idled or shut down, and utilities in the country face materially higher costs of replacement power, a credit negative.

Fukushima Daiichi also had global consequences. Germany's response was to require that all nuclear power plants in the country be shut by 2022. Switzerland opted for a phase-out by 2031. (Most European nuclear plants are owned by companies rated under other the Unregulated Utilities and Power Companies methodology.) Even in countries where the regulatory response was more moderate, increased regulatory scrutiny has raised operating costs, a credit negative, especially in the US, where low natural gas prices have rendered certain primarily smaller nuclear plants uneconomic. Nonetheless, we view robust and independent nuclear safety regulation as a credit-positive for the industry.

Other general issues for nuclear operators include higher costs and lower reliability related to the increasing age of the fleet. In 2013, Duke Energy Florida, Inc. decided to shut permanently Crystal River Unit 3 after it determined that a de-lamination (or separation) in the concrete of the outer wall of the containment building was uneconomic to repair. San Onofre Nuclear Generating Station was closed permanently in 2013 after its owners, including Southern California Edison Company (A3, RUR-up) and San Diego Gas & Electric Company (A2, RUR-up), decided not to pursue a re-start in light of operating defects in two steam generators that had been replaced in 2010 and 2011.

Korea Hydro and Nuclear Power Company Limited and its parent, Korea Electric Power Corporation, faced a scandal related to alleged corruption and acceptance of falsified safety documents provided by its parts suppliers for nuclear plants. Korean prosecutors' widening probe into KHNP's use of substandard parts at many of its 23 nuclear power plants caused three plants to be shut down temporarily.

Appendix E: Regional and Other Considerations

Notching Considerations for US First Mortgage Bonds

In most regions, our approach to notching between different debt classes of the same regulated utility issuer follows the guidance in the publication "Updated Summary Guidance for Notching Bonds, Preferred Stocks and Hybrid Securities of Corporate Issuers," including a one notch differential between senior secured and senior unsecured debt.[17] However, in most cases we have two notches between the first mortgage bonds and senior unsecured debt of regulated electric and gas utilities in the US.

Wider notching differentials between debt classes may also be appropriate in speculative grade. Additional insights for speculative grade issuers are provided in the publication "Loss Given Default for Speculative-Grade Companies."[18]

First mortgage bond holders in the US generally benefit from a first lien on most of the fixed assets used to provide utility service, including such assets as generating stations, transmission lines, distribution lines, switching stations and substations, and gas distribution facilities, as well as a lien on franchise agreements. In our view, the critical nature of these assets to the issuers and to the communities they serve has been a major factor that has led to very high recovery rates for this class of debt in situations of default, thereby justifying a two notch uplift. The combination of the breadth of assets pledged and the bankruptcy-tested recovery experience has been unique to the US.

In some cases, there is only a one notch differential between US first mortgage bonds and the senior unsecured rating. For instance, this is likely when the pledged property is not considered critical infrastructure for the region, or if the mortgage is materially weakened by carve-outs, lien releases or similar creditor-unfriendly terms.

Securitization

The use of securitization, a financing technique utilizing a discrete revenue stream (typically related to recovery of specifically defined expenses) that is dedicated to servicing specific securitization debt, has primarily been used in the US, where it has been quite pervasive in the past two decades. The first generation of securitization bonds were primarily related to recovery of the negative difference between the market value of utilities' generation assets and their book value when certain states switched to competitive electric supply markets and utilities sold their generation (so-called stranded costs). This technique was then used for significant storm costs (especially hurricanes) and was eventually broadened to include environmental related expenditures, deferred fuel costs, or even deferred miscellaneous expenses. States that have implemented securitization frameworks include Arkansas, California, Connecticut, Illinois, Louisiana, Maryland, Massachusetts, Mississippi, New Hampshire, New Jersey, Ohio, Pennsylvania, Texas and West Virginia. In its simplest form, a securitization isolates and dedicates a stream of cash flow into a separate special purpose entity (SPE). The SPE uses that stream of revenue and cash flow to provide annual debt service for the securitized debt instrument. Securitization is typically underpinned by specific legislation to segregate the securitization revenues from the utility's revenues to assure their continued collection, and the details of the enabling legislation may vary from state to state. The utility benefits from the securitization because it receives an immediate source of cash (although it gives up the opportunity to earn a return on the corresponding asset), and ratepayers benefit because the cost of the

[17] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.
[18] A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report,

securitized debt is lower than the utility's cost of debt and much lower than its all-in cost of capital, which reduces the revenue requirement associated with the cost recovery.

In the presentation of US securitization debt in published financial ratios, we make our own assessment of the appropriate credit representation but in most cases follows the accounting in audited statements under US Generally Accepted Accounting Principles (GAAP), which in turn considers the terms of enabling legislation. As a result, accounting treatment may vary. In most states utilities have been required to consolidate securitization debt under GAAP, even though it is technically non- recourse.

In general, we view securitization debt of utilities as being on-credit debt, in part because the rates associated with it reduce the utility's headroom to increase rates for other purposes while keeping all-in rates affordable to customers. Thus, where accounting treatment is off balance sheet, we seek to adjust the company's ratios by including the securitization debt and related revenues for our analysis. Where the securitized debt is on balance sheet, our credit analysis also considers the significance of ratios that exclude securitization debt and related revenues. Since securitization debt amortizes mortgage-style, including it makes ratios look worse in early years (when most of the revenue collected goes to pay interest) and better in later years (when most of the revenue collected goes to pay principal).

Strong levels of government ownership in Asia Pacific (ex-Japan) provide rating uplift

Strong levels of government ownership have dominated the credit profiles of utilities in Asia Pacific (excluding Japan), generally leading to ratings that are a number of notches above the Baseline Credit Assessment. Regulated electric and gas utilities with significant government ownership are rated using this methodology in conjunction with the Joint Default Analysis approach in our methodology for Government-Related Issuers.[19]

Support system for large corporate entities in Japan can provide ratings uplift, with limits

Our ratings for large corporate entities in Japan reflect the unique nature of the country's support system, and they are higher than they would otherwise be if such support were disregarded. This is reflected in the tendency for ratings of Japanese utilities to be higher than their grid implied ratings. However, even for large prominent companies, our ratings consider that support will not be endless and is less likely to be provided when a company has questionable viability rather than being in need of temporary liquidity assistance.

19 A link to this and other sector and cross-sector credit rating methodologies can be found in the Related Research section of this report.

Appendix F: Treatment of Power Purchase Agreements ("PPAs")

Although many utilities own and operate power stations, some have entered into PPAs to source electricity from third parties to satisfy retail demand. The motivation for these PPAs may be one or more of the following: to outsource operating risks to parties more skilled in power station operation, to provide certainty of supply, to reduce balance sheet debt, to fix the cost of power, or to comply with regulatory mandates regarding power sourcing, including renewable portfolio standards. While we regard PPAs that reduce operating or financial risk as a credit positive, some aspects of PPAs may negatively affect the credit of utilities. The most conservative treatment would be to treat a PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized.

Under most PPAs, a utility is obliged to pay a capacity charge to the power station owner (which may be another utility or an Independent Power Producer – IPP); this charge typically covers a portion of the IPP's fixed costs in relation to the power available to the utility. These fixed payments usually help to cover the IPP's debt service and are made irrespective of whether the utility calls on the IPP to generate and deliver power. When the utility requires generation, a further energy charge, to cover the variable costs of the IPP, will also typically be paid by the utility. Some other similar arrangements are characterized as tolling agreements, or long-term supply contracts, but most have similar features to PPAs and are thus we analyze them as PPAs.

PPAs are recognized qualitatively to be a future use of cash whether or not they are treated as debt-like obligations in financial ratios

The starting point of our analysis is the issuer's audited financial statements – we consider whether the utility's accountants determine that the PPA should be treated as a debt equivalent, a capitalized lease, an operating lease, or in some other manner. PPAs have a wide variety of operational and financial terms, and it is our understanding that accountants are required to have a very granular view into the particular contractual arrangements in order to account for these PPAs in compliance with applicable accounting rules and standards. However, accounting treatment for PPAs may not be entirely consistent across US GAAP, IFRS or other accounting frameworks. In addition, we may consider that factors not incorporated into the accounting treatment may be relevant (which may include the scale of PPA payments, their regulatory treatment including cost recovery mechanisms, or other factors that create financial or operational risk for the utility that is greater, in our estimation, than the benefits received). When the accounting treatment of a PPA is a debt or lease equivalent (such that it is reported on the balance sheet, or disclosed as an operating lease and thus included in our adjusted debt calculation), we generally do not make adjustments to remove the PPA from the balance sheet.

However, in relevant circumstances we consider making adjustments that impute a debt equivalent to PPAs that are off-balance sheet for accounting purposes.

Regardless of whether we consider that a PPA warrants or does not warrant treatment as a debt obligation, we assess the totality of the impact of the PPA on the issuer's probability of default. Costs of a PPA that cannot be recovered in retail rates creates material risk, especially if they also cannot be recovered through market sales of power.

Additional considerations for PPAs

PPAs have a wide variety of financial and regulatory characteristics, and each particular circumstance may be treated differently by Moody's. Factors which determine where on the continuum we treat a particular PPA include the following:

» Risk management: An overarching principle is that PPAs have normally been used by utilities as a risk management tool and we recognize that this is the fundamental reason for their existence. Thus, we will not automatically penalize utilities for entering into contracts for the purpose of reducing risk associated with power price and availability. Rather, we will look at the aggregate commercial position, evaluating the risk to a utility's purchase and supply obligations. In addition, PPAs are similar to other long-term supply contracts used by other industries and their treatment should not therefore be fundamentally different from that of other contracts of a similar nature.

» Pass-through capability: Some utilities have the ability to pass through the cost of purchasing power under PPAs to their customers. As a result, the utility takes no risk that the cost of power is greater than the retail price it will receive. Accordingly we regard these PPA obligations as operating costs with no long-term debt-like attributes. PPAs with no pass-through ability have a greater risk profile for utilities. In some markets, the ability to pass through costs of a PPA is enshrined in the regulatory framework, and in others can be dictated by market dynamics. As a market becomes more competitive or if regulatory support for cost recovery deteriorates, the ability to pass through costs may decrease and, as circumstances change, our treatment of PPA obligations will alter accordingly.

» Price considerations: The price of power paid by a utility under a PPA can be substantially above or below the market price of electricity. A below-market price will motivate the utility to purchase power from the IPP in excess of its retail requirements, and to sell excess electricity in the spot market. This can be a significant source of cash flow for some utilities. On the other hand, utilities that are compelled to pay capacity payments to IPPs when they have no demand for the power or at an above-market price may suffer a financial burden if they do not get full recovery in retail rates. We will focus particularly on PPAs that have mark-to-market losses, which typically indicates that they have a material impact on the utility's cash flow.

» Excess Reserve Capacity: In some jurisdictions there is substantial reserve capacity and thus a significant probability that the electricity available to a utility under PPAs will not be required by the market. This increases the risk to the utility that capacity payments will need to be made when there is no demand for the power. We may determine that all of a utility's PPAs represent excess capacity, or that a portion of PPAs are needed for the utility's supply obligations plus a normal reserve margin, while the remaining portion represents excess capacity. In the latter case, we may impute debt to specific PPAs that are excess or take a proportional approach to all of the utility's PPAs.

» Risk-sharing: Utilities that own power plants bear the associated operational, fuel procurement and other risks. These must be balanced against the financial and liquidity risk of contracting for the purchase of power under a PPA. We will examine on a case-by case basis the relative credit risk associated with PPAs in comparison to plant ownership.

» Purchase requirements: Some PPAs are structured with either options or requirements to purchase the asset at the end of the PPA term. If the utility has an economically meaningful requirement to purchase, we would most likely consider it to be a debt obligation. In most such cases, the obligation would already receive on-balance sheet treatment under relevant accounting standards.

» Default provisions: In most cases, the remedies for default under a PPA do not include acceleration of amounts due, and in many cases PPAs would not be considered as debt in a bankruptcy scenario and could potentially be cancelled. Thus, PPAs may not materially increase Loss Given Default for the utility.

In addition, PPAs are not typically considered debt for cross- default provisions under a utility's debt and liquidity arrangements. However, the existence of non-standard default provisions that are debt-like would have a large impact on our treatment of a PPA. In addition, payments due under PPAs are senior unsecured obligations, and any inability of the utility to make them materially increases default risk.

Each of these factors will be considered by our analysts and a decision will be made as to the importance of the PPA to the risk analysis of the utility.

Methods for estimating a liability amount for PPAs

According to the weighting and importance of the PPA to each utility and the level of disclosure, we may approximate a debt obligation equivalent for PPAs using one or more of the methods discussed below. In each case we look holistically at the PPA's credit impact on the utility, including the ability to pass through costs and curtail payments, the materiality of the PPA obligation to the overall business risk and cash flows of the utility, operational constraints that the PPA imposes, the maturity of the PPA obligation, the impact of purchased power on market-based power sales (if any) that the utility will engage in, and our view of future market conditions and volatility.

» Operating Cost: If a utility enters into a PPA for the purpose of providing an assured supply and there is reasonable assurance that regulators will allow the costs to be recovered in regulated rates, we may view the PPA as being most akin to an operating cost. Provided that the accounting treatment for the PPA is, in this circumstance, off-balance sheet, we will most likely make no adjustment to bring the obligation onto the utility's balance sheet.

» Annual Obligation x 6: In some situations, the PPA obligation may be estimated by multiplying the annual payments by a factor of six (in most cases). This method is sometimes used in the capitalization of operating leases. This method may be used as an approximation where the analyst determines that the obligation is significant but cannot otherwise be quantified otherwise due to limited information.

» Net Present Value: Where the analyst has sufficient information, we may add the NPV of the stream of PPA payments to the debt obligations of the utility. The discount rate used will be our estimate of the cost of capital of the utility.

» Debt Look-Through: In some circumstances, where the debt incurred by the IPP is directly related to the off-taking utility, there may be reason to allocate the entire debt (or a proportional part related to share of power dedicated to the utility) of the IPP to that of the utility.

» Mark-to-Market: In situations in which we believe that the PPA prices exceed the market price and thus will create an ongoing liability for the utility, we may use a net mark-to-market method, in which the NPV of the utility's future out-of-the-money net payments will be added to its total debt obligations.

» Consolidation: In some instances where the IPP is wholly dedicated to the utility, it may be appropriate to consolidate the debt and cash flows of the IPP with that of the utility. If the utility purchases only a portion of the power from the IPP, then that proportion of debt might be consolidated with the utility.

If we have determined to impute debt to a PPA for which the accounting treatment is not on-balance sheet, we will in some circumstances use more than one method to estimate the debt equivalent obligations imposed by the PPA, and compare results. If circumstances (including regulatory treatment or market conditions) change over time, the approach that is used may also vary.

Moody's Related Research

The credit ratings assigned in this sector are primarily determined by this credit rating methodology. Certain broad methodological considerations (described in one or more credit rating methodologies) may also be relevant to the determination of credit ratings of issuers and instruments in this sector. Potentially related sector and cross-sector credit rating methodologies can be found here.

For data summarizing the historical robustness and predictive power of credit ratings assigned using this credit rating methodology, see link.

Please refer to Moody's Rating Symbols & Definitions, which is available here, for further information. Definitions of Moody's most common ratio terms can be found in "Moody's Basic Definitions for Credit Statistics, User's Guide", accessible via this link.

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MOODY'S
INVESTORS SERVICE

ATO-1 Lead Lag Study

ATO-CWC1 A Rebuttal
Test Period

Atmos Energy Corporation-Kentucky
Cash Working Capital Lead/Lag Analysis
For Forecast Test Year Ended March 31, 2026

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lead	Net Lag (d) - (e)	Rebuttal CWC Requirement (c) x (f)	CWC As filed	Change to As filed
	(a)	(b)	(c)		(d)		(e)	(f)	(g)		
1	Gas Supply Expense										
2	Purchased Gas	87,640,898	240,112	*CWC2*	34.63	*CWC3*	39.49	(4.86)	(1,166,944)	(1,166,944)	0
3											
4	Operation and Maintenance Expense										
5	O&M, Labor	13,853,745	37,955	*CWC2*	34.63	*CWC4*	14.33	20.30	770,487	782,524	(12,038)
6	O&M, Non-Labor	17,958,888	49,202	*CWC2*	34.63	*CWC5*	26.64	7.99	393,002	584,940	(191,938)
7	Total O&M Expense	31,812,633							1,163,488	1,367,464	(203,976)
8											
9	Taxes Other Than Income										
10	Ad Valorem	9,889,824	27,095	*CWC2*	34.63	*CWC6*	278.99	(244.36)	(6,620,893)	(8,291,572)	1,670,679
11	Taxes Property and Other	1,102	3	*CWC2*	34.63	*CWC6*	58.82	(24.19)	(73)	(73)	0
12	Payroll Taxes	375,952	1,030	*CWC2*	34.63	*CWC6*	13.68	20.95	21,578	21,578	0
13	Franchise and other pass through	9,795,658	26,837	*CWC2*	34.63	*CWC6*	40.37	(5.74)	(154,173)	(154,173)	0
14	Public Service Commission	339,222	929	*CWC2*	34.63	*CWC6*	(186.50)	221.13	205,430	210,074	(4,644)
15	DOT	232,790	638	*CWC2*	34.63	*CWC6*	59.00	(24.37)	(15,548)	(15,548)	0
16											
17	Allocated Taxes-Shared Services										
18	Ad Valorem	50,549	138	*CWC2*	34.63	*CWC6*	213.50	(178.87)	(24,684)	(24,684)	0
19	Payroll Taxes	299,774	821	*CWC2*	34.63	*CWC6*	13.68	20.95	17,199	17,199	0
20											
21	Allocated Taxes-Business Unit										
22	Ad Valorem		0	*CWC2*	34.63	*CWC6*	278.99	(244.36)	0	0	0
23	Payroll Taxes	94,109	258	*CWC2*	34.63	*CWC6*	13.68	20.95	5,405	5,405	0
24	Total Taxes Other Than Income	21,078,982							(6,565,759)	(8,231,794)	1,666,035
25											
26	Federal Income Tax	*11,010,909*									
27	Current Taxes	0	0	*CWC2*	34.63	*CWC7*	38.25	(3.62)	0	0	0
28	Deferred Taxes	11,010,909	30,167	*CWC2*	34.63	*CWC7*	0.00	34.63	1,044,683	1,052,925	(8,242)
29											
30	State Income Tax	2,803,651									
31	Current Taxes	0	0	*CWC2*	34.63	*CWC8*	38.25	(3.62)	0	0	0
32	Deferred Taxes	2,803,651	7,681	*CWC2*	34.63	*CWC8*	0.00	34.63	265,993	268,729	(2,736)
33											
34	Depreciation	22,028,375	60,352	*CWC2*	34.63		0	34.63	2,089,990	2,089,990	0
35											
36	Interest Expense - STD	188,470	516	*CWC2*	34.63	*(1)*	19.40	15.23	7,859	7,859	0
37											
38	Interest Expense - LTD	9,968,711	27,312	*CWC2*	34.63	*CWC9*	91.40	(56.77)	(1,550,534)	(1,563,422)	12,887
39											
40	Return on Equity	41,554,931	113,849	*CWC2*	34.63		0	34.63	3,942,591	3,975,628	(33,037)
41											
42	TOTAL	228,087,560							(768,634)	(2,199,566)	1,430,932
43											
44	(1) Please see prior case relied file labeled "CWC1 STD Days Outstanding.pdf (Page 9)" for calculation of average days held										

ATO-1 Lead Lag Study

ATO-CWC1 Rebuttal
Base Period

Atmos Energy Corporation-Kentucky
Cash Working Capital Lead/Lag Analysis
For Forecast Test Year Ended March 31, 2026

Line No.	Description	Test Year Expenses	Average Daily Expense (b) / 365 days		Revenue Lag		Expense Lead	Net Lag (d) - (e)	CWC Requirement (c) x (f)	CWC As filed	Change to As filed
	(a)	(b)	(c)		(d)		(e)	(f)	(g)	(h)	
1	Gas Supply Expense										
2	Purchased Gas	52,986,727	145,169	*CWC2*	34.63	*CWC3*	39.49	(4.86)	(705,521)	(703,594)	1,927
3											
4	Operation and Maintenance Expense										
5	O&M, Labor	7,950,060	21,781	*CWC2*	34.63	*CWC4*	14.33	20.30	442,154	693,495	251,341
6	O&M, Non-Labor	25,586,867	70,101	*CWC2*	34.63	*CWC5*	26.64	7.99	559,933	625,932	65,999
7	Total O&M Expense	33,536,927							1,002,087	1,319,428	317,340
8											
9	Taxes Other Than Income										
10	Ad Valorem	11,322,473	31,020	*CWC2*	34.63	*CWC6*	278.99	(244.36)	(7,580,000)	(7,559,406)	20,595
11	Taxes Property and Other	1,103	3	*CWC2*	34.63	*CWC6*	58.82	(24.19)	(73)	(73)	(0)
12	Payroll Taxes	391,151	1,072	*CWC2*	34.63	*CWC6*	13.68	20.95	22,458	22,389	(69)
13	Franchise and other pass through	9,795,658	26,837	*CWC2*	34.63	*CWC6*	40.37	(5.74)	(154,173)	(153,754)	419
14	Public Service Commission	302,323	828	*CWC2*	34.63	*CWC6*	(186.50)	221.13	183,096	154,053	(29,043)
15	DOT	237,690	651	*CWC2*	34.63	*CWC6*	59.00	(24.37)	(15,865)	(15,826)	38
16											
17	Allocated Taxes-Shared Services										
18	Ad Valorem	56,976	156	*CWC2*	34.63	*CWC6*	213.50	(178.87)	(27,904)	(27,845)	58
19	Payroll Taxes	366,921	1,005	*CWC2*	34.63	*CWC6*	13.68	20.95	21,054	21,002	(52)
20											
21	Allocated Taxes-Business Unit										
22	Ad Valorem		0	*CWC2*	34.63	*CWC6*	278.99	(244.36)	0	0	0
23	Payroll Taxes	163,558	448	*CWC2*	34.63	*CWC6*	13.68	20.95	9,385	9,362	(23)
24	Total Taxes Other Than Income	22,637,853							(7,542,022)	(7,550,099)	(8,077)
25											
26	Federal Income Tax	*6,106,612*									
27	Current Taxes	0	0	*CWC2*	34.63	*CWC7*	38.25	(3.62)	0	0	0
28	Deferred Taxes	6,106,612	16,730	*CWC2*	34.63	*CWC7*	0.00	34.63	579,360	575,392	(3,968)
29											
30	State Income Tax	321,401									
31	Current Taxes	0	0	*CWC2*	34.63	*CWC8*	38.25	(3.62)	0	0	0
32	Deferred Taxes	321,401	881	*CWC2*	34.63	*CWC8*	0.00	34.63	30,509	30,284	(225)
33											
34	Depreciation	19,915,761	54,564	*CWC2*	34.63		0	34.63	1,889,551	1,884,379	(5,172)
35											
36	Interest Expense - STD	185,517	508	*CWC2*	34.63	*(1)*	19.40	15.23	7,737	7,804	68
37											
38	Interest Expense - LTD	9,523,202	26,091	*CWC2*	34.63	*CWC9*	91.40	(56.77)	(1,481,217)	(1,493,365)	(12,148)
39											
40	Return on Equity	41,246,594	113,004	*CWC2*	34.63		0	34.63	3,913,329	3,945,442	32,114
41											
42	TOTAL	186,460,594							(2,306,187)	(1,984,329)	321,858
43											
44	(1) Please see prior case relied file labeled "CWC1 STD Days Outstanding.pdf (Page 9)" for calculation of average days held										

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS	**)**	
ENERGY CORPORATION FOR AN	**)**	
ADJUSTMENT OF RATES; APPROVAL OF	**)**	**Case No. 2024-00276**
TARIFF REVISIONS; AND OTHER	**)**	
GENERAL RELIEF	**)**	

<u>REBUTTAL TESTIMONY OF DYLAN W. D'ASCENDIS</u>

RATE OF RETURN

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dylan W. D'Ascendis. I am employed by ScottMadden, Inc. as Partner. My business address is 1820 Chapel Avenue W., Suite 300, Cherry Hill, NJ 08003.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this rebuttal testimony (referred to throughout as my "Rebuttal Testimony") before the Kentucky Public Service Commission ("Commission") on behalf of Atmos Energy Corporation's Kentucky operations ("Atmos Energy" or the "Company").

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE?

A. Yes, I did.

II. PURPOSE AND SUMMARY

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

A. The purpose of my Rebuttal Testimony is two-fold. First, I update my return on common equity ("ROE") analyses to reflect current market data. Second, I respond to the direct testimony of Mr. Richard A. Baudino, witness for the Kentucky Office of the Attorney General, ("AG") as it relates to the appropriate capital structure and capital cost rates applicable to Atmos Energy's Kentucky jurisdictional rate base.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. I have updated my ROE analysis as of January 31, 2025. Based on these updated analyses, my reasonable range of ROEs attributable to Atmos Energy is between

10.37% and 11.85% (unadjusted) and 10.43% and 11.91% (adjusted), from which I have maintained my specific ROE recommendation of 10.95%. In view of current markets and the updated results of my ROE models, Mr. Baudino's recommended ROE of 9.40% understates the investor required return at this time. My Rebuttal Testimony also responds to substantive recommendations offered by Mr. Baudino and the application of his analytical models in his direct testimony. As it relates to his specific analytical models, I generally disagree with the inputs and the application of Mr. Baudino's Discounted Cash Flow ("DCF") model and Capital Asset Pricing Model ("CAPM). I also disagree with Mr. Baudino's proposed deduction of 10 basis points for Pipeline Replacement Program ("PRP") assets, his failure to reflect the differences in size and credit rating between Atmos Energy and his proxy group, and his failure to reflect flotation costs.

Q. HAVE YOU PREPARED SCHEDULES IN SUPPORT OF YOUR RECOMMENDATION?

A. Yes, I have. Exhibit DWD-1R through DWD-13R, which have been prepared by me or under my direct supervision.

III. UPDATED ANALYSES

Q. HAVE YOU UPDATED YOUR COST OF COMMON EQUITY ANALYSES FOR YOUR REBUTTAL TESTIMONY?

A. Yes, I have. Due to the passage of time since my Direct Testimony analysis (data as of July 31, 2024), I have updated my analysis using data as of January 31, 2025.

Q. HAVE YOU APPLIED ANY OF YOUR RETURN ON EQUITY ("ROE") MODELS DIFFERENTLY IN YOUR UPDATED ANALYSES?

A. While my application of the models remains unchanged, Yahoo! Finance no longer provides projected five-year earnings per share ("EPS") growth rates, and as such, my updated DCF analysis does not include these growth rates.

Q. HAVE YOU UPDATED YOUR UTILITY PROXY GROUP IN YOUR UPDATED ANALYSES?

A. Yes, I have. I added Southwest Gas Holdings, Inc ("SWX") to my Utility Proxy Group. This addition is based on SWX completing its spinoff of Centuri Holdings Inc ("Centuri") in April 2024. Given enough time has passed since the Centuri spinoff (i.e., the 60 trading days I use in my DCF analysis), I have included SWX in my Utility Proxy Group, which now consists of seven natural gas utilities.

Q. PLEASE SUMMARIZE YOUR UPDATED COST OF COMMON EQUITY RESULTS BASED ON YOUR UPDATED ANALYSIS.

A. Using data as of January 31, 2025, my updated results are presented in page 2 of Schedule DWD-1R, and in Table 1, below.

Table 1: Summary of Common Equity Cost Rate

	Including PRPM	**Excluding PRPM**
Discounted Cash Flow Model	10.37%	10.37%
Risk Premium Model	11.03%	11.00%
Capital Asset Pricing Model	11.21%	11.19%
Market Models Applied to Comparable Risk, Non-Price Regulated Companies	11.88%	11.85%
Indicated Range of Common Equity Cost Rates Before Adjustments for Company-Specific Risk	10.37% - 11.88%	10.37% - 11.85%
Size Adjustment	0.05%	0.05%
Credit Risk Adjustment	-0.04%	-0.04%
Flotation Cost Adjustment	0.05%	0.05%
Indicated Range of Common Equity Cost Rates after Adjustment	10.43% – 11.94%	10.43% – 11.91%
Recommended Cost of Common Equity	10.95%	10.95%

Given the indicated range of common equity cost rates for Atmos Energy of 10.43% to 11.91%, I maintain my recommended ROE of 10.95% for the Company.

IV. RESPONSE TO AG WITNESS BAUDINO

A. CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE MR. BAUDINO'S TESTIMONY REGARDING ATMOS ENERGY'S CAPITAL STRUCTURE.

A. Mr. Baudino recommends the Commission approve a common equity ratio of 52.5%, consistent with recent capital structure requests from gas distribution companies in Kentucky[1] and believes that Atmos Energy's 60.88% common equity ratio is unreasonable and should be rejected by the Commission.[2]

[1] Baudino Direct Testimony, at 36.
[2] Baudino Direct Testimony, at 34.

Q. DO YOU BELIEVE THAT ATMOS ENERGY'S PROPOSED ACTUAL COMMON EQUITY RATIO OF 60.88% IS REASONABLE?

A. Yes, I do.

Q. IS THERE GUIDANCE TO IMPUTE A HYPOTHETICAL CAPITAL STRUCTURE IN THIS INSTANCE?

A. Yes, there is. The factors typically considered relative to the use of a regulated subsidiary's actual or expected capital structure, or a hypothetical capital structure, are provided by David C. Parcell in The Cost of Capital – A Practitioner's Guide ("CRRA Guide"), prepared for the Society of Utility and Regulatory Financial Analysts ("SURFA"), and provided as the study guide to candidates for SURFA's Certified Rate of Return Analyst Certification Examination. The CRRA Guide notes that there are circumstances where a hypothetical capital structure is used in favor of an actual or expected capital structure. These circumstances are:

(i) The utility's capital structure is deemed to be substantially different from the typical or "proper" capital structure; or

(ii) The utility is funded as part of a diversified organization whose overall capital structure reflects its diversified nature rather than its utility operations only.[3]

Phillips echoes the CRRA Guide when he states:

> Debt ratios began to rise in the late 1960s and early 1970s, and the financial condition of the public utility sector began to deteriorate. It became the common practice to use actual or expected capitalizations; actual where a historic test year is used, expected when a projected or future test year is used.[83] (footnote omitted)

[3] David C. Parcell, The Cost of Capital – A Practitioner's Guide, Prepared for the Society of Utility and Regulatory Financial Analysts, 2020 Edition, p. 47.

> The objective, in short, shifted from minimization of the short-term cost of capital to protection of a utility's ability "to raise capital at all times." This objective requires that a public utility make every effort to keep indebtedness at a prudent and conservative level."[84] (footnote omitted)
>
> A hypothetical capital structure is used only where a utility's actual capitalization is clearly out of line with those of other utilities in its industry or where a utility is diversified.[85] (footnote omitted) (italics added)[4]

Q. HOW DOES THE REQUESTED COMMON EQUITY RATIO OF 60.88% COMPARE TO THE COMMON EQUITY RATIOS MAINTAINED BY THE UTILITY PROXY GROUP?

A. The Company's requested common equity ratio of 60.88% falls within the common equity ratios maintained by the Utility Proxy Group, which range from 40.23% to 62.38% for the fiscal year 2023. As shown on page 1 of Exhibit DWD-2R, I also examined the past eight quarter average capital structures for the Utility Proxy Group, which range from 31.92% to 59.06% (including short-term debt), or 35.43% to 59.24% (excluding short-term debt).

I also considered *Value Line Investment Survey's ("Value Line")* projected capital structures for the Utility Proxy Group for 2024-2029, as shown on page 3 of Exhibit DWD-2R. That analysis shows a range of projected common equity ratios between 42.50% and 61.00%.

Finally, I surveyed the authorized equity ratios of natural gas utility companies from 2020 through the present, which ranged from 32.27% to 62.38% as shown on page 4 of Exhibit DWD-2R.

[4] Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, 1993, Public Utility Reports, Inc., Arlington, VA, at 391.

In view of the above, it is clear that Atmos Energy's requested capital structure is consistent with the range of capital structures maintained by the Utility Proxy Group and their operating subsidiaries, and is appropriate to be used for Atmos Energy's ratemaking capital structure.

Q. IS ATMOS ENERGY'S CAPITAL STRUCTURE FUNDED AS PART OF A DIVERSIFIED ORGANIZATION?

A. No, it is not. Table 2 below presents the percentage of revenues, net operating income, and assets attributable to regulated and natural gas operations for Atmos Energy Corporation. As we can see, Atmos Energy Corporation is significantly comprised of natural gas distribution operations, and is exclusively a regulated entity. Because it is not funded as part of a diversified organization, it does not fail the criteria noted by Parcell and presented above.

Table 2: Atmos Energy Corporation Percentage of Revenues, Net Operating Income, and Assets Attributable to Natural Gas Operations – FY 2023[5]

	Regulated Operations	Natural Gas Operations
Revenues	100%	95.82%
Net Operating Income	100%	66.35%
Assets	100%	79.78%

Q. MR. BAUDINO REFERENCES THE CAPITAL STRUCTURE REQUESTS OF COLUMBIA GAS OF KENTUCKY ("COLUMBIA") (DOCKET NO. 2024-00092) AND DELTA GAS COMPANY ("DELTA") (DOCKET NO. 2024-00346) IN HIS JUSTIFICATION OF HIS RECOMMENDED EQUITY RATIO OF 52.50%.[6] DID THE COMPANY WITNESSES IN THOSE

[5] Source: SEC Form 10-K for the fiscal year ended 2021 at 50-51.
[6] Baudino Direct Testimony, at 35-36.

DOCKETS PROPOSE THE ACTUAL CAPITAL STRUCTURES OF COLUMBIA AND DELTA?

A. Yes, they did. Mr. Vincent V. Rea, witness for Columbia, recommended the 13-month average capital structure through the fully-forecasted test period ending December 31, 2025.[7] Likewise, Mr. Paul R. Moul, witness for Delta, recommended the 13-month average capital structure for the June 30, 2026 forecasted test year.[8] Atmos Energy is similarly requesting its actual capital structure from which its rate base is financed.

Q. IS THE APPROVAL OF A HYPOTHETICAL CAPITAL STRUCTURE FOR A UTILITY WHEN THEIR ACTUAL CAPITAL STRUCTURE IS REASONABLE CONSISTENT WITH SOUND FINANCIAL PRINCIPLES?

A. No, it is not. Reliance upon a hypothetical capital structure, when a utility's actual capital structure is reasonable, violates the basic financial principle that it is the use of the funds invested which gives rise to the risk of the investment. Atmos Energy's capital structure represents the actual capital financing of its Kentucky operations, to which the overall rate of return will be applied.

Q. DOES THE FINANCIAL LITERATURE SUPPORT THIS?

A. Yes. As Brealey and Myers state:

> But the company cost of capital rule can also get a firm into trouble if the new projects are more or less risky than its existing business. Each project should be evaluated at its own opportunity cost of capital. This is a clear implication of the value-additivity principle introduced in Chapter 7. For a firm composed of assets A and B, the firm value is
>
> Firm Value = PV (AB) = PV (A) + PV (B) = sum of separate asset

7 Docket No. 2024-00092, Direct Testimony of Vincent V. Rea, at 53.
8 Docket No. 2024-00346, Direct Testimony of Paul R. Moul, at 15.

values

> Here PV(A) and PV(B) are valued just as if they were mini-firms in which stockholders could invest directly …If the firm considers investing in a third project C, it should also value C as if C were a mini-firm. *That is*, the firm should discount the cash flows of C at the expected rate of return that investors would demand to make a separate investment in C. *The true cost of capital depends on the use to which the capital is put.* (italics in original)[9]

In addition, Levy and Sarnat state:

> The cost of capital and the discount rate are two concepts which are used throughout the book interchangeably. However, there is a distinction between the *firm's* cost of capital and specific *project's* cost of capital. (italics in original)
>
> In any case where the risk profile of the individual projects differ from that of the firm, an adjustment should be made in the required discount rate, to reflect this deviation in the risk profile.[10]

It is fundamental that individual investors expect a return commensurate with the risk associated with where their capital is invested. In this Case, that capital is provided by Atmos Energy and invested in Atmos Energy's Kentucky rate base. Hence, the Kentucky operations must be viewed on their own merits, including the actual capital structure financing its Kentucky rate base. As *Bluefield* so clearly states:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; . . .

[9] Richard A. Brealey and Stewart C. Myers, Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205 (emphasis added in first paragraph).

[10] Haim Levy and Marshall Sarnat, Capital Investments and Decisions, 5th Ed. (Prentice/Hall International, 1986) at 464-465.

In other words, it is the "risks and uncertainties" surrounding the property employed for the "convenience of the public" which determines the appropriate level of rates. In this case, the property employed "for the convenience of the public" is the rate base of Atmos Energy's Kentucky operations. Therefore, it is the total investment risk inherent in Atmos Energy's capital structure, which is presumed to proportionately finance the entirety of those Kentucky operations, and relevant to the appropriate rate of return for Atmos Energy's Kentucky rate base.

In view of the foregoing, Atmos Energy's actual capital structure at June 30, 2024, is appropriate for ratemaking purposes.

Q. PLEASE SUMMARIZE MR. BAUDINO'S RECOMMENDATIONS AS THEY RELATE TO THE COMPANY'S COST OF CAPITAL.

A. Mr. Baudino recommends a capital structure consisting of 47.50% long-term debt and 52.50% common equity, including an ROE of 9.40%.[11] Mr. Baudino's indicated ROEs range from 8.11% to 10.52% based on the results of his constant growth DCF and CAPM analyses applied to his proxy group of seven regulated natural gas utilities.[12] Mr. Baudino ultimately recommends a 9.40% ROE, which is consistent with the average and median growth rate DCF results and within the range of his CAPM results.[13] Mr. Baudino also recommends the Commission authorize an ROE ten basis points lower than his recommended ROE for the Company's PRP rider.[14]

[11] Baudino Direct Testimony, at 2.
[12] Baudino Direct Testimony, at 33.
[13] Baudino Direct Testimony, at 33.
[14] Baudino Direct Testimony, at 4.

Q. DO YOU HAVE ANY CONCERNS WITH MR. BAUDINO'S DIRECT TESTIMONY AND HIS ULTIMATE RECOMMENDATIONS?

A. Yes, I do. I have concerns regarding the following: (1) his recommended capital structure; (2) the conclusions drawn from his review of capital market conditions; (3) his inclusion of Chesapeake Utilities Corporation ("CPK") in his proxy group; (4) his application of the DCF model; (5) his application of the CAPM; (6) his failure to reflect the unique characteristics of the Companies in his recommended ROE; and (7) his proposed 10-basis point downward adjustment for assets subject to the PRP rider.

B. <u>ASSESSMENT OF CAPITAL MARKETS CONDITIONS</u>

Q. PLEASE SUMMARIZE MR. BAUDINO'S ASSESSMENT OF CURRENT CAPITAL MARKET CONDITIONS.

A. Mr. Baudino reviews several factors that influence ROEs, including current levels of interest rates and inflation, equity market volatility, economic growth, and unemployment.[15] I agree with the majority of his observations, including his comment that the cost of equity for regulated utilities is interest rate sensitive, and that the cost of equity generally (but not always) moves in the same direction as interest rates.

Q. DOES MR. BAUDINO'S RECOMMENDED ROE REFLECT CHANGES IN MARKET CONDITIONS SINCE THE COMPANY'S MOST RECENT RATE CASE?

[15] Baudino Direct Testimony, at 5.

A. No. In Case No. 2021-00214, the Company was awarded a 9.23% ROE. During the pendency of the Company's latest rate case, the 30-year Government Bond averaged 2.18% and the A-rated Moody's Public Utility bond yield was 3.40%. During the current Case, the 30-year Treasury and A-rated Public Utility Bond average yields are 4.46% and 5.52%, respectively. Mr. Baudino's 9.40% ROE recommendation is only 17 basis points higher in the current Case than in the Company's previous rate case despite long-term Treasury bond yields increasing by 228 basis points and A-rated Public Utility Bond yields increasing 212 basis points. Interestingly, in August 2024 Mr. Baudino recommended an ROE of 9.60% for Columbia Gas of Kentucky,[16] 20 basis points above his recommendation in this Case. The average 30-year Treasury yield reported by Mr. Baudino was 4.49%, while in the instant Case that number is 4.58%.

Q. CAN YOU QUANTIFY THE CHANGE IN THE ROE GIVEN THE CHANGE IN INTEREST RATES IN VIEW OF MR. BAUDINO'S STATEMENT THAT AUTHORIZED ROES AND INTEREST RATES TEND TO MOVE IN THE SAME DIRECTION?

A. Yes. To determine whether there is a relationship between interest rates and authorized ROEs, I performed two analyses: (1) a correlation analysis, and (2) a regression analysis between A-rated Public Utility Bonds and authorized ROEs as published by Regulatory Research Associates. As shown on Rebuttal Exhibit DWD-3R, the correlation between A-rated bond yields and authorized ROEs was 0.95, which is a strong positive correlation (i.e., they move in the same direction).

16 Commonwealth of Kentucky Before the Public Service Commission, Case No. 2024-00092, Direct Testimony of Richard A. Baudino, August 14, 2024, at 3.

The extent of the relative movement between the two variables was derived by conducting a regression analysis of the data. Also as shown on Exhibit DWD-3R, for every 100-basis point move in A-rated Public Utility Bond yields, the expected authorized ROE moves approximately 52 basis points in the same direction. The recent 212-basis-point increase in A-rated Utility Bond yields from the most recent case indicates a 110-basis-point increase in the authorized ROE. Applying that 110-basis-point increase to the Company's' authorized ROE of 9.23% indicates an ROE of 10.33%. The implied ROE of 10.33% based on relative interest rate movements shows Mr. Baudino's recommended ROE of 9.40% is inadequate.

Q. MR. BAUDINO STATES THAT RECENT LONG-TERM BOND YIELDS HAVE BEEN LOWER SINCE OCTOBER 2023.[17] IS HE CORRECT?

A. No, he is not. On January 10, 13, and 14, 2025, 30-year Treasury bond yields closed above the 4.95% October 2023 yield, which means interest rates are comparable to the October 2023 levels referenced by Mr. Baudino. The last time 30-year Treasury yields were at current levels was in 2010. The 39 ROEs authorized for regulated natural gas utilities in 2010 averaged 10.15%. Similarly, the 30-year Treasury yield was above 4.00% for 243 trading days in 2024 and has not dropped below 4.75% in January 2025. The last time 30-year Treasury yields traded above 4.00% for over 200 days in a calendar year was in 2008, during with the average authorized ROE for regulated natural gas utilities was 10.39%. While I do not recommend that the Commission use this data directly in its determination of the ROE for Atmos Energy in this Case, it is another directional indicator that the ROE should be set at a higher

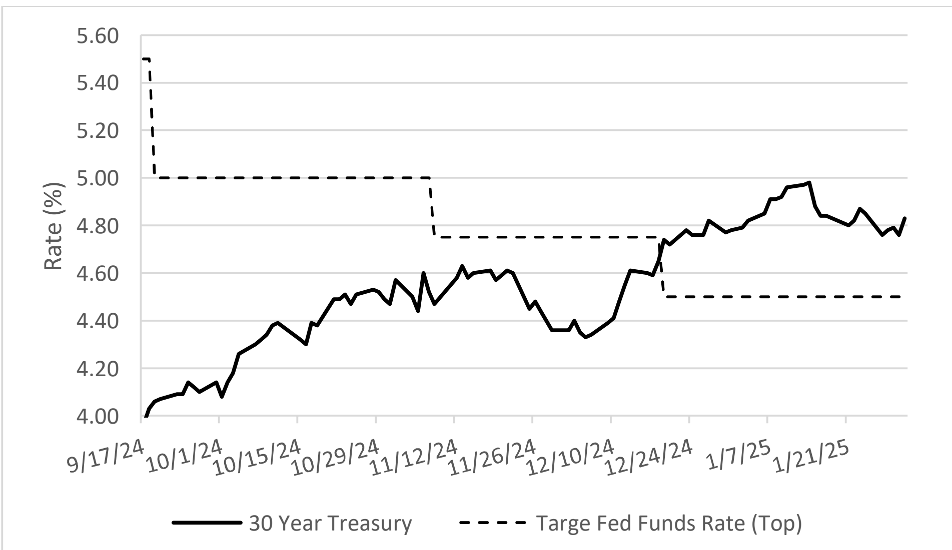
[17] Baudino Direct Testimony, at 9.

level than what has recently been approved and that Mr. Baudino's ROE recommendation is inadequate.

Q. WILL FEDERAL RESERVE ACTIONS NECESSARILY REDUCE LONG-TERM TREASURY YIELDS?[18]

A. Not necessarily. As mentioned by Mr. Baudino, long-term interest rates are set more by market forces than Federal Reserve ("Fed") action.[19] As shown in Chart 1 below, the Fed has cut the Fed Funds Rate by 100 basis points since September 17, 2024, and since that time, 30-year Treasury yields increased from 3.96% to approximately 4.83%.

<u>Chart 1: Federal Funds Rate and 30-Year Treasury Yield Relationship[20]</u>



During this period, the correlation between the Fed Funds Rate and 30-year Treasury bonds was -0.85, indicating a strong negative relationship. As noted above, long-term bond yields have been higher and for longer than any time in the

[18] Baudino Direct Testimony, at 9.
[19] Baudino Direct Testimony, at 7.
[20] Source of Information: Federal Reserve Data Download Program; and https://www.newyorkfed.org/markets/reference-rates/effr

past decade. As evidenced by Chart 1 above, Fed actions to cut the Fed Funds Rate has not reduced long-term bond yields.

Q. DO YOU AGREE WITH MR. BAUDINO'S ASSESSMENT OF THE CURRENT STATE OF INFLATION IN THE ECONOMY AND EXPECTATIONS FOR INFLATION IN THE FUTURE?

A. I generally agree that inflation has declined substantially from Mr. Baudino's noted peak in the Consumer Price Index ("CPI") in June 2022 at 9.1%,[21] however the Federal Reserve has not come close to achieving its 2.0% inflation goal noted by Mr. Baudino on page 8 of his direct testimony. Core inflation has held steady based on December 2024 Personal Consumption Expenditures Price Index[22] and remains almost 50% higher than the Federal Reserve's target of 2.0%. Reviewing Mr. Baudino's Microsoft Excel support confirms these observations.

Q. DO YOU AGREE WITH MR. BAUDINO'S ASSESSMENT OF MARKET VOLATILITY AND THE RETURNS OF THE UTILITY INDUSTRY COMPARED TO THE OVERALL STOCK MARKET?

A. No, I do not. First, I disagree with the use of the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX") as a measure of long-term expectations of market volatility. As noted by Mr. Baudino in his direct testimony at page 12, VIX only measures investor expected volatility for the next 30 days, which would not match the investment horizon of an investor in the operations of Atmos Energy (i.e. into perpetuity). Second, I do not agree with the limited time frame used by Mr.

[21] Baudino Direct Testimony, at 10.

[22] December PCE Index measured at 2.6%; https://www.bea.gov/data/personal-consumption-expenditures-price-index

Baudino for his comparison of market returns, S&P Utilities Index returns, and S&P Gas Utilities Index returns. As shown on Exhibit DWD-4R, since the onset of the COVID-19 pandemic, S&P Utilities and S&P Gas Utilities have been more volatile (as measured by annualized volatility)[23] and returned less than the S&P 500. Investments with higher risk and lower return than the market should not qualify as robust investments.

Q. PLEASE SUMMARIZE THIS SECTION.

A. Despite correctly observing interest rates and authorized ROEs move in the same direction, Mr. Baudino does not fully reflect increasing interest rates since the Company's most recent rate case in his recommendation. This is reinforced by the fact that when interest rates were last at these levels, authorized ROEs on average exceeded 10.00%. Inflation is 50% higher than the Fed target of 2%, which increases return requirements, and using a more representative timeframe shows that utility investments are more volatile and have returned less than investments in the S&P 500 return requirements further raising utility investor return requirements. Given the above, Mr. Baudino's 9.40% recommendation is significantly understated.

C. PROXY GROUP

Q. DO YOU DISAGREE WITH MR. BAUDINO'S PROXY GROUP?

A. Yes, I do. Mr. Baudino should not have included CPK in his proxy group. CPK is not a natural gas distribution utility, but rather is an energy delivery company with multiple operating segments. Mr. Baudino notes that 70.6% of CPK's revenue is

[23] Defined as the standard deviation of returns over the period multiplied by the square root of the number of trading days in a year (252).

derived from regulated energy operations[24], however, he fails to mention that only 34.36% of CPK's net operating income is derived from regulated natural gas distribution operations.[25] This percentage of net operating income ("NOI") does not indicate that CPK is a regulated natural gas distribution company and it is inappropriate to include CPK in a natural gas utility proxy group.

Q. ARE REVENUES A VALID MEASURE TO DETERMINE COMPARABILITY OF RISK FOR POTENTIAL PROXY GROUP COMPANIES?

A. No, they are not. I disagree with Mr. Baudino's use of revenues, rather than NOI or assets attributable to regulated natural gas distribution operations to justify his inclusion of CPK in his proxy group. Measures of income are far more likely to be considered by the financial community in making credit assessments and investment decisions than are measures of revenue. From the perspective of credit markets, measures of financial strength and liquidity are focused on cash from operations, which is a direct derivative of earnings, as opposed to revenue. As part of its rating methodology, for example, Moody's assigns a 40.00% weight to measures of financial strength and liquidity, of which 22.50% specifically relates to the ability to cover debt obligations with cash from operations.[26]

Just as rating agencies focus on measures of cash from operations, equity analysts rely on measures of income in assessing equity valuation levels; common measures of relative value include the price-to-earnings ratio, and the ratio of

24 Baudino Direct Testimony, at 16.

25 Chesapeake Utilities Corporation SEC Form 10-K, at PDF page 3, 9.

26 *See*, Moody's Investors Service, Rating Methodology, Regulated Electric and Gas Utilities, June 23, 2017, at 4.

EBITDA.[27] Revenue, however, may be several steps removed from the earnings and cash flows that form the basis of equity valuations. Focusing on revenue may mislead the analyst into assuming a given operating unit is the primary driver of expected growth when the majority of earnings and cash flows are derived from other business segments. Here, we are considering whether the underlying utility is the principal source of long-term growth, and as such, focusing on revenue may obscure important elements of the analysis.

Additionally, the use of assets attributable to natural gas distribution operations are more representative of operating risk because of the ratemaking paradigm (rate base * weighted average cost of capital = operating income). Given that CPK is clearly not primarily a natural gas distribution utility, I recommend the Commission rely solely on the seven companies included in my updated Utility Proxy Group when determining the indicated ROE for the Company using the DCF model.

D. DISCOUNTED CASH FLOW MODEL

Q. PLEASE BRIEFLY DESCRIBE MR. BAUDINO'S CONSTANT GROWTH DCF ANALYSIS AND RESULTS.

A. Mr. Baudino calculates an average dividend yield of 3.53% by dividing each proxy company's annualized dividend as reported in the December 27, 2024 edition of *Value Line Summary & Index* by its monthly stock price for the six-month period ending December 31, 2024.[28] He also calculates an average dividend yield of 3.76% for the companies in my Utility Proxy Group using the same methodology.

27 Earnings Before Interest, Taxes, Depreciation, and Amortization.
28 Baudino Direct Testimony, at 17.

For the expected growth rate, Mr. Baudino relies on EPS growth rate projections from *Value Line*, Zacks, and S&P Capital IQ, as well as dividend per share ("DPS") growth rate projections from *Value Line*.[29] Mr. Baudino then calculates his DCF results based on the mean and median growth rate of the four sources noted above. Mr. Baudino refers to the DCF results produced using mean growth rates as "Method 1", and DCF results produced using median growth rates as "Method 2". The mean DCF results of his Method 1 and 2 were 9.33% and 9.46%, respectively.[30] Mr. Baudino also applies the same approach to my Utility Proxy Group. The mean DCF results of his Method 1 and 2 applied to my Utility Proxy Group were 9.23% and 9.36%, respectively.[31]

Q. DO YOU HAVE ANY PRELIMINARY OBSERVATIONS ON THE INPUTS MR. BAUDINO USED IN HIS DCF ANALYSIS?

A. Yes, I do. Mr. Baudino's price data is as of Tuesday, December 31, 2024. At the time of his analysis, the *Value Line Summary & Index* for January 3, 2025 was available for him to use as it is published weekly on Mondays (in this case, Monday, December 30, 2024, and would be considered by investors at the time of his analysis.

Q. DO YOU HAVE ANY CONCERNS WITH MR. BAUDINO'S APPLICATION OF THE DCF MODEL?

A. Yes, I do. My concerns are as follows: (1) Mr. Baudino's use of DPS growth rates; (2) his use of outdated dividend data; and (3) his substitution of Chesapeake

[29] Baudino Direct Testimony, at 18.
[30] Baudino Direct Testimony, at 21.
[31] Baudino Direct Testimony, at 21.

Utilities, New Jersey Resources ("NJR"), and Northwest Natural Holding Co.'s ("NWN") Zacks EPS growth rate with an S&P Capital IQ EPS growth rate.[32]

Q. WHY DO YOU NOT AGREE WITH THE USE OF DPS GROWTH RATES IN THE DCF MODEL?

A. As discussed in my Direct Testimony,[33] over the long run, there can be no growth in DPS without growth in EPS. Earnings expectations have a more significant, but not sole, influence on market prices than dividend expectations. Thus, the use of earnings growth rates in a DCF analysis provides a better match between investors' market appreciation expectations implicit in market prices and the growth rate component of the DCF. Consequently, earnings expectations have a significant influence on market prices which affect market price appreciation, and hence, the "growth" experienced by investors. This should be evident by listening to financial news reports on radio, TV, or reading newspapers. In fact, Morin states:

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are a cause of g. The accuracy of these forecasts in the sense of whether they turn out to be correct is not at issue here, as long as they reflect widely held expectations. As long as the forecasts are typical and/or influential in that they are consistent with current stock price levels, they are relevant. The use of analysts' forecasts in the DCF model is sometimes denounced on the grounds that it is difficult to forecast earnings and dividends for only one year, let alone for longer time periods. This objection is unfounded, however, because it is present investor expectations that are being priced; it is the consensus forecast that is embedded in price and therefore in required return, and not the future as it will turn out to be.

[32] Baudino Direct Testimony, at 20.
[33] D'Ascendis Direct Testimony, at 18.

* * *

> Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecasts to a greater extent than on historic data.[34]

In addition, studies performed by Cragg and Malkiel demonstrate that analysts' forecasts are superior to historical growth rate extrapolations. They state:

> Efficient market hypotheses suggest that valuation should reflect the information available to investors. Insofar as analysts' forecasts are more precise than other types we should therefore expect their differences from other measures to be reflected in the market. It is therefore noteworthy that our regression results do support the hypothesis that analysts' forecasts are needed even when calculated growth rates are available. As we noted when we described the data, security analysts do not use simple mechanical methods to obtain their evaluations of companies. The growth-rate figures we obtained were distilled from careful examination of all aspects of the companies' records, evaluation of contingencies to which they might be subject, and whatever information about their prospects the analysts could glean from the companies themselves of from other sources. It is therefore notable that the results of their efforts are found to be so much more relevant to the valuation than the various simpler and more "objective" alternatives that we tried.[35]

In addition, Vander Weide and Carleton conclude:

> . . . our studies affirm the superiority of analysts' forecasts over simple historical growth extrapolations in the stock price formation process. Indirectly, this finding lends support to the use of valuation models whose input includes expected growth rates.[36]

Burton G. Malkiel, the Chemical Bank Chairman's Professor of Economics at Princeton University and author of the widely read national bestseller book on

[34] Roger A. Morin, Modern Regulatory Finance, PUR Books, 2021, at 371-373. ("Morin").

[35] John G. Cragg and Burton G. Malkiel, Expectations and the Structure of Share Prices (University of Chicago Press, 1982) Chapter 4.

[36] James H. Vander Weide and Willard T. Carleton, *Investor Growth Expectations: Analysts vs. History* (The Journal of Portfolio Management, Spring 1988) 78-82.

investing entitled, A Random Walk Down Wall Street (2011), also expressed support for projected EPS growth rates in testimony before the Public Service Commission of South Carolina in November 2002. Malkiel affirmed his belief in the superiority of analysts' earnings forecasts when he testified:

> With all the publicity given to tainted analysts' forecasts and investigations instituted by the New York Attorney General, the National Association of Securities Dealers, and the Securities & Exchange Commission, I believe the upward bias that existed in the late 1990s has indeed diminished. In summary, I believe that current analysts' forecasts are more reliable than they were during the late 1990s. *Therefore, analysts' forecasts remain the proper tool to use in performing a Gordon Model DCF analysis.*[37]

Q. IN REVIEWING THE FINANCIAL LITERATURE, DID YOU DISCOVER ANY ARTICLES THAT SUPPORTED THE USE OF HISTORICAL OR PROJECTED DPS GROWTH RATES FOR USE IN A DCF MODEL?

A. No, I did not.

Q. LIKEWISE, ARE YOU AWARE OF ANY SOURCES OF DATA WHICH PROVIDE PROJECTED DPS GROWTH RATES TO INVESTORS?

A. *Value Line* is the only source of which I am aware that publishes projected DPS growth rates. If investors indeed valued projected DPS growth rates, there would be a market for that data. As they are not relied on by investors to determine their required returns on investments, there is not. Conversely, projected EPS growth rates are widely available to investors through many sources.[38]

37 Malkiel rebuttal testimony, South Carolina Electric and Gas Co., pp. 16-17, Docket No. 2002-223-E) (italics added for emphasis).

38 For example, Mr. Baudino, and I both use projected EPS growth rates from *Value Line*, Zacks, and S&P Capital IQ.

Q. HAVE YOU PERFORMED ANY ANALYSES TO DETERMINE WHICH MEASURES OF GROWTH ARE STATISTICALLY RELATED TO THE PROXY COMPANIES' STOCK VALUATION LEVELS?

A. Yes, I have. My analysis is based on the methodological approach used by Carleton and Vander Weide, who compared the predictive capability of historical growth estimates and analysts' forecasts on the valuation levels of 65 utility companies.[39] I structured the analysis to understand whether projected earnings or dividend growth rates best explain utility stock valuations. In particular, my analysis examined the statistical relationship between the price-to-earnings ("P/E") ratios of gas utilities as classified by *Value Line*, and the projected EPS and DPS growth rates as reported by *Value Line*. To determine which, if any, of those growth rates are statistically related to utility stock valuations, I performed a series of regression analyses in which the projected growth rates were explanatory variables and the median P/E ratio was the dependent variable. The results of those analyses are presented in Exhibit DWD-5R.

In that analysis, I performed two separate regressions with the P/E as the dependent variable, and projected EPS and DPS as the independent variables. I then reviewed the T- and F-Statistics to determine whether the variables and equations were statistically significant.

Q. WHAT DID THOSE ANALYSES REVEAL?

A. As shown in Exhibit DWD-5R, the only growth rate that was statistically significant and positively related to the median P/E ratio was the projected EPS growth rate.

[39] James H. Vander Weide and Willard T. Carleton, *Investor Growth Expectations: Analysts vs History*, The Journal of Portfolio Management (Spring 1988).

Because projected EPS growth is the only growth rate that is both statistically and positively related to utility valuation, projected earnings is the proper measure of growth in the constant growth DCF model.

Q. WHAT IS YOUR CONCLUSION ON THE APPROPRIATE GROWTH RATE FOR USE IN THE DCF MODEL?

A. In view of the above, I recommend the Commission rely solely on projected EPS growth rates when determining the indicated ROE for the Company using the DCF model.

Q. PLEASE COMMENT ON MR. BAUDINO'S DIVIDEND DATA.

A. Mr. Baudino relies on the most recently paid dividend for each company as reported in *Value Line's Summary and Index* for his for his dividend data.[40] In reviewing the data, in addition to his use of an earlier version than available at the time of his analysis, I discovered that the dividends reported by *Value Line* are not the most recent ex- dividend, the dividend that a holder of record as of December 31, 2024, would be entitled to. For example, Atmos Energy Corporation's ("ATO") dividend reported by *Value Line* was $0.805. Any stockholders before the ex-dividend date of November 25, 2024, would receive a dividend of $0.87. Mr. Baudino acknowledges that an ROE analysis is a forward-looking process, and his DCF model necessarily assumes the applicable dividend is what investors would receive moving forward. That dividend is $0.87. Therefore, I have updated Mr. Baudino's DCF analysis to include the dividends available to investors at the time of his analysis.

[40] Baudino Direct Testimony, at 17.

Q. PLEASE COMMENT ON MR. BAUDINO'S SUBSTITUTION OF ZACKS GROWTH RATES FOR S&P CAPITAL IQ GROWTH RATES.

A. Mr. Baudino correctly acknowledges that three out of the seven Zacks forecasts for his proxy group are missing.[41] However, instead of marking the growth rates as a not-available ("NA"), he chose to substitute the S&P Capital IQ growth rates. While both providers may publish a consensus growth rate, they clearly do not aggregate estimates from the same analysts, or their published consensus growth rates would be identical. Mr. Baudino offers no analytical or theoretical support for his substitution, and instead should have marked the missing Zacks growth rates as an NA.

Q. WHAT WOULD BE THE INDICATED RESULT OF MR. BAUDINO'S DCF MODEL IF HE RELIED SOLELY ON PROJECTED EPS GROWTH RATES, USED THE CORRECT EX-DATE DIVIDENDS, DIDN'T DOUBLE-COUNT S&P CAPITAL IQ GROWTH RATES, AND EXCLUDED CPK FOR HIS PROXY GROUP?

A. As shown on Exhibit DWD-6R, Mr. Baudino's average Method 1 and 2 DCF model results would be 9.80% and 10.01%, respectively. In view of these corrected results, Mr. Baudino's indicated DCF cost rates of 9.33% and 9.46% are understated.

[41] Baudino Direct Testimony, at 20.

E. <u>CAPITAL ASSET PRICING MODEL</u>

Q. PLEASE DESCRIBE MR. BAUDINO'S CAPM ANALYSIS AND RESULTS.

A. Mr. Baudino performs eight CAPM calculations, each of which use his proxy group average *Value Line* and S&P Capital IQ beta of 0.83 and risk-free rate of 4.58%.[42] His eight market risk premiums ("MRP") use the following sources: (1) *Value Line Summary Index*; (2) Kroll historical MRP using the arithmetic mean return on large stocks less the long-term average income return of long-term government bonds; (3) the Ibbotson and Chen "supply side" MRP; (4) the Ibbotson and Chen "supply side" MRP excluding pre-World War II data; (5) the Kroll "recommended" MRP; (6) a MRP estimate from KPMG Corporate Finance and Evaluations; (7) an implied MRP from the Damodaran website; and (8) IESE Business School Survey MRP. Indicated ROEs from Mr. Baudino's application of the CAPM range from 8.30% to 10.52%, averaging 9.22%.[43]

Q. DOES MR. BAUDINO'S USE OF THE DECEMBER 27, 2024 DATA AFFECT HIS INDICATED CAPM COST RATE?

A. Yes, it does. As discussed previously, Mr. Baudino should have used the most-recently published edition of *Value Line's Summary and Index,* dated January 3, 2025, which was available to Mr. Baudino and other investors on December 31, 2024. Using *Value Line's* median estimated dividend yield for all dividend paying stocks (2.10%) and the median estimated 3–5-year price appreciation potential of all stocks in the *Value Line* universe (45%) in the January 3rd, 2025 edition, the market required return estimate is 11.83%, as opposed to the 10.78% presented in

[42] Baudino Exhibit RAB-4.
[43] Baudino Direct Testimony, at 32.

Mr. Baudino's direct testimony.[44] This translates to a market risk premium of 7.25%, and a CAPM/ECAPM return on equity of 10.59% and 10.90% respectively.[45] In view of the above, I recommend the Commission rely on this updated figure for Mr. Baudino's *Value Line* forward-looking MRP when determining the indicated ROE for the Company using the CAPM model.

Q. DO YOU HAVE ANY CONCERNS WITH MR. BAUDINO'S APPLICATION OF THE CAPM?

A. Yes, I do. My concerns are as follows: (1) his calculation of the "supply side" MRP; (2) his time-adjusted historical MRP; (3) his considerations of the Kroll, KPMG, Damodaran, and IESE Business School Survey MRPs in his analysis; and (4) the lack of an ECAPM analysis.

Q. DO YOU GENERALLY AGREE WITH MR. BAUDINO'S *VALUE LINE* FORWARD-LOOKING MRP OF 6.20% AND HISTORICAL LONG-TERM ARITHMETIC MEAN MRP OF 7.17%

A. Yes, I do. They are similar calculations to what I use in the calculation of my average MRP. I do have a concern with Mr. Baudino's use of the December 27, 2024 *Value Line* Summary & Index, as it is inconsistent with his spot date of December 31, 2024 as discussed previously.

Q. DO YOU AGREE WITH MR. BAUDINO'S SUPPLY SIDE MRP OF 6.22%?

A. No. I do not agree with Mr. Baudino's supply side MRP because the MRP mismatches a projected return on the market with a historical bond yield. A more correct way to derive that MRP would be to use the projected market return and

[44] Baudino Direct Testimony, at 25.
[45] Exhibit DWD-7R

subtract a risk-free rate. The Ibbotson and Chen supply side model produces a forward-looking geometric return on the market of 9.73%.[46] Because the arithmetic mean is appropriate for cost of capital purposes,[47] the geometric mean projected market return of 9.73% must be converted to an arithmetic mean return. Converting the 9.73% geometric mean return to an arithmetic mean return results in an arithmetic, forward-looking market return of 11.69%.[48] Subtracting the applicable risk-free rate of 4.58% results in a forward-looking MRP of 7.11%.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON THE SUPPLY-SIDE MRP?

A. Yes, I do. The Supply-Side MRP does not "remove" the effect of the price-to-earnings ("P/E") ratios in estimating the MRP, it develops an estimate absent "any change in investor predictions."[49] The resulting formula translates into a modified version of the market DCF. However, as noted above, the resulting equity return estimate needs to be adjusted to reflect an arithmetic return, consistent with the historical MRP calculation Mr. Baudino relies on. While slightly below the long-term arithmetic average annual return, the 11.69% implied return is consistent Mr. Baudino's historical approach and corrected *Value Line* approach.

[46] Baudino Exhibit RAB-4.
[47] SBBI – 2023, at 193.
[48] The conversion of a geometric mean return to an arithmetic mean return is shown in SBBI – 2023, at 200; 11.69% = 9.73% + 19.78%^2/2.
[49] Roger G. Ibbotson and Peng Chen, *Long-Run Stock Returns: Participating in the Real Economy*, Financial Analysts Journal, January/February 2003, at p. 94.

Q. DO YOU AGREE WITH MR. BAUDINO'S TIME-ADJUSTED HISTORICAL MARKET RISK PREMIUM (SUPPLY SIDE LESS WORLD WAR II BIAS)?

A. No, I do not. Kroll's Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2023 ("SBBI – 2023") makes it clear that the arbitrary selection of short historical periods is highly suspect and unlikely to be representative of long-term trends in market data. For example, SBBI - 2023 states:

> The estimate of the equity risk premium depends on the length of the data series studied. A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influences by very good and very poor short-term returns. When calculated using a long data series, the historical equity risk premium is relatively stable. Furthermore, because an average of the realized equity risk premium, is quite volatile when calculated using a short history, using a long series makes it less likely that the analyst can justify any number he or she wants. The magnitude of how shorter time periods can affect the result will be explored later in this Chapter.
>
> Some analysts estimate the expected equity risk premium using a shorter, more recent period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain unusual events. Some of the most unusual events of the last 100 years took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, the collapse of the high-yield bond market, the major contraction and consolidation of the thrift industry, the collapse of the Soviet Union, the development of the European Economic Community, the attacks of Sept. 11, 2001, the global financial crisis of 2008-2009, and most recently, the market crash in the first quarter of 2020 that was precipitated by the spread of the COVID-19 virus.
>
> It is even difficult for economists to predict the economic environment of the future. For example, if one were analyzing the stock market in 1987 before the crash, it would be statistically improbable to predict the impending short-term volatility without considering the stock market crash and market volatility of the 1929-1931 period.

> Without an appreciation of the 1920s and 1930s, no one would believe that such events could happen. The 97-year period starting with 1926 represents what can happen: It includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect unusual events to occur from time to time, and their return expectations reflect this.[50]

To this point, Mr. Baudino cites the downward bias in bond historical returns, which references the 1940s and the immediate post-war period, when the Fed artificially held down government bond yields, increasing historical MRPs for that period. It could be argued that in the period between 2008 and 2015 and from 2020 to 2022, the Fed did the same (artificially held down lending rates) to spur growth. As Kroll stated above, without a view of the prior period, it would be improbable for an analyst to predict future events during similar circumstances.

In view of all of the foregoing, it is indeed appropriate to use long-term historical equity risk premiums derived from the arithmetic mean long-term historical return on large company common stocks, and the arithmetic mean long-term historical income return on long-term U.S. government securities, for cost of capital purposes.

Q. WHAT IS YOUR POSITION ON THE 5.00% MRP QUOTED BY KROLL?

A. A forecast is only as good as its inputs, and if the assumptions within those forecasts are by its nature unpredictable (e.g., productivity growth forecasts), they are of little value. In addition, the determination of the MRP as calculated by Kroll is not

[50] SBBI – 2023, at 193-194.

transparent, especially in view of the historical MRP and supply side MRP presented in SBBI – 2023, which is already well known by investors. Because of the transparency of the historical data and how to gather and use the components of the supply side model, both the historical MRP (using the long-term arithmetic mean return on large company stocks less the long-term arithmetic income returns on long-term Government bonds) and the supply side model are superior measures of the MRP, when compared to Kroll's simplistic and opaque MRP forecast.

Q. WHY IS THE KROLL MRP MORE OPAQUE THAN OTHER MEASURES OF THE MRP?

A. The MRP is calculated by subtracting a risk-free rate from the investor-required return on the market. Typically, the return on the market uses observable market measures (e.g. historical average returns, Ibbotson and Chen Supply Side Model ("Ibbotson-Chen")), but the Kroll MRP does not define how they calculate their expected return on the market. Similarly, the risk-free rate is typically also based on market measures (e.g., historical interest rates, forecasted interest rates), but Kroll does not explain how they derive their 3.5% normalized risk-free rate. The extent to which yields have remained above 4.00% as noted previously further calls Kroll's estimates into question. Because Kroll does not reveal how they derive their estimates, we do not know if they are indeed based on market measures.

Q. WHAT CONCERNS DO YOU HAVE REGARDING THE KPMG MRP?

A. Similar to the Kroll MRP, the KPMG MRP calculation is not transparent. Also, KPMG Corporate Finance & Valuations Netherland's Equity Market Risk Premium site clearly states limiting conditions to its calculation:

> Note: Other KPMG country practices may have a deviating view on the MRP, as it is dependent on other parameters of the cost of capital determination, which may differ from country to country. In addition, commonly applied local market practice or regulatory requirements may also lead to different conclusions on individual parameters such as the MRP.[51]

A further review of KPMG's report reveals that the MRP calculated by KPMG is a global MRP, not a U.S.-specific MRP. As noted in the summary of the report, KPMG gives more weight to "the S&P 500, FTSE and STOXX 600".[52] Mr. Baudino has not provided any support for why a global MRP would be considered by U.S. investors. As a result of the lack of clarity of the MRP coupled with its limiting conditions and inapplicability to the U.S. market, the KPMG MRP should be rejected by the Commission.

Q. PLEASE NOW RESPOND TO MR. BAUDINO'S USE OF THE AVERAGE DAMODARAN 4.49% MRP.

A. Damodaran's method, which is a two-stage form of the DCF model, calculates the present value of cash flows over the five-year initial period, together with the terminal price (based on the Gordon Model), to be received in the last (i.e., fifth) year. The model's principal inputs include the following assumptions:

- Over the coming five years, the S&P 500 Index (the "Index") will appreciate at a rate equal to the compound growth rate in "Operating Earnings";

[51] https://indialogue.io/clients/reports/public/5d9da61986db2894649a7ef2/5d9da63386db2894649a7ef5

[52] KPMG Corporate Finance & Valuations Netherlands, Equity Market Risk Premium – Research Summary, 31 December 2024, at 7.

- Cash flows associated with owning the Index will be equal to the historical average Earnings, Dividends, and Buyback yields, applied to the projected Index value each year; and
- Beginning in the terminal year, the Index will appreciate, in perpetuity, at a rate equal to the 30-day average yield on 30-year Treasury securities.

In terms of historical experience, over the long-term the broad economy has grown at a long-term compound average growth rate of 6.11%.[53] Considered from another perspective, Kroll reports the long-term rate of capital appreciation on Large Company stocks to be 7.90%.[54] Using current data as of February 2025,[55] Damodaran's model assumes, however, that the market index will grow by just 4.80% over the coming five years.[56]

Mr. Baudino has not explained why growth beginning five years in the future, and extending in perpetuity, will be approximately one-half of long-term historical growth. Nowhere in his testimony has Mr. Baudino explained the fundamental, systemic changes that would so dramatically reduce long-term economic growth, or why they are best measured by the 30-day average long-term Treasury yield.

Further, research by the Federal Reserve Bank of San Francisco calls into question the relationship between interest rates and macroeconomic growth. As the

53 Source: Bureau of Economic Analysis for the years 1929 to 2024. *See also*, www.bea.gov/data/gdp/gross-domestic-product.

54 SBBI-2023, at 137.

55 From Damodaran Online, ERPFeb25 Spreadsheet.

56 From Damodaran Online, ERPFeb25 Spreadsheet. Five-year growth rate = (Expected Terminal Value / Intrinsic Value) ^ (1/5) – 1 = (7,637.50 / 6,040.53) ^ (1/5) - 1 = 4.80%.

authors noted, "[o]ver the past three decades, it appears that private forecasters have incorporated essentially no link between potential growth and the natural rate of interest: The two data series have a zero correlation."[57] In view of this, the Commission should reject Mr. Baudino's Damodaran CAPM.

Q. PLEASE NOW RESPOND TO MR. BAUDINO'S USE OF THE IESE BUSINESS SCHOOL SURVEY 5.50% MRP.

A. Damodaran, who was cited by Mr. Baudino throughout his testimony, states the following about the applicability of survey MRPs:

> While survey premiums have become more accessible, very few practitioners seem to be inclined to use the numbers from these surveys in computations and there are several reasons for this reluctance:
>
> 1. Survey risk premiums are responsive to recent stock prices movements, with survey numbers generally increasing after bullish periods and decreasing after market decline. Thus, the peaks in the SIA survey premium of individual investors occurred in the bull market of 1999, and the more moderate premiums of 2003 and 2004 occurred after the market collapse in 2000 and 2001.
>
> 2. Survey premiums are sensitive not only to whom the question is directed at but how the question is asked. For instance, individual investors seem to have higher (and more volatile) expected returns on equity than institutional investors and the survey numbers vary depending upon the framing of the question.[footnote omitted]
>
> 3. In keeping with other surveys that show differences across sub-groups, the premium seems to vary depending on who gets surveyed. Kaustia, Lehtoranta and Puttonen (2011) surveyed 1,465 Finnish investment advisors and note that not only are male advisors more likely to provide an estimate but that their estimated premiums are roughly 2% lower than

[57] FRBSF Economic Letter, *Does Slower Growth Imply Lower Interest Rates?*, November 10, 2014, at 3.

> those obtained from female advisors, after controlling for experience, education and other factors.[footnote omitted]
>
> 4. Studies that have looked at the efficacy of survey premiums indicate that if they have any predictive power, it is in the wrong direction. Fisher and Statman (2000) document the negative relationship between investor sentiment (individual and institutional) and stock returns.[footnote omitted] In other words, investors becoming more optimistic (and demanding a larger premium) is more likely to be a precursor to poor (rather than good) market returns.
>
> As technology aids the process, the number and sophistication of surveys of both individual and institutional investors will also increase. However, it is also likely that these survey premiums will be more reflective of the recent past rather than good forecasts of the future.[58]

As a result, the Commission should reject Mr. Baudino's IESE Business School (Fernandez) Survey MRP.

Q. HAS MR. BAUDINO INCLUDED AN ECAPM ANALYSIS?

A. No, he has not, even though Mr. Baudino does note the lack of predictive power of beta on page 24 of his direct testimony.

Q. WHY DOESN'T MR. BAUDINO EMPLOY THE ECAPM?

A. Mr. Baudino does not employ the ECAPM because he claims that the ECAPM is not used by investors.[59]

[58] Aswath Damodaran, Stern School of Business, *Equity Risk Determinants, Estimation and Implications – The 2022 Edition*, Updated March 23, 2022, at 27-28.

[59] Baudino Direct Testimony, at 55.

Q. MR. BAUDINO CLAIMS THAT WHILE YOU CITED THE SOURCE OF THE ECAPM FORMULA, YOU PROVIDED NO EVIDENCE THAT THE ECAPM IS USED BY INVESTORS.[60] PLEASE RESPOND.

A. Mr. Baudino is mistaken. Because the subject of beta's inaccuracy is debated in financial literature, the mere presence of that literature is proof that investors would consider the ECAPM in their investment decisions.

Q. IS THERE ADDITIONAL EVIDENCE THAT SUPPORTS THE VALIDITY OF THE ECAPM?

A. Yes, there is. The empirical issues with the CAPM have been present since the presentation of the model, as noted by Dianna R. Harrington in her text <u>Modern Portfolio Theory & the Capital Asset Pricing Model</u>:

> So far we have learned some very interesting things about the CAPM and reality. Some of the earliest work tested realized data (history) against data generated by simulated portfolios. Early studies by Douglas (1969) and Lintner (Douglas [1969]) showed discrepancies between what was expected on the basis of the CAPM and the actual relationships that were apparent in the capital markets. Theoretically, the minimal rate of return from the portfolios (the intercept) and the actual risk-free rate for the period should have been equal. They were not.
>
> * * *
>
> Another study, now more famous than Lintner's was done by Black, Jensen, and Scholes (1972). Lintner had used what is called a cross-sectional method (looking at a number of stock returns during one time period), whereas Black, Jensen, and Scholes used a time-series method (using returns for a number of stocks over several time periods). To make their test, Black, Jensen, and Scholes assumed that what had happened in the past was a good proxy for the investor expectations (a frequent assumption in CAPM tests). Using historical data, they generated estimates using what we call the market model:

60 Baudino Direct Testimony, at 55.

$$R_{jt} = \alpha_j + \beta_j (R_{mt}) + \varepsilon_j$$

Where:

R = total returns
β = the slope of the line (the incremental return for risk)
α = the intercept or a constant (expected to be 0 over time and across all firms)
ε = an error term (expected to be random, without information)
m = the market proxy
j = the firm or portfolio
t = the time period

Instead of using single stocks, they formed portfolios in an effort to wash out one source of error; because betas of single firms are quite unstable.

On the basis of the CAPM, they expected to find

1. That the intercept was equal to the risk-free rate (their proxy was the Treasury bill rate)
2. That the capital market line had a positive slope and that riskier (higher beta) securities provided higher return

Instead they found

1. That the intercept was different from the risk-free rate
2. That high-risk securities earned less and low-risk securities earned more than predicted by the model
3. That the intercept seemed to depend on the beta of any asset: high-beta stocks had a different intercept than low-beta stocks

* * *

Fama and MacBeth (1974) criticized the Black, Jensen, and Scholes study (hereafter called BJS). In a reformulation of the study, they supported the first of the BJS findings. They found that the intercept exceeded the risk-free proxy, but did not find the evidence to support the other BJS conclusions.[61]

Harrington discusses Black's potential solution to this phenomenon:

[61] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 43-45.

> Black's replacement for the risk-free asset was a portfolio that had no covariability with the market portfolio. Because the relevant risk in the CAPM is systematic risk, a risk-free asset would be the one with no volatility relative to the market – that is, a portfolio with a beta of zero. All investor-perceived levels of risk could be obtained from various linear combinations of Black's zero-beta portfolio and the market portfolio… Since R_z (the rate of return of the zero-beta asset) and R_m are uncorrelated (as R_f and R_m were assumed to be in the simple CAPM), the investor can choose from various combinations of R_z and R_m. On segment R_mY, R_z, is sold short and proceeds are invested in R_m. On segment R_zR_m, portions of the zero-beta portfolio are purchased. At R_m, the investor is fully invested in the market portfolio. The equilibrium CAPM was rewritten by Black as follows:
>
> $$E\,(R_i) = (1 - \beta_i)\,E\,(R_z) + \beta_i E(R_m)$$
>
> Where:
> E indicates expected,
> $E\,(R_z)$ is less than $E(R_m)$, and
> R_z holdings over the whole market must be in equilibrium. That is, the number of short sellers and lenders of securities must be equal.
>
> Black's adaptation is intriguing. The result of using this model is a capital market line that has a less steep slope and a higher intercept than those of the simple CAPM. If Black's model is more correct in its description of investor behavior in the marketplace, then the use of the simple model would produce equity return predictions that would be too low for sticks with betas greater than one and too high for stocks with betas of less than one.[62]

As such, while I still find the CAPM to be appropriate, if Mr. Baudino is of the opinion that the CAPM is not reliable, he should have applied an ECAPM analysis. Further, as discussed below, the ECAPM is not simply a second adjustment to a company's beta.

[62] Dianna R. Harrington, Modern Portfolio Theory & the Capital Asset Pricing Model – A User's Guide, Prentice-Hall, Inc. 1983, at 30-31.

Q. MR. BAUDINO STATES THAT THE USE OF THE ECAPM SUGGESTS THAT PUBLISHED BETAS ARE INCORRECT AND SHOULD NOT BE RELIED UPON BY INVESTORS IN THEIR CAPM?[63]

A. This is an incorrect understanding of the ECAPM. The slope of the SML should not be confused with beta. As Brigham and Gapenski state:

> The slope of the SML reflects the degree of risk aversion in the economy – the greater the average investor's aversion to risk, then (1) the steeper is the slope of the line, (2) the greater is the risk premium for any risky asset, and (3) the higher is the required rate of return on risky assets.[12]
>
> [12]Students sometimes confuse beta with the slope of the SML. This is a mistake. As we saw earlier in connection with Figure 6-8, and as is developed further in Appendix 6A, beta does represent the slope of a line, but *not* the Security Market Line. This confusion arises partly because the SML equation is generally written, in this book and throughout the finance literature, as $k_i = R_F + b_i(k_M – R_F)$, and in this form b_i looks like the slope coefficient and $(k_M – R_F)$ the variable. It would perhaps be less confusing if the second term were written $(k_M – R_F)b_i$, but this is not generally done.[64]

In addition, in Appendix 6A of Brigham and Gapenski's textbook entitled "Calculating Beta Coefficients," the authors demonstrate that beta, which accounts for regression bias, is not a return adjustment, but rather is based on the slope of a different line.

[63] Baudino Direct Testimony, at 55.

[64] Eugene F. Brigham and Louis C. Gapenski, Financial Management – Theory and Practice, 4th Ed. (The Dryden Press, 1985), at 201-204.

Q. HAVE OTHER JURISDICTIONS CONSIDERED THE ECAPM?

A. Yes, it has been accepted in Alaska, Minnesota, Mississippi, Nevada, New York, and Virginia.[65]

Q. WHAT WOULD THE RESULTS OF MR. BAUDINO'S CAPM ANALYSIS BE GIVEN YOUR CRITIQUES ABOVE?

A. Rebuttal Exhibit DWD-7R adjusts Mr. Baudino's CAPM analysis in the following ways: (1) eliminates the supply side World War II bias, Kroll, KPMG, Damodaran, and IESE Business School Survey MRPs; (2) replaces the geometric long-term supply side model with an arithmetic supply-side model; and (3) applies the ECAPM. The indicated results of the adjusted applications of both the traditional CAPM and the ECAPM to Mr. Baudino's proxy group are 10.53% and 10.83%, respectively.

[65] The Regulatory Commission of Alaska, Docket P-97-7, Order Rejecting 1997, 1998, 1999 and 2000 Filed TAPS Rates; Setting Just and Reasonable Rates; Requiring Refunds and Filings; and Outlining Phase II Issues, November 27, 2002, at 146; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota, Findings of Fact, Conclusions of Law, and Recommendation, August 19, 2016, at 29; Mississippi Public Service Commission, Docket No. 01-UN-0548, Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi, Final Order, December 3, 2001, at 19; Public Utilities Commission of Nevada, Docket No. 20-02023, Application of Southwest Gas Corporation for authority to increase its retail natural gas utility service rates for Southern and Northern Nevada, Order, September 23, 2020, at 35; New York Public Service Commission, Case 16-G-0058, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, December 16, 2016, at 32; In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina, Docket No. E-22, Sub 562 Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, February 24, 2020, at 40.

Q. WHAT WOULD MR. BAUDINO'S COMMON EQUITY COST RATES BE BASED ON THE CORRECTIONS TO HIS DCF AND CAPM ANALYSES DISCUSSED ABOVE?

A. The results of corrections to Mr. Baudino's DCF and CAPM are provided in Table 3, below:

Table 3: Summary of Baudino Corrected Results

Measure	**Recommended Range**	
Discounted Cash Flow Model	9.80% - 10.01%	
	CAPM	**ECAPM**
Capital Asset Pricing Model	10.53%	10.83%

In view of these corrected results, Mr. Baudino's reasonable range of ROEs would be from 9.80% to 10.83%. However, an indicated range of ROEs from 9.80% to 10.83% still understates the Company's ROE because it does not reflect their smaller size and increased credit risk relative to the proxy group, nor does it account for flotation costs.

Q. DID YOU CONDUCT A STUDY TO DETERMINE THE FORECAST ACCURACY OF THE KROLL RECOMMENDED MARKET RETURN, THE DAMODARAN IMPLIED MARKET RETURN, AND THE FERNANDEZ STUDY IMPLIED MARKET RETURN RELATIVE TO THE SBBI – 2023 HISTORICAL MARKET RETURN AND THE IBBOTSON-CHEN STUDY?

A. Yes, I did. I have calculated the forecast bias[66] of the long-term historical average return, the Ibbotson-Chen study, and the implied market returns from Kroll, Damodaran, and the Fernandez Survey from 2008-2023 to determine the most accurate measure of the following years' market return.[67] For example, the long-term average market return from 1926-2008 was used to determine the forecasted return for 2009. The result of this analysis is shown as Exhibit DWD-8R and Table 4, below:

Table 4: Comparison of Forecast Bias for Various Measures 2009-2023

Year	Observed Market Return	Long-Term Average Return	Ibbotson-Chen Study Return	Kroll Forecasted Market Return	Damodaran
2009	26.46%	11.67%	10.50%	11.65%	8.64%
2010	15.06%	11.85%	10.08%	11.12%	8.20%
2011	2.11%	11.88%	9.63%	10.54%	8.49%
2012	16.00%	11.77%	10.00%	11.34%	7.89%
2013	32.39%	11.82%	9.50%	11.49%	7.54%
2014	13.69%	12.05%	9.00%	11.43%	8.00%
2015	1.38%	12.07%	9.00%	11.41%	7.95%
2016	11.96%	11.95%	9.00%	11.46%	8.39%
2017	21.83%	11.95%	9.00%	11.28%	8.14%
2018	-4.38%	12.06%	8.50%	11.19%	7.49%
2019	31.49%	11.88%	9.00%	11.23%	8.64%
2020	18.40%	12.09%	8.00%	11.31%	7.12%
2021	28.71%	12.16%	8.00%	11.32%	5.65%
2022	-18.11%	12.33%	8.00%	11.11%	5.75%
2023	26.61%	12.02%	9.00%	11.31%	9.82%
Sum	223.60%	179.55%	136.21%	169.20%	117.71%
Forecast Bias[68]		80.30%	75.67%	60.92%	52.64%

[66] Forecast bias can be described as a tendency to either over-forecast or under-forecast a given variable.

[67] 2008 was selected as the starting year as it is the first year Kroll published its recommended MRP and risk-free rate.

[68] Calculated by dividing the sum of the forecast returns by the sum of the actual returns.

As shown in Table 4, while all measures of the projected market return (i.e., forecast bias values less than 100%), the long-term arithmetic mean return is the most accurate predictor of the next years' return as compared to the other measures. This result is consistent with Campbell, who states that when returns are serially uncorrelated, the arithmetic average represents the best forecast of future returns in any randomly selected future year.[69] Given this analysis, the Commission should reject Mr. Baudino's alternative MRPs used in his CAPM analysis.

F. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

Q. DOES MR. BAUDINO CONSIDER A SIZE ADJUSTMENT IN HIS RECOMMENDED ROE?

A. No, he does not. Mr. Baudino claims that since Atmos Energy's Kentucky operations is part of Atmos Energy Corporation, it should not be allowed a size premium.[70]

Q. SINCE THE COMPANY IS A PART OF ATMOS ENERGY CORPORATION, WHY IS THE SIZE OF ATMOS ENERGY CORPORATION NOT MORE APPROPRIATE TO USE WHEN DETERMINING THE SIZE ADJUSTMENT?

A. The return derived in this Case will not apply to Atmos Energy Corporation's operations as a whole, but only to the Company's Kentucky operations. As such, the Company's Kentucky operations should be considered a stand-alone company, as discussed in my Direct Testimony.[71]

[69] John Y. Campbell, "Forecasting US Equity Returns in the 21st Century," Social Security Administration, July 2001.
[70] Baudino Direct Testimony, at 58-59.
[71] D'Ascendis Direct Testimony, at 50.

Q. MR. BAUDINO STATES THAT BECAUSE THE CAPITAL STRUCTURE AND COST OF DEBT PROPOSED BY THE COMPANY IS THAT OF ATMOS ENERGY CORPORATION ("ATO"), IT IS INCORRECT TO LOOK AT THE COMPANY ON A STAND-ALONE BASIS. DO YOU AGREE?

A. No, I do not. As an operating division of ATO, the Company's rate base would be assumed to be financed the same as ATO.

Q. MR. BAUDINO STATES ON PAGE 59 OF HIS DIRECT TESTIMONY THAT "TAKING HIS POSITION EVEN FURTHER, IF INVESTORS DID THAT FOR KENTUCKY OPERATIONS, THEN THEY WOULD ALSO DO IT FOR ATMOS ENERGY'S SIX OTHER OPERATING DIVISIONS… IN SUCH A SCENARIO, THE SUMMED ROE PLUS SIZE PREMIUMS OF THE SEVEN DIVISIONS WOULD INDEED BE GREATER THAN THE WHOLE OF ATMOS ENERGY'S CONSOLIDATED ROE." PLEASE COMMENT.

A. Mr. Baudino's statement above is a perfect description of the portfolio effect, which theorizes that owning a basket of risky securities is less risky than individual owners owning separate securities. Utility holding companies invest in individual operating utilities, all at their assumed individual levels of risk. As the utility holding company diversifies its holdings over several geographic and regulatory territories, the overall riskiness of the portfolio decreases even if some of the underlying individual securities are riskier than the portfolio. But this does not imply that the individual utilities held by the holding company are less risky.

Looking at holding companies instead of the operating subsidiaries violates the stand-alone principle of ratemaking. Mr. Baudino's concern should be dismissed.

Q. YOU PRESENTED SEVERAL STUDIES SUPPORTING YOUR SIZE ADJUSTMENT IN YOUR DIRECT TESTIMONY.[72] DID MR. BAUDINO RESPOND TO THOSE STUDIES?

A. No, he did not.

Q. DOES MR. BAUDINO CONSIDER A CREDIT RISK ADJUSTMENT IN HIS RECOMMENDED ROE?

A. No, he does not. Mr. Baudino does however state that I am "inconsistent" by evaluating the credit risk adjustment for Atmos Energy on a total company basis, while evaluating the size premium based on Atmos' Kentucky operations.[73] I do not agree with his justification as Atmos Energy is assumed to be financed with the same proportions of debt and equity as ATO, which would reflect the same financial risk. The size premium I employ reflects risks not contemplated by credit ratings (i.e., there is no minimum size requirement for any given rating).

Q. MR. BAUDINO ARGUES THAT FLOTATION COSTS SHOULD NOT BE CONSIDERED BECAUSE, IN HIS OPINION, "IT IS LIKELY THAT FLOTATION COSTS ARE ALREADY ACCOUNTED FOR IN CURRENT STOCK PRICES".[74] WHAT IS YOUR RESPONSE TO MR. BAUDINO ON THAT POINT?

A. I disagree. The models used to estimate the appropriate ROE assume no "friction"

[72] D'Ascendis Direct Testimony, at 52-54.
[73] Baudino Direct Testimony, at 59.
[74] Baudino Direct Testimony, at 60.

or transaction costs, as these costs are not reflected in the market price (in the case of the DCF model) or risk premium (in the case of the Risk Premium Model ("RPM") and the CAPM). Mr. Baudino provides no support for his opinion that current stock prices account for flotation costs, and his position should be disregarded.

Q. WHAT IS MR. BAUDINO'S RANGE OF ROES APPLICABLE TO THE COMPANY AFTER ADJUSTMENT?

A. Mr. Baudino's corrected, adjusted results are summarized in Table 5, below:

Table 5: Summary of Baudino Corrected Results with Adjustments

Measure	
Indicated Range of ROEs Before Adjustment	9.80% - 10.83%
Business Risk Adjustment[75]	0.05%
Credit Risk Adjustment[76]	-0.04%
Flotation Cost Adjustment[77]	0.05%
Indicated Range of ROEs After Adjustment	9.85% - 10.88%

In view of these corrected and adjusted model results, Mr. Baudino's initial range of ROEs from 8.11% to 10.52% significantly understates the ROE for the Company at this time.

G. PROPOSED REDUCTION IN ROE FOR PRP RIDER

Q. DOES MR. BAUDINO PROPOSE A LOWER ROE FOR ASSETS SUBJECT TO THE PRP RIDER?

A. Yes, he does. Mr. Baudino recommends a 10-basis-point deduction to the authorized ROE for assets subject to the PRP Rider.

[75] *See* Exhibit DWD-1R
[76] *See* Exhibit DWD-1R
[77] *See* Exhibit DWD-1R

Q. DOES MR. BAUDINO OFFER ANY EVIDENCE OR SUPPORT FOR HIS RECOMMENDATION?

A. No, he does not. Mr. Baudino offered no substantive evidence in support of his position other than stating it is what the Commission has done previously.[78] In addition, Mr. Baudino offered no response to the evidence I put forward on pages 60 through 62 of my Direct Testimony. Given Mr. Baudino's lack of evidence supporting his position, and our unrebutted analysis that shows the prevalence of infrastructure mechanisms in the tariffs of comparable utilities, which means any risk associated with them would be reflected in market data, I urge the Commission to reconsider its prior position in this Case.

H. CRITIQUES ON COMPANY TESTIMONY

Q. DOES MR. BAUDINO HAVE CRITIQUES OF YOUR ROE ANALYSES?

A. Yes. Mr. Baudino's critiques of my analyses are as follows: (1) my recommended ROE is out of line with recently authorized returns; (2) the exclusion of DPS growth rates in my DCF analyses (3) the application of my RPM; (4) the application of my CAPM and ECAPM; (5) my use of a non-price regulated proxy group comparable in total risk to my Utility Proxy Group; (6) my application of a size premium to my indicated ROE; (7) my application of a credit risk adjustment to my indicated ROE; and (8) my application of a flotation cost adjustment to my indicated ROE.

I have already addressed critique numbers (2) and (6) – (8) previously in my Rebuttal Testimony, so I will not address them again here. I will address the remaining critiques in turn below.

[78] Baudino Direct Testimony, at 37.

i. <u>AUTHORIZED ROES</u>

Q. PLEASE SUMMARIZE MR. BAUDINO'S USE OF AUTHORIZED ROES THROUGHOUT HIS TESTIMONY.

A. Mr. Baudino offers an inconsistent opinion on the use of authorized ROEs as benchmarks for the investor required return. On page 39 of his direct testimony, he states he does "not recommended that the KPSC base its ROE award for Atmos on the ROE awards from other commissions around the country." However, in arguing against my recommendations, earlier on page 39 he claims that my recommended ROE is a "clear and obvious outlier when compared to a range of commission-allowed ROEs." On page 52, he then states that one would have to "go back to the year 2002 for an average allowed ROE anywhere close to the CAPM results Mr. D'Ascendis presented."[79] While I agree with Mr. Baudino's position that allowed ROEs should not be a substitute for market analyses, his seemingly conflicting positions obscure that important fact.

Q. PLEASE DISCUSS THE APPLICABILITY OF HISTORICALLY AUTHORIZED ROES FOR COST OF CAPITAL PURPOSES.

A. While authorized ROEs may be reasonable benchmarks of acceptable ROEs, care must be exercised when evaluating their applicability in any given case, because they necessarily do not reflect the current cost of common equity. The reason why historical authorized returns do not reflect the investor-required return is because authorized ROEs are a lagging indicator of investor-required returns, i.e., authorized ROEs are based on market data presented in an evidentiary record,

79 Mr. Baudino makes similar comparisons to authorized ROEs on pages 47, 48, and 54.

which spans a period before the decision, sometimes lasting over a year in some cases. Simply put, historical authorized returns do not completely reflect the investor-required return because the economic conditions in the past are not representative of economic conditions now. On page 39 of his testimony, Mr. Baudino appears to agree with this when stating that he does not "recommend that the KPSC base its ROE award for Atmos on the ROE awards from other commissions around the country."[80] Because of this, Mr. Baudino's simple comparisons of my recommended ROE to previously authorized ROEs are of little value.

A more useful way to use historical authorized ROEs for cost of capital purposes would be to determine whether a relationship between authorized ROEs (or equity risk premiums) and interest rates exists so one can determine an expectational ROE or equity risk premium ("ERP") given an interest rate. As discussed in my Direct Testimony, and as shown above, it is clear that an inverse relationship exists between ERPs and interest rates (i.e., as interest rates move, ERPs move in the opposite direction, but not to the extent of the interest rate move), which is confirmed in the work of Harris and Marston (2001) and Brigham, Dilip, Shome, and Vinson (1985).[81] As presented above, the inverse relationship between ROEs and interest rates yields an indicated ROE of 10.33%.

The only useful data that can be discerned by historically allowed ROEs would be the relationship between those ROEs and prevailing interest rates at the time of the decision. For all of these reasons, the KPSC should not rely on

[80] Baudino Direct Testimony, at 39.
[81] D'Ascendis Direct Testimony, at 33.

historically authorized ROEs in setting the ROE for Atmos Energy in this Case and instead focus on the market analyses put forth in my testimonies.

ii. RISK PREMIUM MODEL

Q. PLEASE SUMMARIZE MR. BAUDINO'S CRITIQUES OF YOUR RPM.

A. Mr. Baudino has the following critiques of my RPM: (1) that my regression-based MRPs and ERPs has little predictive value; (2) that I did not demonstrate that the PRPM is relied on by investors or accepted by utility commissions; (3) that the level of the PRPM results are "excessive"; (4) that the projected market returns used in my total market approach RPM are excessive; (5) that my regression-based ERP based on authorized returns is not considered by investors. I will address each of these critiques in turn.

Q. MR. BAUDINO CLAIMS THAT THE EXPLANATORY POWER OF YOUR REGRESSION-BASED MARKET RISK PREMIUM IS POOR AND CANNNOT BE USED ACCURATELY FOR FORECASTING PURPOSES.[82] PLEASE RESPOND.

A. "R Square" can be defined as "the portion of the movement in the dependent variable that can be explained by the regression model".[83] There is no specific thresholds for which I consider regression models to have low or high R Square values. As noted by Halcoussis in *Understanding Econometrics*:

> There is no absolute standard for R2, one that says, for example, "An R2 larger than 0.75 (or any number) means the model is good." Typically, R2 is higher in time series regressions than in cross-sectional regressions. The area of study is important also. If changes in the dependent variable are hard to explain, then 0.40 might be a

[82] Baudino Direct Testimony, at 43-44.
[83] Dennis Halcoussis, Understanding Econometrics, 2005, at 58.

great R2, but if the dependent variable is easily predicted, an R2 of 0.80 may indicate a poor fit.[84]

While the three regressions that I use in my analyses may have “low” or “acceptable” R Square values, the relevant fact is that the relationships I examined have the expected sign, and are statistically significant, not whether the R Square values meet a specific threshold.

Q. MR. BAUDINO CLAIMS THAT YOU HAVE NOT PROVED THAT YOUR PRPM IS RELIED ON BY INVESTORS.[85] PLEASE RESPOND.

A. As discussed in my Direct Testimony,[86] the PRPM is based on the research of Dr. Robert F. Engle, dating back to the early 1980s. Dr. Engle discovered that the volatility of market prices, returns, and risk premiums clusters over time, making prices, returns, and risk premiums highly predictable. In 2003, he shared the Nobel Prize in Economics for this work, characterized as “methods of analyzing economic time series with time-varying volatility (ARCH).[87] Dr. Engle[88] noted that relative to volatility, “the standard tools have become the ARCH/GARCH[89] models.” Hence, the methodology is not exclusively used by me and would be relied on by investors.

84 Dennis Halcoussis, Understanding Econometrics, 2005, at 58.
85 Baudino Direct Testimony, at 45.
86 D’Ascendis Direct Testimony, at 25-26.
87 www.nobelprize.org
88 Robert Engle, *GARCH 101: The Use of ARCH/GARCH Models in Applied Econometrics,* Journal of Economic Perspectives, Volume 15, No. 4, Fall 2001, at 157-168.
89 Autoregressive Conditional Heteroskedasticity/Generalized Autoregressive Conditional Heteroskedasticity.

Q. IS THE PRPM CITED IN ACADEMIC LITERATURE BESIDES THE ARTICLES CITED ABOVE AND IN YOUR DIRECT TESTIMONY?

A. Yes, it is. The PRPM is cited in the following textbooks on cost of capital by authors unaffiliated with the authors of the academic articles cited above:

- Shannon Pratt and Roger Grabowski, <u>Cost of Capital: Applications and Examples</u>, (Fifth Edition), Wiley & Sons, 2015;
- Shannon Pratt and Roger Grabowski, The Lawyer's Guide to Cost of Capital: Understanding Risk and Return for Valuing Businesses and Other Investments, ABA Publishing, 2015; and
- Roger A. Morin, <u>Modern Regulatory Finance</u>, PUR Books, 2021.

On the subject of the PRPM, Pratt and Grabowski, who Mr. Baudino cites on several occasions in his direct testimony, state:

> Empirical testing of this new model has yielded data allowing a comparison of results with other techniques including the DCF and CAPM. The results- combined with the stability of PRPM estimates- suggests that the model is robust when applied to electric, natural gas, combination electric and gas, and water utility companies.[90]

In addition, Morin states:

> PRPM cost of capital estimates then began to proliferate based on extensive work published in the Journal of Regulatory Economics, The Electricity Journal, and Energy Policy Journal. It is only a matter of time before the technique becomes more mainstream in regulatory proceedings.
>
> ***
>
> It is well known that security markets exhibit periods of relative calm and periodic high volatility for a variety of reasons. The

[90] Shannon Pratt, Roger Grabowski, "The Lawyer's Guide to The Cost of Capital: Understanding Risk and Return for Valuing Businesses and Other Investments", American Bar Association, 2015, at 421.

> GARCH technique does not explain the volatility but *models* its clustering. Investment analysts and financial institutions typically use models such as GARCH to estimate the volatility of returns for stocks, bonds, and market indices. They use the resulting information to help determine pricing decisions and judge which assets will potentially provide higher returns, as well as to forecast the returns. At its core, GARCH is a statistical modelling technique used in analyzing time-series data where the variance error is believed to be serially uncorrelated, and is used to help predict the volatility of returns on financial assets.[91]

Q. MR. BAUDINO STATES THAT YOU HAVE NOT SHOWN THAT THE PRPM HAS BEEN WIDELY ACCEPTED BY REGULATORY COMMISSIONS. PLEASE RESPOND.

A. In Docket No. 2017-292-WS, the Public Service Commission of South Carolina ("PSC SC") accepted Blue Granite Water Company's entire requested ROE, which included the PRPM. The relevant portion states:

> The Commission finds Mr. D'Ascendis' arguments persuasive. He provided more indicia of market returns, by using more analytical methods and proxy group calculations. Mr. D'Ascendis' use of analysts' estimates for his DCF analysis is supported by consensus, as is his use of the arithmetic mean. The Commission also finds that Mr. D'Ascendis' non-price regulated proxy group more accurately reflects the total risk faced [by] price regulated utilities and CWS. Furthermore, there is no dispute that CWS is significantly smaller than its proxy group counterparts, and, therefore, it may present a higher risk. An appropriate ROE for CWS is 10.45% to 10.95%. The Company used an ROE of 10.5% in computing its Application, a return on the low end of Mr. D'Ascendis' range, and the Commission finds that ROE is supported by the evidence.[92]

In addition, in Docket No. W-354, Subs 363, 364 and 365, the State of North Carolina Utilities Commission ("NCUC") approved my RPM and CAPM analyses,

[91] Morin, at 139-140, 142.
[92] PSC SC Docket No. 2017-292-WS - Order No. 2018-345, at 14. (May 17, 2018).

which used PRPM analyses as presented in this Case. The relevant portion of the order states:

> In doing so the Commission finds that the DCF (8.81%), Risk Premium (10.00%) and CAPM (9.29%) model results provided by witness D'Ascendis, as updated to use current rates in D'Ascendis Late-Filed Exhibit No. 1, as well as the risk premium (9.57%) analysis of witness Hinton, are credible, probative, and are entitled to substantial weight as set forth below.[93]

As discussed in my Direct Testimony,[94] I recognize the Commission has rejected the PRPM in several dockets, the soundness of the model, as evidenced by the underlying theory and academic vetting of the model should lead the Commission to reconsider it in this Case.

Q. MR. BAUDINO STATES THAT THE ULTIMATE RESULT PRODUCED BY THE PRPM IS "EXCESSIVE" AND MERELY SERVES TO INFLATE YOUR RPM RESULTS.[95] PLEASE RESPOND.

A. Mr. Baudino is mistaken. Regarding the level of indicated ROEs being a determinant of the PRPM being a flawed model, Mr. Baudino only looks to the results and not the underlying theory of the model, which won the Nobel Prize for Economics, and has not been rebutted in the academic literature for a decade since being published in the Journal of Economics and Business in June 2011. Since Mr. Baudino does not rebut the underlying model nor uncovers any issues in the calculation of the GARCH-in-mean model, his claim should be dismissed by the Commission.

93 NCUC Docket No. W-354, Sub 363, 364, 365, *Order Granting Partial Rate Increase and Requiring Customer Notice*, at PDF 72 (March 31, 2020).
94 D'Ascendis Direct Testimony, at 27-29.
95 Baudino Direct Testimony, at 47.

Regarding the impact of the PRPM on the results, the inclusion of the PRPM adds only four basis points to the top of my range of indicated results, which would not be considered “excessive”.

Q. MR. BAUDINO CLAIMS THAT YOUR ERP BASED ON THE BETA-ADJUSTED TOTAL MARKET APPROACH IS UNREPRESENTATIVE OF CURRENT INVESTOR REQUIRED ROES. PLEASE RESPOND.

A. Mr. Baudino fails to consider the other measures I have considered in calculating my overall ERP. As shown on Rebuttal Exhibit DWD-9R, the 5.21% and 5.17% ERPs recommended in my Direct Testimony and updated analysis both fall within the 49th percentile, of historical ERPs (as measured by the return on the S&P Utility Index less the yield on an A-rated utility bond). Mr. Baudino’s concerns regarding the level of my ERPs in my RPM should be dismissed.

Q. PLEASE RESPOND TO MR. BAUDINO’S CRITIQUE OF YOUR REGRESSION RISK PREMIUM BASED ON AUTHORIZED ROES.[96]

A. Mr. Baudino suggests that I have not supported my risk premium based on a regression of authorized ROEs, despite the fact I provided two academic journals supporting the inverse relationship between interest rates and the equity risk premium[97] Mr. Baudino’s also provides anecdotal evidence that interest rates and authorized ROEs move in the same direction.[98] Further, it is widely accepted that the concept of utility regulation as a substitute for competition, *i.e.*, the authorized

[96] Baudino Direct Testimony, at 51.
[97] D’Ascendis Direct Testimony, at 33, footnote 32.
[98] Baudino Direct Testimony, at 6.

ROE, is intended to be equivalent to the investor required return. The CRRA Guide, which, as noted previously, is the training manual for SURFA states:

> In a sense, the "visible hand of public regulation was (created) to replace the invisible hand of Adam Smith in order to protect consumers against exorbitant charges, restriction of output, deterioration of service, and unfair discrimination."[footnote omitted]
>
> ***
>
> As indicated above, regulation of public utilities reflects a belief that the competitive mechanism alone cannot be relied upon to protect the public interest. Essentially, it is theorized that a truly competitive market involving utilities cannot survive and, thereby, will fail to promote the general economic welfare. But this does not mean that regulation should alter the norm of competitive behavior for utilities. On the contrary, the primary objective of regulation is to produce market results (*i.e.*, price and quantity supplied) in the utility sectors of the economy closely approximating those conditions which would be obtained if utility rates and services were determined competitively.[99]

Additionally, in Principles of Public Utility Rates, Bonbright states:

> Lest the reader of this chapter gain the impression that it is intended to deny the relevance of any tests of reasonable rates derived from the theory or the behavior of competitive prices, let me state my conviction that no such conclusion would be warranted. On the contrary, a study of price behavior both under assumed conditions of pure competition and under actual conditions of mixed competition is essential to the development of sound principles of utility rate control. Not only that: any good program of public utility rate making must go a certain distance in accepting competitive-price principles as guides to monopoly pricing. For rate regulation must necessarily try to accomplish the major objectives that unregulated competition is designed to accomplish; and the similarity of purpose calls for a considerable degree of similarity of price behavior.
>
> Regulation, then, as I conceive it, is indeed a substitute for competition; and it is even a partly imitative substitute. But so is a Diesel locomotive a partly imitative substitute for a steam locomotive, and so is a telephone message a partly imitative substitute for a telegraph message. What I am trying to emphasize

[99] David C. Parcell, Cost of Capital Manual, Society of Utility and Regulatory Financial Analysts, 2010 Edition, at 3-4.

> by these crude analogies is that the very nature of a monopolistic public utility is such as to preclude an attempt to make the emulation of competition very close. The fact, for example, that theories of pure competition leave no room for rate discrimination, while suggesting a reason for viewing the practice with skepticism, does not prove that discrimination should be outlawed. And a similar statement would apply alike to the use of an original-cost or a fair value rate base, neither of which is defensible under the theory or practice of competitive pricing.[100]

Finally, Phillips states in The Regulation of Public Utilities:

> Public utilities are no longer, if they were ever, isolated from the rest of the economy. It is possible that the expanding utility sector has been taking too large a share of the nation's resources, especially of investment.[footnote omitted] At a minimum, regulation must be viewed in the context of the entire economy – and evaluated in a similar context. Public utilities have always operated within the framework of a competitive system. They must obtain capital, labor and materials in competition with unregulated industries. Adequate profits are not guaranteed to them. Regulation then, should provide incentives to adopt new methods, improve quality, increase efficiency, cut costs, develop new markets and expand output in line with customer demand. In short, regulation is a substitute for competition and should attempt to put the utility sector under the same restraints competition places on the industrial sector.[101]

In view of the above, regulation is indeed a substitute for competition and ROEs determined by regulatory commissions would be perceived by investors as the required cost of capital. That being said, as discussed in my Direct Testimony,[102] an authorized ROE should provide the utility with the opportunity to earn a return that is (1) adequate to attract capital at reasonable cost and terms; (2) sufficient to ensure their financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. If the ROE authorized by a

[100] James C. Bonbright, Principles of Public Utility Rates, Columbia University Press, 1961, at 106-107.

[101] Charles F. Phillips, The Regulation of Public Utilities, Public Utility Reports, Inc., 1993, at 173.

[102] D'Ascendis Direct Testimony, at 7.

regulatory commission does not satisfy these standards, that ROE would not be an indication of a market cost of equity.

iii. <u>CAPITAL ASSET PRICING MODEL</u>

Q. PLEASE SUMMARIZE MR. BAUDINO'S CRITIQUES ON YOUR APPLICATION OF THE CAPM.

A. Mr. Baudino critiques the following: (1) my projected market return; (2) the level of certain of my MRPs; and (3) my use of the ECAPM. As I discussed the applicability of the ECAPM previously, I will not repeat that discussion here. I will address the remaining critiques in turn.

Q. MR. BAUDINO STATES THAT YOUR MARKET RETURN ESTIMATES, AS DERIVED BY *VALUE LINE SUMMARY AND INDEX* AND *VALUE LINE*/BLOOMBERG/S&P CAPITAL IQ DATA IS OUT OF LINE.[103] PLEASE RESPOND.

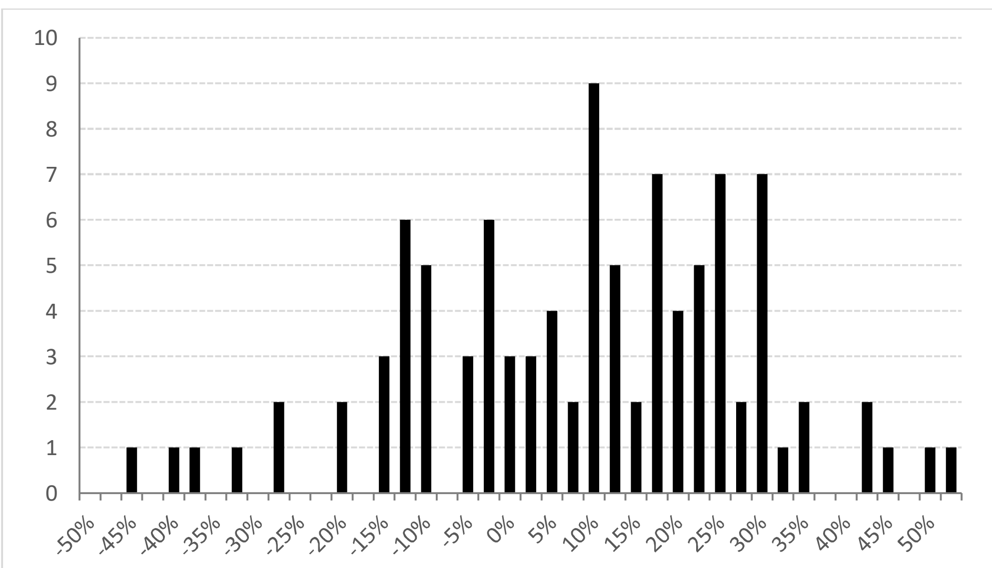
A. Again, Mr. Baudino fails to consider the other four measures I have considered. The average implied market return for my Direct (12.82%) and Rebuttal Testimonies (12.84%) represent the approximately 47th percentile of actual returns observed from 1926 to 2024 as shown on Rebuttal Exhibit DWD-10R. As discussed in my Direct Testimony and as noted by Mr. Baudino, multiple measures give greater insight into the investor-required return than a limited number of measures. The average implied market return for my Direct and Rebuttal Testimonies are 12.82% and 12.84%, respectively, which are comparable to the average historical market return of approximately 12.00%. Moreover, because

[103] Baudino Direct Testimony, at 53-54.

market returns historically have been volatile, my market return estimates are statistically indistinguishable from the long-term arithmetic average market data on which Mr. Baudino relies.[104]

Recalling that Mr. Baudino includes historical data among the methods he used to estimate the MRP, I therefore produced a histogram of the annual MRPs reported by Kroll. The results of that analysis, which are presented in Chart 2 below, demonstrate average MRPs of 8.63% (Direct Testimony) to 8.28% (Rebuttal Testimony) occur approximately 49 percent of the time.

Chart 2: Frequency Distribution of Observed Market Risk Premia, 1926-2024[105]



[104] SBBI-2023, at Appendix A-1.
[105] Rebuttal Exhibit DWD-9.

Q. MR. BAUDINO CLAIMS THAT YOUR MRP CALCULATIONS INCLUDE OVERSTATED EXPECTED MARKET RETURNS DUE TO UNSUSTAINABLY HIGH EARNINGS GROWTH RATES.[106] PLEASE RESPOND.

A. Mr. Baudino's assertion that the growth rates from *Value Line*, Bloomberg, and S&P Capital IQ are "unsustainably high" and "vastly exceed both the historical capital appreciation for the S&P 500 as well as historical and projected GDP growth rates."[107]

Regarding GDP growth rates, I calculated the correlation coefficient between year-over-year GDP growth and Large-Capitalization Stock returns since 1929 and found a correlation of 0.14, meaning there is little-to-no link between GDP growth and stock returns. In addition, the relationship between the two was not statistically significant. Because GDP growth and market returns are not related, his reasoning to discount my MRP calculations is misplaced.

Q. DO YOU HAVE ANY COMMENTS ON MR. BAUDINO'S REFERENCE THAT MRPS RANGING FROM 5% TO 8% IS APPROPRIATE?[108]

A. Yes, I do. First, Mr. Baudino does not provide any additional information on when an MRP should be 5% and when it should be 8%, seemingly leaving it up to judgment. This is contradictory to his position that the Commission should rely on the facts of the case. Second, as shown on Rebuttal Exhibit DWD-7R, which contains my corrections to Mr. Baudino's CAPM, all of the MRPs shown in that

106 Baudino Direct Testimony, at 49.
107 Baudino Direct Testimony, at 49.
108 Baudino Direct Testimony, at 55.

Schedule fall within the range of 5% to 8%. Finally, Mr. Baudino relies on an MRP of 4.49% from Damodaran, 50 basis points below the stated range. My updated MRP is only 29 basis points above the stated range.

iv. <u>NON-PRICE REGULATED GROUP</u>

Q. PLEASE SUMMARIZE MR. BAUDINO'S CONCERN WITH YOUR NON-PRICE REGULATED PROXY GROUP.

A. Mr. Baudino's concern is that non-utility companies face risks that lower risk gas utility companies do not face.[109]

Q. DOES MR. BAUDINO DISCUSS THE IMPORTANCE OF DETERMINING COMPARATIVE LEVELS OF RISK IN MAKING INVESTMENT DECISIONS?

A. Yes, he does. Mr. Baudino states the task of a rate of return analyst is to "estimate a return on equity that is equivalent to that being offered by other risk-comparable firms", which he notes could be a "utility stock, a utility bond, a mutual fund, a money market fund, or any other number of investment vehicles."[110] Mr. Baudino clearly recognizes that risk-comparable investments do not necessarily have to be regulated utilities.

Q. HAVE YOU SHOWN YOUR NON-PRICE REGULATED PROXY GROUP TO BE COMPARABLE IN RISK TO YOUR UTILITY PROXY GROUP?

A. Yes, I have. As discussed in my Direct Testimony, the selection criteria for my Non-Price Regulated Proxy Group were based on a range of unadjusted betas (a measure of systematic risk) and a range of standard errors of the regression (a

[109] Baudino Direct Testimony, at 56.
[110] Baudino Direct Testimony, at 5.

measure of unsystematic risk), which gave rise to those betas, and together measure total risk.[111]

As to the comparability of my Non-Price Regulated and Utility Proxy Groups, the selection criteria for my Non-Price Regulated Proxy Group was based on ranges of two measures of risk, the unadjusted beta of the proxy group, which measures systematic, or market risk, and the standard error of the regression, which gave rise to those betas, measuring non-systematic or diversifiable risk. Systematic plus non-systematic risk is one definition of total risk.[112] Mr. Baudino echoes this fact on page 21 of his direct testimony.

Business and financial risks may vary between companies and proxy groups, but if the collective average betas and standard errors of the regression of the group are similar, then the total, or aggregate, non-diversifiable market risks and diversifiable risks are similar, as noted in "Comparable Earnings: New Life for an Old Precept" provided in Rebuttal Exhibit DWD-12R. Thus, because the non-price regulated companies are selected based on analyses of market data, they are comparable in total risk (even though individual risks may vary) to the Utility Proxy Group. This is demonstrated clearly on page 273 of Jack C. Francis' Investments: Analysis and Management (page 3 of Rebuttal Exhibit DWD-13R), which shows that total risk can be "partitioned into its systematic and unsystematic components." Essentially, companies that have similar betas and standard errors of regression have similar total investment risk.

[111] D'Ascendis Direct Testimony, at 41-42.
[112] Business risk plus financial risk is a second definition of total risk.

Q. IS THERE A SPECIFIC ADVANTAGE TO USING YOUR SELECTION CRITERIA, WHICH USES MEASURES OF SYSTEMATIC AND UNSYSTEMATIC RISK, INSTEAD OF USING THE COMBINATION OF BUSINESS AND FINANCIAL RISK?

A. Yes. *Value Line* unadjusted betas and the standard error of the regressions giving rise to those betas are measurable objective values, whereas total business risk[113] and financial risk measures are more subjective. In view of all of the above, Mr. Baudino's concerns regarding my Non-Price Regulated Proxy Group should be dismissed by the Commission.

Q. HAVE YOU CONDUCTED ANOTHER ANALYSIS TO DETERMINE WHETHER YOUR UTILITY PROXY GROUP AND NON-PRICE REGULATED PROXY GROUP ARE OF COMPARABLE RISK?

A. Yes, I have. On page 23 of Mr. Baudino's direct testimony, he mentions that *Value Line's* Safety Ranking is a proxy for a company's total risk. I compared the average and median Safety Ranking for the Utility Proxy Group and Non-Price Regulated Proxy Group, as shown on Table 6, below:

Table 6: Comparison of Safety Rankings of Mr. D'Ascendis' Utility Proxy Group and Non-Price Regulated Proxy Group

Group	Average Safety Ranking	Median Safety Ranking
Utility Proxy Group	1.86	2.00
Non-Price Regulated Proxy Group	1.84	2.00

113 Business risk in excess of size risk, which is measurable, as discussed previously.

As shown, the Safety Rankings of the Utility Proxy Group and the Non-Price Regulated Proxy Group are comparable, indicating comparable total risk.[114] This, in addition to all of the above should lead the Commission to consider the results of my Non-Price Regulated Proxy Group in its determination of the Companies' ROE in this Case.

V. CONCLUSION

Q. SHOULD ANY OR ALL OF THE ARGUMENTS MADE BY MR. BAUDINO PERSUADE THE COMMISSION TO LOWER THE RETURN ON COMMON EQUITY THAT IS APPROVED FOR THE COMPANY BELOW YOUR RECOMMENDATION?

A. No, they should not. Mr. Baudino incorrectly relies on previous ROEs and unsupported inputs in developing his recommended ROE. Those inaccuracies lead to a recommendation inconsistent with the increased yields reflective of the markets at this time. My recommended cost of common equity of 10.95% relies on academic and empirically supported data and will provide the Company with sufficient earnings to enable it to attract necessary new capital efficiently, and at a reasonable cost, to the benefit of both customers and investors.

Q. IS ATMOS ENERGY'S REQUESTED ACTUAL CAPITAL STRUCTURE APPROPRIATE FOR RATEMAKING PURPOSES?

A. Yes, it is.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

[114] I note that the highest possible Safety Rank is a 1, so Table 4 illustrates that my Non-Price Regulated Proxy Group is actually *less* risky than my Utility Proxy Group.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS ENERGY CORPORATION FOR AN ADJUSTMENT OF RATES; APPROVAL OF TARIFF REVISIONS; AND OTHER GENERAL RELIEF	)))))	**Case No. 2024-00276**

CERTIFICATE AND AFFIDAVIT

The Affiant, Dylan W. D'Ascendis, 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. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Dylan W. D'Ascendis

STATE OF NEW JERSEY
COUNTY OF BURLINGTON

SUBSCRIBED AND SWORN to before me by Dylan W. D'Ascendis on this the 3rd day of March, 2025.

Notary Public
My Commission Expires: 2/1/2027

Joyce E Kelly
NOTARY PUBLIC
State of New Jersey
ID # 2416714
My Commission Expires 2/1/2027

Atmos Energy Corporation
Table of Contents
Supporting Exhibits Accompanying the Rebuttal Testimony of
Dylan W. D'Ascendis, CRRA, CVA

Atmos Energy Corporation
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Type of Capital	Ratios(1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	38.93%	4.11%	(1)	1.60%
Short-Term Debt	0.19%	17.14%	(1)	0.03%
Common Equity	60.88%	10.95%	(2)	6.67%
Total	100.00%			8.30%

Notes:
(1) Company Provided.
(2) From page 2 of this Exhibit.

Atmos Energy Corporation
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Seven Natural Gas Companies	Proxy Group of Seven Natural Gas Companies (exc. PRPM)
1.	Discounted Cash Flow Model (DCF) (1)	10.37%	10.37%
2.	Risk Premium Model (RPM) (2)	11.03%	11.00%
3.	Capital Asset Pricing Model (CAPM) (3)	11.21%	11.19%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	11.88%	11.85%
5.	Indicated Common Equity Cost Rate before Adjustment for Unique Risk	10.37% - 11.88%	10.37% - 11.85%
6.	Business Risk Adjustment (5)	0.05%	0.05%
7.	Credit Risk Adjustment (6)	-0.04%	-0.04%
8.	Flotation Cost Adjustment (7)	0.05%	0.05%
9.	Indicated Common Equity Cost Rate after Adjustment	10.43% - 11.94%	10.43% - 11.91%
10.	Recommended Common Equity Cost Rate	10.95%	

Notes:
(1) From page 3 of this Exhibit.
(2) From page 11 of this Exhibit.
(3) From page 21 of this Exhibit.
(4) From page 26 of this Exhibit.
(5) Adjustment to reflect the Company's greater business risk relative to the Utility Proxy Group as detailed in Mr. D'Ascendis' Direct Testimony.
(6) Company-specific risk adjustment to reflect Atmos' lower risk due to a lower long-term rating relative to the proxy group as detailed in Mr. D'Ascendis' Direct Testimony.
(7) From page 35 of this Exhibit.

Atmos Energy Corporation
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Seven Natural Gas Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
Proxy Group of Seven Natural Gas Companies	Average Dividend Yield (1)	Value Line Projected Five Year Growth in EPS (2)	Zack's Five Year Projected Growth Rate in EPS	S&P Capital IQ Projected Five Year Growth in EPS	Average Projected Five Year Growth in EPS (3)	Adjusted Dividend Yield (4)	Indicated Common Equity Cost Rate (5)
Atmos Energy Corporation	2.44 %	7.00 %	7.10 %	7.71 %	7.27 %	2.53 %	9.80 %
New Jersey Resources Corporation	3.78	5.00	NA	5.90	5.45	3.88	9.33
NiSource Inc.	3.05	9.50	8.10	7.80	8.47	3.18	11.65
Northwest Natural Holding Company	4.81	6.50	NA	5.50	6.00	4.95	10.95
ONE Gas, Inc.	3.72	3.50	4.70	2.63	3.61	3.79	7.40
Southwest Gas Holdings, Inc.	3.37	10.00	6.50	10.51	9.00	3.52	12.52
Spire Inc.	4.59	4.50	5.80	6.82	5.71	4.72	10.43
						Average	10.30 %
						Median	10.43 %
						Average of Mean and Median	10.37 %

NA= Not Available

Notes:

(1) Indicated dividend at 01/31/2025 divided by the average closing price of the last 60 trading days ending 01/31/2025 for each company.
(2) From pages 4 through 10 of this Exhibit.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 5) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Atmos Energy Corporation, 2.44% x (1+(1/2 x 7.27%)) = 2.53%.
(5) Column 5 + Column 6.
(6) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information:

Value Line Investment Survey
www.zacks.com Downloaded on 01/31/2025
S&P Capital IQ

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 146.11 | P/E RATIO 20.4 (Trailing: 21.5 Median: 20.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 4 Lowered 2/16/24
SAFETY 1 Raised 6/6/14
TECHNICAL 3 Raised 10/25/24
BETA .90 (1.00 = Market)

18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$109-$165 $137 (-5%)

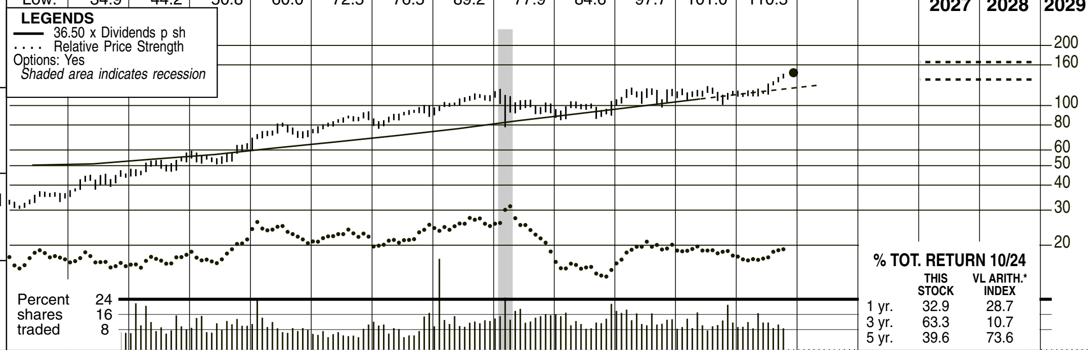
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	165	(+15%)	6%
Low	135	(-10%)	1%

Institutional Decisions

	4Q2023	1Q2024	2Q2024
to Buy	358	367	342
to Sell	295	292	311
Hld's(000)	137294	137412	144146

High:	47.4	58.2	64.8	82.0	93.6	100.8	115.2	121.1	105.3	123.0	125.3	146.9
Low:	34.9	44.2	50.8	60.0	72.5	76.5	89.2	77.9	84.6	97.7	101.0	110.5



% TOT. RETURN 10/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	32.9	28.7
3 yr.	63.3	10.7
5 yr.	39.6	73.6

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
79.52	53.69	53.12	48.15	38.10	42.88	49.22	40.82	32.23	26.01	28.00	24.32	22.41	25.73	29.82	28.79	26.55	27.55	Revenues per sh A	35.70
4.19	4.29	4.64	4.72	4.76	5.14	5.42	5.81	6.19	6.62	7.24	7.57	8.03	8.64	9.30	10.04	11.05	11.95	"Cash Flow" per sh	13.65
2.00	1.97	2.16	2.26	2.10	2.50	2.96	3.09	3.38	3.60	4.00	4.35	4.72	5.12	5.60	6.10	6.83	7.20	Earnings per sh AB	8.35
1.30	1.32	1.34	1.36	1.38	1.40	1.48	1.56	1.68	1.80	1.94	2.10	2.30	2.50	2.72	2.96	3.22	3.48	Div'ds Decl'd per sh C■	4.25
5.20	5.51	6.02	6.90	8.12	9.32	8.32	9.61	10.46	10.72	13.19	14.19	15.38	14.87	17.35	18.90	18.95	23.40	Cap'l Spending per sh	21.75
22.60	23.52	24.16	24.98	26.14	28.47	30.74	31.48	33.32	36.74	42.87	48.18	53.95	59.71	66.85	73.20	80.70	82.60	Book Value per sh	89.15
90.81	92.55	90.16	90.30	90.24	90.64	100.39	101.48	103.93	106.10	111.27	119.34	125.88	132.42	140.90	148.49	155.00	158.00	Common Shs Outst'g D	175.00
13.6	12.5	13.2	14.4	15.9	15.9	16.1	17.5	20.8	22.0	21.7	23.2	22.3	18.8	19.3	18.7	17.3		Avg Ann'l P/E Ratio	18.0
.82	.83	.84	.90	1.01	.89	.85	.88	1.09	1.11	1.17	1.24	1.15	1.02	1.12	1.08	.96		Relative P/E Ratio	1.00
4.8%	5.3%	4.7%	4.2%	4.1%	3.5%	3.1%	2.9%	2.4%	2.3%	2.2%	2.1%	2.2%	2.6%	2.5%	2.6%	2.7%		Avg Ann'l Div'd Yield	2.8%
						4940.9	4142.1	3349.9	2759.7	3115.5	2901.8	2821.1	3407.5	4201.7	4275.4	4115	4350	Revenues ($mill) A	6250
						289.8	315.1	350.1	382.7	444.3	511.4	580.5	665.6	774.4	885.9	1043.0	1145	Net Profit ($mill)	1475
						39.2%	38.3%	36.4%	36.6%	27.0%	21.4%	19.5%	18.8%	9.1%	11.4%	15.6%	19.0%	Income Tax Rate	25.0%
						5.9%	7.6%	10.5%	13.9%	14.3%	17.6%	20.6%	19.5%	18.4%	20.7%	25.3%	26.3%	Net Profit Margin	23.6%
						44.3%	43.5%	38.7%	44.0%	34.3%	38.0%	40.0%	38.4%	37.9%	37.9%	39.0%	40.0%	Long-Term Debt Ratio	40.0%
						55.7%	56.5%	61.3%	56.0%	65.7%	62.0%	60.0%	61.6%	62.1%	62.1%	61.0%	60.0%	Common Equity Ratio	60.0%
						5542.2	5650.2	5651.8	6965.7	7263.6	9279.7	11323	12837	15180	17509	20500	21750	Total Capital ($mill)	26000
						6725.9	7430.6	8280.5	9259.2	10371	11788	13355	15064	17240	19607	22000	23100	Net Plant ($mill)	28000
						6.4%	6.6%	7.2%	6.4%	6.9%	6.1%	5.5%	5.5%	5.4%	5.5%	6.5%	6.5%	Return on Total Cap'l	7.0%
						9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.5%	9.0%	Return on Shr. Equity	9.5%
						9.4%	9.9%	10.1%	9.8%	9.3%	8.9%	8.5%	8.4%	8.2%	8.1%	8.5%	9.0%	Return on Com Equity	9.5%
						4.7%	4.9%	5.1%	4.9%	4.8%	4.6%	4.4%	4.3%	4.2%	4.2%	4.5%	4.5%	Retained to Com Eq	4.5%
						50%	51%	50%	50%	48%	48%	49%	49%	49%	49%	48%	48%	All Div'ds to Net Prof	50%

CAPITAL STRUCTURE as of 6/30/24
Total Debt $7876.1 mill. **Due in 5 Yrs** $915.0 mill.
LT Debt $7866.5 mill. **LT Interest** $135.0 mill.
(LT interest earned: 8.3x; total interest coverage: 8.3x)
Leases, Uncapitalized Annual rentals $41.3 mill.

Pfd Stock None

Pension Assets-9/23 $502.4 mill.
Oblig. $431.6 mill.
Common Stock 155,232,827 shs.
as of 8/2/24

MARKET CAP: $22.7 billion (Large Cap)

CURRENT POSITION ($MILL.)	2022	2023	6/30/24
Cash Assets	51.6	15.4	674.6
Other	2996.1	870.4	1034.0
Current Assets	3047.7	885.8	1708.6
Accts Payable	496.0	336.1	319.4
Debt Due	2386.4	253.4	9.6
Other	720.2	763.1	655.9
Current Liab.	3602.6	1352.6	984.9
Fix. Chg. Cov.	1238%	1059%	1075%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-4.0%	-.5%	4.0%
"Cash Flow"	6.5%	7.0%	6.5%
Earnings	9.5%	9.0%	7.0%
Dividends	7.0%	8.5%	7.5%
Book Value	9.5%	12.0%	5.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	914.5	1319.1	605.6	568.3	3407.5
2022	1012.8	1649.8	816.4	722.7	4201.7
2023	1484.0	1541.0	662.7	587.7	4275.4
2024	1158.5	1647.2	701.5	607.8	4115
2025	1250	1725	750	625	4350

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.71	2.30	.78	.37	5.12
2022	1.86	2.37	.92	.51	5.60
2023	1.91	2.48	.94	.80	6.10
2024	2.08	2.85	1.08	.86	6.83
2025	2.23	2.92	1.15	.90	7.20

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.575	.575	.575	.625	2.35
2021	.625	.625	.625	.68	2.56
2022	.68	.68	.68	.74	2.78
2023	.74	.74	.74	.805	3.03
2024	.805	.805	.805	.87	

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for fiscal 2023: 66.5%, residential; 28.0%, commercial; 3.8%, industrial; and 1.7% other. The company sold Atmos Energy Marketing, 1/17. Officers and directors own approximately .5% of common stock (12/23 Proxy). President and Chief Executive Officer: Kevin Akers. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy Corporation ought to exhibit bottom-line improvement, once again, in fiscal 2025 (which started on October 1st). We believe that will be brought about partially by the distribution division, supported to a large extent by benefits of higher rates plus an expanded customer base. The pipeline and storage unit stands to have a better performance, too. Even though the company's effective income tax rate may well climb, we look for earnings per share to be in the neighborhood of $7.20. That would show a 5% increase from fiscal 2024's $6.83 tally. Concerning the following fiscal year, profits might advance at a similar percentage rate, to $7.55 a share, as operating margins widen further.

Capital spending for fiscal 2025 is expected to be roughly $3.7 billion. That is some 26% higher than the prior-year level of around $2.9 billion. Similar to fiscal 2024, a considerable portion of the resources are being utilized to enhance the safety and reliability of Atmos Energy's natural gas distribution and transmission systems. Leadership adds that it projects total capital expenditures from fiscal 2025 through fiscal 2029 to be roughly $24 billion. A meaningful amount of the investments will continue to be deployed to where they are presently. Assuming that the balance sheet remains healthy, the company ought to have little trouble achieving those goals.

The quarterly common stock dividend was raised around 8%, to $0.87 per share. What's more, we anticipate additional steady hikes in the distribution out to 2027-2029. The payout ratio over that span should be manageable, in the vicinity of 50%.

These top-quality shares have reached fresh highs since our last full-page report in August. It appears that price movement stems partially from investor optimism regarding the energy firm's near-term prospects. But 3- to 5-year capital appreciation potential is minimal, even after raising our Target Price Range. Too, the dividend yield is not exciting versus *Value Line's* Natural Gas Utility Industry average. Meanwhile, the stock possesses a 4 (Below Average) rank for Timeliness.

Frederick L. Harris, III November 22, 2024

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. gains (loss): '10, 5¢; '11, (1¢); '18, $1.43; '20, 17¢. Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 14¢; '17, 13¢. Next earnings report due early Feb.
(C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	100

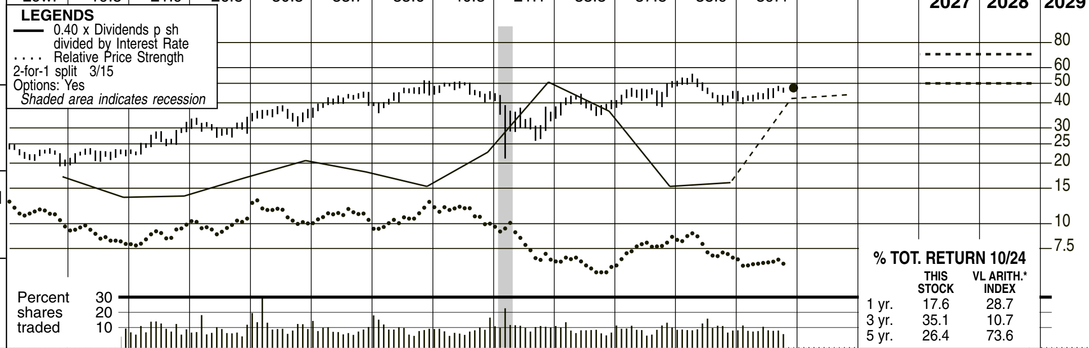
NEW JERSEY RES. NYSE-NJR

RECENT PRICE **47.56** | P/E RATIO **15.9** (Trailing: 20.2 Median: 17.0) | RELATIVE P/E RATIO **0.84** | DIV'D YLD **3.8%** | VALUE LINE

TIMELINESS **4** Raised 3/29/24
SAFETY **2** Lowered 4/17/20
TECHNICAL **2** Raised 10/25/24
BETA 1.00 (1.00 = Market)

High:	23.8	32.1	34.1	38.9	45.4	51.8	51.2	44.7	44.4	51.4	55.8	48.7
Low:	19.5	21.9	26.8	30.5	33.7	35.6	40.3	21.1	33.3	37.8	38.9	39.4

Target Price Range 2027 | 2028 | 2029



18-Month Target Price Range

Low-High	Midpoint (% to Mid)
\$40-\$60	\$50 (5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+45%)	13%
Low	50	(+5%)	5%

Institutional Decisions

	4Q2023	1Q2024	2Q2024
to Buy	161	167	167
to Sell	143	140	139
Hld's(000)	70304	70181	71950

% TOT. RETURN 10/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.6	28.7
3 yr.	35.1	10.7
5 yr.	26.4	73.6

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
45.37	31.17	32.05	36.30	27.08	38.38	44.40	32.09	21.90	26.28	33.24	29.01	20.39	22.71	30.38	20.12	*19.00*	*21.00*	Revenues per sh A	*25.00*
1.81	1.58	1.63	1.70	1.86	1.93	2.73	2.52	2.46	2.68	3.72	2.99	3.30	3.36	3.86	4.22	*4.50*	*4.50*	"Cash Flow" per sh	*5.25*
1.35	1.20	1.23	1.29	1.36	1.37	2.08	1.78	1.61	1.73	2.72	1.96	2.07	2.16	2.50	2.70	*2.90*	*2.90*	Earnings per sh B	*3.50*
.56	.62	.68	.72	.77	.81	.86	.93	.98	1.04	1.11	1.19	1.27	1.36	1.45	1.56	*1.71*	*1.76*	Div'ds Decl'd per sh C ■	*1.95*
.86	.90	1.05	1.13	1.26	1.33	1.52	3.76	4.15	3.80	4.39	5.83	4.65	5.42	6.50	5.13	*5.00*	*5.50*	Cap'l Spending per sh	*6.25*
8.64	8.29	8.81	9.36	9.80	10.65	11.48	12.99	13.58	14.33	16.18	17.37	19.26	17.18	19.00	20.40	*22.30*	*23.65*	Book Value per sh D	*28.35*
84.12	83.17	82.35	82.89	83.05	83.32	84.20	85.19	85.88	86.32	87.69	89.34	95.80	94.95	95.64	97.57	*100.00*	*100.00*	Common Shs Outst'g E	*100.00*
12.3	14.9	15.0	16.8	16.8	16.0	11.7	16.6	21.3	22.4	15.6	24.3	17.7	17.5	17.0	17.7	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.74	.99	.95	1.05	1.07	.90	.62	.84	1.12	1.13	.84	1.29	.91	.94	.98	1.02	*Value Line*		Relative P/E Ratio	*.95*
3.3%	3.5%	3.7%	3.3%	3.4%	3.7%	3.5%	3.1%	2.9%	2.7%	2.6%	2.5%	3.5%	3.6%	3.4%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 6/30/24
Total Debt \$3246.0 mill. **Due in 5 Yrs** \$580 mill.
LT Debt \$2793.7 mill. **LT Interest** \$125 mill.
Incl. \$9.3 mill. capitalized leases.
(Interest coverage: 4.85x)
Pension Assets-9/23 \$405.0 mill. **Oblig.** \$493.7 mill.

Pfd Stock None

Common Stock 99,167,564 shs. as of 8/2/24

MARKET CAP: \$4.7 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
3738.1	2734.0	1880.9	2268.6	2915.1	2592.0	1953.7	2156.6	2906.0	1963.0	*1900*	*2100*	Revenues (\$mill) A	*2500*
176.9	153.7	138.1	149.4	240.5	175.0	196.2	207.7	240.3	261.8	*290*	*290*	Net Profit (\$mill)	*350*
30.2%	26.3%	15.5%	17.2%	--	--	NMF	10.3%	21.4%	15.8%	*21.5%*	*22.0%*	Income Tax Rate	*22.0%*
4.7%	5.6%	7.3%	6.6%	8.2%	6.7%	10.0%	9.6%	8.3%	13.3%	*15.3%*	*13.8%*	Net Profit Margin	*14.0%*
38.2%	43.2%	47.7%	44.6%	45.4%	49.8%	55.1%	57.0%	57.8%	58.2%	*57.5%*	*57.0%*	Long-Term Debt Ratio	*55.0%*
61.8%	56.8%	52.3%	55.4%	54.6%	50.2%	44.9%	43.0%	42.2%	41.8%	*42.5%*	*43.0%*	Common Equity Ratio	*45.0%*
1564.4	1950.6	2230.1	2233.7	2599.6	3088.9	4104.2	3793.0	4302.6	4758.8	*5250*	*5500*	Total Capital (\$mill)	*6300*
1884.1	2128.3	2407.7	2609.7	2651.0	3041.2	3983.0	4213.5	4649.9	5022.1	*5400*	*5750*	Net Plant (\$mill)	*6500*
12.1%	8.6%	6.9%	7.7%	10.1%	6.4%	5.6%	6.5%	5.6%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	*13.0%*	*12.5%*	Return on Shr. Equity	*12.5%*
18.3%	13.9%	11.8%	12.1%	16.9%	11.3%	10.6%	12.7%	13.2%	13.2%	*13.0%*	*12.5%*	Return on Com Equity	*12.5%*
11.0%	7.0%	4.8%	5.0%	10.2%	4.6%	4.3%	5.6%	6.2%	5.6%	*5.5%*	*5.0%*	Retained to Com Eq	*5.5%*
40%	50%	60%	59%	40%	59%	60%	56%	53%	58%	*58%*	*61%*	All Div'ds to Net Prof	*56%*

CURRENT POSITION (\$MILL.)	2022	2023	6/30/24
Cash Assets	1.1	1.0	22.4
Other	755.0	531.1	512.0
Current Assets	756.1	532.1	534.4
Accts Payable	156.6	151.8	144.6
Debt Due	499.1	368.3	452.3
Other	448.5	286.5	297.4
Current Liab.	1104.2	806.6	894.3
Fix. Chg. Cov.	545%	520%	310%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-3.0%	-6.0%	*2.5%*
"Cash Flow"	7.0%	4.5%	*5.0%*
Earnings	5.0%	2.5%	*5.0%*
Dividends	6.5%	6.5%	*5.0%*
Book Value	7.5%	7.0%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES (\$ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	454.3	802.2	367.6	532.5	2156.6
2022	675.8	912.3	552.3	765.5	2906.0
2023	723.6	644.0	264.1	331.3	1963.0
2024	467.2	657.9	275.6	*499.3*	*1900*
2025	*715*	*625*	*305*	*455*	*2100*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	.46	1.77	d.15	.07	2.16
2022	.69	1.36	d.04	.50	2.50
2023	1.14	1.16	.10	.30	2.70
2024	.74	1.41	d.09	*.84*	*2.90*
2025	*.75*	*1.40*	*.Nil*	*.75*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.3125	.3125	.3125	.3325	1.27
2021	.3325	.3325	.3325	.3625	1.36
2022	.3625	.3625	.3625	.3625	1.45
2023	.39	.39	.39	.39	1.56
2024	.42	.42	.42	.45	

BUSINESS: New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in NJ, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had 576,000 cust. at 9/30/23. Fiscal 2023 volume: 128 bill. cu. ft. (23% interruptible, 50% residential, commercial & firm transportation, 27% other). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2023 dep. rate: 2.8%. Has 1,350 empls. Off./dir. own less than 1% of common; BlackRock, 15.9%; Vanguard, 11.4% (12/23 Proxy). CEO, President & Director: Steven D. Westhoven. Incorporated: New Jersey. Address: 1415 Wyckoff Road, Wall, NJ 07719. Telephone: 732-938-1480. Web: www.njresources.com.

New Jersey Resources likely ended fiscal 2024 on a good note. (Fiscal year ended September 30th.) The company reported earnings per share of \$2.06 over the first nine months, down from \$2.40 in the year before. The broader energy markets have been volatile over the past two-plus years, but New Jersey Resources' diverse business mix has helped to smooth out some turbulence. Still, the negative overall comparison factors in multiple benefits unique to 2023, including a winter storm event and a tax valuation allowance. As such, operating results have generally expanded at a steady pace. Similarly, we expect a good operating result was reached in the fiscal-fourth quarter. However, our target of \$0.84 per share is bolstered by the likely recognition of significant revenue from asset management agreements within the Energy Services segment. This should bring the year-end tally to \$2.90 per share.

Looking ahead, earnings growth may stall somewhat in the absence of similar beneficial items. The bottom-line comparison may be more challenging next year without specific financial items to bolster results. However, core operations are likely to maintain the pace. The ongoing base rate case for NJ Natural Gas is proceeding, and could be resolved before the start of 2025, which would surely help results. Unfortunately, the company has planned significant investment of up to \$1.5 billion over the next two years, targeting the utility infrastructure as well as renewable energy projects. The latter of these planned investments could face headwinds with the potential for shifts in renewable energy policies and incentives, adding a degree of uncertainty and risk. The potential for tariffs may also elevate maintenance and other operating costs.

The stock doesn't offer strong price appreciation potential over the long run, at the recent quotation. To its credit, the company did recently raise its dividend by 7%, to \$0.45 per share. Investors may also appreciate the stock's Safety rank of 2 (Above Average). However, other stocks within the industry appear to offer better price appreciation potential for those looking to gain exposure to regulated gas utilities.

Earl B. Humes *November 22, 2024*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly. revenues and egs. may not sum to total due to rounding and change in shares outstanding. Next earnings report due November 25th.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2023: \$585 million, \$6.00/share.
(E) In millions, adjusted for 3/15 split.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	65

NISOURCE INC. NYSE-NI

RECENT PRICE 36.22 | P/E RATIO 20.1 (Trailing: 20.2, Median: 21.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.1% | VALUE LINE

TIMELINESS 4 Lowered 9/6/24
SAFETY 2 Raised 2/23/24
TECHNICAL 2 Raised 11/22/24
BETA .95 (1.00 = Market)

High:	33.5	44.9	49.2	26.9	27.8	28.1	30.7	30.5	27.8	32.6	29.0	36.4
Low:	24.8	32.1	16.0	19.0	21.7	22.4	24.7	19.6	21.1	23.8	22.9	24.8

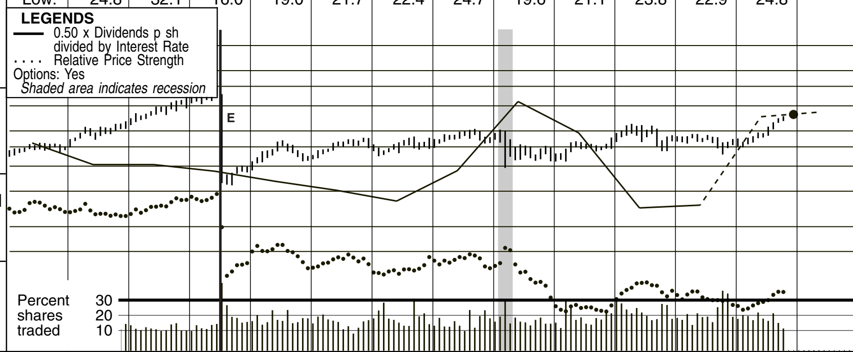
18-Month Target Price Range
Low-High: $25-$42 | Midpoint (% to Mid): $34 (-10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	35	(-5%)	3%

Institutional Decisions

	4Q2023	1Q2024	2Q2024
to Buy	313	331	328
to Sell	253	236	249
Hld's(000)	413866	425705	439719



Target Price Range 2027 | 2028 | 2029
80
60
50
40
30
25
20
15
10
7.5

% TOT. RETURN 10/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	45.0	28.7
3 yr.	58.5	10.7
5 yr.	48.3	73.6

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
32.36	24.02	22.99	21.33	16.31	18.04	20.47	14.58	13.90	14.46	13.74	13.63	11.95	12.09	14.23	12.33	*12.60*	*13.55*	Revenues per sh	*15.15*
3.32	2.96	3.19	2.98	3.13	3.41	3.60	2.27	2.71	2.07	2.86	3.17	3.15	3.26	3.47	3.64	*3.95*	*4.05*	"Cash Flow" per sh	*4.45*
1.34	.84	1.06	1.05	1.37	1.57	1.67	.63	1.00	.39	1.30	1.31	1.32	1.37	1.47	1.60	*1.75*	*1.80*	Earnings per sh A	*2.15*
.92	.92	.92	.92	.94	.98	1.02	.83	.64	.70	.78	.80	.84	.88	.94	1.00	*1.06*	*1.12*	Div'ds Decl'd per sh B ■	*1.20*
3.54	2.81	2.88	3.99	4.83	5.99	6.42	4.26	4.57	5.03	4.88	4.72	4.49	4.53	6.32	5.93	*5.30*	*6.50*	Cap'l Spending per sh	*7.00*
17.24	17.54	17.63	17.71	17.90	18.77	19.54	12.04	12.60	12.82	13.08	13.36	12.44	13.33	13.14	22.71	*22.55*	*23.25*	Book Value per sh C	*26.05*
274.26	276.79	279.30	282.18	310.28	313.68	316.04	319.11	323.16	337.02	372.36	382.14	391.76	404.30	411.10	446.38	*465.00*	*465.00*	Common Shs Outst'g D	*475.00*
12.1	14.3	15.3	19.4	17.9	18.9	22.7	37.3	23.2	NMF	19.3	21.3	18.7	18.0	19.6	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.73	.95	.97	1.22	1.14	1.06	1.19	1.88	1.22	NMF	1.04	1.13	.96	.99	11.8	.97	*Value Line*		Relative P/E Ratio	*1.05*
5.7%	7.6%	5.7%	4.5%	3.8%	3.3%	2.7%	3.5%	2.8%	2.8%	3.1%	2.9%	3.4%	3.6%	3.3%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.0%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $13614.5 mill. **Due in 5 Yrs** $4536 mill.
LT Debt $12086.3 mill. **LT Interest** $505 mill.
(Interest cov. earned: 5.5x) (54% of Cap'l)

Leases, Uncapitalized Annual rentals $9.6 mill.
Pension Assets-12/23 $1.4 bill. **Oblig.** $1.4 bill.

Common Stock 466,778,943 shs.
as of 10/22/24

MARKET CAP: $16.9 billion (Large Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
6470.6	4651.8	4492.5	4874.6	5114.5	5208.9	4681.7	4899.6	5850.6	5505.4	*5850*	*6300*	Revenues ($mill)	*7200*
530.7	198.6	328.1	128.6	478.3	549.8	562.6	626.3	648.2	716.3	*815*	*835*	Net Profit ($mill)	*1020*
36.9%	41.6%	35.7%	71.0%	19.7%	17.0%	18.3%	15.7%	17.2%	17.8%	*19.0%*	*19.0%*	Income Tax Rate	*19.0%*
--	--	--	--	--	--	--	2.0%	2.3%	3.5%	*3.0%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
56.9%	60.7%	59.8%	63.5%	55.3%	56.8%	61.6%	56.9%	55.7%	52.2%	*54.0%*	*55.0%*	Long-Term Debt Ratio	*55.0%*
43.1%	39.3%	40.2%	36.5%	37.9%	36.9%	32.5%	33.5%	31.6%	45.5%	*46.0%*	*45.0%*	Common Equity Ratio	*45.0%*
14331	9792.0	10129	11832	12856	13843	14972	16131	17099	21192	*22800*	*24000*	Total Capital ($mill)	*27500*
16017	12112	13068	14360	15543	16912	16620	17882	19843	22275	*25250*	*26000*	Net Plant ($mill)	*28000*
5.3%	4.0%	5.0%	2.6%	5.1%	5.3%	5.0%	4.9%	3.8%	3.4%	*3.5%*	*3.5%*	Return on Total Cap'l	*3.5%*
8.6%	5.2%	8.1%	3.0%	8.3%	9.2%	9.8%	9.0%	9.3%	7.1%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
8.6%	5.2%	8.1%	3.0%	9.6%	9.7%	10.4%	10.6%	12.0%	7.4%	*8.0%*	*8.0%*	Return on Com Equity	*8.5%*
3.4%	NMF	3.0%	NMF	4.0%	3.8%	3.8%	4.2%	4.0%	2.8%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
61%	NMF	63%	NMF	60%	64%	67%	64%	64%	63%	*61%*	*62%*	All Div'ds to Net Prof	*56%*

CURRENT POSITION ($MILL.)	2022	2023	9/30/24
Cash Assets	40.8	2245.4	126.2
Other	2543.5	2254.0	1489.8
Current Assets	2584.3	4499.4	1616.0
Accts Payable	899.5	749.4	614.6
Debt Due	1791.9	3072.4	1528.2
Other	1969.1	1443.3	1342.7
Current Liab.	4660.5	5265.1	3485.5
Fix. Chg. Cov.	255%	225%	445%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-5.0%	-3.5%	*5.5%*
"Cash Flow"	.5%	6.5%	*5.5%*
Earnings	1.5%	15.0%	*9.5%*
Dividends	-.5%	3.5%	*4.5%*
Book Value	-3.0%	.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1545.6	986.0	959.4	1408.6	4899.6
2022	1873.3	1183.2	1089.5	1704.6	5850.6
2023	1966.0	1090.0	1027.4	1422.0	5505.4
2024	1706.3	1084.7	1076.3	*1982.7*	*5850*
2025	*1840*	*1175*	*1160*	*2125*	*6300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	.77	.13	.11	.39	1.37
2022	.75	.12	.10	.50	1.47
2023	.77	.11	.19	.53	1.60
2024	.85	.21	.20	*.49*	*1.75*
2025	*.85*	*.20*	*.20*	*.55*	*1.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.21	.21	.21	.21	.84
2021	.22	.22	.22	.22	.88
2022	.235	.235	.235	.235	.94
2023	.25	.25	.25	.25	1.00
2024	.265	.265	.265	.265	

BUSINESS: NiSource Inc. is a holding company for Northern Indiana Public Service Company (NIPSCO), which supplies electricity and gas to the northern third of Indiana. Customers: 488,833 electric in Indiana, 3,200,000 gas in Indiana, Ohio, Pennsylvania, Kentucky, Virginia, Maryland, through its Columbia subsidiaries. Revenue breakdown, 2023: electrical, 32%; gas, 67%; other, less than 1%. Generating capacity, coal, 69.4%; purchased & other, 30.6%. 2023 reported depreciation rates: 3.5% electric, 2.4% gas. Has 7,364 employees. Chairman: Richard L. Thompson. President & Chief Executive Officer: Lloyd Yates. Incorporated: Indiana. Address: 801 East 86th Avenue, Merrillville, Indiana 46410. Telephone: 877-647-5990. Internet: www.nisource.com.

NiSource posted a better third-quarter profit than we expected. The earnings figure was steady versus both the year before and the prior quarter. We had thought the bottom line would dip to $0.13 per share during the gas utility's low season. Instead, higher rate base investments brought in an additional $61 million in revenues, and financing benefits added $26 million to the bottom line. Taking a closer look, the company's performance has been bolstered by lower energy costs, providing a significant boost to margins. However, depreciation expense is also rising rapidly, as the company is currently investing heavily in new capital projects aimed at infrastructure hardening and expanding upon clean-energy programs. Interest expense is up, too, as a result. On balance, the bottom-line has expanded nicely over the first nine months.

The good recent operating performance may come up against headwinds in the near term. As noted, the company has benefited from energy prices, due to a cost-pass-through mechanism that typically lags twelve months. Otherwise, the company has had to contend with some cost inflation. We think its probable that the lower energy costs will soon subside, leaving higher operating costs that will pressure earnings growth. To wit, management appears to agree, as our full-year 2024 bottom-line target of $1.75 is at the top of their guidance range. We've cut our full-year 2025 target by $0.05 as well, to $1.80, reflecting the recent share-count expansion of roughly 4%, per the end of the most recent quarter.

NiSource's current capital investment cycle is a key driver for future performance. Leadership updated its five-year capital plan to $19.3 billion, an increase of $2.9 billion from prior expectations. This focuses further on investments in power generation, gas compliance, infrastructure hardening, and modernization of technology systems. The plan aims to drive an 8% to 10% rate base growth.

The shares have gained over 45% in price these past twelve months, and currently trade within the bounds of our 3- to 5-year projections. Other investment opportunities show greater upside potential at this juncture.

Earl B. Humes *November 22, 2024*

(A) Dil. EPS. Excl. gains (losses) on disc. ops.: '08, ($1.14); '15, (30¢); '18, ($1.48). Next egs. report due late February. Qtl'y egs. may not sum to total due to rounding.
(B) Div'ds historically paid in mid-Feb., May, Aug., Nov. ■ Div'd reinv. avail.
(C) Incl. intang in '23: $1485.9 million, $3.33/sh.
(D) In mill.
(E) Spun off Columbia Pipeline Group (7/15)

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	25
Earnings Predictability	70

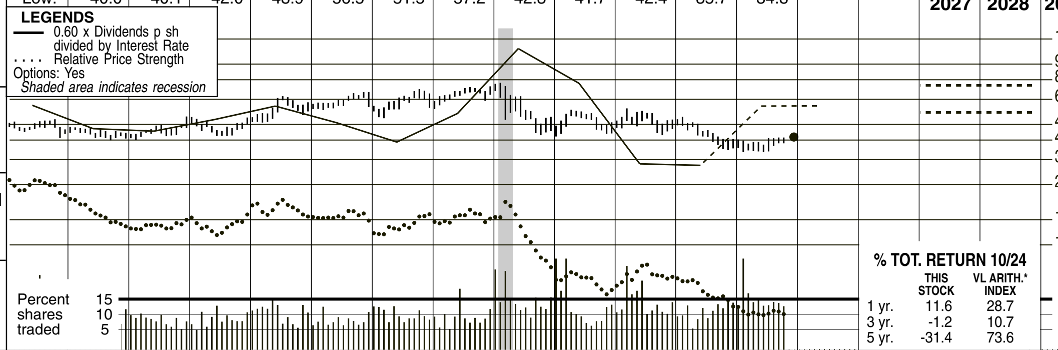
N.W. NATURAL NYSE-NWN

RECENT PRICE 41.44 | P/E RATIO 14.6 (Trailing: 19.0 / Median: 24.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 3 Raised 8/16/24
SAFETY 2 Raised 2/23/24
TECHNICAL 4 Lowered 7/26/24
BETA .85 (1.00 = Market)

High:	46.6	52.6	52.3	66.2	69.5	71.8	74.1	77.3	56.8	57.6	52.4	41.9
Low:	40.0	40.1	42.0	48.9	56.5	51.5	57.2	42.3	41.7	42.4	35.7	34.8

LEGENDS
— 0.60 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range
2027 | 2028 | 2029

18-Month Target Price Range
Low-High: $28-$49 — Midpoint (% to Mid): $39 (-5%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+80%)	19%
Low	55	(+35%)	11%

Institutional Decisions

	4Q2023	1Q2024	2Q2024
to Buy	123	131	132
to Sell	90	105	104
Hld's(000)	28414	28777	29331

Percent shares traded: 15 / 10 / 5

% TOT. RETURN 10/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.6	28.7
3 yr.	-1.2	10.7
5 yr.	-31.4	73.6

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
39.16	38.17	30.56	31.72	27.14	28.02	27.64	26.39	23.61	26.52	24.45	24.49	25.29	27.64	29.20	31.82	28.75	28.55	Revenues per sh	31.10
5.31	5.20	5.18	5.00	4.94	5.04	5.05	4.91	4.93	1.04	5.28	5.15	5.69	6.17	5.71	5.83	5.55	6.55	"Cash Flow" per sh	7.15
2.57	2.83	2.73	2.39	2.22	2.24	2.16	1.96	2.12	d1.94	2.33	2.19	2.30	2.56	2.54	2.59	2.30	3.00	Earnings per sh A	3.15
1.52	1.60	1.68	1.75	1.79	1.83	1.85	1.86	1.87	1.88	1.89	1.90	1.91	1.92	1.93	1.94	1.95	1.96	Div'ds Decl'd per sh B■	1.98
3.92	5.09	9.35	3.76	4.91	5.13	4.40	4.37	4.87	7.43	7.43	7.95	9.18	9.49	9.53	8.70	10.00	9.50	Cap'l Spending per sh	10.00
23.71	24.88	26.08	26.70	27.23	27.77	28.12	28.47	29.71	25.85	26.41	28.42	29.05	30.04	33.08	34.12	37.40	36.95	Book Value per sh D	39.00
26.50	26.53	26.58	26.76	26.92	27.08	27.28	27.43	28.63	28.74	28.88	30.47	30.59	31.13	35.53	37.63	40.00	42.00	Common Shs Outst'g C	45.00
18.1	15.2	17.0	19.0	21.1	19.4	20.7	23.7	26.9	- -	26.6	30.9	25.0	19.5	19.6	16.6	*Bold figures are*		Avg Ann'l P/E Ratio	20.0
1.09	1.01	1.08	1.19	1.34	1.09	1.09	1.19	1.41	- -	1.44	1.65	1.28	1.06	1.13	.96	*Value Line*		Relative P/E Ratio	1.10
3.3%	3.7%	3.6%	3.9%	3.8%	4.2%	4.1%	4.0%	3.3%	3.0%	3.0%	2.8%	3.3%	3.8%	3.9%	4.5%	*estimates*		Avg Ann'l Div'd Yield	3.3%

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
754.0	723.8	676.0	762.2	706.1	746.4	773.7	860.4	1037.4	1197.5	1150	1200	Revenues ($mill)	1400
58.7	53.7	58.9	d55.6	67.3	65.3	70.3	78.7	86.3	93.9	92.5	125	Net Profit ($mill)	140
41.5%	40.0%	40.9%	- -	26.4%	16.2%	23.1%	25.8%	25.2%	25.7%	25.0%	25.0%	Income Tax Rate	25.0%
7.8%	7.4%	8.7%	NMF	9.5%	8.8%	9.1%	9.1%	8.3%	7.8%	8.0%	10.5%	Net Profit Margin	10.1%
44.8%	42.5%	44.4%	47.9%	48.1%	48.2%	49.2%	52.8%	51.5%	52.6%	52.5%	55.0%	Long-Term Debt Ratio	55.0%
55.2%	57.5%	55.6%	52.1%	51.9%	51.8%	50.8%	47.2%	48.5%	47.4%	47.5%	45.0%	Common Equity Ratio	45.0%
1389.0	1357.7	1529.8	1426.0	1468.9	1672.0	1748.8	1979.7	2421.6	2709.2	3150	3450	Total Capital ($mill)	3900
2121.6	2182.7	2260.9	2255.0	2421.4	2438.9	2654.8	2871.4	3114.4	3358.0	3750	3900	Net Plant ($mill)	4200
5.8%	5.5%	5.1%	NMF	5.8%	5.2%	5.2%	5.1%	3.6%	3.5%	3.0%	3.5%	Return on Total Cap'l	3.5%
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	6.0%	8.0%	Return on Shr. Equity	8.0%
7.6%	6.9%	6.9%	NMF	8.8%	7.5%	7.9%	8.4%	7.3%	7.3%	6.0%	8.0%	Return on Com Equity	8.0%
1.1%	.6%	.9%	NMF	2.1%	1.4%	1.7%	2.4%	2.1%	1.7%	1.0%	2.5%	Retained to Com Eq	2.5%
85%	92%	87%	NMF	76%	82%	79%	71%	79%	75%	85%	65%	All Div'ds to Net Prof	63%

CAPITAL STRUCTURE as of 6/30/24
Total Debt $1654.7 mill. **Due in 5 Yrs** $1415 mill.
LT Debt $1574.8 mill. **LT Interest** $80 mill.

(Total interest coverage: 5.0x)

Pension Assets-12/23 $283.0 mill.
Oblig. $425.5 mill.

Pfd Stock None

Common Stock 38,670,272 shares
as of 7/26/24

MARKET CAP $1.6 billion (Small Cap)

CURRENT POSITION ($MILL.)	2022	2023	6/30/24
Cash Assets	29.3	32.9	65.2
Other	714.9	568.5	357.9
Current Assets	744.2	601.4	423.1
Accts Payable	180.7	145.4	93.6
Debt Due	348.9	240.7	79.9
Other	369.1	310.8	262.0
Current Liab.	898.7	696.9	435.5
Fix. Chg. Cov.	320%	240%	315%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-2.5%	- -	4.5%
"Cash Flow"	1.0%	2.5%	5.0%
Earnings	-1.0%	2.5%	6.5%
Dividends	1.5%	.5%	.5%
Book Value	1.0%	.5%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	315.9	148.9	101.5	294.1	860.4
2022	350.3	195.0	116.8	375.3	1037.4
2023	462.4	237.9	141.5	355.7	1197.5
2024	433.5	211.7	136.9	367.9	1150
2025	450	220	135	395	1200

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.94	d.02	d.67	1.31	2.56
2022	1.80	.05	d.56	1.36	2.54
2023	2.01	.03	d.65	1.21	2.59
2024	1.69	d.07	d.71	1.39	2.30
2025	2.10	.05	d.60	1.45	3.00

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.4775	.4775	.4775	.48	1.91
2021	.48	.48	.48	.483	1.92
2022	.483	.483	.483	.485	1.93
2023	.485	.485	.485	.488	1.94
2024	.488	.488	.488	.49	

BUSINESS: Northwest Natural Holding Co. distributes natural gas to 1,000 communities, 795,000 customers, in Oregon (88% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 3.7 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 38%; commercial, 23%; industrial, gas transportation, 39%. Employs 1,380. BlackRock Inc. owns 17.6% of shares; Vanguard, 12.4%; Off./Dir., .84% (4/24 proxy). CEO: David H. Anderson. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural's stock is up 12% in price since our late August review. The shares reached a twelve-month high on Tuesday, November 12th, after the company posted earnings results. The gas utility notched a loss of $0.71 per share, in line with our forecast, for the business' low season quarter. Management's commentary helped to improve investors' sentiment as it provided an update on the Oregon gas utility rate case and detailed various strategic objectives.

The third quarter was mostly in line with expectations. The earnings per share declined year over year, primarily as a result of regulatory lag on capital investments, as well as inflationary pressures. Operating expenses rose, including a $1.3 million rise in labor and material costs, and a $3.6 million increase in depreciation and general taxes. Other income also decreased $4.6 million from lower interest income and higher pension expense. Consolidated, net losses were $3.5 million worse this year, or $0.05 per share.

We expected earnings per share to bottom out this year, and begin to improve markedly by the end of 2025. The completion of the Oregon rate case is expected to improve earnings and resolve the regulatory lag. Capital expenditures are likely to be stable or lower next year as the company focuses primarily on safety and reliability projects. The acquisition of Putman Infrastructure and through Infrastructure Capital Holdings (ICH) by the water services subsidiary should help to expand that niche. Too, the completion of two landfill natural gas facilities should contribute to good results expected ahead.

Our long-term earnings-growth forecast is slightly above management's own target range. We expect strong economic fundamentals, including a steady regional economy, a good customer expansion rate, and a recent rise in single-family housing permits, will drive core utility performance, though, as we've seen this year, the regulatory environment remains a risk. We've targeted 6.5% earnings per share growth, compared to Northwest's guidance of 4% to 6%.

These shares could be of interest to long-term investors seeking a good-value position with a utility company.

Earl B. Humes — *November 22, 2024*

(A) Diluted earnings per share. Excludes non-recurring items: '08, ($0.03); '09, $0.06; May not sum due to rounding. Next earnings report due in late Febraury.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2023: $163 million, $4.33/share.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	20
Earnings Predictability	20

ONE GAS, INC. NYSE-OGS

RECENT PRICE **75.02** | P/E RATIO **18.8** (Trailing: 19.5 Median: 21.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS 4 Lowered 11/22/24
SAFETY 2 New 6/2/17
TECHNICAL 2 Raised 11/8/24
BETA .85 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$47-$87	$67 (-10%)

2027-29 PROJECTIONS

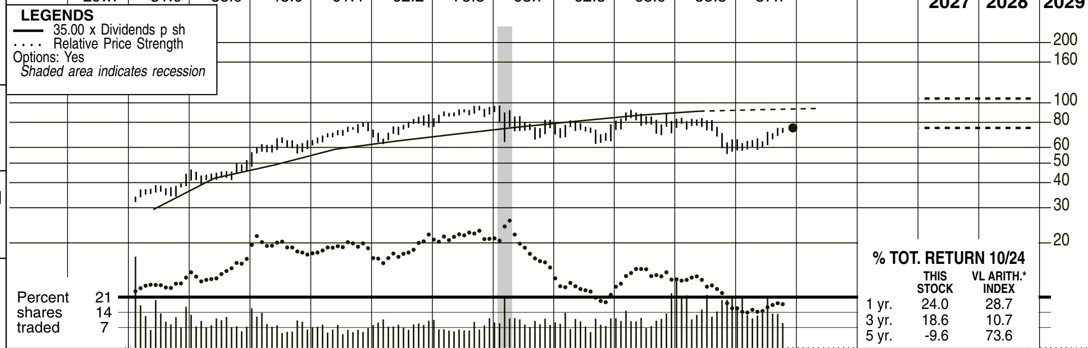
	Price	Gain	Ann'l Total Return
High	105	(+40%)	12%
Low	75	(Nil)	4%

Institutional Decisions

	4Q2023	1Q2024	2Q2024
to Buy	159	170	143
to Sell	160	147	160
Hld's(000)	52932	51905	53086

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	44.3	51.8	67.4	79.5	87.8	96.7	97.0	81.9	92.3	84.3	75.4
Low:	31.9	38.9	48.0	61.4	62.2	75.8	63.7	62.5	68.9	55.5	57.7

Target Price Range 2027 2028 2029



% TOT. RETURN 10/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	24.0	28.7
3 yr.	18.6	10.7
5 yr.	-9.6	73.6

The shares of ONE Gas, Inc. began trading "regular-way" on the New York Stock Exchange on February 3, 2014. That happened as a result of the separation of ONEOK's natural gas distribution operation. Regarding the details of the spinoff, on January 31, 2014, ONEOK distributed one share of OGS common stock for every four shares of ONEOK common stock held by ONEOK shareholders of record as of the close of business on January 21. It should be mentioned that ONEOK did not retain any ownership interest in the new company.

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
34.92	29.62	27.30	29.43	31.08	31.32	28.78	33.72	46.58	41.95	**36.65**	**38.95**	Revenues per sh	**70.15**
4.52	4.82	5.43	5.96	6.32	6.96	7.36	7.71	8.13	9.04	**9.10**	**9.45**	"Cash Flow" per sh	**13.95**
2.07	2.24	2.65	3.02	3.25	3.51	3.68	3.85	4.08	4.14	**3.85**	**4.05**	Earnings per sh A	**5.00**
.84	1.20	1.40	1.68	1.84	2.00	2.16	2.32	2.48	2.60	**2.64**	**2.68**	Div'ds Decl'd per sh B■	**2.85**
5.70	5.63	5.91	6.81	7.50	7.91	8.87	9.23	11.01	11.79	**12.10**	**12.30**	Cap'l Spending per sh	**12.60**
34.45	35.24	36.12	37.47	38.86	40.35	42.01	43.81	46.69	48.91	**51.75**	**55.95**	Book Value per sh	**60.20**
52.08	52.26	52.28	52.31	52.57	52.77	53.17	53.63	55.35	56.55	**56.50**	**56.50**	Common Shs Outst'g C	**57.00**
17.8	19.8	22.7	23.5	23.1	25.3	21.7	18.9	19.9	18.0	*Bold figures are*		Avg Ann'l P/E Ratio	**18.0**
.94	1.00	1.19	1.18	1.25	1.35	1.11	1.02	1.16	1.01	*Value Line*		Relative P/E Ratio	**1.00**
2.3%	2.7%	2.3%	2.4%	2.5%	2.3%	2.7%	3.2%	3.1%	3.5%	*estimates*		Avg Ann'l Div'd Yield	**3.2%**
1818.9	1547.7	1427.2	1539.6	1633.7	1652.7	1530.3	1808.6	2578.0	2372.0	**2070**	**2200**	Revenues ($mill)	**4000**
109.8	119.0	140.1	159.9	172.2	186.7	196.4	206.4	221.7	231.2	**220**	**230**	Net Profit ($mill)	**285**
38.4%	38.0%	37.8%	36.4%	23.7%	18.7%	17.5%	16.3%	17.3%	14.9%	**16.5%**	**16.5%**	Income Tax Rate	**20.0%**
6.0%	7.7%	9.8%	10.4%	10.5%	11.3%	12.8%	11.4%	8.6%	9.7%	**10.6%**	**10.5%**	Net Profit Margin	**7.1%**
40.1%	39.5%	38.7%	37.8%	38.6%	37.7%	41.5%	61.1%	50.7%	43.8%	**46.0%**	**45.0%**	Long-Term Debt Ratio	**51.0%**
59.9%	60.5%	61.3%	62.2%	61.4%	62.3%	58.5%	38.9%	49.3%	56.2%	**54.0%**	**55.0%**	Common Equity Ratio	**49.0%**
2995.3	3042.9	3080.7	3153.5	3328.1	3415.5	3815.7	6032.9	5246.2	4926.3	**5415**	**5750**	Total Capital ($mill)	**7000**
3293.7	3511.9	3731.6	4007.6	4283.7	4565.2	4867.1	5190.8	5628.8	6135.2	**6650**	**7025**	Net Plant ($mill)	**8200**
4.4%	4.7%	5.2%	5.8%	5.9%	6.4%	6.0%	3.9%	5.0%	5.9%	**5.5%**	**5.5%**	Return on Total Cap'l	**5.5%**
6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	**7.5%**	**7.5%**	Return on Shr. Equity	**8.5%**
6.1%	6.5%	7.4%	8.2%	8.4%	8.8%	8.8%	8.8%	8.6%	8.4%	**7.5%**	**7.5%**	Return on Com Equity	**8.5%**
3.7%	3.1%	3.5%	3.7%	3.7%	3.8%	3.7%	3.5%	3.4%	3.2%	**2.5%**	**2.5%**	Retained to Com Eq	**3.5%**
40%	53%	52%	55%	56%	56%	58%	60%	60%	62%	**68%**	**66%**	All Div'ds to Net Prof	**57%**

CAPITAL STRUCTURE as of 9/30/24
Total Debt $3365.3 mill. **Due in 5 Yrs** $890.0 mill.
LT Debt $2384.9 mill. **LT Interest** $120.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x)
Leases, Uncapitalized Annual rentals $6.7 mill.
Pfd Stock None
Pension Assets-12/23 $977.0 mill. **Oblig.** $962.1 mill.
Common Stock 56,655,256 shs. as of 10/28/24
MARKET CAP: $4.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	9/30/24
Cash Assets	9.7	18.8	18.8
Other	1207.9	746.4	671.7
Current Assets	1217.6	765.2	690.5
Accts Payable	360.5	278.1	146.8
Debt Due	572.7	888.9	980.4
Other	256.2	310.2	260.4
Current Liab.	1189.4	1477.2	1387.6
Fix. Chg. Cov.	540%	390%	405%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	- -	7.0%	9.5%
"Cash Flow"	- -	7.0%	9.0%
Earnings	- -	6.0%	3.5%
Dividends	- -	8.5%	2.5%
Book Value	- -	4.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	625.3	315.6	273.9	593.8	1808.6
2022	971.5	428.9	359.4	818.2	2578.0
2023	1032.1	398.1	335.8	606.0	2372.0
2024	758.3	354.1	340.4	**617.2**	**2070**
2025	**800**	**375**	**350**	**675**	**2200**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	1.79	.56	.38	1.12	3.85
2022	1.83	.59	.44	1.23	4.08
2023	1.84	.58	.45	1.27	4.14
2024	1.75	.48	.34	**1.28**	**3.85**
2025	**1.84**	**.53**	**.38**	**1.30**	**4.05**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.54	.54	.54	.54	2.16
2021	.58	.58	.58	.58	2.32
2022	.62	.62	.62	.62	2.48
2023	.65	.65	.65	.65	2.60
2024	.66	.66	.66	.66	

BUSINESS: ONE Gas, Inc. provides natural gas distribution services to more than two million customers. There are three divisions: Oklahoma Natural Gas, Kansas Gas Service, and Texas Gas Service. The company purchased 160 Bcf of natural gas supply in 2023, compared to 165 Bcf in 2022. Total volumes delivered by customer (fiscal 2023): transportation, 59.3%; residential, 29.7%; commercial & industrial, 10.6%; other, .4%. ONE Gas has around 3,900 employees. BlackRock owns 14.5% of common stock; The Vanguard Group, 11.6%; American Century Investment, 7.5%; officers and directors, 1.5% (4/24 Proxy). CEO: Robert S. McAnnally. Incorporated: Oklahoma. Address: 15 East Fifth Street, Tulsa, Oklahoma 74103. Tel.: 918-947-7000. Internet: www.onegas.com.

ONE Gas appears to be headed for a down year. Indeed, through the first nine months, profits of $2.57 per share were 10.5% below the $2.87 figure that was generated for the same period in 2023. That partly reflected higher employee-related costs, stemming from planned investments in the company's workforce and ongoing in-sourcing efforts. Depreciation & amortization expense increased, too, given additional capital investments. Moreover, sales volumes declined and interest charges climbed. But new rates aided results to a certain degree during the period. Although we do not anticipate any big problems for ONE Gas in the fourth quarter, the bottom line stands to end up around $3.85 a share for the whole year. That would indicate a 7% decrease from 2023's $4.14 tally. But concerning 2025, a 5% or so recovery, to $4.05 per share, seems plausible, assuming that the operating environment is generally favorable.

Business prospects out to 2027-2029 look promising. The company is the leading natural gas distributor, as measured by number of customers, in both Oklahoma and Kansas, and holds the number-three position in Texas. Furthermore, we believe these markets have decent growth potential and are located in one of the most active drilling areas in the United States. Also, supported by the sound finances, ONE Gas ought to continue to satisfy its obligations (including capital expenditures and working capital requirements) with little trouble.

There are risk factors to consider, though. The company's lack of geographic diversification leaves it somewhat more vulnerable to regional economic downturns and regulations. Moreover, there's competition from other energy suppliers, such as propane dealers and electric companies. Finally, pipeline ruptures, leaks, and other unfortunate events can take a major toll on earnings if not adequately covered by insurance.

What about the stock? The dividend yield looks respectable when stacked against other equities in *Value Line's* Natural Gas Utility Industry. However, capital gains possibilities over the 3- to 5-year span are unspectacular, at the recent quotation. These shares are untimely, too.

Frederick L. Harris, III November 22, 2024

(A) Diluted EPS. Excludes nonrecurring gain: 2017, $0.06. Next earnings report due early Feb. Quarterly EPS figures for 2022 don't equal total due to rounding.
(B) Dividends historically paid in early March, June, Sept., and Dec. ■ Dividend reinvestment plan. Direct stock purchase plan.
(C) In millions.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	40
Earnings Predictability	100

SOUTHWEST GAS NYSE-SWX

RECENT PRICE 77.10 | P/E RATIO 20.7 (Trailing: 31.0 / Median: 21.0) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS E– Suspended 11/17/23
SAFETY 2 Raised 2/23/24
TECHNICAL E– Suspended 11/17/23
BETA .95 (1.00 = Market)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High:	56.0	64.2	63.7	79.6	86.9	86.0	92.9	81.6	73.5	95.6	68.0	79.0
Low:	42.0	47.2	50.5	53.5	72.3	62.5	73.3	45.7	57.0	59.5	53.8	57.6

Target Price Range
2027 | 2028 | 2029

18-Month Target Price Range

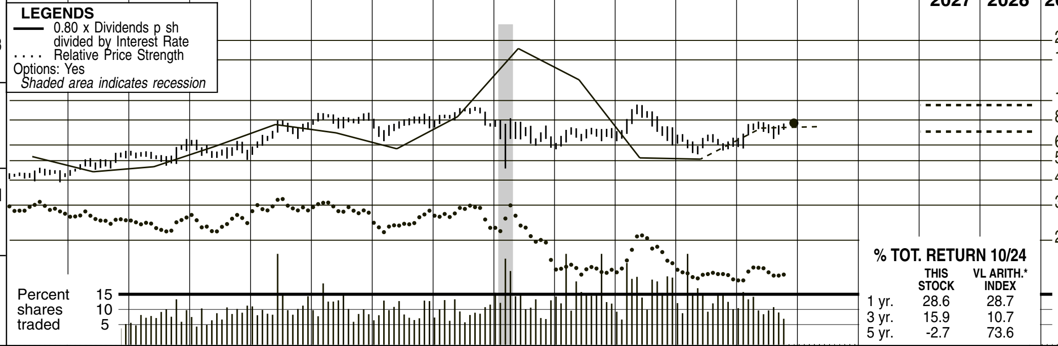
Low-High	Midpoint (% to Mid)
$51-$91	$71 (-10%)

2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+25%)	*8%*
Low	70	(-10%)	*1%*

Institutional Decisions

	4Q2023	1Q2024	2Q2024
to Buy	130	122	141
to Sell	144	149	131
Hld's(000)	66489	65977	66812



% TOT. RETURN 10/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	28.6	28.7
3 yr.	15.9	10.7
5 yr.	-2.7	73.6

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
48.53	42.00	40.18	41.07	41.77	42.08	45.61	52.00	51.82	53.00	54.31	56.72	57.68	60.91	73.90	76.22	*71.55*	*73.95*	Revenues per sh	*76.65*
5.76	6.16	6.46	6.81	7.73	8.24	8.47	8.62	9.29	8.83	8.14	9.40	9.87	9.46	3.91	8.29	*8.75*	*9.85*	"Cash Flow" per sh	*10.90*
1.39	1.94	2.27	2.43	2.86	3.11	3.01	2.92	3.18	3.62	3.68	3.94	4.14	3.39	d3.10	2.13	*2.80*	*3.60*	Earnings per sh A	*4.50*
.90	.95	1.00	1.06	1.18	1.32	1.46	1.62	1.80	1.98	2.08	2.18	2.28	2.38	2.48	2.48	*2.48*	*2.52*	Div'ds Decl'd per sh B■†	*2.60*
6.79	4.81	4.73	8.29	8.57	7.86	8.53	10.30	11.15	12.97	14.44	17.06	14.43	11.84	12.80	12.19	*13.15*	*12.50*	Cap'l Spending per sh	*14.00*
23.49	24.44	25.62	26.66	28.35	30.47	31.95	33.61	35.03	37.74	42.47	45.56	46.77	48.89	47.95	47.72	*51.70*	*54.25*	Book Value per sh	*56.35*
44.19	45.09	45.56	45.96	46.15	46.36	46.52	47.38	47.48	48.09	53.03	55.01	57.19	60.42	67.12	71.56	*72.00*	*73.00*	Common Shs Outst'g C	*75.00*
20.3	12.2	14.0	15.7	15.0	15.8	17.9	19.4	21.6	22.2	20.6	21.3	16.8	19.9	- -	29.1	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
1.22	.81	.89	.98	.95	.89	.94	.98	1.13	1.12	1.11	1.13	.86	1.08	- -	1.68	*Value Line*		Relative P/E Ratio	*.90*
3.2%	4.0%	3.2%	2.8%	2.8%	2.7%	2.7%	2.9%	2.6%	2.5%	2.7%	2.6%	3.3%	3.5%	3.2%	4.0%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
2121.7	2463.6	2460.5	2548.8	2880.0	3119.9	3298.9	3680.5	4960.0	5454.0	*5150*	*5400*	Revenues ($mill)	*5750*
141.1	138.3	152.0	173.8	182.3	213.9	232.3	200.8	d203.3	150.9	*200*	*265*	Net Profit ($mill)	*335*
35.7%	36.4%	33.9%	32.8%	25.3%	20.5%	21.6%	16.1%	NMF	21.2%	*21.0%*	*21.0%*	Income Tax Rate	*21.0%*
6.7%	5.6%	6.2%	6.8%	6.3%	6.9%	7.0%	5.5%	NMF	2.8%	*3.9%*	*4.9%*	Net Profit Margin	*5.9%*
52.4%	49.3%	48.2%	49.8%	48.3%	47.9%	50.5%	58.2%	57.8%	57.4%	*55.0%*	*55.0%*	Long-Term Debt Ratio	*56.0%*
47.6%	50.7%	51.8%	50.2%	51.7%	52.1%	49.5%	41.8%	42.2%	42.6%	*45.0%*	*45.0%*	Common Equity Ratio	*44.0%*
3123.9	3143.5	3213.5	3613.3	4359.3	4806.4	5407.2	7069.5	7621.4	8024.5	*8200*	*8800*	Total Capital ($mill)	*9600*
3658.4	3891.1	4132.0	4523.7	5093.2	5685.2	6176.1	7594.0	7024.5	7518.2	*8000*	*8500*	Net Plant ($mill)	*9250*
5.7%	5.5%	5.8%	5.8%	5.2%	5.4%	5.3%	3.5%	NMF	1.9%	*2.5%*	*3.0%*	Return on Total Cap'l	*3.5%*
9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.4%	*5.5%*	*6.5%*	Return on Shr. Equity	*8.0%*
9.5%	8.7%	9.1%	9.6%	8.1%	8.5%	8.7%	6.8%	NMF	4.4%	*5.5%*	*6.5%*	Return on Com Equity	*8.0%*
5.0%	4.0%	4.1%	4.5%	3.6%	3.9%	4.0%	2.1%	NMF	NMF	*.5%*	*2.0%*	Retained to Com Eq	*3.5%*
47%	54%	55%	53%	55%	54%	54%	69%	NMF	116%	*89%*	*70%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 9/30/24
Total Debt $5045.1 mill. **Due in 5 Yrs** $1008 mill.
LT Debt $4382.1 mill. **LT Interest** $300 mill.
(Total interest coverage: 2.6x) (55% of Cap'l)

Leases, Uncapitalized Annual rentals $24.9 mill.
Pension Assets-12/23 $1202.0 mill. **Oblig.** $1352.2 mill.

Pfd Stock None

Common Stock 71,743,666 shs.
as of 10/25/24

MARKET CAP: $5.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2022	2023	9/30/24
Cash Assets	123.1	106.5	456.6
Other	3584.6	1774.6	998.8
Current Assets	3707.7	1881.1	1455.4
Accts Payable	662.1	346.9	227.0
Debt Due	1587.4	671.1	663.0
Other	1173.5	666.8	812.7
Current Liab.	1173.5	1684.8	1702.7
Fix. Chg. Cov.	265%	145%	225%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	3.5%	3.0%	*6.0%*
"Cash Flow"	4.0%	1.5%	*8.5%*
Earnings	5.5%	4.5%	*10.0%*
Dividends	8.5%	7.0%	*5.5%*
Book Value	6.5%	7.0%	*7.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	885.9	821.4	888.7	1084.5	3680.5
2022	1267.4	1146.1	1125.6	1420.9	4960.0
2023	1603.3	1293.6	1169.5	1387.6	5454.0
2024	1581.0	1182.2	1079.2	*1307.6*	*5150*
2025	*1660*	*1240*	*1225*	*1275*	*5400*

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2021	2.03	.43	d.19	1.15	3.39
2022	1.58	d.10	d.18	d4.18	d3.10
2023	.67	.40	.04	1.02	2.13
2024	1.22	.25	Nil	*1.33*	*2.80*
2025	*1.75*	*.65*	*.15*	*1.05*	*3.60*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.545	.570	.570	.570	2.26
2021	.570	.595	.595	.595	2.36
2022	.595	.62	.62	.62	2.46
2023	.62	.62	.62	.62	2.48
2024	.62	.62	.62		

BUSINESS: Southwest Gas Holdings, Inc. is the parent holding company of Southwest Gas. Centuri Group spun-off 4/22/24. Southwest Gas is a regulated gas distributor serving 2.2 million customers in Arizona, Nevada, and California. 2023 margin mix: residential 68%; small commercial, 20%; large commercial and industrial, 8%; transportation, 4%. Total throughput: 2.2 billion therms. Southwest has 2,371 employees; Centuri 12,572. Off. & dir. own .4% of common stock; Carl C. Icahn, 15.4%; BlackRock, 13.0%; The Vanguard Group, 10.1%; (3/24 Proxy). Chairman: Michael J. Melarkey. Pres. & CEO: Karen S. Haller. Inc.: DE. Addr.: 8360 S. Durango Drive, P.O. Box 98510 Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas Holdings delivered another weaker-than-expected quarterly performance in the September period. Following the 2024 spin-off of the Centuri Group, the business has posted two quarters of year-over-year earnings declines. To be fair, the September and June periods both reflect the low season for gas usage, so Southwest's breakeven performance is not necessarily indicative of the utility's performance. In fact, Southwest Gas Corporation, the regulated utility business, achieved a significant expansion of operating profit compared to the previous year, as a result of rate relief from earlier investments made in Nevada and California, along with good customer growth trends. The poor comparison was actually a result of challenges at the Centuri Group, of which Southwest Holdings maintains an approximately 80% ownership interest. As such, Southwest's financial statements still present consolidated results. Centuri, the infrastructure services subsidiary, faced reduced work volumes and operational issues that led to higher costs and lower margins. Higher interest expense is also impacting earnings.

We've cut our near-term earnings forecasts to reflect recent headwinds. The utility should continue to perform well, but losses at Centuri are likely to subtract from results. We've lowered our profit target from $240 million (which is what the utility business is likely to earn independently) to $200 million. The recently refreshed rate structures and other key rate cases on the horizon exemplify the impetus for simplifying the company's operations away from auxiliary businesses. However, the separation of Centuri remains uncertain, contingent on market conditions that will influence the timing and structure of a sale. Until then, challenges at the Centuri group could create headwinds for Southwest's bottom line. We've cut our earnings-per-share targets from $3.25 in 2024 and $3.90 in 2025 to $2.80 and $3.60, respectively.

The stock has risen 9% in price since our August review. Despite the struggle at Centuri, investors are likely impressed with the gas utility's operating strength. We think conservative accounts may enjoy the dividend and lower risk here.

Earl B. Humes — *November 22, 2024*

(A) Diluted earnings. Excl. nonrec. gains (losses): '22, 10¢. Next egs. report due late February. **(B)** Dividends historically paid early March, June, September, and December.
■† Div'd reinvestment and stock purchase plan avail. **(C)** In millions.
(D) Totals may not sum due to rounding.
(E) Rank suspended 11/17/2023 for spin-off of the Centuri Group.

Company's Financial Strength	A
Stock's Price Stability	80
Price Growth Persistence	25
Earnings Predictability	5

SPIRE INC. NYSE-SR

RECENT PRICE **66.08** | P/E RATIO **15.5** (Trailing: 15.9 Median: 19.0) | RELATIVE P/E RATIO **0.82** | DIV'D YLD **4.8%** | VALUE LINE

TIMELINESS	3 Raised 2/16/24
SAFETY	2 Raised 6/20/03
TECHNICAL	2 Raised 11/15/24
BETA .90 (1.00 = Market)	

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$47-$76	$62 (-5%)

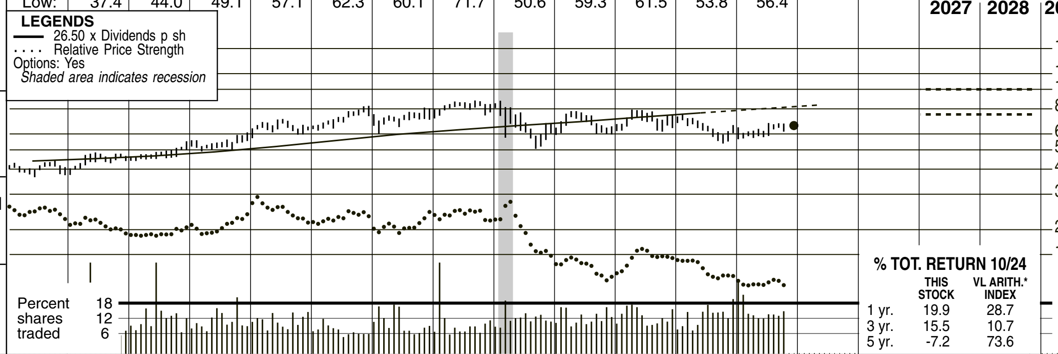
2027-29 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+50%)	15%
Low	75	(+15%)	8%

Institutional Decisions

	4Q2023	1Q2024	2Q2024
to Buy	140	135	160
to Sell	123	134	108
Hld's(000)	48459	48507	49797

High:	48.5	55.2	61.0	71.2	82.9	81.1	88.0	88.0	77.9	79.2	75.8	68.0
Low:	37.4	44.0	49.1	57.1	62.3	60.1	71.7	50.6	59.3	61.5	53.8	56.4



% TOT. RETURN 10/24

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.9	28.7
3 yr.	15.5	10.7
5 yr.	-7.2	73.6

2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	© VALUE LINE PUB. LLC	27-29
100.44	85.49	77.83	71.48	49.90	31.10	37.68	45.59	33.68	36.07	38.78	38.30	35.96	43.24	41.88	50.12	*45.15*	*45.25*	Revenues per sh A	*57.25*
4.22	4.56	4.11	4.62	4.58	3.12	3.87	6.15	6.16	6.54	7.55	7.12	5.25	9.09	8.44	8.60	*8.90*	*9.25*	"Cash Flow" per sh	*11.00*
2.64	2.92	2.43	2.86	2.79	2.02	2.35	3.16	3.24	3.43	4.33	3.52	1.44	4.96	3.95	3.85	*4.30*	*4.55*	Earnings per sh A B	*5.50*
1.49	1.53	1.57	1.61	1.66	1.70	1.76	1.84	1.96	2.10	2.25	2.37	2.49	2.60	2.74	2.88	3.02	*3.16*	Div'ds Decl'd per sh C■	*3.60*
2.57	2.36	2.56	3.02	4.83	4.00	3.96	6.68	6.42	9.08	9.86	16.15	12.37	12.09	10.52	12.45	*14.30*	*11.25*	Cap'l Spending per sh	*14.50*
22.12	23.32	24.02	25.56	26.67	32.00	34.93	36.30	38.73	41.26	44.51	45.14	44.19	46.74	49.08	50.29	*52.75*	*55.50*	Book Value per sh D	*66.05*
21.99	22.17	22.29	22.43	22.55	32.70	43.18	43.36	45.65	48.26	50.67	50.97	51.60	51.70	52.50	53.20	*58.00*	*60.00*	Common Shs Outst'g E	*62.00*
14.3	13.4	13.7	13.0	14.5	21.3	19.8	16.5	19.6	19.8	16.7	22.8	51.1	13.6	17.5	17.3	*14.2*		Avg Ann'l P/E Ratio	*16.0*
.86	.89	.87	.82	.92	1.20	1.04	.83	1.03	1.00	.90	1.21	2.62	.73	1.01	1.00	*.79*		Relative P/E Ratio	*.90*
3.9%	3.9%	4.7%	4.3%	4.1%	4.0%	3.8%	3.5%	3.1%	3.1%	3.1%	3.0%	3.4%	3.8%	4.0%	4.3%	4.9%		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 6/30/24
Total Debt $4500.3 mill. **Due in 5 Yrs** $2310.0 mill.
LT Debt $3422.3 mill. **LT Interest** $140.0 mill.
(Total interest coverage: 2.4x)

Leases, Uncapitalized Annual rentals $9.8 mill.
Pension Assets-9/23 $630.3 mill. **Oblig.** $832.5 mill.
Pfd Stock $242.0 mill. **Pfd Div'd** $14.8 mill.
Common Stock 57,750,474 shs.
as of 7/28/24

MARKET CAP: $3.8 billion (Mid Cap)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		27-29
1627.2	1976.4	1537.3	1740.7	1965.0	1952.4	1855.4	2235.5	2198.5	2666.3	*2620*	*2715*	Revenues ($mill) A	*3550*
84.6	136.9	144.2	161.6	214.2	184.6	88.6	271.7	220.8	217.5	*240*	*260*	Net Profit ($mill)	*340*
27.6%	31.2%	32.5%	32.4%	- -	15.7%	12.3%	20.1%	21.1%	15.1%	*19.5%*	*19.5%*	Income Tax Rate	*24.0%*
5.2%	6.9%	9.4%	9.3%	10.9%	9.5%	4.8%	12.2%	10.0%	8.2%	*9.2%*	*9.6%*	Net Profit Margin	*9.6%*
55.1%	53.0%	50.9%	50.0%	45.7%	45.0%	49.0%	52.5%	51.2%	54.9%	*51.0%*	*51.0%*	Long-Term Debt Ratio	*51.0%*
44.9%	47.0%	49.1%	50.0%	54.3%	49.7%	46.1%	43.2%	44.6%	41.3%	*45.0%*	*45.0%*	Common Equity Ratio	*45.0%*
3359.4	3345.1	3601.9	3986.3	4155.5	4625.6	4946.0	5597.3	5777.0	6471.3	*6800*	*7400*	Total Capital ($mill)	*9100*
2759.7	2941.2	3300.9	3665.2	3970.5	4352.0	4680.1	5055.7	5370.4	5778.9	*6150*	*6530*	Net Plant ($mill)	*7675*
3.1%	5.1%	4.9%	5.0%	6.3%	5.1%	2.9%	5.8%	4.9%	4.8%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.5%*
5.6%	8.7%	8.2%	8.1%	9.5%	7.3%	3.5%	10.2%	7.8%	7.5%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.5%*
5.6%	8.7%	8.2%	8.1%	9.5%	7.9%	3.2%	10.6%	8.0%	7.6%	*8.0%*	*8.0%*	Return on Com Equity	*8.5%*
1.5%	3.7%	3.3%	3.3%	4.7%	2.7%	NMF	5.1%	2.5%	1.9%	*2.0%*	*1.5%*	Retained to Com Eq	*2.5%*
73%	58%	59%	60%	51%	66%	NMF	54%	71%	76%	*77%*	*79%*	All Div'ds to Net Prof	*70%*

CURRENT POSITION ($MILL.)	2022	2023	6/30/24
Cash Assets	6.5	5.6	7.4
Other	1585.5	1071.3	818.4
Current Assets	1592.0	1076.9	825.8
Accts Payable	617.4	253.1	205.2
Debt Due	1318.7	1112.1	1078.0
Other	417.5	390.2	426.6
Current Liab.	2353.6	1755.4	1709.8
Fix. Chg. Cov.	393%	294%	310%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '21-'23 to '27-'29
Revenues	-1.0%	4.5%	*4.0%*
"Cash Flow"	8.0%	5.0%	*4.0%*
Earnings	5.0%	3.0%	*4.5%*
Dividends	5.0%	5.5%	*4.5%*
Book Value	5.5%	3.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	512.6	1104.9	327.8	290.2	2235.5
2022	555.4	880.9	448.0	314.2	2198.5
2023	814.0	1123.4	418.5	310.4	2666.3
2024	756.6	1128.5	414.1	*320.8*	*2620*
2025	*795*	*1140*	*445*	*335*	*2715*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2021	1.65	3.55	.03	d.26	4.96
2022	1.01	3.27	d.10	d.20	3.95
2023	1.66	3.33	d.48	d.66	3.85
2024	1.52	3.58	d.28	*d.52*	*4.30*
2025	*1.50*	*3.45*	*d.16*	*d.24*	*4.55*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2020	.6225	.6225	.6225	.6225	2.49
2021	.65	.65	.65	.65	2.60
2022	.685	.685	.685	.685	2.74
2023	.72	.72	.72	.72	2.88
2024	.755	.755	.755	.755	

BUSINESS: Spire Inc., formerly known as the Laclede Group, Inc., is a holding company for natural gas utilities, which distributes natural gas across Missouri, including the cities of St. Louis and Kansas City, Alabama, and Mississippi. Has roughly 1.7 million customers. Acquired Missouri Gas 9/13, Alabama Gas Co 9/14. Utility therms sold and transported in fiscal 2023: 3.2 bill. Revenue mix for regulated operations: residential, 67%; commercial and industrial, 25%; transportation, 5%; other, 3%. Officers and directors own 2.9% of common shares; American Century Companies, 15.4% (12/23 proxy). Chairman: Edward Glotzbach; CEO: Steve Lindsey. Inc.: Missouri. Address: 700 Market Street, St. Louis, Missouri 63101. Tel.: 314-342-0500. Internet: www.spireenergy.com.

It appears that Spire managed to post healthy bottom-line results in fiscal 2024, which concluded September 30th. (Please be aware that fourth-quarter figures were not disclosed to the public when this report went to press.) Recall that during the first nine months, earnings per share increased 7%, to $4.82, compared to the previous-year tally of $4.51. That was brought about partly by the Gas Utility division, which benefited from new rates. The Midstream unit and Gas Marketing segment had improved performances for that period, as well. If there were no big setbacks in the fourth quarter, we think full-year profits rebounded about 12%, to $4.30 a share, relative to fiscal 2023's $3.85 total.

Concerning fiscal 2025, earnings per share stand to grow in the mid-single-digit percentage range, to $4.55. This is based, to a certain extent, on our assumption that the business climate is generally favorable. Improvements in operating efficiencies ought to provide further assistance.

Corporate finances are sufficient. When the third quarter concluded, cash and equivalents were $7.4 million. Too, there was $1.3 billion available through a revolving credit facility maturing in July, 2027. Also, long-term debt resided at a manageable 50% of total capital, and short-term borrowings were not a major problem.

Prospects out to the end of the decade look decent. The gas utilities currently serve about 1.7 million customers in Mississippi, Alabama, and Missouri. Moreover, the other operations, particularly pipelines, hold promise. Additional expansionary projects and technological enhancements in customer service and elsewhere should be beneficial to Spire, as well. Finally, future acquisitions are probable, supported, of course, by the sound balance sheet.

The good-quality stock might be of interest to income-focused investors. Indeed, the dividend yield stacks up nicely relative to those of other equities in *Value Line's* Natural Gas Utility Industry. What's more, we anticipate further steady increases in the payout over the 2027-2029 span.

Frederick L. Harris, III November 22, 2024

(A) Fiscal year ends Sept. 30th. **(B)** Based on diluted shares outstanding. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late Jan. **(C)** Dividends paid in early January, April, July, and October. ■ Dividend reinvestment plan available. **(D)** Incl. deferred charges. In '23: $1,171.6 mill., $22.02/sh. **(E)** In millions. **(F)** Qtly. egs. may not sum due to rounding or change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	25
Earnings Predictability	50

Atmos Energy Corporation
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Seven Natural Gas Companies	Proxy Group of Seven Natural Gas Companies (excl. PRPM)
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.35 %	5.35 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.40	0.40
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.75 %	5.75 %
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group (3)	0.07	0.07
5.	Adjusted Bond Yield	5.82 %	5.82 %
6.	Equity Risk Premium (4)	5.21	5.18
7.	Risk Premium Derived Common Equity Cost Rate	11.03 %	11.00 %

Notes: (1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 17 and 18 of this Exhibit).

(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.40% from page 12 of this Exhibit.

(3) Adjustment to reflect the A3 Moody's LT issuer rating of the Utility Proxy Group as shown on page 13 of this Exhibit. The 0.07% upward adjustment is derived by taking 1/3 of the spread between A2 and Baa2 Public Utility Bonds (1/3 * 0.20% = 0.07%) as derived from page 12 of this Exhibit.

(4) From page 15 of this Exhibit.

Atmos Energy Corporation
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] Aa Rated Public Utility Bond	[3] A2 Rated Public Utility Bond	[4] Baa2 Rated Public Utility Bond
Jan-2025	5.48 %	5.75 %	5.88 %	6.07 %
Dec-2024	5.20	5.45	5.58	5.77
Nov-2024	5.14	5.43	5.56	5.76
Average	5.27 %	5.54 %	5.67 %	5.87

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:	0.40 % (1)
Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:	0.20 % (2)
A2 Rated Public Utility Bonds Over Aa2 Rated Public Utility Bonds:	0.13 % (3)

Notes:
(1) Column [3] - Column [1].
(2) Column [4] - Column [3].
(3) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

Atmos Energy Corporation
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Seven Natural Gas Companies

	Moody's Long-Term Issuer Rating January 2025		Standard & Poor's Long-Term Issuer Rating January 2025	
Proxy Group of Seven Natural Gas Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Atmos Energy Corporation	A1	5.0	A-	7.0
New Jersey Resources Corporation	A1	5.0	NR	- -
NiSource Inc.	Baa1	8.0	BBB+	8.0
Northwest Natural Holding Company	Baa1	8.0	A+	5.0
ONE Gas, Inc.	A3	7.0	A-	7.0
Southwest Gas Holdings, Inc.	Baa1	8.0	BBB	9.0
Spire Inc.	A1/A2	5.5	BBB+	8.0
Average	A3	6.6	A-	7.3

Notes:
(1) From page 14 of this Exhibit.

Source Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Atmos Energy Corporation
Judgment of Equity Risk Premium for the
Proxy Group of Seven Natural Gas Companies

Line No.		Proxy Group of Seven Natural Gas Companies	Proxy Group of Seven Natural Gas Companies (excl. PRPM)
1.	Calculated equity risk premium based on the total market using the beta approach (1)	5.78 %	5.75 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A2 rated bonds (2)	5.12	5.06
3.	Predicted Equity Risk Premium Based on Regression Analysis of 848 Fully-Litigated Natural Gas Cases (3)	4.72	4.72
4.	Average equity risk premium	5.21 %	5.18 %

Notes: (1) From page 16 of this Exhibit.
(2) From page 19 of this Exhibit.
(3) From page 20 of this Exhibit.

Atmos Energy Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Seven Natural Gas Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Seven Natural Gas Companies	Proxy Group of Seven Natural Gas Companies (excl. PRPM)
1.	Kroll Equity Risk Premium (1)	6.10 %	6.10 %
2.	Regression on Kroll Risk Premium Data (2)	6.82	6.82
3.	Kroll Equity Risk Premium based on PRPM (3)	7.50	NA
4	Equity Risk Premium Based on Value Line Summary and Index (4)	5.45	5.45
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	10.74	10.74
6.	Conclusion of Equity Risk Premium	7.32 %	7.28 %
7.	Adjusted Beta (6)	0.79	0.79
8.	Forecasted Equity Risk Premium	5.78 %	5.75 %

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll 2023 SBBI® Yearbook and Bloomberg Professional Services minus the arithmetic mean monthly yield of Moody's average Aaa and Aa2 corporate bonds from 1928-2024.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2024 referenced in Note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the average consensus forecast of Aaa corporate bonds of 5.35% (from page 11 of this Exhibit).

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The Ibbotson equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between Ibbotson large company common stock monthly returns and average Aaa and Aa corporate monthly bond yields, from January 1928 through January 2025.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.35% (from page 11 of this Exhibit) from the projected 3-5 year total annual market return of 10.80% (described fully in note 1 on page 22 of this Exhibit).

(5) Using data from the Bloomberg Professional Services, Value Line, and S&P Global Market Intelligence for the S&P 500, an expected total return of 16.09% was derived based upon expected dividend yields as a proxy for income returns and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.35% results in an expected equity risk premium of 10.74%.

(6) Average of mean and median beta from page 21 of this Exhibit.

Sources of Information:
Kroll 2023 SBBI® Yearbook
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index
Blue Chip Financial Forecasts, November 27, 2024 and January 31, 2025
S&P Capital IQ
Bloomberg Professional Services

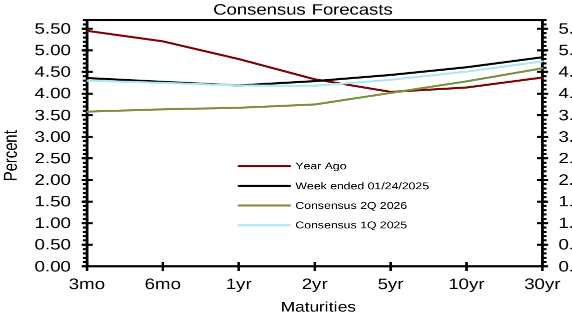
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Jan 24	Jan 17	Jan 10	Jan 3	Dec	Nov	Oct	4Q 2024	**2025**	**2025**	**2025**	**2025**	**2026**	**2026**
Federal Funds Rate	4.33	4.33	4.33	4.33	4.48	4.64	4.83	4.65	**4.3**	**4.2**	**4.0**	**3.9**	**3.8**	**3.6**
Prime Rate	7.50	7.50	7.50	7.50	7.65	7.81	8.00	7.82	**7.5**	**7.3**	**7.1**	**7.0**	**6.9**	**6.8**
SOFR	4.31	4.29	4.29	4.41	4.53	4.64	4.85	4.67	**4.3**	**4.2**	**4.0**	**3.9**	**3.8**	**3.6**
Commercial Paper, 1-mo.	4.33	4.33	4.31	4.32	4.50	4.62	4.78	4.63	**4.4**	**4.3**	**4.0**	**3.9**	**3.8**	**3.6**
Treasury bill, 3-mo.	4.36	4.35	4.35	4.36	4.39	4.62	4.72	4.58	**4.3**	**4.1**	**3.9**	**3.8**	**3.7**	**3.6**
Treasury bill, 6-mo.	4.27	4.28	4.25	4.25	4.32	4.43	4.44	4.40	**4.2**	**4.1**	**3.9**	**3.8**	**3.7**	**3.6**
Treasury bill, 1 yr.	4.19	4.21	4.19	4.17	4.23	4.33	4.20	4.25	**4.2**	**4.0**	**3.9**	**3.8**	**3.7**	**3.7**
Treasury note, 2 yr.	4.29	4.31	4.31	4.26	4.23	4.26	3.97	4.15	**4.2**	**4.0**	**3.9**	**3.9**	**3.8**	**3.8**
Treasury note, 5 yr.	4.43	4.49	4.48	4.39	4.25	4.23	3.91	4.13	**4.3**	**4.2**	**4.2**	**4.1**	**4.1**	**4.0**
Treasury note, 10 yr.	4.61	4.69	4.68	4.58	4.39	4.36	4.10	4.28	**4.5**	**4.4**	**4.4**	**4.4**	**4.3**	**4.3**
Treasury note, 30 yr.	4.84	4.90	4.91	4.79	4.58	4.54	4.38	4.50	**4.7**	**4.7**	**4.7**	**4.7**	**4.6**	**4.6**
Corporate Aaa bond	5.52	5.61	5.62	5.50	5.29	5.23	5.07	5.20	**5.5**	**5.4**	**5.4**	**5.4**	**5.4**	**5.4**
Corporate Baa bond	5.93	6.03	6.04	5.92	5.71	5.66	5.52	5.63	**6.2**	**6.2**	**6.2**	**6.2**	**6.2**	**6.2**
State & Local bonds	4.18	4.24	4.18	4.15	4.10	4.08	4.05	4.08	**4.4**	**4.5**	**4.5**	**4.4**	**4.4**	**4.4**
Home mortgage rate	6.96	7.04	6.93	6.91	6.72	6.81	6.43	6.65	**6.9**	**6.8**	**6.7**	**6.6**	**6.5**	**6.5**

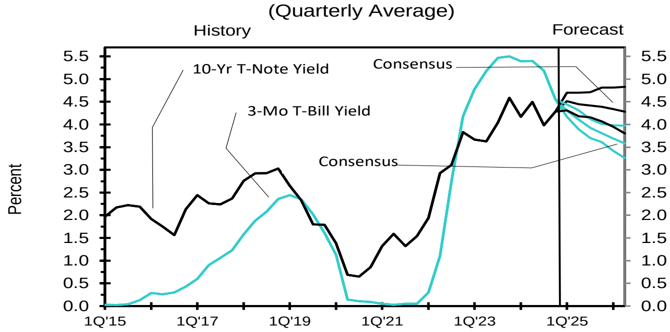
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	**1Q**	**2Q**	**3Q**	**4Q**	**1Q**	**2Q**
Key Assumptions	2023	2023	2023	2023	2024	2024	2024	2024	**2025**	**2025**	**2025**	**2025**	**2026**	**2026**
Fed's AFE $ Index	115.5	114.6	115.0	116.6	115.5	117.3	114.9	117.9	**120.1**	**120.2**	**119.4**	**118.6**	**118.2**	**117.7**
Real GDP	2.8	2.4	4.4	3.2	1.6	3.0	3.1	2.3	**2.2**	**2.1**	**2.0**	**2.0**	**2.0**	**2.0**
GDP Price Index	3.6	1.9	3.2	1.5	3.0	2.5	1.9	2.2	**2.5**	**2.5**	**2.5**	**2.5**	**2.5**	**2.1**
Consumer Price Index	3.8	3.0	3.4	2.7	3.8	2.8	1.2	3.1	**2.9**	**2.6**	**2.6**	**2.6**	**2.6**	**2.5**
PCE Price Index	3.9	2.9	2.7	1.7	3.4	2.5	1.5	2.3	**2.5**	**2.4**	**2.5**	**2.4**	**2.4**	**2.3**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. All interest rate data are sourced from Haver Analytics. Historical data for Fed's Major Currency Index are from FRSR H.10. Historical data for Real GDP, GDP Price Index and PCE Price Index are from the Bureau of Economic Analysis (BEA). Consumer Price Index history is from the Department of Labor's Bureau of Labor Statistics (BLS).

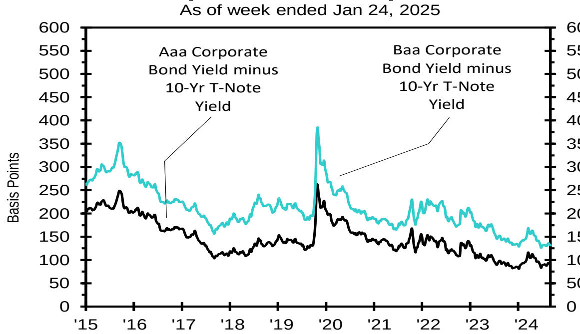
US Treasury Yield Curve
Week ended Jan 24, 2025 & Year Ago vs. 4Q 2024 & 1Q 2026 Consensus Forecasts



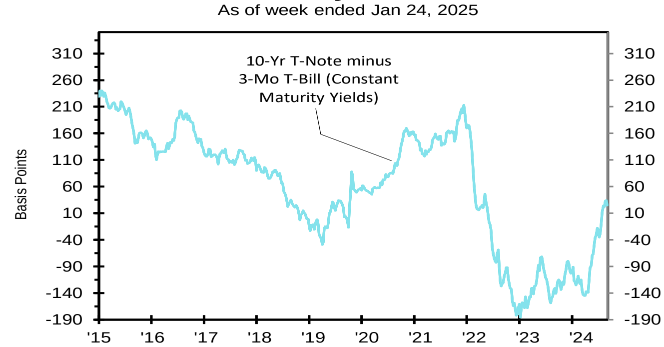
US 3-Mo T-Bills & 10-Yr T-Note Yield
(Quarterly Average)



Corporate Bond Spreads
As of week ended Jan 24, 2025



US Treasury Yield Curve
As of week ended Jan 24, 2025



Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2026 through 2030 and averages for the five-year periods 2026-2030 and 2031-2035. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
		2026	2027	2028	2029	2030	2026-2030	2031-2035
1. Federal Funds Rate	**CONSENSUS**	**3.4**	**3.3**	**3.3**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	3.7	3.7	3.6	3.7	3.7	3.7	3.6
	Bottom 10 Average	3.0	2.9	2.9	2.9	2.8	2.9	2.9
2. Prime Rate	**CONSENSUS**	**6.5**	**6.4**	**6.4**	**6.4**	**6.3**	**6.4**	**6.3**
	Top 10 Average	6.8	6.8	6.7	6.8	6.7	6.7	6.7
	Bottom 10 Average	6.2	6.1	6.1	6.0	5.9	6.1	5.9
3. SOFR	**CONSENSUS**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
	Top 10 Average	3.6	3.6	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.1	3.0	3.0	2.9	2.9	3.0	2.9
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.4**	**3.4**	**3.4**	**3.4**	**3.3**	**3.4**	**3.3**
	Top 10 Average	3.6	3.6	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.2	3.1	3.1	3.0	3.0	3.1	3.0
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.3**	**3.3**	**3.2**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	3.6	3.6	3.5	3.6	3.6	3.6	3.5
	Bottom 10 Average	3.1	3.0	2.9	2.9	2.8	2.9	2.8
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.4**	**3.3**	**3.3**	**3.2**	**3.2**	**3.3**	**3.2**
	Top 10 Average	3.6	3.6	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.1	3.0	3.0	2.9	2.8	3.0	2.9
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.4**	**3.4**	**3.3**	**3.3**	**3.3**	**3.3**	**3.3**
	Top 10 Average	3.7	3.7	3.6	3.6	3.6	3.6	3.6
	Bottom 10 Average	3.2	3.1	3.0	3.0	2.9	3.0	2.9
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.6**	**3.6**	**3.5**	**3.5**	**3.5**	**3.5**	**3.5**
	Top 10 Average	3.9	3.9	3.9	3.9	3.9	3.9	3.9
	Bottom 10 Average	3.3	3.2	3.1	3.1	3.0	3.1	3.0
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.8**	**3.8**	**3.8**	**3.8**	**3.7**	**3.8**	**3.8**
	Top 10 Average	4.2	4.3	4.3	4.3	4.3	4.3	4.3
	Bottom 10 Average	3.4	3.4	3.3	3.3	3.2	3.3	3.2
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**4.0**	**4.1**	**4.0**	**4.0**	**3.9**	**4.0**	**4.0**
	Top 10 Average	4.5	4.6	4.5	4.5	4.5	4.5	4.5
	Bottom 10 Average	3.6	3.5	3.4	3.4	3.3	3.5	3.4
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.3**	**4.4**	**4.3**	**4.3**	**4.2**	**4.3**	**4.2**
	Top 10 Average	4.7	4.8	4.8	4.8	4.8	4.8	4.7
	Bottom 10 Average	3.9	3.9	3.8	3.8	3.7	3.8	3.8
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.1**	**5.2**	**5.2**	**5.1**	**5.1**	**5.2**	**5.1**
	Top 10 Average	5.5	5.7	5.6	5.6	5.6	5.6	5.5
	Bottom 10 Average	4.8	4.8	4.7	4.7	4.6	4.7	4.6
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.0**	**6.1**	**6.0**	**6.0**	**6.0**	**6.0**	**5.9**
	Top 10 Average	6.4	6.6	6.5	6.5	6.4	6.5	6.4
	Bottom 10 Average	5.7	5.7	5.6	5.6	5.5	5.6	5.5
14. State & Local Bonds Yield	**CONSENSUS**	**4.1**	**4.3**	**4.2**	**4.2**	**4.3**	**4.2**	**4.1**
	Top 10 Average	4.5	4.6	4.6	4.6	4.6	4.6	4.6
	Bottom 10 Average	3.8	3.9	3.9	3.9	3.9	3.9	3.6
15. Home Mortgage Rate	**CONSENSUS**	**6.2**	**6.1**	**6.0**	**6.0**	**5.9**	**6.0**	**5.9**
	Top 10 Average	6.6	6.6	6.5	6.4	6.4	6.5	6.4
	Bottom 10 Average	5.7	5.7	5.6	5.5	5.4	5.6	5.4
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**115.5**	**115.0**	**114.5**	**113.9**	**113.2**	**114.4**	**112.6**
	Top 10 Average	117.0	116.3	115.8	115.3	114.8	115.8	114.6
	Bottom 10 Average	113.9	113.6	113.1	112.5	111.8	113.0	110.9
		Year-Over-Year, % Change					Five-Year Averages	
		2026	2027	2028	2029	2030	2026-2030	2031-2035
B. Real GDP	**CONSENSUS**	**1.9**	**2.0**	**2.0**	**2.0**	**2.0**	**2.0**	**1.9**
	Top 10 Average	2.2	2.3	2.3	2.2	2.2	2.2	2.2
	Bottom 10 Average	1.7	1.7	1.8	1.7	1.7	1.7	1.7
C. GDP Chained Price Index	**CONSENSUS**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.1**
	Top 10 Average	2.4	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.3**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**
	Top 10 Average	2.6	2.5	2.4	2.5	2.4	2.5	2.4
	Bottom 10 Average	2.1	2.0	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.2**	**2.2**	**2.1**	**2.1**	**2.1**	**2.2**	**2.1**
	Top 10 Average	2.5	2.3	2.3	2.3	2.3	2.3	2.3
	Bottom 10 Average	2.0	2.0	1.9	2.0	2.0	2.0	2.0

Projected Market Appreciation of the S&P Utility Index
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.		Implied Equity Risk Premium	Implied Equity Risk Premium (excl. PRPM)
1.	Historical Equity Risk Premium (1)	4.16 %	4.16 %
2.	Regression of Historical Equity Risk Premium (2)	4.78	4.78
3	Forecasted Equity Risk Premium Based on PRPM (3)	5.30	NA
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg, Value Line, and S&P Capital IQ Data) (4)	6.22	6.22
5.	Average Equity Risk Premium (5)	5.12 %	5.06 %

Notes: (1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2024. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

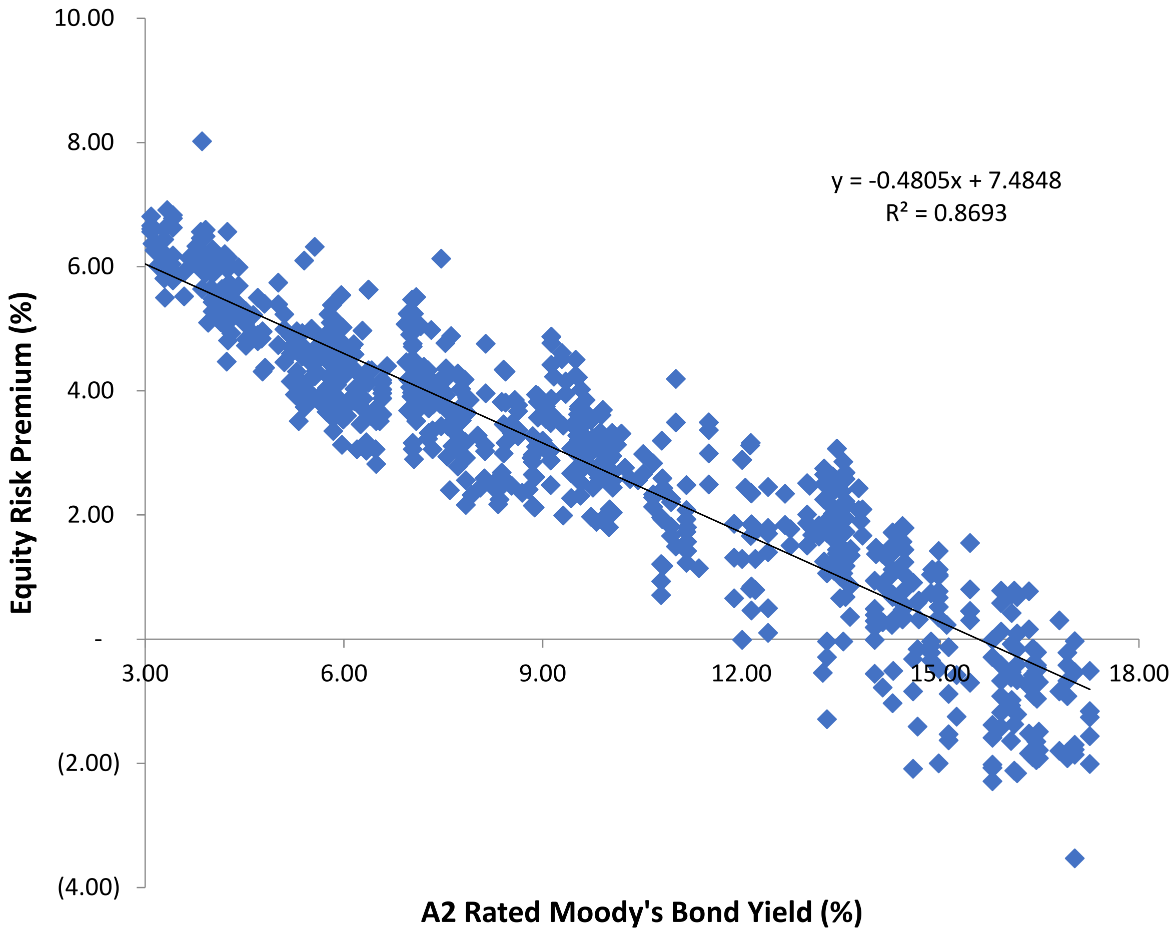
(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2024 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the prospective A2 rated public utility bond yield of 5.75% (from line 3, page 11 of this Exhibit).

(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 through January 2025.

(4) Using data from Bloomberg, Value Line, and S&P Capital IQ for the S&P Utilities Index, an expected return of 11.97% was derived based on expected dividend yields as a proxy for income returns and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.75%, calculated on line 3 of page 11 of this Exhibit results in an equity risk premium of 6.22%. (11.97% - 5.75% = 6.22%).

(5) Average of lines 1 through 4.

Atmos Energy Corporation
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Natural Gas Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.4848 %	-0.4805	5.75 %	4.72 %

Notes:
(1) From line 3 of page 11 of this Exhibit.

Source of Information: Regulatory Research Associates.

Atmos Energy Corporation
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Seven Natural Gas Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seven Natural Gas Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.90	0.61	0.75	8.28 %	4.56 %	10.77 %	11.29 %	11.03 %
New Jersey Resources Corporation	1.00	0.63	0.81	8.28	4.56	11.27	11.66	11.46
NiSource Inc.	0.95	0.58	0.77	8.28	4.56	10.93	11.41	11.17
Northwest Natural Holding Company	0.85	0.73	0.79	8.28	4.56	11.10	11.53	11.32
ONE Gas, Inc.	0.85	0.65	0.75	8.28	4.56	10.77	11.29	11.03
Southwest Gas Holdings, Inc.	0.95	0.83	0.89	8.28	4.56	11.93	12.16	12.04 (4)
Spire Inc.	0.90	0.67	0.78	8.28	4.56	11.02	11.47	11.24
Mean			0.79			11.11 %	11.54 %	11.21 %
Median			0.78			11.02 %	11.47 %	11.21 %
Average of Mean and Median			0.79			11.07 %	11.51 %	11.21 %

Results Excluding PRPM MRP

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Seven Natural Gas Companies	Value Line Adjusted Beta	Bloomberg Adjusted Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Atmos Energy Corporation	0.90	0.61	0.75	8.25 %	4.56 %	10.75 %	11.26 %	11.01 %
New Jersey Resources Corporation	1.00	0.63	0.81	8.25	4.56	11.24	11.64	11.44
NiSource Inc.	0.95	0.58	0.77	8.25	4.56	10.91	11.39	11.15
Northwest Natural Holding Company	0.85	0.73	0.79	8.25	4.56	11.08	11.51	11.29
ONE Gas, Inc.	0.85	0.65	0.75	8.25	4.56	10.75	11.26	11.01
Southwest Gas Holdings, Inc.	0.95	0.83	0.89	8.25	4.56	11.90	12.13	12.02 (4)
Spire Inc.	0.90	0.67	0.78	8.25	4.56	11.00	11.45	11.22
Mean			0.79			11.09 %	11.52 %	11.19 %
Median			0.78			11.00 %	11.45 %	11.19 %
Average of Mean and Median			0.79			11.05 %	11.49 %	11.19 %

Notes on page 22 of this Exhibit.

Atmos Energy Corporation
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using five different measures from four sources: Kroll, Value Line, Bloomberg, and S&P Capital IQ as illustrated below:

Measure 1: Kroll Arithmetic Mean MRP (1926-2024)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2024:	12.29	%
Arithmetic Mean Income Returns on Long-Term Government Bonds:	4.99	
MRP based on Kroll Historical Data:	7.31	%

Measure 2: Application of a Regression Analysis to Kroll Historical Data
(1926-2024) 7.93 %

Measure 3: Application of the PRPM to Kroll Historical Data
(January 1928 through January 2025) 8.39 %

Measure 4: Value Line Projected MRP (Thirteen weeks ending January 31, 2025)

Total projected return on the market 3-5 years hence*:	10.80	%
Risk-Free Rate (see note 2):	4.56	
MRP based on Value Line Summary & Index:	6.24	%

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Bloomberg, Value Line, and S&P Capital IQ Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	16.09	%
Risk-Free Rate (see note 2):	4.56	
MRP based on Bloomberg, Value Line, and S&P Capital IQ data	11.53	%

Average of all MRP Measures:	8.28	%
Average MRP Excluding the PRPM MRP:	8.25	%

(2) For reasons explained in the Direct Testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 17 and 18 of this Exhibit.) The projection of the risk-free rate is illustrated below:

First Quarter 2025	4.70	%
Second Quarter 2025	4.70	
Third Quarter 2025	4.70	
Fourth Quarter 2025	4.70	
First Quarter 2026	4.60	
Second Quarter 2026	4.60	
2026-2030	4.30	
2031-2035	4.20	
	4.56	%

(3) Average of Column 6 and Column 7.

(4) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Sources of Information:
Value Line Summary and Index
Blue Chip Financial Forecasts, November 27, 2024 and January 31, 2025
Kroll 2023 SBBI® Yearbook
S&P Capital IQ
Bloomberg Professional Services

Atmos Energy Corporation
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Proxy Group of Seven Natural Gas Companies

The criteria for selection of the proxy group of non-price regulated companies comparable in total risk to the proxy group of seven natural gas companies was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The proxy group of non-price regulated companies was selected based on the unadjusted beta range of 0.64 - 0.92 and residual standard error of the regression range of 2.8409 - 3.3885 of the proxy group of seven natural gas companies.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus three standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1369. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus,} \quad 0.1369 = \frac{3.1147}{\sqrt{518}} = \frac{3.1147}{22.7596}$$

Source of Information: Value Line Proprietary Database, December 2024.
Value Line Investment Survey (Standard Edition).

Atmos Energy Corporation
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

	[1]	[2]	[3]	[4]
Proxy Group of Seven Natural Gas Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Atmos Energy Corporation	0.85	0.75	2.8989	0.0647
New Jersey Resources Corporation	0.95	0.91	3.0464	0.0680
NiSource Inc.	0.90	0.83	2.6470	0.0591
Northwest Natural Holding Company	0.85	0.71	3.3761	0.0754
ONE Gas, Inc.	0.85	0.71	3.2540	0.0726
Southwest Gas Holdings, Inc.	0.90	0.80	3.4852	0.0778
Spire Inc.	0.85	0.74	3.0953	0.0691
Average	0.88	0.78	3.1147	0.0695
Beta Range (+/- 2 std. Devs. of Beta)	0.64	0.92		
2 std. Devs. of Beta	0.14			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.8409	3.3885		
Std. dev. of the Res. Std. Err.	0.1369			
2 std. devs. of the Res. Std. Err.	0.2738			

Source of Information: Value Line Proprietary Database, December 2024.

Atmos Energy Corporation
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

	[1]	[2]	[3]	[4]
Proxy Group of Forty-Nine Non-Price Regulated Companies	Value Line Adjusted Beta	Unadjusted Beta	Residual Standard Error of the Regression	Standard Deviation of Beta
Abbott Labs.	0.90	0.79	2.9573	0.0660
AbbVie Inc.	0.85	0.70	3.1365	0.0700
Air Products & Chem.	0.90	0.83	3.0324	0.0677
Alphabet Inc.	0.90	0.81	3.1907	0.0712
Altria Group	0.85	0.76	2.8948	0.0646
Apple Inc.	0.95	0.91	3.2127	0.0717
Assurant Inc.	0.90	0.79	3.0394	0.0679
AutoZone Inc.	0.95	0.88	3.2399	0.0723
Booz Allen Hamilton	0.85	0.74	3.2930	0.0735
Brady Corp.	0.95	0.90	2.8860	0.0644
BWX Technologies	0.80	0.68	3.2662	0.0729
CACI Int'l	0.90	0.80	3.0359	0.0678
Casey's Gen'l Stores	0.90	0.79	3.1661	0.0707
Cencora	0.80	0.66	2.9646	0.0662
CSW Industrials	0.90	0.77	3.2779	0.0732
CVS Health	0.90	0.79	3.3646	0.0751
Danaher Corp.	0.90	0.81	3.0286	0.0676
Dolby Labs.	0.95	0.87	2.9508	0.0659
Exponent, Inc.	0.95	0.88	3.3456	0.0747
Fastenal Co.	0.90	0.80	2.9253	0.0653
Franklin Electric	0.90	0.82	2.9333	0.0655
GATX Corp.	0.95	0.90	2.9875	0.0667
Henry (Jack) & Assoc	0.85	0.74	3.1928	0.0713
Hunt (J.B.)	0.95	0.91	3.2647	0.0729
Huntington Ingalls	0.95	0.89	3.3736	0.0753
L3Harris Technologie	0.90	0.83	3.1556	0.0711
Landstar System	0.80	0.65	2.8665	0.0640
Lockheed Martin	0.85	0.75	2.8741	0.0642
McKesson Corp.	0.85	0.70	3.1485	0.0703
Microsoft Corp.	0.90	0.78	2.8520	0.0637
MSC Industrial Direc	0.90	0.84	2.9545	0.0660
Oracle Corp.	0.85	0.70	3.0995	0.0692
O'Reilly Automotive	0.90	0.84	3.0259	0.0676
OSI Systems	0.90	0.81	3.2160	0.0718
Packaging Corp.	0.95	0.85	2.8607	0.0639
Pfizer, Inc.	0.80	0.67	3.1709	0.0708
Philip Morris Int'l	0.95	0.87	2.8750	0.0642
Prestige Consumer	0.85	0.75	3.3470	0.0747
Selective Ins. Group	0.85	0.74	2.9941	0.0668
Service Corp. Int'l	0.90	0.84	3.1842	0.0711
Sherwin-Williams	0.95	0.90	2.9254	0.0653
Smith (A.O.)	0.90	0.79	3.0828	0.0688
Thermo Fisher Sci.	0.85	0.77	2.8565	0.0638
UniFirst Corp.	0.90	0.81	3.0115	0.0672
UnitedHealth Group	0.95	0.90	3.1445	0.0702
Universal Corp.	0.80	0.68	3.2233	0.0720
VeriSign Inc.	0.90	0.80	2.8857	0.0644
Waters Corp.	0.95	0.86	3.2280	0.0721
Watsco, Inc.	0.85	0.76	3.1218	0.0697
Average	0.89	0.80	3.0829	0.0688
Proxy Group of Seven Natural Gas Companies	0.88	0.78	3.1147	0.0695

Source of Information: Value Line Proprietary Database, December 2024.

Atmos Energy Corporation
Summary of Cost of Equity Models Applied to
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

Principal Methods	Proxy Group of Forty-Nine Non-Price Regulated Companies		Proxy Group of Forty-Nine Non-Price Regulated Companies (excl. PRPM)	
Discounted Cash Flow Model (DCF) (1)	11.56	%	11.56	%
Risk Premium Model (RPM) (2)	12.37		12.33	
Capital Asset Pricing Model (CAPM)	11.83	(3)	11.80	(4)
Mean	11.92	%	11.90	%
Median	11.83	%	11.80	%
Average of Mean and Median	11.88	%	11.85	%

Notes:
(1) From page 27 of this Exhibit.
(2) From page 28 of this Exhibit.
(3) From page 31 of this Exhibit.
(4) From page 32 of this Exhibit.

Atmos Energy Corporation
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

Proxy Group of Forty-Nine Non-Price Regulated Companies	[1] Average Dividend Yield	[2] Value Line Projected Five Year Growth in EPS	[3] Zack's Five Year Projected Growth Rate in EPS	[4] S&P Capital IQ Projected Five Year Growth in EPS	[5] Average Projected Five Year Growth Rate in EPS (1)	[6] Adjusted Dividend Yield	[7] Indicated Common Equity Cost Rate (2)	
Abbott Labs.	2.02 %	4.00 %	10.40 %	9.57 %	7.99 %	2.10 %	10.09 %	
AbbVie Inc.	3.70	4.00	8.10	9.51	7.20	3.83	11.03	
Air Products & Chem.	2.29	10.50	7.40	11.13	9.68	2.40	12.08	
Alphabet Inc.	0.43	13.50	17.40	16.90	15.93	0.46	16.39	
Altria Group	7.56	6.00	3.60	4.31	4.64	7.74	12.38	
Apple Inc.	0.42	9.00	13.70	9.57	10.76	0.44	11.20	
Assurant Inc.	1.49	9.50	NA	NA	9.50	1.56	11.06	
AutoZone Inc.	-	11.50	11.80	12.73	12.01	-	NA	
Booz Allen Hamilton	1.54	10.00	13.30	13.15	12.15	1.63	13.78	
Brady Corp.	1.29	15.50	NA	11.00	13.25	1.38	14.63	
BWX Technologies	0.79	9.00	9.60	10.55	9.72	0.83	10.55	
CACI Int'l	-	4.50	14.10	14.08	10.89	-	NA	
Casey's Gen'l Stores	0.49	12.00	12.60	12.53	12.38	0.52	12.90	
Cencora	0.92	6.50	10.40	9.10	8.67	0.96	9.63	
CSW Industrials	0.25	13.50	NA	12.50	13.00	0.27	13.27	
CVS Health	5.06	1.50	15.40	12.76	9.89	5.31	15.20	
Danaher Corp.	0.46	2.00	8.90	9.43	6.78	0.48	7.26	
Dolby Labs.	1.68	9.50	NA	NA	9.50	1.76	11.26	
Exponent, Inc.	1.18	7.00	NA	NA	7.00	1.22	8.22	
Fastenal Co.	2.21	9.00	9.80	9.26	9.35	2.31	11.66	
Franklin Electric	1.03	7.50	12.00	12.00	10.50	1.08	11.58	
GATX Corp.	1.55	10.50	NA	NA	10.50	1.63	12.13	
Henry (Jack) & Assoc	1.26	6.50	8.70	8.65	7.95	1.31	9.26	
Hunt (J.B.)	0.98	6.00	16.40	12.48	11.63	1.04	12.67	
Huntington Ingalls	2.77	10.00	7.40	7.36	8.25	2.88	11.13	
L3Harris Technologie	2.03	11.00	8.80	8.89	9.56	2.13	11.69	
Landstar System	0.80	5.00	NA	11.00	8.00	0.83	8.83	
Lockheed Martin	2.61	9.50	4.40	4.40	6.10	2.69	8.79	
McKesson Corp.	0.48	10.00	14.10	13.77	12.62	0.51	13.13	
Microsoft Corp.	0.77	14.50	14.40	13.19	14.03	0.82	14.85	
MSC Industrial Direc	4.14	0.50	NA	NA	0.50	4.15	4.65	(3)
Oracle Corp.	0.91	10.00	10.20	11.16	10.45	0.96	11.41	
O'Reilly Automotive	-	10.50	12.10	11.92	11.51	-	NA	
OSI Systems	-	10.50	12.90	14.05	12.48	-	NA	
Packaging Corp.	2.12	9.00	9.00	11.31	9.77	2.22	11.99	
Pfizer, Inc.	6.56	2.50	14.20	5.93	7.54	6.81	14.35	
Philip Morris Int'l	4.28	5.00	8.00	9.54	7.51	4.44	11.95	
Prestige Consumer	-	5.50	8.00	8.00	7.17	-	NA	
Selective Ins. Group	1.59	17.50	NA	16.40	16.95	1.72	18.67	(3)
Service Corp. Int'l	1.45	4.50	9.70	9.75	7.98	1.51	9.49	
Sherwin-Williams	0.78	12.00	10.30	9.00	10.43	0.82	11.25	
Smith (A.O.)	1.90	9.00	12.00	12.00	11.00	2.00	13.00	
Thermo Fisher Sci.	0.29	6.00	6.30	10.17	7.49	0.30	7.79	
UniFirst Corp.	0.70	7.00	NA	NA	7.00	0.72	7.72	
UnitedHealth Group	1.52	12.00	12.40	15.03	13.14	1.62	14.76	
Universal Corp.	5.99	13.50	NA	NA	13.50	6.39	19.89	(3)
VeriSign Inc.	-	12.00	NA	NA	12.00	-	NA	
Waters Corp.	-	6.50	4.40	6.81	5.90	-	NA	
Watsco, Inc.	2.13	7.00	NA	NA	7.00	2.20	9.20	
	NA = Not Available					Mean	11.53 %	
						Median	11.58 %	
					Average of Mean and Median		11.56 %	

Notes:

(1) Average of columns 2 through 4 excluding negative growth rates and extreme positive values.

(2) The application of the DCF model to the domestic, non-price regulated comparable risk companies is identical to the application of the DCF to the Utility Proxy Groups. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of 1/31/2025. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5 year projected growth in EPS provided by Value Line, www.zacks.com, and S&P Capital IQ (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

(3) Results were excluded from the final average and median as they were more than two standard deviations from the proxy group's mean.

Source of Information: Value Line Investment Survey.
www.zacks.com, Downloaded on 01/31/2025
S&P Capital IQ

Atmos Energy Corporation
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Forty-Nine Non-Price Regulated Companies		Proxy Group of Forty-Nine Non-Price Regulated Companies (excl. PRPM)
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.14	%	6.14
2.	Adjustment to Reflect Bond rating Difference of Non-Price Regulated Companies (2)	(0.14)		(0.14)
3.	Adjusted Bond Yield	6.00		6.00
4.	Equity Risk Premium (3)	6.37		6.33
5.	Risk Premium Derived Common Equity Cost Rate	12.37	%	12.33

Notes: (1) Average forecast of Baa corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated November 27, 2024 and January 31, 2025 (see pages 17 and 18 of this Exhibit). The estimates are detailed below.

First Quarter 2025	6.20	%
Second Quarter 2025	6.20	
Third Quarter 2025	6.20	
Fourth Quarter 2025	6.20	
First Quarter 2026	6.20	
Second Quarter 2026	6.20	
2026-2030	6.00	
2031-2035	5.90	
Average	6.14	%

(2) The average yield spread of Baa2 rated corporate bonds over A2 corporate bonds for the three months ending January 2025. To reflect the A3/Baa1 average rating of the Non-Price Regulated Proxy Group, the yield on the Baa corporate bond must be adjusted by 1/2 of the spread between A2 and Baa2 corporate bond yields as shown below:

	A2 Corp. Bond Yield	Baa2 Corp. Bond Yield	Spread
Jan-25	5.81 %	6.09 %	0.28 %
Dec-24	5.53	5.80	0.27
Nov-24	5.50	5.78	0.28
		Average yield spread	0.28
		1/2 of spread	0.14

(3) From page 30 of this Exhibit.

Atmos Energy Corporation
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Forty-Nine Non-Price Regulated Companies

	Moody's Long-Term Issuer Rating January 2025		Standard & Poor's Long-Term Issuer Rating January 2025	
Proxy Group of Forty-Nine Non-Price Regulated Companies	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Abbott Labs.	Aa3	4.0	AA-	4.0
AbbVie Inc.	A3	7.0	A-	7.0
Air Products & Chem.	A2	6.0	A	6.0
Alphabet Inc.	Aa2	3.0	AA+	2.0
Altria Group	A3	7.0	BBB	9.0
Apple Inc.	Aaa	1.0	AA+	2.0
Assurant Inc.	Baa2	9.0	BBB	9.0
AutoZone Inc.	Baa1	8.0	BBB	9.0
Booz Allen Hamilton	NA	--	NA	--
Brady Corp.	NA	--	NA	--
BWX Technologies	Ba2	12.0	BB	12.0
CACI Int'l	NA	--	BB+	11.0
Casey's Gen'l Stores	NA	--	NA	--
Cencora	Baa2	9.0	BBB+	8.0
CSW Industrials	NA	--	NA	--
CVS Health	Baa3	10.0	BBB	9.0
Danaher Corp.	A3	7.0	A-	7.0
Dolby Labs.	NA	--	NA	--
Exponent, Inc.	NA	--	NA	--
Fastenal Co.	NA	--	NA	--
Franklin Electric	NA	--	NA	--
GATX Corp.	Baa2	9.0	BBB	9.0
Henry (Jack) & Assoc	NA	--	NA	--
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
Huntington Ingalls	Baa3	10.0	BBB-	10.0
L3Harris Technologie	Baa2	9.0	BBB	9.0
Landstar System	NA	--	NA	--
Lockheed Martin	A2	6.0	A-	7.0
McKesson Corp.	A3	7.0	BBB+	8.0
Microsoft Corp.	Aaa	1.0	AAA	1.0
MSC Industrial Direc	NA	--	NA	--
Oracle Corp.	Baa2	9.0	BBB	9.0
O'Reilly Automotive	Baa1	8.0	BBB	9.0
OSI Systems	NA	--	NA	--
Packaging Corp.	Baa2	9.0	BBB	9.0
Pfizer, Inc.	A2	6.0	A	6.0
Philip Morris Int'l	A2	6.0	A-	7.0
Prestige Consumer	NA	--	BB	12.0
Selective Ins. Group	Baa2	9.0	BBB	9.0
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Sherwin-Williams	Baa2	9.0	BBB	9.0
Smith (A.O.)	NA	--	NA	--
Thermo Fisher Sci.	A3	7.0	A-	7.0
UniFirst Corp.	NA	--	NA	--
UnitedHealth Group	A2	6.0	A+	5.0
Universal Corp.	WR	--	BBB-	10.0
VeriSign Inc.	Baa3	10.0	BBB	9.0
Waters Corp.	NA	--	NA	--
Watsco, Inc.	NA	--	NA	--
Electric CEM Proxy Group Average	A3/Baa1	7.5	BBB+	7.8

Notes:
(1) From page 14 of this Exhibit.

Source of Information:
Bloomberg Professional Services.

Atmos Energy Corporation
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Seven Natural Gas Companies

Line No.	Equity Risk Premium Measure	Proxy Group of Forty-Nine Non-Price Regulated Companies	Proxy Group of Forty-Nine Non-Price Regulated Companies (excl. PRPM)
1.	Kroll Equity Risk Premium (1)	6.10 %	6.10 %
2.	Regression on Kroll Risk Premium Data (2)	6.82	6.82
3.	Kroll Equity Risk Premium based on PRPM (3)	7.50	NA
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	5.45	5.45
5.	Equity Risk Premium Based on Bloomberg, Value Line, and S&P Global Market Intelligence S&P 500 Companies (5)	10.74	10.74
6.	Conclusion of Equity Risk Premium	7.32 %	7.28 %
7.	Adjusted Beta (6)	0.87	0.87
8.	Forecasted Equity Risk Premium	6.37 %	6.33 %

Notes:
(1) From note 1 of page 16 of this Exhibit.
(2) From note 2 of page 16 of this Exhibit.
(3) From note 3 of page 16 of this Exhibit.
(4) From note 4 of page 16 of this Exhibit.
(5) From note 5 of page 16 of this Exhibit.
(6) Average of mean and median beta from page 31 of this Exhibit.

Sources of Information:
Stocks, Bonds, Bills, and Inflation - 2023 SBBI Yearbook, Kroll.
Value Line Summary and Index.
Blue Chip Financial Forecasts, November 27, 2024 and January 31, 2025.
Bloomberg Professional Services.

Atmos Energy Corporation
Traditional CAPM and ECAPM Results for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

Proxy Group of Forty-Nine Non-Price Regulated Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Nine Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Abbott Labs.	0.90	0.69	0.80	8.28 %	4.56 %	11.18 %	11.60 %	11.39 %
AbbVie Inc.	0.80	0.52	0.66	8.28	4.56	10.02	10.73	10.38
Air Products & Chem.	0.90	0.87	0.89	8.28	4.56	11.93	12.16	12.04
Alphabet Inc.	0.90	1.03	0.97	8.28	4.56	12.59	12.65	12.62
Altria Group	0.85	0.47	0.66	8.28	4.56	10.02	10.73	10.38
Apple Inc.	0.95	0.95	0.95	8.28	4.56	12.42	12.53	12.48
Assurant Inc.	0.90	0.81	0.85	8.28	4.56	11.60	11.91	11.75
AutoZone Inc.	0.90	0.67	0.78	8.28	4.56	11.02	11.47	11.24
Booz Allen Hamilton	0.85	0.96	0.90	8.28	4.56	12.01	12.22	12.11
Brady Corp.	0.95	0.69	0.82	8.28	4.56	11.35	11.72	11.53
BWX Technologies	0.85	0.83	0.84	8.28	4.56	11.51	11.84	11.68
CACI Int'l	0.90	0.81	0.86	8.28	4.56	11.68	11.97	11.82
Casey's Gen'l Stores	0.90	0.65	0.78	8.28	4.56	11.02	11.47	11.24
Cencora	0.80	0.56	0.68	8.28	4.56	10.19	10.85	10.52
CSW Industrials	0.90	1.19	1.05	8.28	4.56	13.25	13.15	13.20
CVS Health	0.90	0.68	0.79	8.28	4.56	11.10	11.53	11.32
Danaher Corp.	0.90	0.90	0.90	8.28	4.56	12.01	12.22	12.11
Dolby Labs.	0.95	0.91	0.93	8.28	4.56	12.26	12.40	12.33
Exponent, Inc.	0.95	1.15	1.05	8.28	4.56	13.25	13.15	13.20
Fastenal Co.	0.85	0.96	0.90	8.28	4.56	12.01	12.22	12.11
Franklin Electric	0.90	1.04	0.97	8.28	4.56	12.59	12.65	12.62
GATX Corp.	0.95	1.04	1.00	8.28	4.56	12.84	12.84	12.84
Henry (Jack) & Assoc	0.85	0.74	0.80	8.28	4.56	11.18	11.60	11.39
Hunt (J.B.)	0.95	1.07	1.01	8.28	4.56	12.92	12.90	12.91
Huntington Ingalls	0.95	1.03	0.99	8.28	4.56	12.76	12.78	12.77
L3Harris Technologie	0.95	0.85	0.90	8.28	4.56	12.01	12.22	12.11
Landstar System	0.80	0.96	0.88	8.28	4.56	11.84	12.09	11.97
Lockheed Martin	0.85	0.45	0.65	8.28	4.56	9.94	10.67	10.30
McKesson Corp.	0.85	0.65	0.75	8.28	4.56	10.77	11.29	11.03
Microsoft Corp.	0.90	1.02	0.96	8.28	4.56	12.51	12.59	12.55
MSC Industrial Direc	0.90	0.89	0.90	8.28	4.56	12.01	12.22	12.11
Oracle Corp.	0.85	1.31	1.08	8.28	4.56	13.50	13.33	13.42
O'Reilly Automotive	0.90	0.61	0.75	8.28	4.56	10.77	11.29	11.03
OSI Systems	0.90	1.23	1.07	8.28	4.56	13.42	13.27	13.35
Packaging Corp.	0.95	0.77	0.86	8.28	4.56	11.68	11.97	11.82
Pfizer, Inc.	0.80	0.50	0.65	8.28	4.56	9.94	10.67	10.30
Philip Morris Int'l	0.90	0.49	0.70	8.28	4.56	10.35	10.98	10.66
Prestige Consumer	0.90	0.68	0.79	8.28	4.56	11.10	11.53	11.32
Selective Ins. Group	0.90	0.64	0.77	8.28	4.56	10.93	11.41	11.17
Service Corp. Int'l	0.95	0.92	0.94	8.28	4.56	12.34	12.47	12.40
Sherwin-Williams	0.95	1.17	1.06	8.28	4.56	13.33	13.21	13.27
Smith (A.O.)	0.90	0.98	0.94	8.28	4.56	12.34	12.47	12.40
Thermo Fisher Sci.	0.85	0.88	0.86	8.28	4.56	11.68	11.97	11.82
UniFirst Corp.	0.90	0.64	0.77	8.28	4.56	10.93	11.41	11.17
UnitedHealth Group	0.95	0.31	0.63	8.28	4.56	9.78	10.54	10.16
Universal Corp.	0.85	0.73	0.79	8.28	4.56	11.10	11.53	11.32
VeriSign Inc.	0.90	0.71	0.80	8.28	4.56	11.18	11.60	11.39
Waters Corp.	0.95	1.01	0.98	8.28	4.56	12.67	12.71	12.69
Watsco, Inc.	0.90	1.38	1.14	8.28	4.56	14.00	13.71	13.85 (4)
		Mean	0.87			11.73 %	12.01 %	11.83 %
		Median	0.86			11.68 %	11.97 %	11.82 %
		Average of Mean and Median	0.87			11.71 %	11.99 %	11.83 %

Notes:
(1) From note 1 of page 22 of this Exhibit.
(2) From note 2 of page 22 of this Exhibit.
(3) Average of CAPM and ECAPM cost rates.

Atmos Energy Corporation
Traditional CAPM and ECAPM Results (excl. PRPM MRP) for the Proxy Groups of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Seven Natural Gas Companies

Proxy Group of Forty-Nine Non-Price Regulated Companies

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Forty-Nine Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Abbott Labs.	0.90	0.69	0.80	8.25 %	4.56 %	11.16 %	11.57 %	11.37 %
AbbVie Inc.	0.80	0.52	0.66	8.25	4.56	10.01	10.71	10.36
Air Products & Chem.	0.90	0.87	0.89	8.25	4.56	11.90	12.13	12.02
Alphabet Inc.	0.90	1.03	0.97	8.25	4.56	12.56	12.63	12.59
Altria Group	0.85	0.47	0.66	8.25	4.56	10.01	10.71	10.36
Apple Inc.	0.95	0.95	0.95	8.25	4.56	12.40	12.50	12.45
Assurant Inc.	0.90	0.81	0.85	8.25	4.56	11.57	11.88	11.73
AutoZone Inc.	0.90	0.67	0.78	8.25	4.56	11.00	11.45	11.22
Booz Allen Hamilton	0.85	0.96	0.90	8.25	4.56	11.99	12.19	12.09
Brady Corp.	0.95	0.69	0.82	8.25	4.56	11.33	11.70	11.51
BWX Technologies	0.85	0.83	0.84	8.25	4.56	11.49	11.82	11.66
CACI Int'l	0.90	0.81	0.86	8.25	4.56	11.66	11.94	11.80
Casey's Gen'l Stores	0.90	0.65	0.78	8.25	4.56	11.00	11.45	11.22
Cencora	0.80	0.56	0.68	8.25	4.56	10.17	10.83	10.50
CSW Industrials	0.90	1.19	1.05	8.25	4.56	13.22	13.12	13.17
CVS Health	0.90	0.68	0.79	8.25	4.56	11.08	11.51	11.29
Danaher Corp.	0.90	0.90	0.90	8.25	4.56	11.99	12.19	12.09
Dolby Labs.	0.95	0.91	0.93	8.25	4.56	12.23	12.38	12.31
Exponent, Inc.	0.95	1.15	1.05	8.25	4.56	13.22	13.12	13.17
Fastenal Co.	0.85	0.96	0.90	8.25	4.56	11.99	12.19	12.09
Franklin Electric	0.90	1.04	0.97	8.25	4.56	12.56	12.63	12.59
GATX Corp.	0.95	1.04	1.00	8.25	4.56	12.81	12.81	12.81
Henry (Jack) & Assoc	0.85	0.74	0.80	8.25	4.56	11.16	11.57	11.37
Hunt (J.B.)	0.95	1.07	1.01	8.25	4.56	12.89	12.87	12.88
Huntington Ingalls	0.95	1.03	0.99	8.25	4.56	12.73	12.75	12.74
L3Harris Technologie	0.95	0.85	0.90	8.25	4.56	11.99	12.19	12.09
Landstar System	0.80	0.96	0.88	8.25	4.56	11.82	12.07	11.94
Lockheed Martin	0.85	0.45	0.65	8.25	4.56	9.92	10.65	10.28
McKesson Corp.	0.85	0.65	0.75	8.25	4.56	10.75	11.26	11.01
Microsoft Corp.	0.90	1.02	0.96	8.25	4.56	12.48	12.56	12.52
MSC Industrial Direc	0.90	0.89	0.90	8.25	4.56	11.99	12.19	12.09
Oracle Corp.	0.85	1.31	1.08	8.25	4.56	13.47	13.31	13.39
O'Reilly Automotive	0.90	0.61	0.75	8.25	4.56	10.75	11.26	11.01
OSI Systems	0.90	1.23	1.07	8.25	4.56	13.39	13.24	13.32
Packaging Corp.	0.95	0.77	0.86	8.25	4.56	11.66	11.94	11.80
Pfizer, Inc.	0.80	0.50	0.65	8.25	4.56	9.92	10.65	10.28
Philip Morris Int'l	0.90	0.49	0.70	8.25	4.56	10.34	10.95	10.65
Prestige Consumer	0.90	0.68	0.79	8.25	4.56	11.08	11.51	11.29
Selective Ins. Group	0.90	0.64	0.77	8.25	4.56	10.91	11.39	11.15
Service Corp. Int'l	0.95	0.92	0.94	8.25	4.56	12.32	12.44	12.38
Sherwin-Williams	0.95	1.17	1.06	8.25	4.56	13.31	13.18	13.24
Smith (A.O.)	0.90	0.98	0.94	8.25	4.56	12.32	12.44	12.38
Thermo Fisher Sci.	0.85	0.88	0.86	8.25	4.56	11.66	11.94	11.80
UniFirst Corp.	0.90	0.64	0.77	8.25	4.56	10.91	11.39	11.15
UnitedHealth Group	0.95	0.31	0.63	8.25	4.56	9.76	10.52	10.14
Universal Corp.	0.85	0.73	0.79	8.25	4.56	11.08	11.51	11.29
VeriSign Inc.	0.90	0.71	0.80	8.25	4.56	11.16	11.57	11.37
Waters Corp.	0.95	1.01	0.98	8.25	4.56	12.65	12.69	12.67
Watsco, Inc.	0.90	1.38	1.14	8.25	4.56	13.97	13.68	13.82 (4)
		Mean	0.87			11.71 %	11.98 %	11.80 %
		Median	0.86			11.66 %	11.94 %	11.80 %
		Average of Mean and Median	0.87			11.69 %	11.96 %	11.80 %

Notes:
(1) From note 1 of page 22 of this Exhibit.
(2) From note 2 of page 22 of this Exhibit.
(3) Average of CAPM and ECAPM cost rates.

Atmos Energy Corporation
Derivation of Investment Risk Adjustment Based upon
Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on January 31, 2025 (1) (millions)	(times larger)	[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	Atmos Energy Corporation	$ 653.639		8	1.14%	
2.	Proxy Group of Seven Natural Gas Companies	$ 8,163.170	12.5 x	3	0.61%	0.53%

	[A] Decile	[B] Market Capitalization of Smallest Company (millions)	[C] Market Capitalization of Largest Company (millions)	[D] Size Premium (Return in Excess of CAPM)*
Largest	1	$ 36,942.976	$ 2,662,326.048	-0.06%
	2	14,910.719	36,391.113	0.46%
	3	7,493.607	14,820.048	0.61%
	4	4,622.261	7,461.284	0.64%
	5	3,011.224	4,621.785	0.95%
	6	1,864.293	3,010.806	1.21%
	7	1,050.083	1,862.491	1.39%
	8	555.880	1,046.037	1.14%
	9	213.039	554.523	1.99%
Smallest	10	1.576	212.644	4.70%

*From 2024 Kroll Cost of Capital Navigator

Notes:
(1) From page 34 of this Exhibit.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.53% in Column [4], Line No. 2 is derived as follows 0.53% = 1.14% - 0.61%.

Atmos Energy Corporation
Market Capitalization of Atmos Energy Corporation and the
Proxy Group of Seven Natural Gas Companies

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2023 (millions)	[2] Book Value per Share at Fiscal Year End 2023 (1)	[3] Total Common Equity at Fiscal Year End 2023 (millions)	[4] Closing Stock Market Price on January 31, 2025	[5] Market-to-Book Ratio on January 31, 2025 (2)	[6] Market Capitalization on January 31, 2025 (3) (millions)
Atmos Energy Corporation		NA	NA	382.469 (4)	NA		
Based upon Proxy Group of Seven Natural Gas Companies						170.9 (5)	$ 653.639 (6)
Proxy Group of Seven Natural Gas Companies							
Atmos Energy Corporation	NYSE	148.493	$ 73.203	$ 10,870.06	$ 142.510	194.7 %	$ 21,161.707
New Jersey Resources Corporation	NYSE	97.584	$ 20.400	1,990.74	47.950	235.0	4,679.175
NiSource Inc.	NYSE	447.382	$ 17.398	7,783.50	37.300	214.4	16,687.336
Northwest Natural Holding Company	NYSE	37.631	$ 34.116	1,283.84	39.920	117.0	1,502.230
ONE Gas, Inc.	NYSE	56.546	$ 48.914	2,765.88	70.640	144.4	3,994.404
Southwest Gas Holdings, Inc.	NYSE	71.564	$ 46.253	3,310.04	74.680	161.5	5,344.381
Spire Inc.	NYSE	53.170	$ 54.867	2,917.30	70.960	129.3	3,772.959
Average		130.339	$ 42.164	$ 4,417.336	$ 69.137	170.9 %	$ 8,163.170

NA= Not Available

Notes:
(1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Atmos Energy Corporation on January 31, 2025 is assumed to be equal to the market-to-book ratio of Proxy Group of Seven Natural Gas Companies on January 31, 2025 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2023 Annual Forms 10-K
Bloomberg Professional

Atmos Energy Corporation
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances and Flotation Costs for FY 2016 - 2024

		[Column 1]	[Column 2]	[Column 3]	[Column 4]	[Column 5]	[Column 6]	[Column 7]
Fiscal Year	Transaction (1)	Shares Issued	Average Offering Price per Share	Net Proceeds per Share (2)	Gross Equity Issue before Costs	Total Net Proceeds	Total Flotation Costs (3)	Flotation Cost Percentage (4)
2024	At the Market Equity Offering	6,401,469	$ 117.2233	$ 116.6373	$ 750,401,394	$ 746,649,868	$ 3,751,526	0.50%
2023	At the Market Equity Offering	7,272,261	$ 112.7133	$ 111.0946	$ 819,680,535	$ 807,908,920	$ 11,771,616	1.44%
2022	At the Market Equity Offering	7,907,883	$ 100.0634	$ 98.3843	$ 791,290,027	$ 778,011,289	$ 13,278,738	1.68%
2021	At the Market Equity Offering	6,130,875	$ 101.5775	$ 99.0072	$ 622,758,775	$ 607,000,833	$ 15,757,941	2.53%
2020	At the Market Equity Offering	6,101,916	NA	NA	$ 632,630,269	$ 625,894,599	$ 6,735,669	1.06%
2019	At the Market Equity Offering	5,390,836	$ 92.7500	$ 91.6555	$ 500,000,000	$ 494,100,000	$ 5,900,000	1.18%
2018	At the Market Equity Offering	4,558,404	$ 87.7500	$ 86.6751	$ 400,000,000	$ 395,100,000	$ 4,900,000	1.23%
2017	At the Market Equity Offering	1,303,494	$ 76.7169	$ 75.7963	$ 100,000,000	$ 98,800,000	$ 1,200,000	1.20%
2016	At the Market Equity Offering	1,360,756	$ 73.4886	$ 72.4597	$ 100,000,000	$ 98,600,000	$ 1,400,000	1.40%
					$ 4,716,760,999	$ 4,652,065,510	$ 64,695,490	1.37%

Flotation Cost Adjustment

	Average Dividend Yield	Average Projected EPS Growth Rate	Adjusted Dividend Yield	Average DCF Cost Rate Unadjusted for Flotation (5)	DCF Cost Rate Adjusted for Flotation (6)	Flotation Cost Adjustment (7)
Proxy Group of Seven Natural Gas Companies	3.68 %	6.50 %	3.80 %	10.30 %	10.35 %	0.05 %

Source of Information: Atmos Energy Corporation SEC Form 10-Ks, Company-Provided Data

Notes provided on page 2 of this Exhibit

Atmos Energy Corporation
Notes to Accompany the
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

(1) Atmos Energy Corporation SEC Filings, Company-provided.

(2) Column 5 ÷ Column 1.

(3) Column 4 - Column 5.

(4) Column 6 ÷ Column 4.

(5) Using the average growth rate from Schedule DWD-2.

(6) Adjustment for flotation costs based on adjusting the average DCF constant growth cost rate in accordance with the following:

$$K = \frac{D(1+0.5g)}{P(1-F)} + g,$$

where g is the growth factor and F is the percentage of flotation costs.

(7) Flotation cost adjustment of 0.06% equals the difference between the flotation adjusted average DCF cost rate of 10.02% and the unadjusted average DCF cost rate of 9.96% of the Utility Proxy Group.

Sources of Information:

Company SEC Filings; Company-Provided

Atmos Energy Corporation
Range of Capital Structures for the Past Eight Fiscal Quarters for the
Proxy Group of Seven Natural Gas Distribution Companies

Common Equity Ratio (including Short-Term Debt)

Company	2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	8Q average ending Q3 2024
Atmos Energy Corporation	61.01%	60.94%	60.22%	61.30%	61.79%	60.89%	52.91%	53.45%	59.06%
New Jersey Resources Corporation	39.55%	41.31%	38.70%	38.49%	39.42%	39.95%	36.98%	37.59%	39.00%
NiSource Inc.	37.55%	36.54%	37.50%	29.11%	29.60%	30.30%	31.92%	30.80%	32.92%
Northwest Natural Holding Company	43.88%	44.87%	44.58%	43.52%	41.97%	44.04%	43.71%	42.43%	43.62%
ONE Gas, Inc.	47.17%	48.80%	49.52%	49.73%	49.12%	50.34%	49.70%	46.64%	48.88%
Southwest Gas Holdings, Inc.	40.22%	39.89%	38.38%	38.16%	37.57%	37.70%	39.08%	33.44%	38.06%
Spire Inc.	39.23%	39.65%	35.75%	35.05%	35.94%	36.39%	34.73%	36.07%	36.60%
								Minimum	32.92%
								Maximum	59.06%

Total Debt Ratio (including Short-Term Debt)

Company	2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	8Q average ending Q3 2024
Atmos Energy Corporation	38.99%	39.06%	39.78%	38.70%	38.21%	39.11%	47.09%	46.55%	40.94%
New Jersey Resources Corporation	60.45%	58.69%	61.30%	61.51%	60.58%	60.05%	63.02%	62.41%	61.00%
NiSource Inc.	62.45%	63.46%	62.50%	63.01%	64.77%	63.96%	60.02%	59.85%	62.50%
Northwest Natural Holding Company	56.12%	55.13%	55.42%	56.48%	58.03%	55.96%	56.29%	57.57%	56.38%
ONE Gas, Inc.	52.83%	51.20%	50.48%	50.27%	50.88%	49.66%	50.30%	53.36%	51.12%
Southwest Gas Holdings, Inc.	59.78%	60.11%	61.62%	61.84%	62.43%	62.30%	60.92%	66.56%	61.94%
Spire Inc.	57.70%	57.30%	61.17%	61.78%	60.82%	60.40%	62.06%	60.54%	60.22%
								Minimum	40.94%
								Maximum	62.50%

Common Equity Ratio (excluding Short-Term Debt)

Company	2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	8Q average ending Q3 2024
Atmos Energy Corporation	61.01%	60.94%	60.22%	62.15%	61.79%	60.89%	52.91%	54.02%	59.24%
New Jersey Resources Corporation	41.51%	42.91%	40.75%	40.46%	40.58%	41.50%	40.61%	41.20%	41.19%
NiSource Inc.	37.99%	37.67%	39.81%	33.70%	33.20%	32.91%	34.21%	33.98%	35.43%
Northwest Natural Holding Company	46.27%	46.08%	46.02%	44.89%	43.02%	44.69%	44.84%	46.79%	45.33%
ONE Gas, Inc.	56.12%	59.38%	59.44%	50.53%	52.29%	52.50%	52.46%	51.81%	54.32%
Southwest Gas Holdings, Inc.	43.58%	40.40%	41.43%	41.14%	37.82%	37.77%	41.38%	40.23%	40.47%
Spire Inc.	43.48%	44.01%	41.25%	40.07%	38.84%	39.32%	41.47%	42.20%	41.33%
								Minimum	35.43%
								Maximum	59.24%

Long-Term Debt Ratio (excluding Short-Term Debt)

Company	2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	8Q average ending Q3 2024
Atmos Energy Corporation	38.99%	39.06%	39.78%	37.85%	38.21%	39.11%	47.09%	45.98%	40.76%
New Jersey Resources Corporation	58.49%	57.09%	59.25%	59.54%	59.42%	58.50%	59.39%	58.80%	58.81%
NiSource Inc.	62.01%	62.33%	60.19%	57.16%	60.48%	60.85%	57.16%	55.72%	59.49%
Northwest Natural Holding Company	53.73%	53.92%	53.98%	55.11%	56.98%	55.31%	55.16%	53.21%	54.67%
ONE Gas, Inc.	43.88%	40.62%	40.56%	49.47%	47.71%	47.50%	47.54%	48.19%	45.68%
Southwest Gas Holdings, Inc.	56.42%	59.60%	58.57%	58.86%	62.18%	62.23%	58.62%	59.77%	59.53%
Spire Inc.	53.11%	52.61%	55.20%	56.30%	57.67%	57.22%	54.70%	53.83%	55.08%
								Minimum	40.76%
								Maximum	59.53%

Source: S&P Global Market Intelligence; S&P Capital IQ; Company Filings

Atmos Energy Corporation
Range of Capital Structures for the Past Eight Fiscal Quarters for the
Proxy Group of Seven Natural Gas Distribution Companies at the Operating Company Level

Common Equity Ratio (including Short-Term Debt)

Company	2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	8Q average ending Q3 2024
Atmos Energy Corporation	61.01%	60.94%	60.22%	61.30%	61.79%	60.89%	52.91%	53.45%	59.06%
New Jersey Natural Gas Company	55.08%	56.03%	52.41%	53.63%	54.70%	54.56%	51.00%	53.10%	53.81%
NiSource Inc.	37.55%	36.54%	37.50%	29.11%	29.60%	30.30%	31.92%	30.80%	32.92%
Northwest Natural Gas Company	45.43%	48.08%	47.87%	47.15%	46.12%	47.75%	48.56%	47.89%	47.36%
ONE Gas, Inc.	47.17%	48.80%	49.52%	49.73%	49.12%	50.34%	49.70%	46.64%	48.88%
Southwest Gas Holdings, Inc.	47.43%	47.78%	47.97%	47.28%	46.91%	47.24%	40.01%	42.14%	45.84%
Spire Alabama Inc.	54.75%	54.45%	50.57%	50.84%	51.50%	51.18%	49.45%	51.26%	51.75%
Spire Missouri Inc.	47.29%	47.30%	43.81%	44.05%	44.88%	44.90%	43.79%	45.43%	45.18%
								Minimum	32.92%
								Maximum	59.06%

Total Debt Ratio (including Short-Term Debt)

Company	2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4 0	8Q average ending Q3 2024
Atmos Energy Corporation	38.99%	39.06%	39.78%	38.70%	38.21%	39.11%	47.09%	46.55%	40.94%
New Jersey Natural Gas Company	44.92%	43.97%	47.59%	46.37%	45.30%	45.44%	49.00%	46.90%	46.19%
NiSource Inc.	62.45%	63.46%	62.50%	63.01%	64.77%	63.96%	60.02%	59.85%	62.50%
Northwest Natural Gas Company	54.57%	51.92%	52.13%	52.85%	53.88%	52.25%	51.44%	52.11%	52.64%
ONE Gas, Inc.	52.83%	51.20%	50.48%	50.27%	50.88%	49.66%	50.30%	53.36%	51.12%
Southwest Gas Holdings, Inc.	52.57%	52.22%	52.03%	52.72%	53.09%	52.76%	59.99%	57.86%	54.16%
Spire Alabama Inc.	45.25%	45.55%	49.43%	49.16%	48.50%	48.82%	50.55%	48.74%	48.25%
Spire Missouri Inc.	52.71%	52.70%	56.19%	55.95%	55.12%	55.10%	56.21%	54.57%	54.82%
								Minimum	40.94%
								Maximum	62.50%

Common Equity Ratio (excluding Short-Term Debt)

Company	2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	8Q average ending Q3 2024
Atmos Energy Corporation	61.01%	60.94%	60.22%	62.15%	61.79%	60.89%	52.91%	54.02%	59.24%
New Jersey Natural Gas Company	55.08%	56.84%	53.98%	54.19%	54.88%	54.56%	52.81%	54.43%	54.59%
NiSource Inc.	37.99%	37.67%	39.81%	33.70%	33.20%	32.91%	34.21%	33.98%	35.43%
Northwest Natural Gas Company	47.19%	48.08%	48.44%	47.46%	46.12%	47.75%	48.56%	51.41%	48.12%
ONE Gas, Inc.	56.12%	59.38%	59.44%	50.53%	52.29%	52.50%	52.46%	51.81%	54.32%
Southwest Gas Holdings, Inc.	47.43%	47.78%	47.97%	47.28%	46.91%	47.24%	42.90%	43.76%	46.41%
Spire Alabama Inc.	55.47%	55.63%	54.39%	54.55%	54.77%	54.82%	53.75%	60.14%	55.44%
Spire Missouri Inc.	52.50%	52.83%	51.29%	50.58%	47.52%	47.89%	52.08%	51.39%	50.76%
								Minimum	35.43%
								Maximum	59.24%

Total Debt Ratio (excluding Short-Term Debt)

Company	2024 Q3	2024 Q2	2024 Q1	2023 Q4	2023 Q3	2023 Q2	2023 Q1	2022 Q4	8Q average ending Q3 2024
Atmos Energy Corporation	38.99%	39.06%	39.78%	37.85%	38.21%	39.11%	47.09%	45.98%	40.76%
New Jersey Natural Gas Company	44.92%	43.16%	46.02%	45.81%	45.12%	45.44%	47.19%	45.57%	45.41%
NiSource Inc.	62.01%	62.33%	60.19%	57.16%	60.48%	60.85%	57.16%	55.72%	59.49%
Northwest Natural Gas Company	52.81%	51.92%	51.56%	52.54%	53.88%	52.25%	51.44%	48.59%	51.88%
ONE Gas, Inc.	43.88%	40.62%	40.56%	49.47%	47.71%	47.50%	47.54%	48.19%	45.68%
Southwest Gas Holdings, Inc.	52.57%	52.22%	52.03%	52.72%	53.09%	52.76%	57.10%	56.24%	53.59%
Spire Alabama Inc.	44.53%	44.37%	45.61%	45.45%	45.23%	45.18%	46.25%	39.86%	44.56%
Spire Missouri Inc.	47.50%	47.17%	48.71%	49.42%	52.48%	52.11%	47.92%	48.61%	49.24%
								Minimum	40.76%
								Maximum	59.49%

Source: S&P Global Market Intelligence; S&P Capital IQ; Company Filings

Atmos Energy Corporation
Current and Expected Equity Ratios for the
Utility Proxy Group as reported by Value Line Standard Edition

Proxy Group of Seven Natural Gas Companies	Common Equity Ratio 2024	2025	2027 - 2029 Projected
Atmos Energy Corporation	61.00%	60.00%	60.00%
New Jersey Resources Corporation	42.50%	43.00%	45.00%
NiSource Inc.	46.00%	45.00%	45.00%
Northwest Natural Holding Company	47.50%	45.00%	45.00%
ONE Gas, Inc.	54.00%	55.00%	49.00%
Southwest Gas Holdings, Inc.	45.00%	45.00%	44.00%
Spire Inc.	45.00%	45.00%	45.00%
Minimum	42.50%	43.00%	44.00%
Maximum	61.00%	60.00%	60.00%

Source: Value Line Standard Edition, November 22, 2024

Atmos Energy Corporation
Range of Authorized Common Equity Ratios for the
Proxy Group of Seven Natural Gas Distribution Companies (2020 - Present)

Date	State	Company	Case Identification	Common Equity / Total Cap (%)
1/15/2020	Wyoming	MDU Resources Group	D-30013-351-GR-19	51.25
1/16/2020	New York	Consolidated Edison Company	C-19-G-0066	48.00
1/24/2020	Virginia	Roanoke Gas Co.	C-PUR-2018-00013	59.64
2/3/2020	Washington	Cascade Natural Gas Corp.	D-UG-190210	49.10
2/24/2020	Kansas	Atmos Energy Corp.	D-19-ATMG-525-RTS	56.32
2/25/2020	Utah	Questar Gas Co.	D-19-057-02	55.00
2/28/2020	Massachusetts	Fitchburg Gas & Electric Light	DPU 19-131	52.45
3/25/2020	Washington	Avista Corp.	D-UG-190335	48.50
3/26/2020	Maine	Northern Utilities Inc.	D-2019-00092	50.00
4/21/2020	Texas	Atmos Energy Corp.	D-GUD-10900	60.12
5/19/2020	Colorado	Black Hills Colorado Gas Inc.	D-19AL-0075G	50.15
6/16/2020	Texas	CenterPoint Energy Resources	D-GUD-10920	56.95
7/8/2020	Washington	Puget Sound Energy Inc.	D-UG-190530	48.50
8/4/2020	Texas	Texas Gas Service Co.	D-GUD-10928 (Central-Gulf)	59.00
8/21/2020	Wyoming	Questar Gas Co.	D-30010-187-GR-19	55.00
9/14/2020	Tennessee	Chattanooga Gas Co.	D-20-00049	49.23
9/23/2020	New Jersey	South Jersey Gas Co.	D-GR20030243	54.00
9/25/2020	Nevada	Southwest Gas Corp.	D-20-02023 (Southern)	49.26
9/25/2020	Nevada	Southwest Gas Corp.	D-20-02023 (Northern)	49.26
9/28/2020	Arkansas	CenterPoint Energy Resources	D-17-010-FR (2020 filing)	33.07
10/4/2020	South Carolina	Piedmont Natural Gas Co.	D-2020-7-G	52.31
10/7/2020	Massachusetts	Eversource Gas Co MA	DPU 20-59	53.25
10/12/2020	Colorado	Public Service Co. of CO	D-20AL-0049G	55.62
10/16/2020	Oregon	Northwest Natural Gas Co.	D-UG-388	50.00
10/30/2020	Massachusetts	NSTAR Gas Co.	DPU 19-120	54.77
11/7/2020	Maryland	Columbia Gas of Maryland Inc	C-9644	52.63
11/19/2020	New York	NY State Electric & Gas Corp.	C-19-G-0379	48.00
11/19/2020	New York	Rochester Gas & Electric Corp.	C-19-G-0381	48.00
11/19/2020	Florida	Peoples Gas System	D-20200051-GU	54.70
11/24/2020	Wisconsin	Madison Gas & Electric Co.	D-3270-UR-123 (Gas)	55.00
12/9/2020	Arizona	Southwest Gas Corp.	D-G-01551A-19-0055	51.10
12/10/2020	Oregon	Avista Corp.	D-UG 389	50.00
12/16/2020	Maryland	Baltimore Gas and Electric Co.	C-9645 (Gas)	52.00
12/16/2020	New Mexico	New Mexico Gas Co.	C-19-00317-UT	52.00
12/23/2020	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-122 (Gas)	52.53
1/1/2021	Georgia	Atlanta Gas Light Co.	D-42315 (2020 review)	56.00
1/6/2021	Oregon	Cascade Natural Gas Corp.	D-UG 390	50.00
1/6/2021	Delaware	Delmarva Power & Light Co.	D-20-0150	50.37
1/13/2021	Illinois	Ameren Illinois	D-20-0308	52.00
1/26/2021	Nebraska	Black Hills Nebraska Gas LLC	D-NG-109	50.00
2/16/2021	Tennessee	Piedmont Natural Gas Co.	D-20-00086	50.50
2/19/2021	Pennsylvania	Columbia Gas of Pennsylvania	D-R-2020-3018835	54.19
2/24/2021	District of Columbia	Washington Gas Light Co.	FC-1162	52.10
3/25/2021	California	Southwest Gas Corp.	A-19-08-015 (SoCal)	52.00
3/25/2021	California	Southwest Gas Corp.	A-19-08-015 (NoCal)	52.00
3/25/2021	California	Southwest Gas Corp.	A-19-08-015 (LkTah)	52.00
4/9/2021	Maryland	Washington Gas Light Co.	C-9651	52.03
5/5/2021	North Dakota	MDU Resources Group	C-PU-20-379	50.31
5/18/2021	Washington	Cascade Natural Gas Corp.	D-UG-200568	49.10
5/19/2021	New York	Corning Natural Gas Corp.	C-20-G-0101	48.00
6/17/2021	Pennsylvania	PECO Energy Co	D-R-2020-3018929	53.38
7/19/2021	Tennessee	Atmos Energy Corp.	D-21-00019	59.88
7/27/2021	West Virginia	Hope Gas Inc.	C-20-0746-G-42T	47.45
7/30/2021	New Hampshire	Liberty Utilities EnergyNorth	D-DG-20-105	52.00
8/12/2021	New York	KeySpan Gas East Corp.	C-19-G-0310	48.00
8/12/2021	New York	The Brooklyn Union Gas Co.	C-19-G-0309	48.00
9/1/2021	Idaho	Avista Corp.	C-AVU-G-21-01	50.00
9/8/2021	Illinois	North Shore Gas Co.	D-20-0810	51.58
9/14/2021	Virginia	Virginia Natural Gas Inc.	C-PUR-2020-00095	51.89
9/23/2021	Arkansas	CenterPoint Energy Resources	D-17-010-FR (2021 filing)	32.27
9/27/2021	Washington	Avista Corp.	D-UG-200901	48.50
9/29/2021	South Carolina	Piedmont Natural Gas Co.	D-2021-7-G	52.20
9/30/2021	Massachusetts	Boston Gas Co.	DPU 20-120	53.44
10/6/2021	Indiana	Sthrn IN Gas & Electric Co.	Ca-45447	45.74
10/27/2021	Missouri	Spire Missouri Inc.	C-GR-2021-0108	49.86
11/17/2021	Indiana	Indiana Gas Co.	Ca-45468	46.21
11/17/2021	New Jersey	New Jersey Natural Gas Co.	D-GR21030679	54.00
11/18/2021	New York	Central Hudson Gas & Electric	C-20-G-0429	50.00
11/18/2021	Wisconsin	Northern States Power Co.	D- 4220-UR-125 (Gas)	52.50
11/18/2021	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-123 (Gas)	52.50
11/18/2021	Illinois	Northern Illinois Gas Co.	D-21-0098	54.46
11/18/2021	Georgia	Atlanta Gas Light Co.	D-42315 (2021 review)	56.00
11/23/2021	Wisconsin	Madison Gas & Electric Co.	D-3270-UR-124 (Gas)	55.00
11/30/2021	Oklahoma	Oklahoma Natural Gas Co	Ca-PUD202100063	58.55
12/3/2021	Maryland	Columbia Gas of Maryland Inc	C-9664	52.95
12/9/2021	Michigan	DTE Gas Co.	C-U-20940	39.23

Atmos Energy Corporation
Range of Authorized Common Equity Ratios for the
Proxy Group of Seven Natural Gas Distribution Companies (2020 - Present)

Date	State	Company	Case Identification	Common Equity / Total Cap (%)
12/13/2021	Colorado	Black Hills Colorado Gas Inc.	D-21AL-0236G	50.26
12/28/2021	Iowa	Black Hills Iowa Gas Utility	D-RPU-2021-0002	50.01
12/28/2021	Kentucky	Duke Energy Kentucky Inc.	C-2021-00190	51.34
12/28/2021	Kentucky	Columbia Gas of Kentucky Inc	C-2021-00183	52.64
1/6/2022	North Carolina	Piedmont Natural Gas Co.	D-G-9, Sub 781	51.60
1/20/2022	New York	Niagara Mohawk Power Corp.	C-20-G-0381	48.00
1/21/2022	North Carolina	Public Service Co. of NC	D-G-5 Sub 632	51.60
3/22/2022	Nevada	Southwest Gas Corp.	D-21-09001 (Southern)	50.00
3/22/2022	Nevada	Southwest Gas Corp.	D-21-09001 (Northern)	50.00
4/14/2022	New York	Orange & Rockland Utlts Inc.	C-21-G-0073	48.00
5/19/2022	Kentucky	Atmos Energy Corp.	C-2021-00214	54.50
6/16/2022	New York	Corning Natural Gas Corp.	C-21-G-0394	48.00
6/20/2022	Tennessee	Atmos Energy Corp.	D-22-00010	60.59
7/20/2022	New Hampshire	Northern Utilities Inc.	D-DG-21-104	52.00
7/27/2022	Indiana	Northern IN Public Svc Co. LLC	Ca-45621	49.47
8/2/2022	Oregon	Avista Corp.	D-UG 433	50.00
8/17/2022	New Jersey	Elizabethtown Gas Co.	D-GR21121254	52.00
8/18/2022	Minnesota	CenterPoint Energy Resources	D-G-008/GR-21-435	51.00
8/23/2022	Washington	Cascade Natural Gas Corp.	D-UG-210755	47.00
9/15/2022	South Carolina	Piedmont Natural Gas Co.	D-2022-89-G	52.20
10/10/2022	Arkansas	Black Hills Energy Arkansas	D-21-097-U	45.00
10/12/2022	Delaware	Delmarva Power & Light Co.	D-22-0002	49.94
10/24/2022	Oregon	Northwest Natural Gas Co.	D-UG-435	50.00
10/25/2022	Colorado	Public Service Co. of CO	D-22AL-0046G	53.78
10/27/2022	North Dakota	Northern States Power Co.	C-PU-21-381	52.54
10/27/2022	Massachusetts	The Berkshire Gas Co.	DPU 22-20	54.00
11/3/2022	California	San Diego Gas & Electric Co.	A-21-08-014 (Gas)	52.00
11/17/2022	Maryland	Columbia Gas of Maryland Inc	C-9680	52.97
11/30/2022	New Mexico	New Mexico Gas Co.	C-21-00267-UT	52.00
12/15/2022	California	Southern California Gas Co.	A-22-04-011	52.00
12/21/2022	New Jersey	South Jersey Gas Co.	D-GR22040253	54.00
12/22/2022	Washington	Puget Sound Energy Inc.	D-UG-220067	49.00
12/22/2022	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-127 (Gas)	53.40
12/23/2022	Utah	Questar Gas Co.	D-22-057-03	51.00
12/29/2022	Wisconsin	Wisconsin Gas LLC	D-5-UR-110	52.70
12/29/2022	Wisconsin	Wisconsin Electric Power Co.	D-5-UR-110 (WEP-Gas)	58.22
1/19/2023	Texas	Texas Gas Service Co.	D-OSS-22-00009896 (WTXNorth)	59.74
1/23/2023	Arizona	Southwest Gas Corp.	D-G-01551A-21-0368	50.00
1/24/2023	Florida	Florida Public Utilities Co.	D-20220067-GU	45.16
1/26/2023	Ohio	Columbia Gas Ohio Inc.	C-21-0637-GA-AIR	50.60
3/23/2023	Minnesota	Northern States Power Co.	D-G-002/GR-21-678	52.50
3/28/2023	Florida	Pivotal Utility Holdings Inc.	20220069-GU	59.60
5/4/2023	Colorado	Atmos Energy Corp.	D-22AL-0348G	58.00
6/22/2023	Tennessee	Atmos Energy Corp.	D-23-00008	62.20
6/30/2023	Idaho	Intermountain Gas Co.	C-INT-G-22-07	50.00
7/20/2023	New York	Consolidated Edison Company of	C-22-G-0065	48.00
8/31/2023	Idaho	Avista Corp.	C-AVU-G-23-01	50.00
9/20/2023	Maine	Northern Utilities Inc.	D-2023-00051	52.01
9/20/2023	South Carolina	Dominion Energy South Carolina	D-2023-70-G	54.78
10/5/2023	South Carolina	Piedmont Natural Gas Co.	D-2023-7-G	53.13
10/6/2023	Tennessee	Chattanooga Gas Co.	D-23-00029	49.23
10/12/2023	New York	NY State Electric & Gas Corp.	C-22-G-0318	48.00
10/12/2023	New York	Rochester Gas & Electric Corp.	C-22-G-0320	48.00
10/25/2023	Montana	NorthWestern Energy Group	D-2022-7-78 (gas)	48.02
10/26/2023	Oregon	Avista Corp.	D-UG-461	50.00
10/26/2023	Minnesota	Minnesota Energy Resources	D-G-011/GR-22-504	53.00
11/1/2023	Ohio	Duke Energy Ohio Inc.	C-22-0507-GA-AIR	52.32
11/3/2023	Wisconsin	Madison Gas & Electric Co.	D-3270-UR-125 (Gas)	56.06
11/7/2023	Wyoming	Questar Gas Co.	D-30010-215-GR-23	51.56
11/9/2023	Wisconsin	Northern States Power Co.	D-4220-UR-126 (Gas)	52.50
11/9/2023	Wisconsin	Wisconsin Power and Light Co	D-6680-UR-124 (Gas)	53.70
11/16/2023	Illinois	Ameren Illinois	D-23-0067	50.00
11/16/2023	Illinois	Northern Illinois Gas Co.	D-23-0066	50.00
11/16/2023	Illinois	The Peoples Gas Light & Coke C	D-23-0069	50.79
11/16/2023	Illinois	North Shore Gas Co.	D-23-0068	52.58
12/4/2023	Tennessee	Piedmont Natural Gas Co.	D-23-00035	50.09
12/14/2023	Maryland	Baltimore Gas and Electric Co.	C-9692 (GAS)	52.00
12/14/2023	Maryland	Washington Gas Light Co.	C-9704	52.60
12/15/2023	District of Columbia	Washington Gas Light Co.	FC-1169	52.00
12/22/2023	California	Southern California Gas Co.	Advice Letter No. 6207-G	52.00
1/17/2024	Wyoming	Black Hills Wyoming Gas LLC	D-30026-78-GR-23	51.00
1/31/2024	Texas	Texas Gas Service Co.	D-OSS-23-00014399(Rio Grande)	59.07
3/24/2024	Colorado	Black Hills Colorado Gas Inc.	D-23AL-0231G	50.87
3/29/2024	Iowa	MidAmerican Energy Co.	D-RPU-2023-0001	51.50
4/8/2024	Nevada	Southwest Gas Corp.	D-23-09012 (Northern)	50.00
4/8/2024	Nevada	Southwest Gas Corp.	D-23-09012 (Southern)	50.00

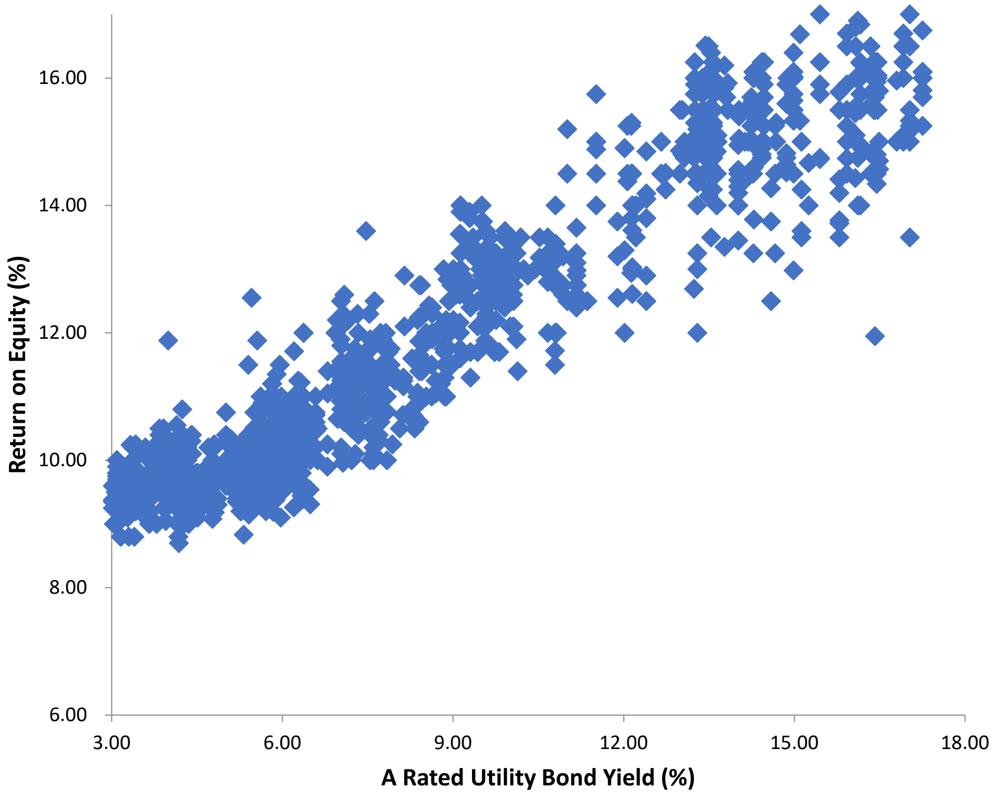
Atmos Energy Corporation
Range of Authorized Common Equity Ratios for the
Proxy Group of Seven Natural Gas Distribution Companies (2020 - Present)

Date	State	Company	Case Identification	Common Equity / Total Cap (%)
4/8/2024	Alaska	ENSTAR Natural Gas Co.	D-U-22-081	54.11
4/17/2024	Ohio	Northeast Ohio NaturalGas Corp	C-23-0154-GA-AIR	51.42
6/26/2024	Texas	CenterPoint Energy Resources	D-OSS-23-00015513 (Texas Cons)	60.61
6/28/2024	Massachusetts	Fitchburg Gas & Electric Light	DPU 23-81	52.26
7/18/2024	New York	Central Hudson Gas & Electric	C-23-G-0419	48.00
7/25/2024	New Mexico	New Mexico Gas Co.	C-23-00255-UT	52.00
7/29/2024	Tennessee	Atmos Energy Corp.	D-24-00006	62.38
7/31/2024	Indiana	Northern IN Public Svc Co. LLC	Ca-45967	52.39
8/12/2024	Tennessee	Chattanooga Gas Co.	D-24-00024	49.23
8/15/2024	New York	KeySpan Gas East Corp.	C-23-G-0226	48.00
8/15/2024	New York	The Brooklyn Union Gas Co.	C-23-G-0225	48.00
9/17/2024	Iowa	Interstate Power & Light Co.	D-RPU-2023-0002 (gas)	51.00
9/18/2024	Nevada	Sierra Pacific Power Co.	D-24-02027	52.40
10/1/2024	Arkansas	Black Hills Energy Arkansas	D-23-074-U	39.64
10/9/2024	New Jersey	Public Service Electric Gas	D-GR23120925	55.00
10/25/2024	Oregon	Northwest Natural Gas Co.	D-UG-490	50.00
10/25/2024	Colorado	Public Service Co. of CO	D-24AL-0049G	54.00
10/31/2024	Illinois	Liberty Utilities (Midstates)	D-24-0043	45.30
11/6/2024	Indiana	Ohio Valley Gas Inc	Ca-46011	83.18
11/7/2024	Michigan	DTE Gas Co.	C-U-21291	39.59
11/7/2024	North Dakota	MDU Resources Group	C-PU-23-341	50.19
11/7/2024	North Dakota	Northern States Power Co.	C-PU-23-367	52.50
11/18/2024	Connecticut	CT Natural Gas Corp.	D-23-11-02 (CNG)	53.00
11/18/2024	Connecticut	The Sthrn CT Gas Co	D-23-11-02 (SCG)	53.00
11/20/2024	Texas	Texas Gas Service Co.	D-OS-24-00017471(Central-Gulf)	59.58
11/21/2024	Arkansas	Summit Utilities Arkansas Inc.	D-23-079-U	41.07
11/21/2024	New Jersey	New Jersey Natural Gas Co.	D-GR24010071	54.00
11/21/2024	New Jersey	Elizabethtown Gas Co.	D-GR24020158	55.00
12/19/2024	New York	Natl Fuel Gas Distribution Cor	C-23-G-0627	48.00
12/19/2024	Wisconsin	Wisconsin Gas LLC	D-5-UR-111	52.76
12/19/2024	Wisconsin	Wisconsin Public Service Corp.	D-6690-UR-128 (Gas)	54.17
12/19/2024	Wisconsin	Wisconsin Electric Power Co.	D-5-UR-111 (Gas)	56.54
12/20/2024	Washington	Avista Corp.	D-UG-240007	48.50
12/30/2024	Kentucky	Columbia Gas of Kentucky Inc	C-2024-00092	52.64
1/7/2025	North Carolina	Piedmont Natural Gas Co.	D-G-9 Sub 837	52.30
1/15/2025	Washington	Puget Sound Energy Inc.	D-UG-240005	50.00
			Minimum	32.27
			Maximum	62.38 (1)

Notes:
(1) Excludes the 83.18% equity ratio authorized for Ohio Valley Gas Inc.

Source of Information: Regulatory Research Associates

Atmos Energy Corporation
Regression Analysis of Return on Equity and
A-Rated Utility Bonds



Constant		Slope	A-Rated Utility Yield (1)		Return on Equity	
7.44329	%	0.5202	5.67	%	10.39	%

Correlation 0.95

2010 Rate Cases 39 Average ROE 10.15 %

Notes:
(1) Average of last three months of A-Rated Utility Bond Yields from Bloomberg Professional

Source of Information: Regulatory Research Associates, Bloomberg Professional

Atmost Energy Corporation
Calculation of Price Appreciation and Annualized Volatility of the
Utility Proxy Group, Other Utility Indices, and Market Indices since January 31, 2020

	Price Appreciation (1)	Annualized Volatility (2)
Atmos Energy Corporation	21.77%	25.60%
New Jersey Resources Corporation	16.05%	35.05%
NiSource Inc.	27.26%	27.22%
Northwest Natural Holding Company	-45.60%	35.07%
ONE Gas, Inc.	-25.25%	32.00%
Southwest Gas Holdings, Inc.	-1.10%	32.99%
Spire Inc.	-15.84%	29.90%
Utility Proxy Group Average	-3.24%	31.12%
Dow Jones Utility Average	6.50%	23.38%
Utilities Select SPDR Fund	12.90%	23.49%
S&P 500 Gas Utilities Sub Ind Index	21.77%	25.59%
Dow Jones Industrial Average	57.65%	20.76%
S&P 500	87.27%	21.37%

Notes:
(1) (01/31/2025 price minus 1/31/2020 price) divided by 1/31/2020 price.
(2) Standard deviation of returns over the period multiplied by the square root of 252, or number of trading days in a year.

Source: S&P Market Intelligence, S&P Capital IQ

Atmos Energy Corporation
Growth Rate Regression Analysis

Company	Ticker	Median P/E Ratio	Proj. Earnings Growth Rate	Proj. Dividend Growth Rate
Ameren Corporation	AEE	20.0	6.50%	6.50%
American Electric Power Company, Inc.	AEP	18.0	6.50%	5.50%
Avangrid, Inc.	AGR	NMF	4.00%	0.50%
ALLETE, Inc.	ALE	19.0	6.00%	3.50%
Atmos Energy Corporation	ATO	20.0	7.00%	7.50%
Avista Corporation	AVA	19.0	5.50%	4.00%
Black Hills Corporation	BKH	18.0	4.00%	4.00%
CMS Energy Corporation	CMS	21.0	6.00%	5.00%
CenterPoint Energy, Inc.	CNP	19.0	6.50%	6.00%
Chesapeake Utilities	CPK	23.0	6.50%	8.00%
Dominion Energy Inc.	D	21.0	3.00%	0.50%
DTE Energy Company	DTE	18.0	4.50%	3.00%
Duke Energy Corporation	DUK	18.0	5.00%	2.00%
Consolidated Edison, Inc.	ED	18.0	6.00%	4.00%
Edison International	EIX	14.0	6.50%	6.00%
Eversource Energy	ES	19.0	6.00%	6.00%
Entergy Corporation	ETR	14.0	0.50%	3.50%
Evergy, Inc.	EVRG	NMF	7.50%	7.00%
Exelon Corporation	EXC	14.0	NMF	NMF
FirstEnergy Corp.	FE	14.0	6.00%	6.00%
Hawaiian Electric Industries, Inc.	HE	19.0	NMF	NMF
IDACORP, Inc.	IDA	20.0	6.00%	5.50%
Alliant Energy Corporation	LNT	21.0	6.00%	6.00%
MGE Energy, Inc.	MGEE	25.0	7.00%	6.50%
NextEra Energy, Inc.	NEE	24.0	8.50%	9.00%
NiSource Inc.	NI	21.0	9.50%	4.50%
New Jersey Resources	NJR	17.0	5.00%	5.00%
NorthWestern Corporation	NWE	17.0	4.50%	1.50%
Northwest Natural Gas Holding	NWN	24.0	6.50%	0.50%
OGE Energy Corp.	OGE	18.0	6.50%	3.00%
One Gas, Inc.	OGS	21.0	3.50%	2.50%
Otter Tail Corporation	OTTR	19.0	4.50%	7.00%
PG&E Corporation	PCG	20.0	9.00%	NMF
Public Service Enterprise Group Incorporated	PEG	16.0	6.50%	6.00%
Pinnacle West Capital Corporation	PNW	17.0	4.00%	1.50%
Portland General Electric Company	POR	18.0	5.50%	5.50%
PPL Corporation	PPL	15.0	7.50%	-0.50%
RGC Resources	RGCO	NA	NA	NA
Southern Company	SO	17.0	6.50%	3.50%
Spire Inc.	SR	19.0	4.50%	4.50%
Sempra Energy	SRE	20.0	6.00%	6.00%
Southwest Gas Holdings	SWX	21.0	10.00%	5.50%
TXNM Energy, Inc	TXNM	19.0	4.00%	5.50%
UGI Corporation	UGI	16.0	6.50%	3.50%
Unitil Corp.	UTL	NA	NA	NA
WEC Energy Group, Inc.	WEC	21.0	6.00%	7.00%
Xcel Energy Inc.	XEL	20.0	6.50%	6.00%

Notes:
Source: Value Line Reports as of January 31, 2025

Atmos Energy Corporation
Growth Rate Regression Analysis

SUMMARY OUTPUT: Median P/E Ratio vs. EPS

Regression Statistics	
Multiple R	0.335822806
R Square	0.112776957
Adjusted R Square	0.090027648
Standard Error	2.469172889
Observations	41

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	30.22422443	30.22422443	4.957379489	0.031825891
Residual	39	237.7757756	6.096814758		
Total	40	268			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	16.02672264	1.389956577	11.53037649	3.90717E-14	13.21527009	18.83817518
Proj. Earnings Growth Rate	50.37370738	22.62443968	2.226517345	0.031825891	4.611458663	96.1359561

SUMMARY OUTPUT: Median P/E Ratio vs. DPS

Regression Statistics	
Multiple R	0.286508813
R Square	0.0820873
Adjusted R Square	0.057931702
Standard Error	2.539476444
Observations	40

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	21.91525684	21.91525684	3.398272393	0.073074259
Residual	38	245.0597432	6.448940609		
Total	39	266.975			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	17.34840871	0.969430433	17.89546533	4.1559E-20	15.3858994	19.31091802
Proj. Dividend Growth Rate	34.98045784	18.9756384	1.843440369	0.073074259	-3.433713782	73.39462947

D'ASCENDIS PROXY GROUP
DCF Growth Rate Analysis

	Company	(1) Value Line DPS	(2) Value Line EPS	(3) S&P IQ EPS	(4) Zacks EPS
1	Atmos Energy		7.00%	7.51%	7.00%
3	New Jersey Resources		5.00%	5.60%	NA
4	NiSource		9.50%	7.78%	7.50%
5	Northwest Natural Holding Company		6.50%	4.83%	NA
6	One Gas, Inc.		3.50%	2.45%	2.90%
7	Spire		4.50%	6.50%	5.80%
	Averages		6.00%	5.78%	5.80%
	Median		5.75%	6.05%	6.40%

Sources: Value Line Investment Survey, Nov. 22, 2024
S&P IQ Pro and Zacks accessed January 3, 2025
S&P IQ Pro EPS growth used as proxies for Zacks EPS for New Jersey Resources and Northwest Natural Holding Co.

D'ASCENDIS PROXY GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) S&P IQ Earning Gr.	(4) Zacks Earnings Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.83%	3.83%	3.83%	3.83%	3.83%
Proxy Group Average Growth Rate		6.00%	5.78%	5.80%	5.86%
Expected Dividend Yield	3.83%	3.94%	3.94%	3.94%	3.94%
DCF Return on Equity		***9.94%***	***9.72%***	***9.74%***	***9.80%***
Method 2:					
Dividend Yield	3.83%	3.83%	3.83%	3.83%	3.83%
Proxy Group Median Growth Rate		5.75%	6.05%	6.40%	6.07%
Expected Dividend Yield	3.83%	3.94%	3.94%	3.95%	3.94%
DCF Return on Equity		***9.69%***	***9.99%***	***10.35%***	***10.01%***

Atmos Energy Corporation
Calculation of the Capital Asset Pricing Model
to Reflect Forward-Looking Interest Rates, Market Risk Premiums
and the Employment of the ECAPM

	Kroll Arithmetic Mean		Value Line S&I 3-5 Year Total Return		Ibbotson and Chen Prospective MRP		Average
CAPM							
Long-Term Annual Return on Stocks	12.04%	(1)	11.83%	(2)	11.69%	(3)	
Prospective 30-Year Treasury Bond Yield	4.87%	(1)	4.58%	(1)	4.58%	(1)	
Market Risk Premium	7.17%		7.25%		7.11%		**7.18%**
Proxy Group Beta (1)	0.83		0.83		0.83		
Beta * Market Premium	5.94%		6.01%		5.89%		
Prospective 30-Year Treasury Bond Yield	4.58%		4.58%		4.58%		
CAPM Cost of Equity	**10.52%**		**10.59%**		**10.47%**		**10.53%**
ECAPM							
Historical Market Risk Premium	7.17%		7.25%		7.11%		
Proxy Group Beta, Value Line	0.83		0.83		0.83		
Beta * Market Premium	5.94%		6.01%		5.89%		
Prospective 30-Year Treasury Bond Yield	4.58%		4.58%		4.58%		
ECAPM Cost of Equity (rf + 0.25(MRP) + 0.75(β*MRP))	**10.83%**		**10.90%**		**10.78%**		**10.83%**

Notes:
(1) Source: Exhibit RAB-4
(2) Source: Value Line Summary and Index, January 3, 2025
(3) Calculated by converting the Ibbotson and Chen projected return on the market from a geometric mean to an arithmetic mean as shown below:

$$R_A = R_G + \frac{\sigma^2}{2}$$

Geometric Mean Return (1)	Standard Deviation of Equity Returns	Arithmetic Mean Return
9.73%	19.78%	11.69%

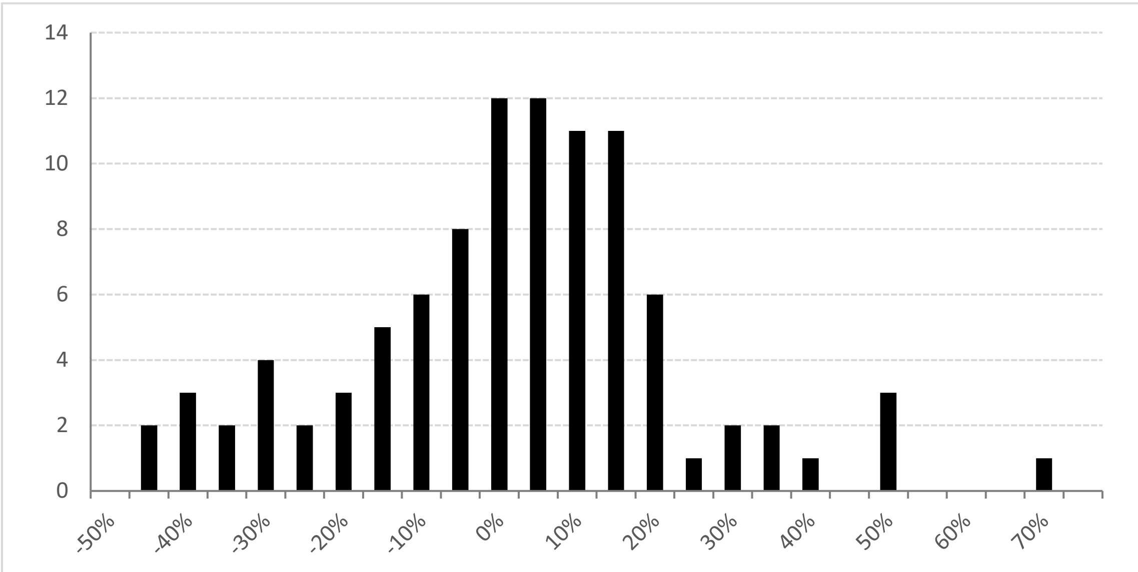
Where:
R_A = Arithmetic Mean
R_G = Geometric Mean
σ = Standard Deviation of Equity Returns
Source: Kroll 2023 SBBI Yearbook, at 200-201.

Atmos Energy Corporation
Comparison of Market Return Measures

	[1]	[2]	[3]	[4]	[5]
	Actual Market Return (1)	LT average Market Return (2)	Kroll (3)	Ibbotson Chen Supply-Side (4)	Damodaran (5)
2009	26.46%	11.67%	10.50%	11.65%	8.64%
2010	15.06%	11.85%	10.08%	11.12%	8.20%
2011	2.11%	11.88%	9.63%	10.54%	8.49%
2012	16.00%	11.77%	10.00%	11.34%	7.89%
2013	32.39%	11.82%	9.50%	11.49%	7.54%
2014	13.69%	12.05%	9.00%	11.43%	8.00%
2015	1.38%	12.07%	9.00%	11.41%	7.95%
2016	11.96%	11.95%	9.00%	11.46%	8.39%
2017	21.83%	11.95%	9.00%	11.28%	8.14%
2018	-4.38%	12.06%	8.50%	11.19%	7.49%
2019	31.49%	11.88%	9.00%	11.23%	8.64%
2020	18.40%	12.09%	8.00%	11.31%	7.12%
2021	28.71%	12.16%	8.00%	11.32%	5.65%
2022	-18.11%	12.33%	8.00%	11.11%	5.75%
2023	26.61%	12.02%	9.00%	11.31%	9.82%
Sum	223.60%	179.55%	136.21%	169.20%	117.71%
Forecast Bias (6)		**80.30%**	**60.92%**	**75.67%**	**52.64%**

Notes:
(1) Source: Kroll, 2023 SBBI, Appendix A-1, A-7; Cost of Capital Navigator
(2) Rolling historic long-term average of data in Column 1 since 1926
(3) Source: Kroll Recommended ERP + Corresponding Risk-Free Rate
(4) Source: SBBI 2023
(5)Damodaran Predicted Market Return
(6) Sum of forecasts divided by sum of actual observations

Atmos Energy Corporation
Frequency Distribution of Equity Risk Premiums, 1928 - 2024



	ERP (With PRPM)	Rank
Direct	5.21%	48.90%

	ERP (Excl. PRPM)	Rank
Direct	5.16%	48.80%

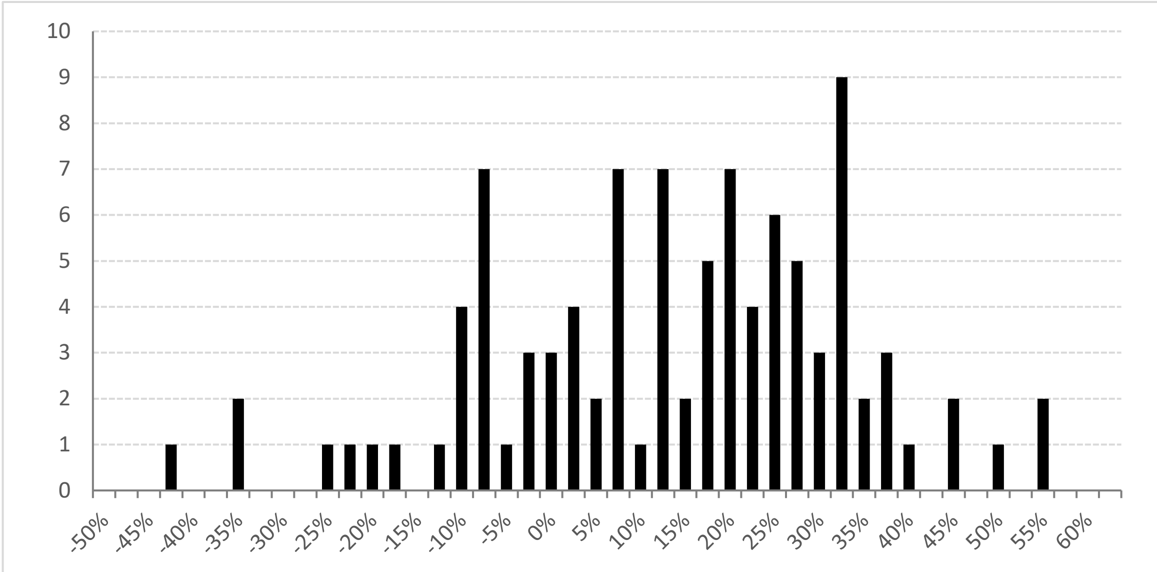
	ERP (With PRPM)	Rank
Rebuttal	5.21%	48.90%

	ERP (Excl. PRPM)	
Rebuttal	5.18%	48.90%

Source of Information: Bloomberg Professional Services; Mergent Bond Record

Atmos Energy Corporation

Frequency Distribution of Observed Market Returns, 1926 - 2024



Average Return from Direct	Rank
12.82%	47.20%

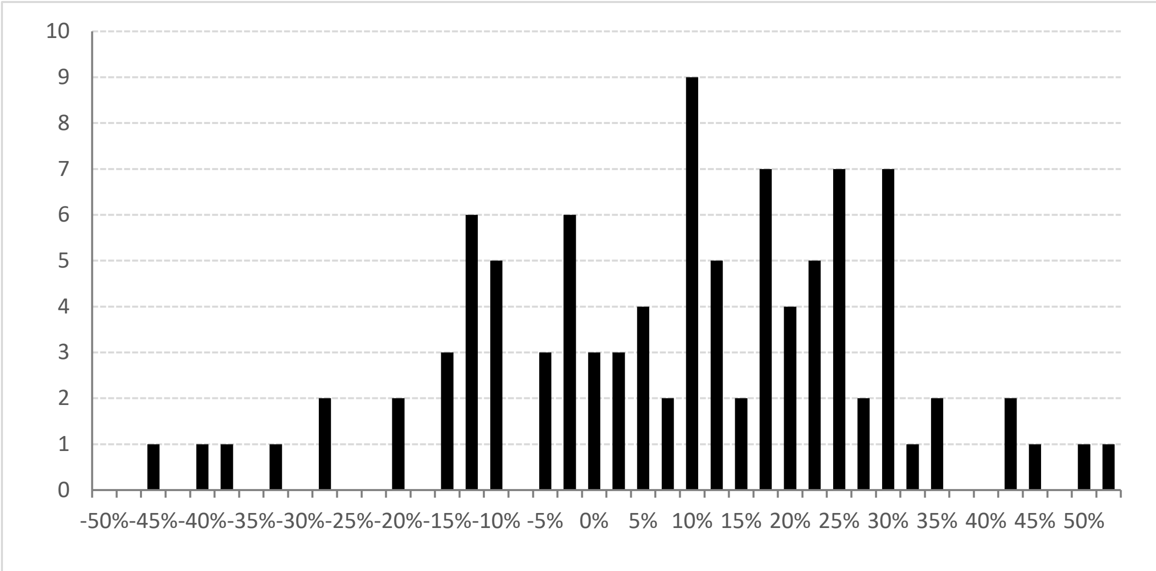
Average Return from Rebuttal	Rank
12.84%	47.30%

Baudino Return	Rank
9.80%	40.80%

Source: Kroll, 2023 SBBI, Appendix A-1, A-7; Cost of Capital Navigator

Atmos Energy Corporation

Frequency Distribution of Market Risk Premium, 1926 - 2024



Average MRP from Direct	Rank
8.63%	49.20%

Average MRP from Rebuttal	Rank
8.28%	49.00%

Baudino MRP	Rank
5.00%	41.70%

Source: Kroll, 2023 SBBI, Appendix A-1, A-7; Cost of Capital Navigator

Atmos Energy Corporation
Summary of Relationship Between GDP Growth and Stock Returns

SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.138
R Square	0.019
Adjusted R Square	0.008
Standard Error	0.194
Observations	95

Y=Large Cap Total Returns
X= GDP Growth

Correlation 0.14

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	0.06819316	0.06819316	1.80278455	0.18264429
Residual	93	3.51787118	0.03782657		
Total	94	3.58606434			

	Coefficients	*Standard Erroi*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.10064	0.02429	4.14269	0.00008	0.05240	0.14889
GDP Growth	0.56576	0.42137	1.34268	0.18264	-0.27099	1.40251

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Comparable Earnings: New Life for an Old Precept

by
Frank J. Hanley
Pauline M. Ahern

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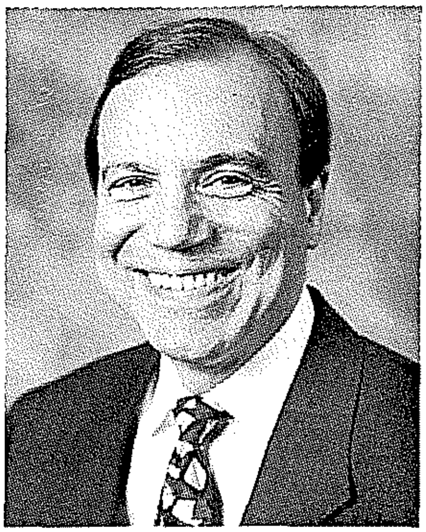
Summer 1994 edition, Arlington, Va.

Comparable Earnings: New Life for an Old Precept

Accelerating deregulation has greatly increased the investment risk of natural gas utilities. As a result, the authors believe it more appropriate than ever to employ the comparable earnings model. We believe our application of the model overcomes the greatest traditional objection to it — lack of comparability of the selected non-utility proxy firms. Our illustration focuses on a target gas pipeline company with a beta of 0.96 — almost equal to the market's beta of 1.00.



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Introduction

The comparable earnings model used to determine a common equity cost rate is deeply rooted in the standard of "corresponding risk" enunciated in the landmark *Bluefield* and *Hope* decisions of the U.S. Supreme Court.[1] With such solid grounding in the foundations of rate of return regulation, comparable earnings should be accepted as a principal model, along with the currently popular market-based models, provided that its most common criticism, non-comparability of the proxy companies, is overcome.

Our comparable earnings model overcomes the non-comparability issue of the non-utility firms selected as a proxy for the target utility, in this example, a gas pipeline company. We should note that in the absence of common stock prices for the target utility (as with a wholly-owned subsidiary), it is appropriate to use the average of a proxy group of similar risk gas pipeline companies whose common stocks are actively traded. As we will demonstrate, our selection process results in a group of domestic, non-utility firms that is comparable in total risk, the sum of business and financial risk, which reflects both non-diversifiable systematic, or market, risk as well as diversifiable unsystematic, or firm-specific, risk.

Embedded in the Landmark Decisions

As stated in *Bluefield* in 1922: "A public utility is entitled to such rates as will permit it to earn a return ... on investments in other business undertakings which are attended by corresponding risks and uncertainties ..."

In addition, the court stated in *Hope* in 1944: "By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks."

Thus, the "corresponding risk" precept of *Bluefield* and *Hope* predates the use of such market-based cost-of-equity models as the Discounted Cash Flow (DCF) and Capital Asset Pricing (CAPM), which were developed later and are currently popular in rate-base/rate-of-return regulation. Consequently, the comparable earnings model has a longer regulatory and judicial history. However, it has far greater relevance now than ever before in its history because significant deregulation has substantially increased natural gas utilities' investment risk to a level similar to that of non-utility firms. As a result, it is

Comparable Earnings *from page 4*

more important than ever to look to similar-risk non-utility firms for insight into common equity cost rate, especially in view of the deficiencies inherent in the currently popular market-based cost of common equity models, particularly the DCF model.

Despite the fact that the landmark decisions are still regarded as having set the standards for determining a fair rate of return, the comparable earnings model has experienced decreased usage by expert witnesses, as well as less regulatory acceptance over the years. We believe the decline in the popularity of the comparable earnings model, in large measure, is attributable to the difficulty of selecting non-utility proxy firms that regulators will accept as comparable to the target utility. Regulatory acceptance is difficult to gain when the selection process is arbitrary. Our application of the model is objective and consistent with fundamental financial tenets.

Principles of Comparable Earnings

Regulation is a substitute for the competition of the marketplace. Moreover, regulated public utilities compete in the capital markets with all firms, including unregulated non-utilities. The comparable earnings model is based upon the opportunity cost principle; i.e., that the true cost of an investment is the return that could have been earned on the next best available alternative investment of similar risk. Consequently, the comparable earnings model is consistent with regulatory and financial principles, as it is a surrogate for the competition of the marketplace, and investors seek the greatest available rate of return for bearing similar risk.

The selection of comparable firms is the most difficult step in applying the comparable earnings model, as noted by Phillips[2] as well as by Bonbright, Danielsen and Kamerschen.[3] The selection of non-utility proxy firms should result in a sufficiently broad-based group in order to minimize the effect of company-specific aberrations. However, if the selection process is arbitrary, it likely would result in a proxy group that is too broad-based, such as the Standard & Poor's 500 Composite Index or the Value Line Industrial Composite. The use of such groups would require subjective adjustments to the comparable earnings results to reflect risk differences between the group(s) and the target utility, a gas pipeline company in this example.

Authors' Selection Criteria

We base the selection of comparable non-utility firms on market-based, objective, quantitative measures of risk resulting from market prices that subsume investors' assessments of all elements of risk. Thus, our approach is based upon the principle of risk and return; namely, that firms of comparable risk should be expected to earn comparable returns. It is also consistent with the "corresponding risk" standard established in *Bluefield* and *Hope*. We measure total investment risk as the sum of non-diversifiable systematic and diversifiable unsystematic risk. We use the unadjusted beta as a measure of systematic risk and the standard error of the estimate (residual standard error) as a measure of unsystematic risk. Both the unadjusted beta and the residual standard error are derived from a regression of the target utility's security returns relative to the market's returns, which takes the general form:

$$r_{it} = a_i + b_i\, r_{mt} + e_{it}$$

where:

- r_{it} = tth observation of the ith utility's rate of return
- r_{mt} = tth observation of the market's rate of return
- e_{it} = tth random error term
- a_i = constant least-squares regression coefficient
- b_i = least-squares regression slope coefficient, the unadjusted beta.

As shown by Francis,[4] the total variation or risk of a firm's return, Var (r_i), comes from two sources:

Var (r_i) = total risk of ith asset

= var$(a_i + b_i r_m + e)$ substituting $(a_i + b_i r_m + e)$ for r_i

= var$(b_i r_m)$ + var (e) since var$(a_i) = 0$

= b_i^2 var(r_m) + var (e) since var$(b_i r_m) = b_i^2$ var(r_m)

= systematic + unsystematic risk

Francis[5] also notes: "The term $\sigma^2(r_i|r_m)$ is called the *residual variance around the regression line* in statistical terms or *unsystematic risk* in capital market theory language. $\sigma^2(r_i|r_m) = \ldots$ = var (e). The residual variance is the squared standard error in regression language, a measure of unsystematic risk." Application of these criteria results in a group of non-utility firms whose average total investment risk is indeed comparable to that of the target gas pipeline.

As a measure of systematic risk, we use the Value Line unadjusted beta. Beta measures the extent to which market-wide or macro-economic events affect a firm's stock price. We use the unadjusted beta of the target utility as a starting point because it results from the regression of the target utility's security returns relative to the market's returns. Thus, the resulting standard deviation of beta relates to the unadjusted beta. We use the standard deviation of the unadjusted beta to determine the range around it as the selection criterion based on systematic risk.

We use the residual standard error of the regression as a measure of unsystematic risk. The residual standard error reflects the extent to which events specific to the firm's operations affect a firm's stock price. Thus, it is a measure of diversifiable, unsystematic, firm-specific risk.

An Illustration of Authors' Approach

Step One: We begin our approach by establishing the selection criteria as a range of both unadjusted beta and residual standard error of the target gas

continued on page 6

Comparable Earnings *from page 5*

from page 5

pipeline company.

As shown in table 1, our target gas pipeline company has a Value Line unadjusted beta of 0.90, whose standard deviation is 0.1250. The selection criterion range of unadjusted beta is the unadjusted beta plus (+) and minus (-) three of its standard deviations. By using three standard deviations, 99.73 percent of the comparable unadjusted betas is captured.

Three standard deviations of the target utility's unadjusted beta equals 0.38 (0.1250 x 3 = 0.3750, rounded to 0.38). Consequently, the range of unadjusted betas to be used as a selection criteria is 0.52 - 1.28 (0.52 = 0.90 - 0.38) and (1.28 = 0.90 + 0.38).

Likewise, the selection criterion range of residual standard error equals the residual standard error plus (+) and minus (-) three of its standard deviations. The standard deviation of the residual standard error is defined as: $\sigma/\sqrt{2N}$.

As also shown in table 1, the target gas pipeline company has a residual standard error of 3.7867. According to the above formula, the standard deviation of the residual standard error would be 0.1664 ($0.1664 = 3.7867/\sqrt{2(259)} = 3.7867/22.7596$, where 259 = N, the number of weekly price change observations over a period of five years). Three standard deviations of the target utility's residual standard error would be 0.4992 (0.1664 x 3 = .4992). Consequently, the range of residual standard errors to be used as a selection criterion is 3.2875 - 4.2859 (3.2875 = 3.7867 - 0.4992) and (4.2859 = 3.7867 + 0.4992).

Step Two: The step one criteria are applied to Value Line's data base of nearly 4,000 firms for which Value Line derives unadjusted betas and residual standard errors on a weekly basis. All firms with unadjusted betas and residual standard errors within the criteria ranges are then selected.

Step Three: In the regulatory ratemaking environment, authorized common equity return rates are applied to a book-value rate base. Thus, the earnings rates on book common equity, or net worth, of competitive, non-utility firms are highly relevant provided those firms are indeed comparable in total risk to the target gas pipeline. The use of the return rates of other utilities has no relevance because their allowed, and hence subsequently achieved, earnings rates are dependent upon the regulatory

table 1

Summary of the Comparable Earnings Analysis for the Proxy Group of 248 Non-Utility Companies Comparable in Total Risk to the Target Gas Pipeline Company[1]

	1	2	3	4	5	6	7	8
			residual	rate of return on net worth				
	adj. beta	unadj. beta	standard error	3-year average[2]	4-year average[2]	5-year average[2]	5-year projected[3]	
average for the proxy group of 248 non-utility companies comparable in total risk to the target gas pipeline company	0.97	0.92	3.7705					
target gas pipeline company	0.96	0.90[4]	3.7867					
median				11.7%	12.0%	12.6%	15.5%	
average of the median historical returns					12.1%			
conclusion[5]								13.8%

[1]The criteria for selection of the non-utility group was that the non-utility companies be domestic and included in *Value Line Investment Survey*. The non-utility group was selected based on an unadjusted beta range of 0.52 to 1.28 and a residual standard error range of 3.2875 to 4.2859.
[2]Ending 1992.
[3]1996-1998/1997-1999.
[4]The average standard deviation of the target gas pipeline company's unadjusted beta is 0.1250.
[5]Equal weight given to both the average of the 3-, 4- and 5-year historical medians (12.1%) and 5-year projected median rate of return on net worth (15.5%). Thus, 13.8% = (12.1% + 15.5% / 2).
Source: Value Line Inc., March 15, 1994
Value Line Investment Survey

Comparable Earnings *from page 6*

process. Consequently, we believe all utilities must be eliminated to avoid circularity. Moreover, we believe non-domestic firms must be eliminated because their reporting methods differ significantly from U.S. firms.

Step Four: We then eliminated those firms for which Value Line does not publish a "Ratings & Report" in *Value Line Investment Survey* so that the historical and projected returns on net worth[6] are from a consistent source. We use historical returns on net worth for the most recent five years, as well as those projected three to five years into the future. We believe it is logical to evaluate both historical and projected return rates because it is reasonable to assume that investors avail themselves of both when they are available from widely disseminated information services, such as Value Line Inc. The use of Value Line's return rates on net worth understates the common equity return rates for two reasons. First, preferred stock is included in net worth. Second, the net worth return rates are as of the end of each period. Thus, the use of average common equity return rates would yield higher results.

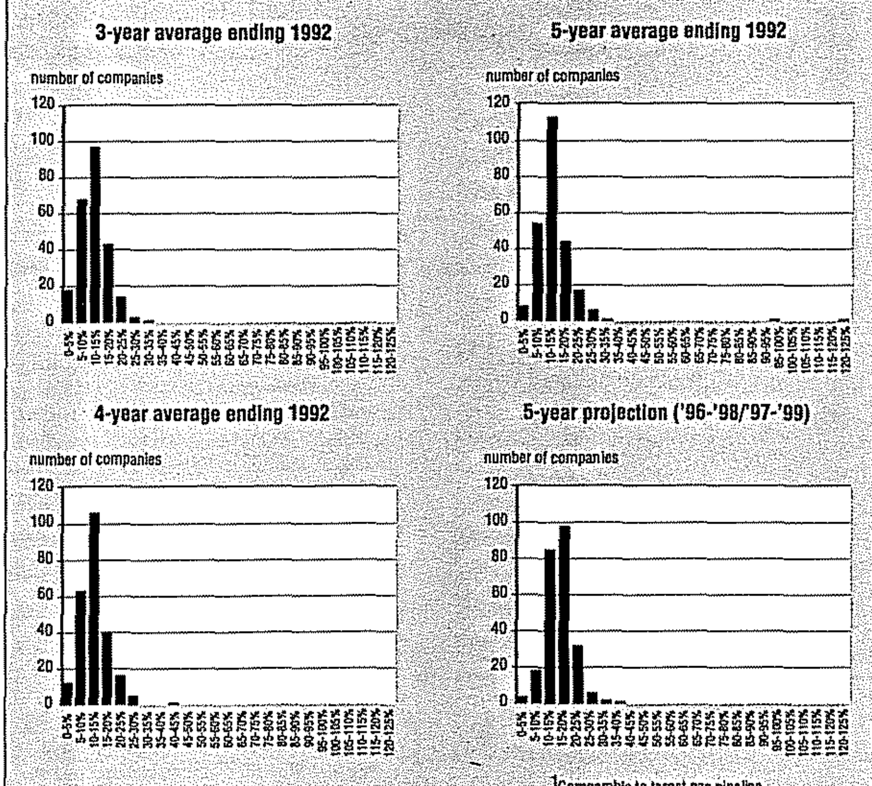
Step Five: Median returns based on the historical average three, four and five years ending 1992 and projected 1996-1998 or 1997-1999 rates of return on net worth are then determined as shown in columns 4 through 7 of table 1. The median is used due to the wide variations and skewness in rates of return on net worth for the non-utility firms as evidenced by the frequency distributions of those returns as shown in illustration 1.

However, we show the average unadjusted beta, 0.92, and residual standard error, 3.7705, for the proxy group in columns 2 and 3 of table 1 because their frequency distributions are not significantly skewed, as shown in illustration 2.

Step Six: Our conclusion of a com-

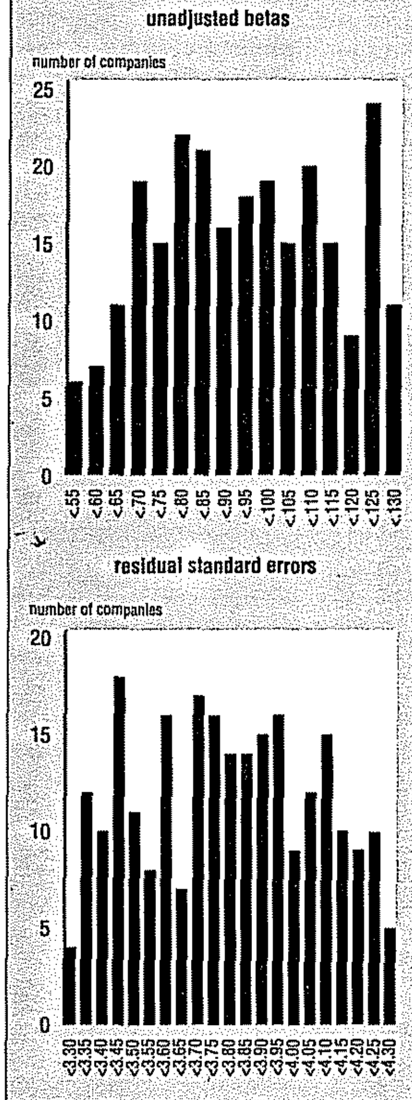
continued on page 8

Illustration 1
Rates of Return on Net Worth for the Proxy Group of 248 Non-Utility Companies[1]



[1]Comparable to target gas pipeline

Illustration 2
Unadjusted Betas and Residual Standard Errors for the Proxy Group of 248 Non-Utility Companies[1]



[1]Comparable to target gas pipeline

Comparable Earnings *from page 7*

parable earnings cost rate is based upon the mid-point of the average of the median three-, four- and five-year historical rates of return on net worth of 12.1 percent as shown in column 5 and the median projected 1996-1998/1997-1999 rate of return on net worth of 15.5 percent as shown in column 7 of table 1. As shown in column 8, it is 13.8 percent.

Summary

Our comparable earnings approach demonstrates that it is possible to select a proxy group of non-utility firms that is comparable in total risk to a target utility. In our example, the 13.8 percent comparable earnings cost rate is very conservative as it is an expected achieved rate on book common equity (a regulatory allowed rate should be greater) and because it is based on end-of-period net worth. A similar rate on average net worth would be about 20 to 40 basis points higher (i.e., 14.0 to 14.2 percent) and still understate the appropriate regulatory allowed rate of return on book common equity.

Our selection criteria are based upon measures of systematic and unsystematic risk, specifically unadjusted beta and residual standard error. They provide the basis for the objective selection of comparable non-utility firms. Our selection criteria rely on changes in market prices over approximately five years. We compare the aggregate total risk, or the sum of systematic and unsystematic risk, which reflects investors' aggregate assessment of both business and financial risk. Thus, no adjustments are necessary to the proxy group results to compensate for the differences in business risk and financial risk, such as accounting practices and debt/equity ratios. Moreover, it is inappropriate to attempt a comparison of the target utility with any individual firm, or subset of firms, in the proxy group because only the average firm of the group is relevant.

Because the comparable earnings model is firmly anchored in the "corresponding risk" precept established in the landmark court decisions, it is worthy of consideration as a principal model for use in estimating the cost rate of common equity capital of a regulated utility. Our approach to the comparable earnings model produces a proxy group that is indeed comparable in total risk because the selection process is objective and quantitative. It therefore overcomes criticism linked to arbitrary selection processes.

All cost-of-common-equity models, including the DCF and CAPM, are fraught with deficiencies, usually stemming from the many necessary but unrealistic assumptions that underlie them. The effects of the deficiencies of individual models can be mitigated by using more than one model when estimating a utility's common equity cost rate. Therefore, when the non-comparability issue is overcome, the comparable earnings model deserves to receive the same consideration as a primary model, as do the currently popular market-based models. ■

[1]*Bluefield Water Works Improvement Co. v. Public Service Commission*. 262 U.S. 679 (1922) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 519 (1944).

[2]Charles F. Phillips Jr., The Regulation of Public Utilities: Theory and Practice, Public Utilities Reports Inc., 1988, p. 379

[3]James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utilities Rates, 2nd edition, Public Utilities Reports Inc. 1988, p. 329

[4]Jack Clark Francis, Investments: Analysis and Management, 3rd edition, McGraw-Hill Book Co., 1980, p. 363

[5]Id., p. 548.

[6]Returns on net worth must be used when relying on Value Line data because returns on book common equity for non-utility firms are not available from Value Line

Report Lists Pipeline, Storage Projects

More than $9 billion worth of projects to expand the nation's natural gas pipeline network are in various stages of development, according to an A.G.A. report. These projects involve nearly 8,000 miles of new pipelines and capacity additions to existing lines and represent 15.3 billion cubic feet (Bcf) per day of new pipeline capacity.

During 1993 and early 1994, construction on 3,100 miles of pipeline was completed or under way, at a cost of nearly $4 billion, says A.G.A. These projects are adding 5.4 Bcf in daily delivery capacity nationwide.

Among the projects completed in 1993 were Pacific Gas Transmission Co.'s 805 miles of looping that allows increased deliveries of Canadian gas to the West Coast; Northwest Pipeline Corp.'s addition of 433 million cubic feet of daily capacity for customers in the Pacific Northwest and Rocky Mountain areas; and the 156-mile Empire State Pipeline in New York.

In addition, major construction projects were started on the systems of Texas Eastern Transmission Corp. and Algonquin Gas Transmission Co. — both subsidiaries of Panhandle Eastern Corp. — and along Florida Gas Transmission Co.'s pipeline.

The report goes on to discuss another $5 billion in proposed projects, which, if completed, will add nearly 5,000 miles of pipeline and 9.8 Bcf per day in capacity, much of it serving Florida and West Coast markets.

A.G.A. also identifies 47 storage projects and says that if all of them are built, existing storage capacity will increase by more than 500 Bcf, or 15 percent.

For a copy of *New Pipeline Construction: Status Report 1993-94* (#F00103), call A.G.A. at (703) 841-8490. Price per copy is $6 for employees of member companies and associates and $12 for other customers.

Investments: Analysis and Management

Fifth Edition

Jack Clark Francis

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Investments: Analysis and Management

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Beta Measurements The beta coefficient is an *index of systematic risk.* Beta coefficients may be used for ranking the systematic risk of different assets. If the beta is larger than 1, $b > 1.0$, then the asset is more volatile than the market and is called an **aggressive asset.** If the beta is less than 1, $b < 1.0$, the asset is a **defensive asset;** its price fluctuations are less volatile than the market's. Figure 10-1 illustrates the characteristic lines for three different assets that have low, medium, and high levels of beta (or undiversifiable risk).

Figure 10-2 shows that IBM is a stock with an average amount of systematic risk. IBM's beta of 1.02 indicates that its return tends to increase 2 percent more than the return on the market average when the market is rising. When the market falls, IBM's return tends to fall 2 percent more than the market's. The characteristic line for IBM has an above average correlation coefficient of $\rho = .7495$, indicating that the returns on this security follow its particular characteristic line slightly more closely than those of the average stock.

Partitioning Risk

Total risk can be measured by the variance of returns, denoted Var(r). This measure of *total risk is partitioned into its systematic and unsystematic components in Equation (10-8).*[7]

$$\begin{aligned} \text{Var}(r_i) &= \text{total risk of } i\text{th asset} \\ &= \text{Var}(a_i + b_i r_{m,t} + e_{i,t}) \\ &\quad \text{by substituting } (a_i + b_i r_{m,t} + e_{i,t}) \text{ for } r_{i,t} \\ &= 0 + \text{Var}(b_i r_{m,t}) + \text{Var}(e_{i,t}) \\ &\quad \text{since Var}(a_i) = 0 \end{aligned} \tag{10-8}$$

$$\begin{aligned} \text{Var}(r_i) &= b_i^2\,\text{Var}(r_m) + \text{Var}(e) \qquad \text{since Var}(b_i r_m) = b_i^2\,\text{Var}(r_m) \\ &= \text{systematic} + \text{unsystematic risk} \end{aligned} \tag{10-8a}$$

$$.01389 = .00780 + .00609 \qquad \text{for IBM}$$

The unsystematic risk measure Var(e) is called in regression language the *residual variance* or, synonymously, the *standard error squared.*

Undiversifiable Proportion The percentage of total risk that is systematic can be measured by the coefficient of determination ρ^2 (that is, the characteristic line's squared correlation coefficient).

[7]In this context, **partition** is a technical statistical term that means to divide the total variance into *mutually exclusive* and *exhaustive* pieces. This partition is only possible if the returns from the market are statistically independent from the residual error terms that occur simultaneously, $\text{Cov}(r_{m,t}, e_{i,t}) = 0$. The mathematics of regression analysis will orthogonalize the residuals and thus ensure that the needed statistical independence exists.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS	**)**	
ENERGY CORPORATION FOR AN	**)**	
ADJUSTMENT OF RATES; APPROVAL OF	**)**	**Case No. 2024-00276**
TARIFF REVISIONS; AND OTHER	**)**	
GENERAL RELIEF	**)**	

REBUTTAL TESTIMONY OF JOEL J. MULTER

INDEX TO THE REBUTTAL TESTIMONY
OF JOEL J. MULTER, WITNESS FOR
ATMOS ENERGY CORPORATION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Joel J. Multer. I am the Vice President of Tax for Atmos Energy Corporation ("Atmos Energy" or the "Company").

Q. ARE YOU THE SAME JOEL J. MULTER THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR REBUTTAL TESTIMONY?

A. Yes. I have prepared or supervised the preparation of the exhibits listed in the table of contents.

II. PURPOSE OF REBUTTAL TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my testimony is to rebut certain recommendations regarding Atmos Energy Corporation's ("Atmos Energy" or the "Company") income tax matters advocated for in the Direct Testimony of Lane Kollen on behalf of the Kentucky Office of Attorney General ("OAG").

Q. WHAT IS YOUR SUMMARY OF MR. KOLLEN'S POSITIONS ON INCOME TAX RELATED MATTERS?

A. Mr. Kollen makes the following five recommendations regarding the amount of deferred tax asset associated with net operating loss carryforwards ("NOLC DTA") included in rate base as well as a recommendation regarding the Company's proposed Tax Rider Tariff. Specifically, he recommends:

(1) that the starting point for the allocated amount of the Company's NOLC DTA allocated to Kentucky be updated to the actual amounts at September 30, 2024;

(2) that the methodology used to determine the amount of NOLC DTA allocated to Kentucky in this case revert back to the allocation methodology used in prior filings and approved by the Commission;

(3) that the Company's NOLC DTA be reduced to reflect only NOLC DTA caused by tax depreciation in excess of book depreciation and that the Commission direct the Company to provide the information necessary to calculate the minimum NOLC DTA necessary to avoid a normalization violation in its next base rate case filing;

(4) that the Commission direct the Company to include the "bridge" months of October 2024 through March 2025 in its NOLC DTA calculations; and

(5) that the Commission deny the Company's request for its proposed Tax Rider Tariff.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN RESPONSE TO MR. KOLLEN'S TESTIMONY.

A.

- I agree with Mr. Kollen's recommendation to update the starting point for the amount of the Company's NOLC DTA allocated to Kentucky to the actual amount at September 30, 2024.
- While I disagree with Mr. Kollen's assertion that the Company failed to comply with the Commission's directive from the Company's previous case, however I accept Mr. Kollen's recommendation to revert back to the allocation methodology used in prior filings and approved by the Commission.

- I disagree with Mr. Kollen's recommendation that the NOLC DTA be reduced to reflect only NOLC DTA caused by tax depreciation in excess of book depreciation because it is proper, economic and reasonable ratemaking practice to include the utility's entire NOLC DTA, not simply the amount generated by tax depreciation in excess in book depreciation. Inclusion in rate base of the utility's entire NOLC DTA maintains consistency between the amount of total income tax expense recovered from customers in cost of service and the amount of income tax expense that has been deferred and yet to be remitted to taxing authority. Furthermore, I disagree with Mr. Kollen's calculation of the amount of NOLC DTA caused by accelerated tax depreciation in excess of book depreciation as Mr. Kollen's attempt at calculating this amount is not proper.
- I disagree with Mr. Kollen's recommendation that the Commission direct the Company in its next base rate case, to provide information necessary to calculate the minimum NOLC DTA necessary to avoid a normalization violation as this recommendation is not necessary given the Company's entire NOLC DTA should be included in rate base.
- I disagree with Mr. Kollen's assertion that the NOLC DTA should be less due to taxable income during the six month "bridge" period consisting of September 30, 2024, through March 31, 2025.
- I disagree with Mr. Kollen's critique of the Company's proposed Tax Rider Tariff and request that the Commission approve the Company's proposed tariff as originally filed.

III. <u>NOLC DTA REQUESTED IN RATE BASE</u>

Q. DO YOU AGREE WITH MR. KOLLEN'S FIRST RECOMMENDATION TO UPDATE THE STARTING POINT FOR THE ALLOCATED AMOUNT OF NOLC DTA INCLUDED IN RATE BASE?

A. Yes. I agree that it is reasonable to update the starting point for the amount of allocated NOLC DTA included in rate base to the actual amounts as of September 30, 2024. My agreement with this adjustment is reflected in the Company's rebuttal revenue requirement presented by Company witness Mr. Greg Waller in Exhibit GKW-R-1 attached to his rebuttal testimony.

Q. REGARDING MR. KOLLEN'S SECOND RECOMMENDATION, DO YOU AGREE WITH MR. KOLLEN'S PREMISE THAT THE COMPANY FAILED TO COMPLY WITH THE COMMISSION'S DIRECTIVE FROM CASE 2021-00214?

A. No.

Q. PLEASE RESTATE THE COMMISSION'S DIRECTIVE IN CASE 2021-00214 ON THIS MATTER?

A. The Commission's directive is as follows:

> *Atmos Kentucky must now track the generation and utilization of NOL ADIT for Kentucky in each fiscal year on a standalone basis based on the expenses incurred and revenue generated from regulated operations in Kentucky, including any revenue from Atmos Kentucky's performance-based rates, without regard to losses incurred by other jurisdictions. In future applications to increase base rates, Atmos Kentucky must file a report showing the generation and utilization of NOL ADIT for Kentucky since this Order based on the expenses incurred and revenue generated from Kentucky operations. If Atmos Kentucky proposes to use a different method to reflect the generation and utilization of NOL ADIT for*

> *Kentucky in its revenue model in such cases, Atmos Kentucky must explain in detail why using that method would be reasonable.*[1]

Q. DID THE COMPANY FAIL TO PREPARE OR FILE SUCH A REPORT IN THIS APPLICATION AS MR. KOLLEN SUGGESTS?

A. No, the Company has complied with the Commission's directive in the preparation and filing of the NOLC DTA in this proceeding and illustrated in Exhibit JJM-1 of my direct testimony. Exhibit JJM-1 represents the Company's report showing the generation and utilization of NOL ADIT based on the expenses incurred and revenue generated from Kentucky operations since the Commission's order in Case 2021-00214.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING MR. KOLLEN'S CRITIQUE OF THE COMPANY'S RESPONSE TO THE COMMISSION'S PREVIOUS ORDER?

A. Yes. Mr. Kollen seems to admit that his critique of the Company's methodology to derive its NOLC DTA in this case, which forms the basis for his recommendation, is results oriented rather than grounded in sound ratemaking principles. His use of italics on the word "increased" on page 12 line 24 and his sentence "The new methodology results in a *greater* amount of the AEC Utility NOLC DTA allocated to the Kentucky division, not less." (page 13 lines 8-9) reveals his bias. Prior to expanding upon his criticisms, he seems to imply that the methodology utilized by the Company, which was ordered by the Commission upon his recommendation in

[1] Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for an Adjustment of Rates* (Ky. PSC May 19, 2022), final Order at 14.

our most recent case, should be dismissed outright precisely due to the result it produces.

Q. NONETHELESS, DO YOU ACCEPT MR. KOLLEN'S SECOND RECOMMENDATION THAT THE COMMISSION RETAIN THE COMPANY'S PRIOR ALLOCATION METHODOLOGY FOR DETERMINING THE COMPANY'S NOLC DTA?

A. Yes. I accept Mr. Kollen's recommendation that the Commission retain the Company's prior allocation methodology. He states specifically that the Company's prior methodology should be retained "if [the Commission] does not adopt the methodology reflected in [his] third adjustment" (page 13 lines 19-20). I agree with Mr. Kollen on both counts, that his second recommendation should be accepted and his third recommendation should be rejected, which I discuss next in my testimony. My agreement with this adjustment is reflected in the Company's rebuttal revenue requirement presented by Company witness Mr. Greg Waller in Exhibit GKW-R-1 attached to his rebuttal testimony.

Q. DO YOU AGREE WITH MR. KOLLEN'S THIRD RECOMMENDATION REGARDING THE NOLC DTA?

A. No.

Q. WHAT IS MR. KOLLEN'S THIRD RECOMMENDATION REGARDING ASSET NOLC ADIT?

A. Mr. Kollen recommends a reduction in NOLC DTA included in rate base to include only the NOLC DTA that is caused by tax depreciation in excess of book depreciation to avoid a potential normalization violation resulting in loss of ability to recognize accelerated tax depreciation.

Q. PLEASE EXPLAIN HOW INCOME TAX EXPENSE IS RECORDED WITHIN THE COMPANY'S FINANCIAL STATEMENTS AND PRESENTED IN UTILITY RATE FILINGS?

A. Income tax expense represents a cost the utility incurs in the provision of its services and, therefore, an expense allowed to be recovered within the utility's revenue requirement. Income tax expense is determined by multiplying the statutory income tax rate (*i.e.* 21% federal income tax rate) by the pre-tax income reported under generally accepted accounting principles ("GAAP"). Because the revenue requirement formula provides for the recovery of expenses plus a return or profit, the amount of income tax expense included in cost of service is generally calculated based on the income tax expense associated with the utility's equity return. The calculation in this proceeding can be found on Schedule E of the Company's revenue requirement model (FR 16(8)(e)) and included in Exhibit GKW-R-1 attached to the rebuttal testimony of Mr. Waller.

Q. HOW DOES THE DETERMINATION OF INCOME UNDER GAAP COMPARE WITH THAT UNDER THE INTERNAL REVENUE CODE?

A. The determination of income under the rules of GAAP differs from the determination of income under the provisions of the Internal Revenue Code ("IRC") primarily due to timing differences in the recognition of expenses and revenue. A common example is accelerated tax depreciation whereby the cost basis of plant assets is allowed to be depreciated on an accelerated basis and over a shorter period of time compared with GAAP. Another example consists of tax repair deductions which represent cost basis of assets that are capitalized and depreciated under GAAP but allowed to be immediately expensed as a repair deduction under the IRC.

Q. WHAT DO THESE DIFFERENCES RESULT IN FOR A UTILITY?

A. These differences between GAAP and IRC result in the ability for the utility to defer portions of total income tax expense to a later period such that total income tax expense is split into two categories: a current portion representing the amount of tax currently due the federal government and a deferred portion representing the amount of current period income tax expense able to be deferred to a later tax year. The portion of total income tax expense that is deferred in a given year is recognized in the utility's financial statements as a deferred income tax expense and captured within the utility's balance sheet as a Deferred Tax Liability (ADIT liability) given these amounts represent a portion of the current period's total income tax expense for which payment has been deferred to a later year.

Q. HOW DOES THIS RELATE TO ESTABLISHING CUSTOMER RATES IN THE RATEMAKING PROCESS?

A. In the context of ratemaking, the portion of total income tax expense recovered from customers in cost of service but deferred is viewed as a cost-free source of funds from the government representing interest-free financing that may be used to supplement the utility's debt and equity needs. As such, regulators either include accumulated deferred income taxes as a reduction to utility rate base or alternatively as a cost-free component of the utility's capital structure.

Q. IS THERE A LIMIT TO HOW MUCH COST-FREE SOURCE OF FUNDS ARE AVAILABLE TO A UTILITY?

A. Yes. Differences between GAAP and IRC determinations of income may result in the deferral of a portion or all of total income tax expense for a given year, but a taxpayer cannot defer more than its total income tax expense. Therefore, when a taxpayer has more tax deductions than income and is in a tax net operating loss position, it must recognize a NOLC Deferred Tax Asset ("NOLC DTA") on the taxpayer's GAAP books. A NOLC DTA represents the tax deductions that have yet to defer income tax expense but are allowed to be carried forward as NOLC to be used to defer total income tax expense in subsequent periods.

Q. WHAT IS THE RESULT OF A NOLC DTA IN THE CONTEXT OF RATEMAKING?

A. Where the deferred tax benefits of deductions giving rise to a NOLC are included as ADIT liabilities reducing that taxpayer's rate base, it is proper, economic and reasonable ratemaking practice to include the utility's entire NOLC DTA asset in rate base as well to maintain consistency between the amount of total income tax expense recovered from customers in cost of service and the amount of tax expense that has been deferred and yet to be remitted to the federal government.

Q. WHY IS INCLUSION OF THE ENTIRE NOLC DTA PROPER, ECONOMIC AND REASONABLE RATEMAKING PRACTICE?

A. Inclusion is appropriate because deferred income taxes, as mentioned above, represents a source of cost-free capital. The Company has not been able to realize the economic benefit of deferring the income taxes but instead has established a receivable, in the form of a NOLC DTA, to receive the cost-free capital *in a future period*, thus it is reasonable to include the full NOLC DTA in rate base until the cost-free source of financing is received through reduced income taxes paid.

Q. IS IT APPROPRIATE, AS MR. KOLLEN RECOMMENDS, FOR THE COMMISSION TO CONSIDER THE ABILITY OF THE ATMOS ENERGY HOLDING INC. ("AEHI") UNREGULATED ENTITIES TO UTILIZE THE TAX LOSSES OF THE ATMOS ENERGY CORPORATION ("AEC") UTILITY DIVISIONS?

A. No, it is not. The revenues, expenses, assets and liabilities of the AEHI unregulated entities are not relevant to this proceeding. The determination of total income tax expense presented in rate filings for recovery from customers is formulaic, based solely on the revenues, expenses, assets, and liabilities including within the filing. Should the utility defer a portion of this expense to a later period, it is sound ratemaking to reflect this deferral as an ADIT liability in rate base representing amounts recovered from customers in rates but not yet remitted to the government and a cost-free source of capital. Mr. Kollen's recommendation that the Commission consider the taxable income or losses of the AEHI unregulated entities is not consistent with the presentation of income tax expense in this filing. No expense of the AEHI unregulated entities have been presented to be recovered from Kentucky customers and, therefore, no income tax expense or benefits of the AEHI entities should be included in this proceeding.

Q. IS MR. KOLLEN CORRECT IN ASSERTING THAT THE COMPANY'S METHODOLOGY FOR DETERMINING NOLC DTA IN THIS FILING IMPOSES A HYPOTHETICAL FOR THE KENTUCKY JURISDICTION THAT AEC UTILITIES DO NOT ACTUALLY INCUR?

A. No. There is no cost, hypothetical or otherwise, being imposed on the Kentucky jurisdiction that AEC utilities does not actually incur. As described earlier in my rebuttal testimony, the amount of income tax expense included in the cost of service is calculated based on the income tax expense associated with the Kentucky jurisdiction utility's equity return. As a result, the Kentucky jurisdiction only seeks to collect from customers the income tax expense associated with the jurisdiction's revenue, assets and operations. The Company does not seek to recover any expenses, including income tax expense, or costs associated with the assets and operations of the AEHI unregulated entities.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NOLC DTA IN RATE BASE WITHIN THIS FILING?

A. No adjustment should be made to the NOLC DTA requested in this filing beyond the two recommendations with which I agree and discussed earlier in my testimony. Where the deferred tax benefits of deductions giving rise to a NOLC are included as ADIT liabilities reducing that taxpayer's rate base, it is proper, economic and reasonable ratemaking practice to include the utility's entire NOLC DTA asset in rate base as well to maintain consistency between the amount of total income tax expense recovered from customers in cost of service and the amount of tax expense that has been deferred and yet to be remitted to the federal government.

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION THAT THE COMMISSION ADOPT HIS CALCULATION OF THE AMOUNT OF NOLC DTA CAUSED BY TAX DEPRECIATION IN EXCESS OF BOOK DEPRECIATION?

A. No.

Q. DOES MR. KOLLEN ACCURATELY DESCRIBE THE NORMALIZATION REQUIREMENTS SET FORTH IN THE INTERNAL REVENUE CODE AND RELATED TREASURY REGULATIONS?

A. In part. As previously discussed, where the deferred tax benefits of deductions giving rise to a NOLC are included as ADIT liabilities reducing that taxpayer's rate base, it is proper, economic and reasonable ratemaking practice to include the utility's entire NOLC DTA in rate base as well to maintain consistency between the amount of total income tax expense recovered from utility customers in cost of service and the amount of tax expense that has been deferred and yet to be remitted to the federal government.

Thus, while his understanding that the IRC and related Treasury Regulations require a *minimum* amount of NOLC DTA to be included in rate base by specifying that NOLC DTA be included in rate base to the extent that it is attributable to accelerated tax depreciation (this is often referred to method/life differences between GAAP and the IRC) is correct, his position does not reflect the economic reality that the Company does not receive the cost free capital as long as it has a NOLC DTA. The IRC only speaks to the cost basis of an asset to be depreciated at an accelerated (method) rate and over a shorter period of time (life).

Q. MR. KOLLEN REFERS TO A SERIES OF INTERNAL REVENUE SERVICE PRIVATE LETTER RULINGS. WHAT GUIDANCE DO THESE RULINGS PROVIDE?

A. The Private Letter Rulings require that the *minimum* amount of NOLC DTA that is attributable to accelerated tax depreciation be determined using the "last dollars deducted" method, also referred to as the "with and without" method, whereby the utility's NOLC is determined with and without accelerated tax depreciation. To the extent accelerated depreciation, as the last tax deduction taken, produces or increases a taxable loss then such loss or increase in loss is concluded to have resulted from accelerated depreciation.

Q. DO THE PRIVATE LETTER RULINGS PROVIDE GUIDANCE REGARDING THE MAXIMUM AMOUNT OF NOLC DTA REQUIRED TO BE ADDED TO RATE BASE?

A. No. Mr. Kollen is incorrect in stating that the *maximum* amount of NOLC DTA required to be added to rate base to avoid a normalization violation is equal to the deferred tax liability (DTL) for the tax depreciation in excess of book depreciation.

Q. DOES THE INTERNAL REVENUE CODE REQUIRE A MAXIMUM NOLC DTA?

A. No. The normalization rules of the tax code only require a *minimum*, not maximum amount of NOLC DTA that must be included in rate base to avoid a normalization violation. The utility's NOLC DTA may be greater than this minimum, as presented by the Company in this filing, but may not be less than the minimum required under the IRC and related Treasury Regulations.

Q. DOES THE COMPANY AGREE WITH MR. KOLLEN THAT ONLY THE AMOUNT OF NOLC DTA ATTRIBUTABLE TO ACCELERATED TAX DEPRECIATION IN EXCESS OF BOOK DEPRECIATION BE INCLUDED IN RATE BASE?

A. No. The Company does not agree that rate base only include NOLC DTA attributable to accelerated tax depreciation in excess of book depreciation. Where the deferred tax benefits of deductions giving rise to a NOLC are included in the establishment of a utility's rates then it is proper, economic and reasonable ratemaking practice to include the utility's entire NOLC DTA asset in rate base as well to maintain synchronization between the amount of total income tax expense recovered from customers in the cost of service and the amount of tax expense that has been deferred and yet to be remitted to the federal government.

Q. DO YOU AGREE WITH MR. KOLLEN'S CALCULATION OF THE AMOUNT OF NOLC DTA THAT IS ATTRIBUTABLE TO ACCELERATED TAX DEPRECIATION? IF NOT, WHY?

A. No, Mr. Kollen's calculation of the amount of NOLC DTA attributable to accelerated depreciation does not properly consider the amount of book depreciation relating to asset cost basis for which the Company has deducted under an IRC section other than accelerated depreciation.

Q. COULD YOU PLEASE PROVIDE AN EXAMPLE OF HOW THE COMPANY MAY DEDUCT ASSET COST BASIS IN A MANNER OTHER THAN ACCELERATED DEPRECIATION?

A. Yes. Assume that the Company places into service two separate assets costing $1,000 each, consisting of Asset A and Asset B. Assume that the Company capitalizes and depreciates Asset A for both book and income tax purposes and that Asset A is depreciated over a five-year period for book purposes and on an accelerated basis over three years for income tax purposes. Assume that Asset B is also capitalized and depreciated over a five-year period for book purposes, however, the Company elects to treat Asset B's cost basis as a tax repair deduction for income tax purposes resulting in the deduction of the entire $1,000 cost of Asset B in the year placed into service.

In this example, the impact on taxable income of Asset A and B would be as follows –

	Year 1	Year 2	Year 3	Year 4	Year 5	Total
Book Depreciation Expense - Asset A	(200)	(200)	(200)	(200)	(200)	(1,000)
Book Depreciation Expense - Asset B	(200)	(200)	(200)	(200)	(200)	(1,000)
Pre Tax Book Income - Book Depreciation Expense	**(400)**	**(400)**	**(400)**	**(400)**	**(400)**	**(2,000)**
Book/Tax Timing Differences:						
Asset A						
Add Back Book Depreciation Expense	200	200	200	200	200	1,000
Subtract Tax Depreciation	(333)	(445)	(148)	(74)	-	(1,000)
Asset A - Subtotal	(133)	(245)	52	126	200	-
Asset B						
Add Back Book Depreciation Expense	200	200	200	200	200	1,000
Subtract Tax Repair Deduction	(1,000)	-	-	-	-	(1,000)
Asset B - Subtotal	(800)	200	200	200	200	-
Actual Taxable Income (Loss)	**(1,333)**	**(445)**	**(148)**	**(74)**	**-**	**(2,000)**

Here, the book/tax difference relating to the cost basis of Asset A is considered to be a difference attributable to the difference between book depreciation and accelerated tax depreciation. However, even though Asset B is depreciated for book purposes, because the asset basis is deducted as a tax repair item, an IRC section other than accelerated depreciation, the book/tax difference relating to the cost basis of Asset B is not attributable to accelerated tax depreciation and is therefore, not subject to the normalization provision of the IRC and related Treasury Regulations.[2]

Q. USING THIS EXAMPLE, HOW WOULD THE AMOUNT OF NOLC ATTRIBUTABLE TO ACCELERATED TAX DEPRECIATION IN EXCESS OF BOOK DEPRECIATION BE DETERMINED UNDER THE IRC AND RELATED REGULATIONS?

A. The IRC, related Treasury Regulations, and a series of Private Letter Rulings issued by the IRS related to the normalization provisions require the utility compare its actual NOLC incurred to what the NOLC would have been had the utility used book depreciation rather than accelerated tax depreciation. Furthermore, the tax guidance provides that only book/tax timing differences associated with accelerated tax depreciation ("method/life" differences) are subject to the normalization requirements. Book/tax timing differences associated with the recovery of asset basis resulting from sections of the IRC other than method/life (*i.e.* basis deducted as a tax repair) are not subject to the normalization requirements[3].

Continuing with the above example, the amount of NOLC considered to be attributable to accelerated tax depreciation and therefore, subject to normalization, would be as follows -

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[2] *See* Exhibit JJM-R-1, which is Private Letter Ruling 202033002 (March 26, 2020). IRS ruled that the normalization rules do not pertain book-tax timing differences other than accelerated depreciation. *See* Exhibit JJM-R-2 Treasury Regulation Section 1.167(l)-1(a)(1) – the normalization requirements pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of service and for reflecting operating results in regulated books of account.

[3] *Id*.

		Year 1	Year 2	Year 3	Year 4	Year 5	Total
	Book Depreciation Expense - Asset A	(200)	(200)	(200)	(200)	(200)	(1,000)
	Book Depreciation Expense - Asset B	(200)	(200)	(200)	(200)	(200)	(1,000)
	Pre Tax Book Income - Book Depreciation Expense	**(400)**	**(400)**	**(400)**	**(400)**	**(400)**	**(2,000)**
	Book/Tax Timing Differences:						
	Asset A						
(a)	Add Back Book Depreciation Expense	200	200	200	200	200	1,000
(b)	Subtract Tax Depreciation	(333)	(445)	(148)	(74)	-	(1,000)
	Asset A - Subtotal	(133)	(245)	52	126	200	-
	Asset B						
	Add Back Book Depreciation Expense	200	200	200	200	200	1,000
	Subtract Tax Repair Deduction	(1,000)	-	-	-	-	(1,000)
	Asset B - Subtotal	(800)	200	200	200	200	-
	Actual Taxable Income (Loss)	**(1,333)**	**(445)**	**(148)**	**(74)**	**-**	**(2,000)**
(b)	Exclude Tax Depreciation	333	445	148	74	-	1,000
(a)	Include Book Depreciation Related to Cost Depreciated for Tax Purposes	(200)	(200)	(200)	(200)	(200)	(1,000)
	Taxable Income (Loss) Without Accelerated Tax Depreciation	**(1,200)**	**(200)**	**(200)**	**(200)**	**(200)**	**(2,000)**
	Annual Taxable Income (Loss) Attributable to Accelerated Tax Depreciation	**(133)**	**(245)**	**52**	**126**	**200**	**-**
	Cumulative Taxable Income (Loss) Attributable to Accelerated Tax Depreciation	**(133)**	**(378)**	**(326)**	**(200)**	**-**	**-**

Q. HOW DOES YOUR EXAMPLE DIFFER FROM THE CALCULATION PROPOSED BY MR. KOLLEN?

A. Mr. Kollen's calculation includes an adjustment for all book depreciation expense - both that associated with asset cost basis that is depreciated for income tax purposes under the IRC and that associated with asset cost basis that is not recovered through the accelerated deprecation provisions of the IRC. In doing so, Mr. Kollen's calculation deflates the amount of NOLC attributable only to accelerated tax depreciation in excess of book depreciation.

Q. IS THE COMPANY ABLE TO QUANTIFY THE AMOUNT OF NOLC DTA ATTRIBUTABLE TO ACCELERATED DEPRECIATION AND THEREFORE, THE MINIMUM AMOUNT NECESSARY TO BE INCLUDED IN RATE BASE TO AVOID A NORMALIZATION VIOLATION?

A. No. The Company is not currently able to quantify the minimum amount of NOLC DTA solely attributable to accelerated tax depreciation.

Q. IS MR. KOLLEN CORRECT IN STATING THAT THE COMPANY HAS INDICATED IT HAS SUFFICIENT INFORMATION TO QUANTIFY THE AMOUNT OF NOLC DTA ATTRIBUTABLE TO ACCELERATED DEPRECIATION?[4]

A. Yes, the Company has indicated that while it does have sufficient information in its records to quantify, this calculation is not readily available and would require the Company to undertake a significant analysis to produce.

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. KOLLEN'S CALCULATION OF NOLC DTA ATTRIBUTABLE TO ACCELERATED TAX DEPRECIATION IN EXCESS OF BOOK DEPRECIATION?

A. I recommend the Commission reject Mr. Kollen's calculation. First, as demonstrated above, Mr. Kollen has incorrectly calculated the minimum amount of NOLC DTA caused by accelerated tax depreciation in excess of book depreciation. Second, it is sound ratemaking practice to include the utility's entire NOLC DTA asset in rate base as the Company has done in this case. Finally, the IRC and related Treasury Regulations only provide a minimum amount of NOLC DTA asset that must be included in rate base to avoid a normalization violation resulting in loss of ability to recognize accelerated tax depreciation but does not speak to the proper economic amount to include for ratemaking. This minimum amount is the amount of NOLC DTA that is attributable to accelerated tax depreciation and Mr. Kollen's attempt at calculating the minimum amount is not proper.

[4] Direct Testimony of Lane Kollen at 9 & 16.

Q. DO YOU AGREE WITH MR. KOLLEN'S RECOMMENDATION THAT THE COMMISSION DIRECT THE COMPANY IN ITS NEXT BASE RATE CASE FILING TO PROVIDE INFORMATION NECESSARY TO CALCULATE THE MINIMUM NOLC DTA NECESSARY TO AVOID A NORMALIZATION VIOLATION?

A. The Company does not agree as this recommendation is not necessary. Where the deferred tax benefits of deductions giving rise to a NOLC are included as ADIT liabilities reducing that taxpayer's rate base, it is proper, economic and reasonable ratemaking practice to include the utility's entire NOLC DTA asset in rate base as well to maintain synchronization between the amount of total income tax expense recovered from customers in cost of service and the amount of tax expense that has been deferred and yet to be remitted to the federal government.

Q. DO YOU AGREE WITH MR. KOLLEN'S ASSERTION THAT THE NOLC DTA SHOULD BE LESS DUE TO TAXABLE INCOME DURING THE SIX MONTH "BRIDGE" PERIOD CONSISTING OF SEPTEMBER 30, 2024 THROUGH MARCH 31, 2025?

A. No. While Mr. Kollen is correct in indicating the Company's NOLC DTA balance in this filing remains the same during the period September 30, 2004 through March 31, 2025, he is incorrect in assuming there would be taxable income and a decrease in the Company's NOLC DTA balance during this period. The Company's recent experience has produced near break-even taxable income with periods of taxable losses as likely as periods of taxable income.

IV. PROPOSED TAX RIDER TARIFF

Q. WHAT IS MR. KOLLEN'S RECOMMENDATION IN RESPONSE TO THE COMPANY'S PROPOSED TAX RIDER TARIFF?

A. Mr. Kollen recommends that the Commission reject the Company's request for a Tax Rider Tariff to capture the effect of income and property tax rate changes as well as the Corporate Alternative Minimum Tax ("CAMT").

Q. WHAT REASON DOES MR. KOLLEN PROVIDE FOR RECOMMENDING THE COMMISSION REJECT THE COMPANY'S PROPOSAL TO INCLUDE CHANGES IN FEDERAL AND STATE INCOME TAX RATES IN THE TAX RIDER TARIFF?

A. Mr. Kollen suggests the Company's proposed Tax Rider Tariff is not necessary to address changes in federal and state income tax rates as the Commission already has the capability to address such changes absent a rider and such capability provides financial incentives for the Company to minimize the costs to comply and any such tax rate changes in a safe and efficient manner.

Q. DO YOU AGREE WITH MR. KOLLEN'S JUSTIFICATION FOR THIS RECOMMENDATION?

A. No. While a separate rider is not the only way to address future changes in income tax rates, the proposed rider would allow for all parties to avoid the time and expense of conducting a proceeding to implement such a change. The Company's proposed rider does not preclude the Commission from undertaking its own analysis and/or requiring additional filings; however, it does promote efficiency by creating a mechanism through which the effect of future income tax rate changes may be efficiently reflected.

Q. WHAT REASON DOES MR. KOLLEN PROVIDE FOR RECOMMENDING THE COMMISSION REJECT THE COMPANY'S PROPOSAL TO INCLUDE CHANGES IN PROPERTY TAX RATES?

A. Mr. Kollen suggests it is inappropriate and impractical to adopt a rider to recover increases in property tax expense due to changes in property tax rates as the existing ratemaking paradigm already provides the Company recovery of its reasonable property tax expense and incorporates the appropriate incentives for the Company to minimize its property tax expense.

Q. DO YOU AGREE WITH MR. KOLLEN'S JUSTIFICATION FOR THIS RECOMMENDATION?

A. No. The Company's proposal would capture the customer impact of both increases and decreases to the expense resulting from property tax rate changes and do so in a manner that is timely and efficient, mitigating the costs involved in additional procedural filings.

Q. WHAT REASON DOES MR. KOLLEN PROVIDE FOR RECOMMENDING THE COMMISSION REJECT THE COMPANY'S PROPOSAL TO INCLUDE A RETURN ON ITS CAMT DTA WITHIN THE TAX RIDER TARIFF?

A. Mr. Kollen suggests the CAMT and CAMT DTA do not apply to the Kentucky division on a standalone basis and that the Atmos Kentucky division is not an "applicable corporation" subject to the CAMT. Mr. Kollen further provides that

that the Company's proposal will allow it to impose a cost on Kentucky customers that is incurred by AEC consolidated due to its unregulated activities, and that the CAMT has nothing to do with the regulated AEC utility divisions.

Q. DO YOU AGREE WITH MR. KOLLEN'S JUSTIFICATIONS FOR THIS RECOMMENDATION?

A. No.

Q. PLEASE EXPLAIN HOW THE CAMT WOULD APPLY TO AEC UTILITY AND ITS RESPECTIVE DIVISIONS?

A. As described in my direct testimony, the CAMT applies to any corporation having three-year average annual adjusted financial statement income ("AFSI") in excess of $1 billion. The provisions of the IRC require that for purposes of determining if a corporation is an applicable corporation, the AFSI of all members of the corporation's controlled group be aggregated.[5] As a result, the test for determining "applicable corporation" is made at the AEC consolidated level. Once AEC meets this definition at a consolidated level, all corporate subsidiaries, such as the AEC utility, as well as all trades or businesses of a corporate subsidiary, such as Atmos Energy Kentucky, are considered applicable corporations subject to the CAMT.

Q. IS MR. KOLLEN CORRECT IN SUGGESTING THAT THE COMPANY'S PROPOSAL WILL ALLOW IT TO IMPOSE A COST ON KENTUCKY CUSTOMERS THAT IS INCURRED BY AEC CONSOLIDATED DUE TO ITS UNREGLATED ACTIVITIES AND THAT THE CAMT HAS NOTHING TO DO WITH ITS UTILITY OPERATIONS?

[5] Exhibit JJM-R-3 Internal Revenue Code Section 59(k)(1)(D).

A. No.

Q. COULD YOU EXPLAIN HOW THE COMPANY'S CAMT ASSET PROPOSAL RELATES TO ITS KENTUCKY DIVISION OPERATIONS?

A. As described above, the determination of applicability of the CAMT is made under the IRC at the Company's consolidated level. Once the consolidated enterprise meets the definition of an "applicable corporation," then the AFSI of the enterprise is subject to the CAMT; however, the CAMT asset to be included in the Company's proposed rider will be determined based on the AFSI of the Kentucky division determined on a stand-alone basis. Therefore, there will be no cost imposed on the Kentucky division customers as the result of the Company's unregulated entities as Mr. Kollen suggests.

Q. HAS THE COMMISSION PREVIOUSLY RECOGNIZED THE NEED TO ADDRESS THE IMPACT OF THE CAMT IN RATES?

A. Yes. The Commission recently approved the inclusion of CAMT deferred tax asset in rate base of Kentucky Power Company in Case No. 2023-00159. Atmos Energy is, therefore, proposing the same methodology to address the impact of the CAMT in rates that the Commission found to be reasonable for use by Kentucky Power Company.

V. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

ELECTRONIC APPLICATION OF ATMOS	)	
ENERGY CORPORATION FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	**Case No. 2024-00276**
TARIFF REVISIONS; AND OTHER	)	
GENERAL RELIEF	)	

CERTIFICATE AND AFFIDAVIT

The Affiant, Joel J. Multer, 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. 2024-00276, in the Matter of the Electronic Application of Atmos Energy Corporation for an Adjustment of Rates; Approval of Tariff Revisions; and Other General Relief, and that if asked the questions propounded therein, this affiant would make the answers set forth in the attached prepared rebuttal testimony.

Joel J. Multer

STATE OF TEXAS

COUNTY OF DALLAS

SUBSCRIBED AND SWORN to before me by Joel J. Multer on this the 4th day of March, 2025.

Ashlea Thorn

Notary Public

My Commission Expires:

ASHLEA THORN
MY COMMISSION EXPIRES
12/06/2027
NOTARY ID: 125261465

PLR 202033002 -- IRC Sec(s). 168, 08/13/2020

Private Letter Rulings & Technical Advice Memoranda (1953 - Present) (RIA)

Private Letter Rulings

Private Letter Ruling 202033002, 08/13/2020, IRC Sec(s). 168

UIL No. 168.24-01

Depreciation-accelerated cost recovery system-accumulated deferred federal income taxes-normalization rules-public utilities.

Headnote:

Regulated utility's depreciation related ADFIT balances created pursuant to normalization rules that were attributable to costs that were capitalized into basis of depreciable assets prior to taxpayer changing its method of accounting for those costs didn't remain subject to normalization rules after change in method of accounting pursuant to which such costs were reclassified as current deductions.

Reference(s): Code Sec. 168;

Full Text:

Number: **202033002**

Release Date: 8/14/2020

Index Number: 168.24-01

Third Party Communication: None

Date of Communication: Not Applicable

Person To Contact: [Redacted Text]

[Redacted Text], ID No.

Telephone Number: [Redacted Text]

Refer Reply To:

CC:PSI:B06

PLR-122510-19

Date:

March 26, 2020

In Re: [Redacted Text]

LEGEND:

Taxpayer =

Parent =

State A =

Commission A =

Commission B =

Date 1 =

Date 2 =

Date 3 =

Date 4 =

Date 5 =

Month 1 =

Month 2 =

Year 1 =

Year 2 =

Year 3 =

Year 4 =

Year 5 =

Year 6 =

Dear [Redacted Text]:

This letter responds to a request for a private letter ruling dated September 26, 2019, and submitted on behalf of Taxpayer regarding the application of the depreciation normalization rules under § 168(i)(9) of the Internal Revenue Code and § 1.167(l)-1 of the Income Tax Regulations (together, the "Normalization Rules") to certain State A state regulatory procedures which are described in this letter. The relevant facts as represented in your submission are set forth below.

FACTS

Taxpayer is an investor-owned regulated utility incorporated under the laws of State A. Taxpayer is an accrual basis taxpayer and reports on a calendar year basis.

Taxpayer is wholly owned by Parent. Parent is a State A corporation. Taxpayer is included in a consolidated federal income tax return of which Parent is the common parent.

Taxpayer is a regulated utility engaged principally in the purchase, transmission, distribution, and sale of electric energy and the purchase, distribution, and sale of natural gas in State A. Taxpayer is subject to regulation as to rates and conditions of service by Commission A as well as Commission B. Both these regulators establish Taxpayer's rates based on its costs, including a provision for a return on the capital employed by Taxpayer in its regulated businesses.

Taxpayer has claimed accelerated depreciation on all of its public utility property (both electric and gas) to the full extent those deductions have been available. Taxpayer has normalized the federal income taxes deferred as a result of its claiming these deductions in accordance with the Normalization Rules. As a consequence, Taxpayer has a substantial balance of accumulated deferred federal income taxes (ADFIT) that is attributable to accelerated depreciation reflected on its regulated books of account for each of its divisions. In accordance with State A ratemaking practice, Taxpayer has reduced its rate base by its ADFIT balance.

Commission B has established a system to track accounts for both jurisdictional electric and gas companies. These accounts prescribe the accounting rules which are used by most large investor-owned electric and gas companies and are employed by Taxpayer's electric and gas divisions. The applicable regulations contain several definitions relevant to Taxpayer's inquiry including definitions for cost of removal (COR), salvage value, net salvage value, service value, and depreciation.

In general, based on these definitions, for purposes of regulatory reporting, the net positive value or net cost of disposing of an asset at the end of its life is incorporated into the annual depreciation charge.

COR is, therefore, most often (but not always) a component of establishing the applicable depreciation rate. In Taxpayer's case, due to the amount of COR it anticipates, in almost all instances its assets have negative net salvage values so that its book depreciation rate is higher than it would be were salvage value not considered. In effect, the annual depreciation charge creates a reserve for COR over the operating life of the asset. Since book depreciation expense is included in Taxpayer's cost of service used for establishing its rates, customers pay for the COR as book depreciation is factored into their rates. This COR reserve is reflected as an addition to Taxpayer's accumulated depreciation account. When the COR is actually incurred, the amount expended is debited to that same account, thereby reducing the balance.

For tax purposes, COR is deductible only when actually incurred. Taxpayer, therefore, reports its customer collections that fund the COR reserve as taxable income over the operating life of an asset, claiming an offsetting tax deduction only at the end of the life of that asset. Taxpayer has normalized COR since the Year 1 tax year. All references below to COR-related deferred tax accounting relate only to COR associated with assets placed in service after Year 2. Since COR is normalized in setting rates, customers are provided a tax benefit commensurate with their funding of COR. In other words, they are provided the COR tax benefit as they fund the COR reserve - prior to the time Taxpayer actually claims that benefit on its tax return.

The tax effect of the COR funding as described creates a deferred tax asset ("DTA"). This represents the future benefit to be derived from the eventual COR tax deduction. The COR-related DTA is included in Taxpayer's overall plant-related ADFIT account that reduces Taxpayer's ADFIT balance.

COR can (and does) impact ADFIT balances in an additional way. The COR included in depreciation expense (that is, the accrual) is an estimate prepared for an entire class of assets contained in a Commission B account. It is likely that any COR estimate will be too high or too low with respect to any individual asset with the ultimate answer remaining unknown until all vintages of each asset class are retired and removed. Any running variance from the estimate is recorded on Taxpayer's balance sheet. Where the accrual exceeds the actual COR, it creates a net credit to the accumulated depreciation account. Where the actual COR exceeds the accrual, it creates a net debit to that account. This treatment means that Taxpayer will recover under-accruals from customers and refund over-accruals to customers through future rate adjustments. These future rate adjustments will give rise to future increases or decreases in taxable income. Under applicable accounting principles, Taxpayer must record the deferred tax consequences of these future events. An over-accrual produces a DTA (the tax benefit of a future deduction due to the refund of the excess collection) while an under-accrual produces a deferred tax liability "DTL" (the tax cost of future taxable income due to the collection of the shortfall).

For the electric distribution division, the COR book/regulatory accrual has always been included in the development of the book depreciation rate. Thus, instead of waiting for the Taxpayer to incur the tax benefit of COR, its' Customers are provided the COR tax benefit as they fund the COR reserve - prior to the time Taxpayer actually claims that benefit on its tax return. This produces a DTA as described. In addition, as of Date 1, Taxpayer has, in total, incurred more COR than it has recovered from customers and, thus, is under-accrued for COR. This has produced a DTL, also as described. Both the DTA and DTL are included within Taxpayer's overall plant-related ADFIT Account.

Prior to Month 1 Year 3, the gas distribution division accrued and collected COR as a component of the book depreciation rate. However, pursuant to order of Commission A, that collection practice was modified in Year 3. Beginning in Month 1 Year 3, the gas-only COR regulatory accrual was removed from the book depreciation rate. Rather, Taxpayer was allowed to record and recover annually (through a fixed dollar depreciation charge incremental to the normal depreciation computed via application of the depreciation rate) an amount representing an estimate of the annual COR that would be incurred in that year. At the time of this modification, the cumulative COR accrued exceeded COR actually incurred (that is, Taxpayer was over-accrued). At that time, Taxpayer had recorded a net DTA (to reflect the tax benefit of the future reduction in rates associated with refunding the excess to customers).

Since converting to this methodology in Year 3, COR actually incurred has significantly exceeded COR accrued and recovered, resulting in a DTL (the tax cost of recovering the under-accrual in the future). As of Date 1, the two components (pre- Month 1 Year 3 and post-Month 2 Year 3) combined represented a net DTL.

Effective Date 2, pursuant to an Order issued by Commission A, gas COR regulatory recovery has reverted back to a component of the book depreciation rate. The fixed dollar accrual which began in Year 3 has been eliminated.

Since Year 4, Taxpayer's tax fixed asset system has separately identified the portion of Taxpayer's book depreciation expense that relates to COR since that date. As a consequence, the system distinguishes between COR book/tax differences and depreciation method/life differences even though they are both derived from Taxpayer's book depreciation. Though the system has the capability of tracking the reversals of these differences separately, in order to set it up to do this, a significant amount of work and data manipulation would be required. It is not currently configured in a manner that would allow this.

In years prior to Year 5, Taxpayer paid income tax at a 35% rate on the recovery of the COR portion of book depreciation (and provided its customers a tax benefit at that tax rate). However, as a result of the tax rate reduction enacted as part of the Tax Cuts and Jobs Act ("TCJA"), Taxpayer will only receive a 21% benefit when the COR deduction is claimed or when any over-accrual is refunded and will pay only a 21% tax on the recovery of any COR under-accrual. In other words, in the case of COR, the tax rate reduction enacted as part of the TCJA has produced both a deferred tax shortfall as well as an excess tax reserve. Because Taxpayer will not recover the 14% "excess" tax it paid on its recovery of the COR component of book depreciation from the government when it claims its COR deduction, it must recover it from its customers. Conversely, because Taxpayer will not pay the 14% "excess" deferred tax it accrued on its obligation to refund over-accrued COR, it must restore the amount to its customers (that is, it also has COR-related excess deferred taxes).

Taxpayer's Changes in Accounting Method for Mixed Service Costs and Repairs

Prior to Taxpayer's Year 6 tax year, in capitalizing its indirect overhead costs - including its mixed service costs - Taxpayer followed the same methodology for both book and tax purposes. Effective for its Year 6 tax year, Taxpayer filed with the Internal Revenue Service an Application for Change in Accounting Method (Form 3115) in which it requested permission to depart from its book method for tax purposes. The result of the change was to recharacterize a substantial quantity of mixed service costs that Taxpayer had previously capitalized into depreciable assets as deductible costs (including additions to cost of goods sold). This resulted in Taxpayer claiming a negative adjustment under § 481(a) (that is, a deduction) to remove from the tax basis of its existing assets all such recharacterized costs to the extent Taxpayer had not previously depreciated them (" Section 481 Adjustment").

Also, prior to Taxpayer's Year 6 tax year, in identifying deductible repairs, Taxpayer followed the same methodology for both book and tax purposes. Effective for its Year 6 tax year, Taxpayer filed an Application for Change in Accounting Method (Form 3115) in which it requested permission to depart from its book method for tax purposes. In general, under its new tax method, Taxpayer elected to use larger units of property than used for book purposes. The result of the change was to characterize many projects that were capitalized for book purposes as deductible repairs for tax purposes. This resulted in Taxpayer claiming a negative § 481 Adjustment to remove from the tax basis of its existing assets all such recharacterized costs to the extent Taxpayer had not previously depreciated them.

Adjustments (additions) were made to Taxpayer's ADFIT accounts, which already reflected the deferred tax consequences of having claimed accelerated depreciation on both types of costs after they were capitalized for tax purposes for the additional deferred taxes produced by the § 481 Adjustments.

Taxpayer's Recent Commission A Proceedings

On Date 3, Taxpayer filed with Commission A to adjust both its electric and its gas rates. The parties to the proceeding reached an agreement and, on or about Date 4, Taxpayer submitted a stipulation to Commission A for its approval. Commission A approved the stipulation on Date 5.

The stipulation provides that:

> 1) Taxpayer will seek a private letter ruling to determine if excess deferred taxes associated with excess tax over book depreciation that is subsequently reversed by accounting method changes relating to repair deductions and the capitalization of mixed service costs are protected by the normalization rules and subject to reversal under the ARAM; and that
> 2) Taxpayer will seek a private letter ruling from the IRS to determine whether post-Year 1 cost of removal is protected by the normalization rules and, if so, whether it is to be treated as

a separate temporary difference or part of the overall depreciation temporary difference for purposes of ARAM amortization.

RULINGS REQUESTED

Taxpayer requests the following guidance:

1) Under the circumstances described above, is Taxpayer's electric distribution COR- related net DTL "protected" by the Normalization Rules?
2) If Taxpayer's electric distribution COR-related deferred tax is "protected," should that shortfall be treated as a discrete "protected" item or as part of the "protected" method/life difference?
3) Under the circumstances described above, is Taxpayer's gas distribution COR- related net DTA accumulated through the depreciation rate prior to Month 1 of Year 3 "protected" by the Normalization Rules?
4) If Taxpayer's gas distribution COR-related deferred tax accumulated through the depreciation rate prior to Month 1 of Year 3 is "protected," should that shortfall be treated as a discrete "protected" item or as part of the "protected" method/life difference?
5) Under the circumstances described above, is Taxpayer's gas distribution COR- related net DTL accumulated through the fixed estimated cash recovery after Month 1 of Year 3 "protected" by the Normalization Rules?
6) If Taxpayer's gas distribution COR-related net DTL accumulated through the fixed estimated cash recovery after Month 1 of Year 3 is "protected," should that shortfall be treated as a discrete "protected" item or as part of the "protected" method/life difference?
7) If Taxpayer's COR-related deferred tax shortfall is "protected," do the Normalization Rules permit Taxpayer to collect a shortfall any more rapidly than using the ARAM?
8) Do Taxpayer's depreciation-related ADFIT balances created pursuant to the Normalization Rules that are attributable to costs that were capitalized into the basis of depreciable assets prior to Taxpayer changing its method of accounting for those costs remain subject to the Normalization Rules after the change in method of accounting pursuant to which such costs were reclassified as current deductions?

LAW AND ANALYSIS

Section 168(f)(2) provides that the depreciation deduction determined under § 168 shall not apply to any public utility property (within the meaning of § 168(i)(10)) if the taxpayer does not use a normalization method of accounting.

In order to use a normalization method of accounting, § 168(i)(9)(A)(i) requires the taxpayer, in computing its tax expense for establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, to use a method of depreciation with respect to public utility property that is the same as, and a depreciation period for such property that is not shorter than, the method and period used to compute its depreciation expense for such purposes. Under § 168(i)(9)(A)(ii), if the amount allowable as a deduction under § 168 differs from the amount that would be allowable as a deduction under § 167 using the method, period, first and last year convention, and salvage value used to compute regulated tax expense under § 168(i)(9)(A)(i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Former § 167(l) generally provided that public utilities were entitled to use accelerated methods for depreciation if they used a "normalization method of accounting." A normalization method of accounting was defined in former § 167(l)(3)(G) in a manner consistent with that found in § 168(i)(9)(A). Section 1.167(l)-1(a)(1) provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under § 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. These regulations do not pertain to other book-tax timing differences with respect to state income taxes, F.I.C.A. taxes, construction costs, or any other taxes and items.

Section 481(a) requires those adjustments necessary to prevent amounts from being duplicated or omitted to be taken into account when a taxpayer's taxable income is computed under a method of accounting different from the method used to compute taxable income for the preceding taxable year. *See also* § 2.05(1) of Rev. Proc. 97-27, 97-27, 1997-1 C.B. 680 (the operative method change revenue procedure at the time Taxpayer filed its Form 3115, *Application for Change in Accounting Method*).

An adjustment under § 481(a) can include amounts attributable to taxable years that are closed by the period of limitation on assessment under § 6501(a). *Suzy's Zoo v. Commissioner*, 114 T.C. 1, 13 (2000), *aff'd*, 273 F.3d 875, 884 [88 AFTR 2d 2001-6916] (9th Cir. 2001); *Superior Coach of Florida, Inc. v. Commissioner*, 80 T.C. 895, 912 (1983), *Weiss v. Commissioner*, 395 F.2d 500 [22 AFTR 2d 5013] (10th Cir. 1968), *Spang Industries, Inc. v. United States*, 6 Cl. Ct. 38, 46 [54 AFTR 2d 84-5873] (1984), *rev'd on other grounds* 791 F.2d 906 [58 AFTR 2d 86-5052] (Fed. Cir. 1986). *See also Mulholland v. United States*, 28 Fed. Cl. 320, 334 [71 AFTR 2d 93-1916] (1993) (concluding that a court has the authority to review the taxpayer's threshold selection of a method of accounting *de novo*, and must determine, *ab initio*, whether the taxpayer's reported income is clearly reflected).

Sections 481(c) and 1.481-4 provide that the adjustment required by § 481(a) may be taken into accounting in determining taxable income in the manner, and subject to the conditions, agreed to by the Service and a taxpayer. Section 1.446-1(e)(3)(i) authorizes the Service to prescribe administrative procedures setting forth the limitations, terms, and conditions deemed necessary to permit a taxpayer to obtain consent to change a method of accounting in accordance with § 446(e). *See also* § 5.02 of Rev. Proc. 97-27.

When there is a change in method of accounting to which § 481(a) is applied, § 2.05(1) of Rev. Proc. 97-27 provides that income for the taxable year preceding the year of change must be determined under the method of accounting that was then employed, and income for the year of change and the following taxable years must be determined under the new method of accounting as if the new method had always been used.

Because of their similarity, we address requests 1, 3, and 5 together. For all of the COR-related amounts at issue in these requests, the amounts are not protected by the Normalization Rules. Generally, § 168(i)(9)(A) does not refer to COR. Moreover, there is no reference to an acceleration of taxes but only to a deferral. While COR may be a component of the calculation of the amount treated as book depreciation, it is a deduction under § 162 and has nothing to do with actual accelerated tax depreciation. While depreciation method and life differences are created and reversed solely through depreciation, such is not the case with COR. While the COR timing differences may often originate as a component of book depreciation, it reverses through the incurred COR expenditure.

Taxpayer's ruling request 8 pertains to the depreciation-related ADIT existing prior to the year of change (Year 6) for public utility property in service as of the end of the taxable year immediately preceding the year of change. Beginning with the year of change, the Year 6 Consent Agreement granted Taxpayer permission to change its (1) method of accounting for mixed service costs to recharacterize a substantial quantity of mixed service costs that Taxpayer had previously capitalized into depreciable assets as deductible costs (including additions to cost of goods sold) and (2) to depart from its book method for tax purposes electing to use for tax purposes larger units of property than used for book purposes which resulted in characterizing many projects that were capitalized for book purposes as deductible repairs for tax purposes.

When there is a change in method of accounting to which § 481(a) is applied, income for the taxable year preceding the year of change must be determined under the method of accounting that was then employed by Taxpayer, and income for the year of change and the following taxable years must be determined under Taxpayer's new method of accounting as if the new method had always been used. *See* § 481(a); § 1.481-1(a)(1); and § 2.05(1) of Rev. Proc. 97-27. In other words: (1) Taxpayer's new method of accounting is implemented beginning in the year of change; (2) Taxpayer's old method of accounting used in the taxable years preceding the year of change is not disturbed; and (3) Taxpayer takes into account a § 481(a) adjustment in computing taxable income to offset any consequent omissions or duplications.

Accordingly, for public utility property in service as of the end of the taxable year immediately preceding the year of change (Year 6), the depreciation-related ADIT existing prior to the year of change for the changes in methods of accounting subject to the Year 6 Consent Agreement does not remain subject to the normalization method of accounting within the meaning of § 168(i)(9) after implementation of the new tax methods of accounting in the year of change and subsequent taxable years.

Based on the foregoing, we conclude that:

1) Under the circumstances described above, Taxpayer's electric distribution COR- related net DTL is not "protected" by the Normalization Rules.
3) Under the circumstances described above, Taxpayer's gas distribution COR-related net DTA accumulated through the depreciation rate prior to Month 1 of Year 3 is not "protected" by the Normalization Rules.
5) Under the circumstances described above, Taxpayer's gas distribution COR-related net DTL accumulated through the fixed estimated cash recovery after Month 1 of Year 3 is not "protected" by the Normalization Rules.

Because these amounts in requests 1, 3, and 5 are not protected by the Normalization Rules, requests 2, 4, 6, and 7 are moot.

8) Taxpayer's depreciation related ADFIT balances created pursuant to the Normalization Rules that are attributable to costs that were capitalized into the basis of depreciable assets prior to Taxpayer changing its method of accounting for those costs do not remain subject to the Normalization Rules after the change in method of accounting pursuant to which such costs were reclassified as current deductions.

Except as specifically set forth above, no opinion is expressed or implied concerning the federal income tax consequences of the above described facts under any other provision of the Code or regulations.

This ruling is directed only to the taxpayer requesting it. Section 6110(k)(3) of the Code provides that it may not be used or cited as precedent.

This ruling is based upon information and representations submitted by Taxpayer and accompanied by penalty of perjury statements executed by an appropriate party. While this office has not verified any of the material submitted in support of the request for rulings, it is subject to verification on examination.

In accordance with the power of attorney on file with this office, a copy of this letter is being sent to your authorized representatives.

Sincerely,

Patrick S. Kirwan

Chief, Branch 6

Office of Associate Chief Counsel

(Passthroughs & Special Industries)

cc: [Redacted Text]

(Reg Caution) Reg §1.167(l)-1 Limitations on reasonable allowance in case of property of certain public utilities.

Income (USTR)

Federal Regulations

Reg § 1.167(l)-1. Limitations on reasonable allowance in case of property of certain public utilities.

Caution: The Treasury has not yet amended Reg § 1.167(l)-1 to reflect changes made by P.L. 101-508

Effective: Reg. §1.167(l)-1 has not been updated to reflect subsequent legislation.

(a) In general.

(1) Scope. Section 167(l) in general provides limitations on the use of certain methods of computing a reasonable allowance for depreciation under section 167(a) with respect to "public utility property" (see paragraph (b) of this section) for all taxable years for which a Federal income tax return was not filed before August 1, 1969. The limitations are set forth in paragraph (c) of this section for "pre-1970 public utility property" and in paragraph (d) of this section for "post-1969 public utility property." Under section 167(l), a taxpayer may always use a straight line method (or other "subsection (l) method" as defined in paragraph (f) of this section). In general, the use of a method of depreciation other than a subsection (l) method is not prohibited by section 167(1) for any taxpayer if the taxpayer uses a "normalization method of regulated accounting" (described in paragraph (h) of this section). In certain cases, the use of a method of depreciation other than a subsection (l) method is not prohibited by section 167(l) if the taxpayer used a "flow-through method of regulated accounting" described in paragraph (i) of this section) for its "July 1969 regulated accounting period" (described in paragraph (g) of this section) whether or not the taxpayer uses either a normalization or a flow-through method of regulated accounting after its July 1969 regulated accounting period. However, in no event may a method of depreciation other than a subsection (l) method be used in the case of pre-1970 public utility property unless such method of depreciation is the "applicable 1968 method" (within the meaning of paragraph (e) of this section). The normalization requirements of section 167(l) with respect to public utility property defined in section 167(l)(3)(A) pertain only to the deferral of Federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under section 167 and the use of straight line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of services and for reflecting operating results in regulated books of account. Regulations under section 167(l) do not pertain to other book-tax timing differences with respect to State income taxes, F.I.C.A. taxes, construction

costs, or any other taxes and items. The rules provided in paragraph (h)(6) of this section are to insure that the same time period is used to determine the deferred tax reserve amount resulting from the use of an accelerated method of depreciation for cost of service purposes and the reserve amount that may be excluded from the rate base or included in no-cost capital in determining such cost of services. The formula provided in paragraph (h)(6)(ii) of this section is to be used in conjunction with the method of accounting for the reserve for deferred taxes (otherwise proper under paragraph (h)(2) of this section) in accordance with the accounting requirements prescribed or approved, if applicable, by the regulatory body having jurisdiction over the taxpayer's regulated books of account. The formula provides a method to determine the period of time during which the taxpayer will be treated as having received amounts credited or charged to the reserve account so that the disallowance of earnings with respect to such amounts through rate base exclusion or treatment as no-cost capital will take into account the factor of time for which such amounts are held by the taxpayer. The formula serves to limit the amount of such disallowance.

(2) Methods of depreciation. For purposes of section 167(l), in the case of a declining balance method each different uniform rate applied to the unrecovered cost or other basis of the property is a different method of depreciation. For purposes of section 167(l), a change in a uniform rate of depreciation due to a change in the useful life of the property or a change in the taxpayer's unrecovered cost or other basis for the property is not a change in the method of depreciation. The use of "guideline lives" or "class lives" for Federal income tax purposes and different lives on the taxpayer's regulated books of account is generally not treated for purposes of section 167(l) as a different method of depreciation. Further, the use of an unrecovered cost or other basis or salvage value for Federal income tax purposes different from the basis or salvage value used on the taxpayer's regulated books of account is not treated as a different method of depreciation.

(3) Application of certain other provisions to public utility property. For rules with respect to application of the investment credit to public utility property, see section 46(e). For rules with respect to the application of the class life asset depreciation range system, including the treatment of the use of "class lives" for Federal income tax purposes and different lives on the taxpayer's regulated books of account, see §1.167(a)-11 and § 1.167(a)-12.

(4) Effect on agreements under section 167(d). If the taxpayer has entered into an agreement under section 167(d) as to any public utility property and such agreement requires the use of a method of depreciation prohibited by section 167(l), such agreement shall terminate as to such property. The termination, in accordance with this subparagraph, shall not affect any other property (whether or not public utility property) covered by the agreement.

(5) Effect of change in method of depreciation. If, because the method of depreciation used by the taxpayer with respect to public utility property is prohibited by section 167(l), the taxpayer changes to a method of depreciation not prohibited by section 167(l), then when the change is made the

unrecovered cost or other basis shall be recovered through annual allowances over the estimated remaining useful life determined in accordance with the circumstances existing at that time.

(b) Public utility property.

(1) In general. Under section 167(1)(3)(A), property is "public utility property" during any period in which it is used predominantly in a "section 167(l) public utility activity." The term "section 167(l) public utility activity" means the trade or business of the furnishing or sale of-

(i) Electrical energy, water, or sewage disposal services,

(ii) Gas or steam through a local distribution system,

(iii) Telephone services,

(iv) Other communication services (whether or not telephone services) if furnished or sold by the Communications Satellite Corporation for purposes authorized by the Communications Satellite Act of 1962 (47 U.S.C. 701), or

(v) Transportation of gas or steam by pipeline,

if the rates for such furnishing or sale, as the case may be, are regulated, i.e., have been established or approved by a regulatory body described in section 167(l)(3)(A). The term "regulatory body described in section 167(l)(3)(A)" means a State (including the District of Columbia) or political subdivision thereof, any agency or instrumentality of the United States, or a public service or public utility commission or other body of any State or political subdivision thereof similar to such a commission. The term "established or approved" includes the filing of a schedule of rates with a regulatory body which has the power to approve such rates, even though such body has taken no action on the filed schedule or generally leaves undisturbed rates filed by the taxpayer involved.

(2) Classification of property. If property is not used solely in a section 167(l) public utility activity, such property shall be public utility property if its predominant use is in a section 167(l) public utility activity. The predominant use of property for any period shall be determined by reference to the proper accounts to which expenditures for such property are chargeable under the system of regulated accounts required to be used for the period for which the determination is made and in accordance with the principles of §1.46-3(g)(4) (relating to credit for investment in certain depreciable property). Thus, for example, for purposes of determining whether property is used predominantly in the trade or business of the furnishing or sale of transportation of gas by pipeline, or furnishing or sale of gas through a local distribution system, or both, the rules prescribed in §1.46-3(g)(4) apply, except that

accounts 365 through 371, inclusive (Transmission Plant), shall be added to the accounts enumerated in subdivision (i) of such paragraph (g)(4).

(c) Pre-1970 public utility property.

(1) Definition.

(i) Under section 167(l)(3)(B), the term "pre-1970 public utility property" means property which was public utility property at any time before January 1, 1970. If a taxpayer acquires pre-1970 public utility property, such property shall be pre-1970 public utility property in the hands of the taxpayer even though such property may have been acquired by the taxpayer in an arm's-length cash sale at fair market value or in a tax-free exchange. Thus, for example, if corporation X which is a member of the same controlled group of corporations (within the meaning of section 1563(a)) as corporation Y sells pre-1970 public utility property to Y, such property is pre-1970 public utility property in the hands of Y. The result would be the same if X and Y were not members of the same controlled group of corporations.

(ii) If the basis of public utility property acquired by the taxpayer in a transaction is determined in whole or in part by reference to the basis of any of the taxpayer's pre-1970 public utility property by reason of the application of any provision of the code, and if immediately after the transaction the adjusted basis of the property acquired is less than 200 percent of the adjusted basis of such pre-1970 public utility property immediately before the transaction, the property acquired is pre-1970 public utility property.

(2) Methods of depreciation not prohibited. Under section 167(l)(1), in the case of pre-1970 public utility property, the term "reasonable allowance" as used in section 167(a) means, for a taxable year for which a Federal income tax return was not filed before August 1, 1969, and in which such property is public utility property, an allowance (allowable without regard to section 167(l)) computed under-

(i) A subsection (l) method, or

(ii) The applicable 1968 method (other than a subsection (l) method) used by the taxpayer for such property, but only if-

(a) The taxpayer uses in respect of such taxable year a normalization method of regulated accounting for such property,

(b) The taxpayer used a flow-through method of regulated accounting for such property for its July 1969 regulated accounting period, or

(c) The taxpayer's first regulated accounting period with respect to such property is after the taxpayer's July 1969 regulated accounting period and the taxpayer used a flow-through method of regulated accounting for its July 1969 regulated accounting period for public utility property of the same kind (or if there is no property of the same kind, property of the most similar kind) most recently placed in service. See paragraph (e)(5) of this section for determination of same (or similar) kind.

(3) Flow-through method of regulated accounting in certain cases. See paragraph (e)(6) of this section for treatment of certain taxpayers with pending applications for change in method of accounting as being deemed to have used a flow-through method of regulated accounting for the July 1969 regulated accounting period.

(4) Examples. The provisions of this paragraph may be illustrated by the following examples:

Example (1). Corporation X, a calendar-year taxpayer subject to the jurisdiction of a regulatory body described in section 167(l)(3)(A), used the straight line method of depreciation (a subsection (l) method) for all of its public utility property for which depreciation was allowable on its Federal income tax return for 1967 (the latest taxable year for which X, prior to August 1, 1969, filed a return). Assume that under paragraph (e) of this section, X's applicable 1968 method is a subsection (l) method with respect to all of its public utility property. Thus, with respect to its pre-1970 public utility property, X may only use a straight line method (or any other subsection (l) method) of depreciation for all taxable years after 1967.

Example (2). Corporation Y, a calendar-year taxpayer subject to the jurisdiction of the Federal Power Commission, is engaged exclusively in the transportation of gas by pipeline. On its Federal income tax return for 1967 (the latest taxable year for which Y, prior to August 1, 1969, filed a return), Y used the declining balance method of depreciation using a rate of 150 percent of the straight-line rate for all of its nonsection 1250 public utility property with respect to which depreciation was allowable. Assume that with respect to all of such property, Y's applicable 1968 method under paragraph (e) of this section is such 150 percent declining balance method. Assume that Y used a normalization method of regulated accounting for all relevant regulated accounting periods. If Y continues to use a normalization method of regulated accounting, Y may compute its reasonable allowance for purposes of section 167(a) using such 150 percent declining balance method for its nonsection 1250 pre-1970 public utility property for all taxable years beginning with 1968, provided the use of such method is allowable without regard to section 167(l). Y may also use a subsection (l) method for any of such pre-1970 public utility property for all taxable years beginning after 1967. However, because each different uniform rate applied to the basis of the property is a different method of depreciation, Y may not use a declining balance method of depreciation using a rate of twice the straight line rate for any of such pre-1970 public utility property for any taxable year beginning after 1967.

Example (3). Assume the same facts as in example (2) except that with respect to all of its nonsection 1250 pre-1970 public utility property accounted for in its July 1969 regulated accounting period Y used a flow-through method of regulated accounting for such period. Assume further that such property is the property on the basis of which the applicable 1968 method is established for pre-1970 public utility property of the same kind, but having a first regulated accounting period after the taxpayer's July 1969 regulated accounting period. Beginning with 1968, with respect to such property Y may compute its reasonable allowance for purposes of section 167(a) using the declining balance method of depreciation and a rate of 150 percent of the straight line rate, whether it uses a normalization or flow-through method of regulated accounting after its July 1969 regulated accounting period, provided the use of such method is allowable without regard to section 167(l).

(d) Post-1969 public utility property.

(1) In general. Under section 167(l)(3)(C), the term "post-1969 public utility property" means any public utility property which is not pre-1970 public utility property.

(2) Methods of depreciation not prohibited. Under section 167(l)(2), in the case of post-1969 public utility property, the term "reasonable allowance" as used in section 167(a) means, for a taxable year, an allowance (allowable without regard to section 167(l)) computed under-

(i) A subsection (l) method,

(ii) A method of depreciation otherwise allowable under section 167 if, with respect to the property, the taxpayer uses in respect of such taxable year a normalization method of regulated accounting, or

(iii) The taxpayer's applicable 1968 method (other than a subsection (l) method) with respect to the property in question, if the taxpayer used a flow-through method of regulated accounting for its July 1969 regulated accounting period for the property of the same (or similar) kind most recently placed in service, provided that the property in question is not property to which an election under section 167(l)(4)(A) applies. See §1.167(l)-2 for rules with respect to an election under section 167(l)(4)(A). See paragraph (e)(5) of this section for definition of same (or similar) kind.

(3) Examples. The provisions of this paragraph may be illustrated by the following examples:

Example (1). Corporation X is engaged exclusively in the trade or business of the transportation of gas by pipeline and is subject to the jurisdiction of the Federal Power Commission. With respect to all its public utility property, X's applicable 1968 method (as determined under paragraph (e) of this section) is the straight line method of depreciation. X may determine its reasonable allowance for depreciation under section 167(a) with respect to its post-1969 public utility property under a straight line method (or other subsection (l) method) or, if X uses a normalization method of regulated accounting, any other method of depreciation, provided that the use of such other method is allowable under section 167 without regard to section 167(l).

Example (2). Assume the same facts as in example (1) except that with respect to all of X's post-1969 public utility property the applicable 1968 method (as determined under paragraph (e) of this section) is the declining balance method using a rate of 150 percent of the straight line rate. Assume further that all of X's pre-1970 public utility property was accounted for in its July 1969 regulated accounting period, and that X used a flow-through method of regulated accounting for such period. X may determine its reasonable allowance for depreciation under section 167 with respect to its post-1969 public utility property by using the straight line method of depreciation (or any other subsection (l) method), by using any method otherwise allowable under section 167 (such as a declining balance method) if X uses a normalization method of regulated accounting, or, by using the declining balance method using a rate of 150 percent of the straight line rate, whether or not X uses a normalization or a flow-through method of regulated accounting.

(e) Applicable 1968 method.

(1) In general. Under section 167(l)(3)(D), except as provided in subparagraphs (3) and (4) of this paragraph, the term "applicable 1968 method" means with respect to any public utility property-

(i) The method of depreciation properly used by the taxpayer in its Federal income tax return with respect to such property for the latest taxable year for which a return was filed before August 1, 1969,

(ii) If subdivision (i) of this subparagraph does not apply, the method of depreciation properly used by the taxpayer in its Federal income tax return for the latest taxable year for which a return was filed before August 1, 1969, with respect to public utility property of the same kind (or if there is no property of the same kind, property of the most similar kind) most recently placed in service before the end of such latest taxable year, or

(iii) If neither subdivision (i) nor (ii) of this subparagraph applies, a subsection (l) method.

If, on or after August 1, 1969, the taxpayer files an amended return for the taxable year referred to in subdivisions (i) and (ii) of this subparagraph, such amended return shall not be taken into consideration in determining the applicable 1968 method. The term "applicable 1968 method" also means with respect to any public utility property, for the year of change and subsequent years, a method of depreciation otherwise allowable under section 167 to which the taxpayer changes from an applicable 1968 method if, such new method results in a lesser allowance for depreciation for such property under section 167 in the year of change and the taxpayer secures the Commissioner's consent to the change in accordance with the procedures of section 446(e) and §1.446-1.

(2) Placed in service. For purposes of this section, property is placed in service on the date on which the period for depreciation begins under section 167. See, for example, § 1.167(a)-10(b) and §1.167(a)-11(c)(2). If under an averaging convention property which is placed in service (as defined in §1.46-3(d)(ii)) by the taxpayer on different dates is treated as placed in service on the same date, then for purposes of section 167(l) the property shall be treated as having been placed in service on the date the period for depreciation with respect to such property would begin under section 167 absent such averaging convention. Thus, for example, if, except for the fact that the averaging convention used assumes that all additions and retirements made during the first half of the year were made on the first day of the year, the period of depreciation for two items of public utility property would begin on January 10 and March 15, respectively, then for purposes of determining the property of the same (or similar) kind most recently placed in service, such items of property shall be treated as placed in service on January 10 and March 15, respectively.

(3) Certain section 1250 property. If a taxpayer is required under section 167(j) to use a method of depreciation other than its applicable 1968 method with respect to any section 1250 property, the term "applicable 1968 method" means the method of depreciation allowable under section 167(j) which is the most nearly comparable method to the applicable 1968 method determined under subparagraph (1) of this paragraph. For example, if the applicable 1968 method on new section 1250 property is the declining balance method using 200 percent of the straight line rate, the most nearly comparable method allowable for new section 1250 property under section 167(j) would be the declining balance method using 150 percent of the straight line rate. If the applicable 1968 method determined under subparagraph (1) of this paragraph is the sum of the years-digits method, the term "most nearly comparable method" refers to any method of depreciation allowable under section 167(j).

(4) Applicable 1968 method in certain cases.

(i)

(a) Under section 167(l)(3)(E), if the taxpayer evidenced within the time and manner specified in (b) of this subdivision (i) the intent to use a method of depreciation under section 167 (other than its applicable 1968 method as determined under subparagraph (1) or (3) of this paragraph or a subsection (l) method) with respect to any public utility property, such method of depreciation shall be deemed to be the taxpayer's applicable 1968 method with respect to such public utility property and public utility property of the same (or most similar) kind subsequently placed in service.

(b) Under this subdivision (i), the intent to use a method of depreciation under section 167 is evidenced-

(1) By a timely application for permission for a change in method of accounting filed by the

taxpayer before August 1, 1969, or

(2) By the use of such method of depreciation in the computation by the taxpayer of its tax expense for purposes of reflecting operating results in its regulated books of account for its July 1969 regulated accounting period, as established in the manner prescribed in subparagraph (g)(1)(i), (ii), or (iii) of this section.

(ii)

(a) If public utility property is acquired in a transaction in which its basis in the hands of the transferee is determined in whole or in part by reference to its basis in the hands of the transferor by reason of the application of any provision of the Code, or in a transfer (including any purchase for cash or in exchange) from a related person, then in the hands of the transferee the applicable 1968 method with respect to such property shall be determined by reference to the treatment in respect of such property in the hands of the transferor.

(b) For purposes of this subdivision (ii), the term "related person" means a person who is related to another person if either immediately before or after the transfer-

(1) The relationship between such persons would result in a disallowance of losses under section 267 (relating to disallowance of losses, etc., between related taxpayers) or section 707(b) (relating to losses disallowed, etc., between partners and controlled partnerships) and the regulations thereunder, or

(2) Such persons are members of the same controlled group of corporations, as defined in section 1563(a) (relating to definition of controlled group of corporations), except that "more than 50 percent" shall be substituted for "at least 80 percent" each place it appears in section 1563(a) and the regulations thereunder.

(5) Same or similar. The classification of property as being of the same (or similar) kind shall be made by reference to the function of the public utility to which the primary use of the property relates. Property which performs the identical function in the identical manner shall be treated as property of the same kind. The determination that property is of a similar kind shall be made by reference to the proper account to which expenditures for the property are chargeable under the system of regulated accounts required to be used by the taxpayer for the period in which the property in question was acquired. Property, the expenditure for which is chargeable to the same account, is property of the most similar kind. Property, the expenditure for which is chargeable to an account for property which serves the same general function, is property of a similar kind. Thus, for example, if corporation X, a

natural gas company, subject to the jurisdiction of the Federal Power Commission, had property properly chargeable to account 366 (relating to transmission plant structures and improvements) acquired an additional structure properly chargeable to account 366, under the uniform system of accounts prescribed for natural gas companies (class A and class B) by the Federal Power Commission, effective September 1, 1968, the addition would constitute property of the same kind if it performed the identical function in the identical manner. If, however, the addition did not perform the identical function in the identical manner, it would be property of the most similar kind.

(6) Regulated method of accounting in certain cases. Under section 167(l)(4)(B), if with respect to any pre-1970 public utility property the taxpayer filed a timely application for change in method of accounting referred to in subparagraph (4)(i) *(b)(1)* of this paragraph and with respect to property of the same (or similar) kind most recently placed in service the taxpayer used a flow-through method of regulated accounting for its July 1969 regulated accounting period, then for purposes of section 167(l)(1)(B) and paragraph (c) of this section the taxpayer shall be deemed to have used a flow-through method of regulated accounting with respect to such pre-1970 public utility property.

(7) Examples. The provisions of this paragraph may be illustrated by the following examples:

Example (1). Corporation X is a calendar-year taxpayer. On its Federal income tax return for 1967 (the latest taxable year for which X, prior to August 1, 1969, filed a return) X used a straight line method of depreciation with respect to certain public utility property placed in service before 1965 and used the declining balance method of depreciation using 200 percent of the straight line rate (double declining balance) with respect to the same kind of public utility property placed in service after 1964. In 1968 and 1970, X placed in service additional public utility property of the same kind. The applicable 1968 method with respect to the above described public utility property is shown in the following chart:

Property held in 1970	**Placed in service**	**Method on 1967 return**	**Applicable 1968 method**
Group 1	Before 1965	Straight line	Straight line
Group 2	After 1964 and before 1968	Double declining balance	Double declining balance
Group 3	After 1967 and before 1969		Do
Group 4	After 1968		Do

Example (2). Corporation Y is a calendar-year taxpayer engaged exclusively in the trade or business of the furnishing of electrical energy. In 1954, Y placed in service hydroelectric generators and for all purposes Y has taken straight line depreciation with respect to such generators. In 1960, Y placed in service fossil fuel generators and for all purposes since 1960 has used the declining balance method of depreciation using a rate of 150 percent of the straight line rate (computed without reduction for salvage) with respect to such generators. After 1960 and before 1970 Y did not place in service any generators. In 1970, Y placed in service additional hydroelectric generators. The applicable 1968 method with respect to the hydroelectric generators placed in service in 1970 would be the straight line method because it was the method used by Y on its return for the latest taxable year for which Y filed a return before August 1, 1969, with respect to property of the same kind (i.e., hydroelectric generators) most recently placed in service.

Example (3). Assume the same facts as in example (2), except that the generators placed in service in 1970 were nuclear generators. The applicable 1968 method with respect to such generators is the declining balance method using a rate of 150 percent of the straight line rate because, with respect to property of the most similar kind (fossil fuel generators) most recently placed in service, Y used such declining balance method on its return for the latest taxable year for which it filed a return before August 1, 1969.

(f) Subsection (l) method. Under section 167(l)(3)(F), the term "subsection (l) method" means a reasonable and consistently applied ratable method of computing depreciation which is allowable under section 167(a), such as, for example, the straight line method or a unit of production method or machine-hour method. The term "subsection (l) method" does not include any declining balance method (regardless of the uniform rate applied), sum of the years-digits method, or method of depreciation which is allowable solely by reason of section 167(b)(4) or (j)(1)(C).

(g) July 1969 regulated accounting period.

(1) In general. Under section 167(l)(3)(I), the term "July 1969 regulated accounting period" means the taxpayer's latest accounting period ending before August 1, 1969, for which the taxpayer regularly computed, before January 1, 1970, its tax expense for purposes of reflecting operating results in its regulated books of account. The computation by the taxpayer of such tax expense may be established by reference to the following:

(i) The most recent periodic report of a period ending before August 1, 1969, required by a regulatory body described in section 167(l)(3)(A) having jurisdiction over the taxpayer's regulated books of account which was filed with such body before January 1, 1970 (whether or not such body has jurisdiction over rates).

(ii) If subdivision (i) of this subparagraph does not apply, the taxpayer's most recent report to its shareholders for a period ending before August 1, 1969, but only if such report was distributed to the shareholders before January 1, 1970, and if the taxpayer's stocks or securities are traded in an established securities market during such period. For purposes of this subdivision, the term "established securities market" has the meaning assigned to such term in §1.453-3(d)(4).

(iii) If subdivisions (i) and (ii) of this subparagraph do not apply, entries made to the satisfaction of the district director before January 1, 1970, in its regulated books of account for its most recent accounting period ending before August 1, 1969.

(2) July 1969 method of regulated accounting in certain acquisitions. If public utility property is acquired in a transaction in which its basis in the hands of the transferee is determined in whole or in part by reference to its basis in the hands of the transferor by reason of the application of any provision of the Code, or in a transfer (including any purchase for cash or in exchange) from a related person, then in the hands of the transferee the method of regulated accounting for such property's July 1969 regulated accounting period shall be determined by reference to the treatment in respect of such property in the hands of the transferor. See paragraph (e)(4)(ii) of this section for definition of "related person".

(3) Determination date. For purposes of section 167(l), any reference to a method of depreciation under section 167(a), or a method of regulated accounting, taken into account by the taxpayer in computing its tax expense for its July 1969 regulated accounting period shall be a reference to such tax expense as shown on the periodic report or report to share-holders to which subparagraph (1)(i) or (ii) of this paragraph applies or the entries made on the taxpayer's regulated books of account to which subparagraph (1)(iii) of this paragraph applies. Thus, for example, assume that regulatory body A having jurisdiction over public utility property with respect to X's regulated books of account requires X to reflect its tax expense in such books using the same method of depreciation which regulatory body B uses for determining X's cost of service for ratemaking purposes. If in 1971, in the course of approving a rate change for X, B retroactively determines X's cost of service for ratemaking purposes for X's July 1969 regulated accounting period using a method of depreciation different from the method reflected in X's regulated books of account as of January 1, 1970, the method of depreciation used by X for its July 1969 regulated accounting period would be determined without reference to the method retroactively used by B in 1971.

(h) Normalization method of accounting.

(1) In general.

(i) Under section 167(l), a taxpayer uses a normalization method of regulated accounting with respect to public utility property-

(a) If the same method of depreciation (whether or not a subsection (l) method) is used to compute both its tax expense and its depreciation expense for purposes of establishing cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account, and

(b) If to compute its allowance for depreciation under section 167 it uses a method of depreciation other than the method it used for purposes described in *(a)* of this subdivision, the taxpayer makes adjustments consistent with subparagraph (2) of this paragraph to a reserve to reflect the total amount of the deferral of Federal income tax liability resulting from the use with respect to all of its public utility property of such different methods of depreciation.

(ii) In the case of a taxpayer described in section 167(l)(1)(B) or (2)(C), the reference in subdivision (i) of this subparagraph shall be a reference only to such taxpayer's "qualified public utility property". See § 1.167(l)-2(b) for definition of "qualified public utility property".

(iii) Except as provided in this subparagraph, the amount of Federal income tax liability deferred as a result of the use of different method of depreciation under subdivision (i) of this subparagraph is the excess (computed without regard to credits) of the amount the tax liability would have been had a subsection (l) method been used over the amount of the actual tax liability. Such amount shall be taken into account for the taxable year in which such different methods of depreciation are used. If, however, in respect of any taxable year the use of a method of depreciation other than a subsection (l) method for purposes of determining the taxpayer's reasonable allowance under section 167(a) results in a net operating loss carryover (as determined under section 172) to a year succeeding such taxable year which would not have arisen (or an increase in such carryover which would not have arisen) had the taxpayer determined his reasonable allowance under section 167(a) using a subsection (l) method, then the amount and time of the deferral of tax liability shall be taken into account in such appropriate time and manner as is satisfactory to the district director.

(2) Adjustments to reserve.

(i) The taxpayer must credit the amount of deferred Federal income tax determined under subparagraph (1)(i) of this paragraph for any taxable year to a reserve for deferred taxes, a depreciation reserve, or other reserve account. The taxpayer need not establish a separate reserve account for such amount but the amount of deferred tax determined under subparagraph (1)(i) of this paragraph must be accounted for in such a manner so as to be readily identifiable. With respect to any account, the aggregate amount allocable to deferred tax under section 167(l) shall not be reduced except to reflect the amount for any taxable year by which Federal income taxes are greater by reason of the prior use of different methods of depreciation under subparagraph (1)(i) of this paragraph. An additional exception is that the aggregate amount allocable to deferred tax under section 167(l) may be properly adjusted to reflect asset retirements or the expiration of the period for depreciation used in determining the allowance for depreciation under section 167(a).

(ii) The provisions of this subparagraph may be illustrated by the following examples:

Example (1). Corporation X is exclusively engaged in the transportation of gas by pipeline subject to the jurisdiction of the Federal Power Commission. With respect to its post-1969 public utility property, X is entitled under section 167(l)(2)(B) to use a method of depreciation other than a subsection (l) method if it uses a normalization method of regulated accounting. With respect to such property, X has not made any election under § 1.167(a)-11 (relating to depreciation based on class lives and asset depreciation ranges). In 1972, X places in service public utility property with an unadjusted basis of $2 million, and an estimated useful life of 20 years. X uses the declining balance method of depreciation with a rate twice the straight line rate. If X uses a normalization method of regulated accounting, the amount of depreciation allowable under section 167(a) with respect to such property for 1972 computed under the double declining balance method would be $200,000. X computes its tax expense and depreciation expense for purposes of determining its cost of service for rate-making purposes and for reflecting operating results in its regulated books of account using the straight line method of depreciation (a subsection (l) method). A depreciation allowance computed in this manner is $100,000. The excess of the depreciation allowance determined under the double declining balance method ($200,000) over the depreciation expense computed using the straight line method ($100,000) is $100,000. Thus, assuming a tax rate of 48 percent, X used a normalization method of regulated accounting for 1972 with respect to property placed in service that year if for 1972 it added to a reserve $48,000 as taxes deferred as a result of the use by X of a method of depreciation for Federal income tax purposes different from that used for establishing its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account.

Example (2). Assume the same facts as in example (1), except that X elects to apply §1.167(a)-11 with respect to all eligible property placed in service in 1972. Assume further that all property X placed in service in 1972 is eligible property. One hundred percent of the asset guideline period for such property is 22 years and the asset depreciation range is from 17.5 years to 26.5 years. X uses the double declining balance method of depreciation, selects an asset depreciation period of 17.5 years, and applies the half-year convention (described in § 1.167(a)-11(c)(2)(iii)). In 1972, the depreciation allowable under section 167(a) with respect to property placed in service in 1972 is $114,285 (determined without regard to the normalization requirements in §1.167(a)-11(b)(6) and in section 167(l)). X computes its tax expense for purposes of determining its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account using the straight line method of depreciation (a subsection (l) method), an estimated useful life of 22 years (that is, 100 percent of the asset guideline period), and the half-year convention. A depreciation allowance computed in this manner is $45,454. Assuming a tax rate of 48 percent, the amount that X must add to a reserve for 1972 with respect to property placed in service that year in order to qualify as using a normalization method of regulated accounting under section 167(l)(3)(G) is $27,429 and the amount in order to satisfy the normalization requirements of §1.167(a)-11(b)(6) is $5,610. X determined such amounts as follows:

(1) Depreciation allowance on tax return (determined without regard to section 167(l) and	$114,285

§1.167(a)-11(b)(6))	
(2) Line (1), recomputed using a straight line method	57,142
(3) Difference in depreciation allowance attributable to different methods (line (1) minus line (2))	$ 57,143
(4) Amount to add to reserve under this paragraph (48 percent of line (3))	27,429
(5) Amount in line (2)	$57,142
(6) Line (5), recomputed by using an estimated useful life of 22 years and the half-year convention	45,454
(7) Difference in depreciation allowance attributable to difference in depreciation periods	$11,688
(8) Amount to add to reserve under §1.167(a)-11(b)(6)(ii) (48 percent of line (7))	5,610

If, for its depreciation expense for purposes of determining its cost of service for rate-making purposes and for reflecting operating results in its regulated books of account, X had used a period in excess of the asset guideline period of 22 years, the total amount in lines (4) and (8) in this example would not be changed.

Example (3). Corporation Y, a calendar-year taxpayer which is engaged in furnishing electrical energy, made the election provided by section 167(l)(4)(a) with respect to its "qualified public utility property" (as defined in §1.167(l)-2(b)). In 1971, Y placed in service qualified public utility property which had an adjusted basis of $2 million, estimated useful life of 10 years, and no salvage value. With respect to property of the same kind most recently placed in service, Y used a flow-through method of regulated accounting for its July 1969 regulated accounting period and the applicable 1968 method is the declining balance method of depreciation using 200 percent of the straight line rate. The amount of depreciation allowable under the double declining balance method with respect to the qualified public utility property would be $200,000. Y computes its tax expense and depreciation expense for purposes of determining its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account using the straight line method of depreciation. A depreciation allowance with respect to the qualified public utility property determined in this manner is $100,000. The excess of the depreciation allowance determined under the double declining balance method ($200,000) over the depreciation expense computed using the straight line method ($100,000) is $100,000. Thus, assuming a tax rate of 48 percent, Y used a normalization method of regulated accounting for 1971 if for 1971 it added to a reserve $48,000 as tax deferred as a result of the use by Y of a method of depreciation for Federal income tax purposes with respect to its qualified public utility property which method was different from that used for establishing its cost of service for ratemaking purposes and for reflecting operating results in its regulated books of account for such property.

Example (4). Corporation Z, exclusively engaged in a public utility activity did not use a flow-through method of regulated accounting for its July 1969 regulated accounting period. In 1971, a regulatory body having jurisdiction over all of Z's property issued an order applicable to all years beginning with 1968 which provided, in effect, that Z use an accelerated method of depreciation for purposes of section 167 and for determining its tax expenses for purposes of reflecting operating results in its regulated books of account. The order further provided that Z normalize 50 percent of the tax deferral resulting from the use of the accelerated method of depreciation and that Z flow-through 50 percent of the tax deferral resulting therefrom. Under section 167(l), the method of accounting provided in the order would not be a normalization method of regulated accounting because Z would not be permitted to normalize 100 percent of the tax deferral resulting from the use of an accelerated method of depreciation. Thus, with respect to its public utility property for purposes of section 167, Z may only use a subsection (l) method of depreciation.

Example (5). Assume the same facts as in example (4) except that the order of the regulatory body provided, in effect, that Z normalize 100 percent of the tax deferral with respect to 50 percent of its public utility property and flow-through the tax savings with respect to the other 50 percent of its property. Because the effect of such an order would allow Z to flow-through a portion of the tax savings resulting from the use of an accelerated method of depreciation, Z would not be using a normalization method of regulated accounting with respect to any of its properties. Thus, with respect to its public utility property for purposes of section 167, Z may only use a subsection (l) method of depreciation.

(3) Establishing compliance with normalization requirements in respect of operating books of account. The taxpayer may establish compliance with the requirement in subparagraph (1)(i) of this paragraph in respect of reflecting operating results, and adjustments to a reserve, in its operating books of account by reference to the following:

(i) The most recent periodic report for a period beginning before the end of the taxable year, required by a regulatory body described in section 167(l)(3)(A) having jurisdiction over the taxpayer's regulated operating books of account which was filed with such body before the due date (determined with regard to extensions) of the taxpayer's Federal income tax return for such taxable year (whether or not such body has jurisdiction over rates).

(ii) If subdivision (i) of this subparagraph does not apply, the taxpayer's most recent report to its shareholders for the taxable year but only if (a) such report was distributed to the shareholders before the due date (determined with regard to extensions) of the taxpayer's Federal income tax return for the taxable year and (b) the taxpayer's stocks or securities are traded in an established securities market during such taxable year. For purposes of this subdivision, the term "established securities market" has the meaning assigned to such term in § 1.453-3(d)(4).

(iii) If neither subdivision (i) nor (ii) of this subparagraph applies, entries made to the satisfaction of the district director before the due date (determined with regard to extensions) of the taxpayer's Federal income tax return for the taxable year in its regulated books of account for its most recent period beginning before the end of such taxable year.

(4) Establishing compliance with normalization requirements in computing cost of service for ratemaking purposes.

(i) In the case of a taxpayer which used a flow-through method or regulated accounting for its July 1969 regulated accounting period or thereafter, with respect to all or a portion of its pre-1970 public utility property, if a regulatory body having jurisdiction to establish the rates of such taxpayer as to such property (or a court which has jurisdiction over such body) issues an order of general application (or an order of specific application to the taxpayer) which states that such regulatory body (or court) will permit a class of taxpayers of which such taxpayer is a member (or such taxpayer) to use the normalization method of regulated accounting to establish cost of service for ratemaking purposes with respect to all or a portion of its public utility property, the taxpayer will be presumed to be using the same method of depreciation to compute both its tax expense and its depreciation expense for purposes of establishing its cost of service for ratemaking purposes with respect to the public utility property to which such order applies. In the event that such order is in any way conditional, the preceding sentence shall not apply until all of the conditions contained in such order which are applicable to the taxpayer have been fulfilled. The taxpayer shall establish to the satisfaction of the Commissioner or his delegate that such conditions have been fulfilled.

(ii) In the case of a taxpayer which did not use the flow-through method of regulated accounting for its July 1969 regulated accounting period or thereafter (including a taxpayer which used a subsection (l) method of depreciation to compute its allowance for depreciation under section 167(a) and to compute its tax expense for purposes of reflecting operating results in its regulated books of account), with respect to any of its public utility property, it will be presumed that such taxpayer is using the same method of depreciation to compute both its tax expense and its depreciation expense for purposes of establishing its cost of service for ratemaking purposes with respect to its post-1969 public utility property. The presumption described in the preceding sentence shall not apply in any case where there is (a) an expression of intent (regardless of the manner in which such expression of intent is indicated) by the regulatory body (or bodies), having jurisdiction to establish the rates of such taxpayer, which indicates that the policy of such regulatory body is in any way inconsistent with the use of the normalization method of regulated accounting by such taxpayer or by a class of taxpayers of which such taxpayer is a member, or (b) a decision by a court having jurisdiction over such regulatory body which decision is in any way inconsistent with the use of the normalization method of regulated accounting by such taxpayer or a class of taxpayers of which such taxpayer is a member. The presumption shall be applicable on January 1, 1970, and shall, unless rebutted, be effective until an inconsistent expression of intent is indicated by such regulatory body or by such court. An example of such an inconsistent expression of intent is the case of a regulatory body which has, after the July 1969 regulated accounting period and before January 1, 1970, directed public utilities subject to its ratemaking jurisdiction to use a flow-through method of regulated accounting, or has issued an order of general application which states that such agency will direct a class of public utilities of which the taxpayer is a member to use a flow-through method of regulated accounting. The presumption described in this subdivision may be rebutted by evidence that the flow-through method of regulated accounting is being used by the taxpayer with respect to such property.

(iii) The provisions of this subparagraph may be illustrated by the following examples:

Example (1). Corporation X is a calendar-year taxpayer and its "applicable 1968 method" is a straight line method of depreciation. Effective January 1, 1970, X began collecting rates which were based on a sum of the years-digits method of depreciation and a normalization method of regulated accounting which rates had been approved by a regulatory body having jurisdiction over X. On October 1, 1971, a court of proper jurisdiction annulled the rate order prospectively, which annulment was not appealed, on the basis that the regulatory body had abused its discretion by determining the rates on the basis of a normalization method of regulated accounting. As there was no inconsistent expression of intent during 1970 or prior to the due date of X's return for 1970, X's use of the sum of the years-digits method of depreciation for purposes of section 167 on such return was proper. For 1971, the presumption is in effect through September 30. During 1971, X may use the sum of the years-digits method of depreciation for purposes of section 167 from January 1 through September 30, 1971. After September 30, 1971, and for taxable years after 1971, X must use a straight line method of depreciation until the inconsistent court decision is no longer in effect.

Example (2). Assume the same facts as in example (1), except that pursuant to the order of annulment, X was required to refund the portion of the rates attributable to the use of the normalization method of regulated accounting. As there was no inconsistent expression of intent during 1970 or prior to the due date of X's return for 1970, X has the benefit of the presumption with respect to its use of the sum of the years-digits method of depreciation for purposes of section 167, but because of the retroactive nature of the rate order X must file an amended return for 1970 using a straight line method of depreciation. As the inconsistent decision by the court was handed down prior to the due date of X's Federal income tax return for 1971, for 1971 and thereafter the presumption of subdivision (ii) of this subparagraph does not apply. X must file its Federal income tax returns for such years using a straight line method of depreciation.

Example (3). Assume the same facts as in example (2), except that the annulment order was stayed pending appeal of the decision to a court of proper appellate jurisdiction. X has the benefit of the presumption as described in example (2) for the year 1970, but for 1971 and thereafter the presumption of subdivision (ii) of this subparagraph does not apply. Further, X must file an amended return for 1970 using a straight line method of depreciation and for 1971 and thereafter X must file its returns using a straight line method of depreciation unless X and the district director have consented in writing to extend the time for assessment of tax for 1970 and thereafter with respect to the issue of normalization method of regulated accounting for as long as may be necessary to allow for resolution of the appeal with respect to the annulment of the rate order.

(5) Change in method of regulated accounting. The taxpayer shall notify the district director of a change in its method of regulated accounting, an order by a regulatory body or court that such method be changed, or an interim or final rate determination by a regulatory body which determination is inconsistent with the method of regulated accounting used by the taxpayer immediately prior to the effective date of such rate determination. Such notification shall be made within 90 days of the date that the change in method, the order, or the determination is effective. In the case of a change in the method of regulated accounting, the taxpayer shall recompute its tax liability for any affected taxable year and such recomputation shall be made in the form of an amended return where necessary unless the taxpayer and the district director have consented in writing to extend the time for assessment of tax with respect to the issue of normalization method of regulated accounting.

(6) Exclusion of normalization reserve from rate base.

(i) Notwithstanding the provisions of subparagraph (1) of this paragraph, a taxpayer does not use a normalization method of regulated accounting if, for ratemaking purposes, the amount of the reserve for deferred taxes under section 167(l) which is excluded from the base to which the taxpayer's rate of return is applied, or which is treated as no-cost capital in those rate cases in which the rate of return is based upon the cost of capital, exceeds the amount of such reserve for deferred taxes for the period used in determining the taxpayer's tax expense in computing cost of service in such ratemaking.

(ii) For the purpose of determining the maximum amount of the reserve to be excluded from the rate base (or to be included as no-cost capital) under subdivision (i) of this subparagraph, if solely an historical period is used to determine depreciation for Federal income tax expense for ratemaking purposes, then the amount of the reserve account for the period is the amount of the reserve (determined under subparagraph (2) of this paragraph) at the end of the historical period. If solely a future period is used for such determination, the amount of the reserve account for the period is the amount of the reserve at the beginning of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during such period. If such determination is made by reference both to an historical portion and to a future portion of a period, the amount of the reserve account for the period is the amount of the reserve at the end of the historical portion of the period and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged to the account during the future portion of the period. The pro rata portion of any increase to be credited or decrease to be charged during a future period (or the future portion of a part-historical and part-future period) shall be determined by multiplying any such increase or decrease by a fraction, the numerator of which is the number of days remaining in the period at the time such increase or decrease is to be accrued, and the denominator of which is the total number of days in the period (or future portion).

(iii) The provisions of subdivision (i) of this subparagraph shall not apply in the case of a final determination of a rate case entered on or before May 31, 1973. For this purpose, a determination is final if all rights to request a review, a rehearing, or a redetermination by the regulatory body which makes such determination have been exhausted or have lapsed. The provisions of subdivision (ii) of this subparagraph shall not apply in the case of a rate case filed prior to June 7, 1974, for which a rate order is entered by a regulatory body having jurisdiction to establish the rates of the taxpayer prior to September 5, 1974, whether or not such order is final, appealable, or subject to further review or reconsideration.

(iv) The provisions of this subparagraph may be illustrated by the following examples:

Example (1). Corporation X is exclusively engaged in the transportation of gas by pipeline subject to the jurisdiction of the Z Power Commission. With respect to its post-1969 public utility property, X is entitled under section 167(l)(2)(B) to use a method of depreciation other than a subsection (l) method if it uses a normalization method of regulated accounting. With respect to X the Z Power Commission for purposes of establishing cost of service uses a recent consecutive 12-month period ending not more than 4 months prior to the date of filing a rate case adjusted for certain known changes occurring within a 9-month period subsequent to the base period. X's rate case is filed on January 1, 1975. The year 1974 is the recorded test period for X's rate case and is the period used in determining X's tax expense in computing cost of service. The rates are contemplated to be in effect for the years 1975, 1976, and 1977. The adjustments for known changes relate only to wages and salaries. X's rate base at the end of 1974 is $145,000,000. The amount of the reserve for deferred taxes under section 167(l) at the end of 1974 is $1,300,000, and the reserve is projected to be $4,400,000 at the end of 1975, $6,600,000 at the end of 1976, and $9,800,000 at the end of 1977. X does not use a normalization method of regulated accounting if the Z Power Commission excludes more than $1,300,000 from the rate base to which X's rate of return is applied. Similarly, X does not use a normalization method of regulated accounting if, instead of the above, the Z Power Commission, in determining X's rate of return which is applied to the rate base, assigns to no-cost capital an amount that represents the reserve account for deferred tax that is greater than $1,300,000.

Example (2). Assume the same facts as in example (1) except that the adjustments for known changes in cost of service made by the Z Power Commission include an additional depreciation expense that reflects the installation of new equipment put into service on January 1, 1975. Assume further that the reserve for deferred taxes under section 167(l) at the end of 1974 is $1,300,000 and that the monthly net increase for the first 9 months of 1975 are projected to be

January 1-31	$310,000
February 1-28	300,000
March 1-31	300,000
April 1-30	280,000
May 1-31	270,000
June 1-30	260,000
July 1-31	260,000
August 1-31	250,000
September 1-30	240,000
	$2,470,000

For its regulated books of account X accrues such increases as of the last day of the month but as a matter of convenience credits increases or charges decreases to the reserve account on the 15th day of the month following the whole month for which such increase or decrease is accrued. The maximum amount that may be excluded from the rate base is $2,470,879 (the amount in the reserve at the end of the historical portion of the period ($1,300,000) and a pro rata portion of the amount of any projected increase for the future portion of the period to be credited to the reserve ($1,170,879)). Such pro rata portion is computed (without regard to the date such increase will actually be posted to the account) as follows:

$310,000 × 243/273 =	$275,934
300,000 × 215/273 =	236,264
300,000 × 184/273 =	202,198
280,000 × 154/273 =	157,949
270,000 × 123/273 =	121,648
260,000 × 93/273 =	88,571
260,000 × 62/273 =	59,048
250,000 × 31/273 =	28,388
240,000 × 1/273 =	879
	$1,170,879

Example (3). Assume the same facts as in example (1) except that for purposes of establishing cost of service the Z Power Commission uses a future test year (1975). The rates are contemplated to be in effect for 1975, 1976, and 1977. Assume further that plant additions, depreciation expense, and taxes are projected to the end of 1975 and that the reserve for deferred taxes under section 167(l) is $1,300,000 for 1974 and is projected to be $4,400,000 at the end of 1975. Assume also that the Z

Power Commission applies the rate of return to X's 1974 rate base of $145,000,000 X and the Z Power Commission through negotiation arrive at the level of approved rates. X uses a normalization method of regulated accounting only if the settlement agreement, the rate order, or record of the proceedings of the Z Power Commission indicates that the Z Power Commission did not exclude an amount representing the reserve for deferred taxes from X's rate base ($145,000,000) greater than $1,300,000 plus a pro rata portion of the projected increases and decreases that are to be credited or charged to the reserve account for 1975. Assume that for 1975 quarterly net increases are projected to be

1st quarter	$910,000
2nd quarter	810,000
3rd quarter	750,000
4th quarter	630,000
Total	$3,100,000

For its regulated books of account X will accrue such increases as of the last day of the quarter but as a matter of convenience will credit increases or charge decreases to the reserve account on the 15th day of the month following the last month of the quarter for which such increase or decrease will be accrued. The maximum amount that may be excluded from the rate base is $2,591,480 (the amount of the reserve at the beginning of the period ($1,300,000) plus a pro rata portion ($1,291,480) of the $3,100,000 projected increase to be credited to the reserve during the period). Such portion is computed (without regard to the date such increase will actually be posted to the account) as follows:

$910,000 × 276/365 =	$688,110
810,000 × 185/365 =	410,548
750,000 × 93/365 =	191,096
630,000 × 1/365 =	1,726
	$1,291,480

(i) Flow-through method of regulated accounting. Under section 167(l)(3)(H), a taxpayer uses a flow-through method of regulated accounting with respect to public utility property if it uses the same method of depreciation (other than a subsection (l) method) to compute its allowance for depreciation under section 167 and to compute its tax expense for purposes of reflecting operating results in its regulated books of account unless such method is the same method used by the taxpayer to determine its depreciation expense for purposes of reflecting operating results in its regulated books of account. Except as provided in the preceding sentence, the method of depreciation used by a taxpayer with respect to public utility property for purposes of determining cost of service for ratemaking purposes or rate base for ratemaking purposes shall not be considered in determining whether the taxpayer used a flow-through method of regulated accounting. A taxpayer may establish use of a flow-through method of regulated accounting in the same manner that compliance with normalization requirements in respect of operating books of account may be established under paragraph (h)(4) of this section.

T.D. 7315 , 6/6/74 .

§59 Other definitions and special rules.

Income (USTR)

Internal Revenue Code

§ 59 Other definitions and special rules.

(a) Alternative minimum tax foreign tax credit.

For purposes of this part-

(1) In general.

The alternative minimum tax foreign tax credit for any taxable year shall be the credit which would be determined under section 27 for such taxable year if-

(A) the pre-credit tentative minimum tax were the tax against which such credit was taken for purposes of section 904 for the taxable year and all prior taxable years beginning after December 31, 1986,

(B) section 904 were applied on the basis of alternative minimum taxable income instead of taxable income, and

(C) the determination of whether any income is high-taxed income for purposes of section 904(d)(2) were made on the basis of the applicable rate specified in section 55(b)(1) in lieu of the highest rate of tax specified in section 1 .

(2) Pre-credit tentative minimum tax.

For purposes of this subsection , the term "pre-credit tentative minimum tax" means the amount determined under the first sentence of section 55(b)(1)(A) .

(3) Election to use simplified section 904 limitation.

(A) In general. In determining the alternative minimum tax foreign tax credit for any taxable year to which an election under this paragraph applies-

(i) subparagraph (B) of paragraph (1) shall not apply, and

(ii) the limitation of section 904 shall be based on the proportion which-

(I) the taxpayer's taxable income (as determined for purposes of the regular tax) from sources without the United States (but not in excess of the taxpayer's entire alternative minimum taxable income), bears to

(II) the taxpayer's entire alternative minimum taxable income for the taxable year.

(B) Election.

(i) In general. An election under this paragraph may be made only for the taxpayer's first taxable year which begins after December 31, 1997, and for which the taxpayer claims an alternative minimum tax foreign tax credit.

(ii) Election revocable only with consent. An election under this paragraph , once made, shall apply to the taxable year for which made and all subsequent taxable years unless revoked with the consent of the Secretary.

(b) Repealed.

(c) Treatment of estates and trusts.

In the case of any estate or trust, the alternative minimum taxable income of such estate or trust and any beneficiary thereof shall be determined by applying part I of subchapter J with the adjustments provided in this part.

(d) Apportionment of differently treated items in case of certain entities.

(1) In general.

The differently treated items for the taxable year shall be apportioned (in accordance with regulations prescribed by the Secretary)-

(A) Regulated investment companies and real estate investment trusts. In the case of a regulated investment company to which part I of subchapter M applies or a real estate investment company to which part II of subchapter M applies, between such company or trust and shareholders and holders of beneficial interest in such company or trust.

(B) Common trust funds. In the case of a common trust fund (as defined in section 584(a)), pro rata among the participants of such fund.

(2) Differently treated items.

For purposes of this section , the term "differently treated item" means any item of tax preference or any other item which is treated differently for purposes of this part than for purposes of computing the regular tax.

(e) Optional 10-year writeoff of certain tax preferences.

(1) In general.

For purposes of this title, any qualified expenditure to which an election under this paragraph applies shall be allowed as a deduction ratably over the 10-year period (3-year period in the case of circulation expenditures described in section 173) beginning with the taxable year in which such expenditure was made (or, in the case of a qualified expenditure described in paragraph (2)(C) , over the 60-month period beginning with the month in which such expenditure was paid or incurred).

(2) Qualified expenditure.

For purposes of this subsection , the term "qualified expenditure" means any amount which, but for an election under this subsection , would have been allowable as a deduction (determined without regard to section 291) for the taxable year in which paid or incurred under-

(A) section 173 (relating to circulation expenditures),

(B) section 174(a) (relating to research and experimental expenditures),

(C) section 263(c) (relating to intangible drilling and development expenditures),

(D) section 616(a) (relating to development expenditures), or

(E) section 617(a) (relating to mining exploration expenditures).

(3) Other sections not applicable.

Except as provided in this subsection , no deduction shall be allowed under any other section for any qualified expenditure to which an election under this subsection applies.

(4) Election.

(A) In general. An election may be made under paragraph (1) with respect to any portion of any qualified expenditure.

(B) Revocable only with consent. Any election under this subsection may be revoked only with the consent of the Secretary.

(C) Partners and shareholders of S corporations. In the case of a partnership, any election under paragraph (1) shall be made separately by each partner with respect to the partner's allocable share of any qualified expenditure. A similar rule shall apply in the case of an S corporation and its shareholders.

(5) Dispositions.

(A) Application of section 1254 . In the case of any disposition of property to which section 1254 applies (determined without regard to this section), any deduction under paragraph (1) with respect to amounts which are allocable to such property shall, for purposes of section 1254 , be treated as a deduction allowable under section 263(c) , 616(a) , or 617(a) , whichever is appropriate.

(B) Application of section 617(d) . In the case of any disposition of mining property to which section 617(d) applies (determined without regard to this subsection), any deduction under paragraph (1) with respect to amounts which are allocable to such property shall, for purposes of section 617(d) , be treated as a deduction allowable under section 617(a) .

(6) Amounts to which election apply not treated as tax preference.

Any portion of any qualified expenditure to which an election under paragraph (1) applies shall not be treated as an item of tax preference under section 57(a) and section 56 shall not apply to such expenditure.

(f) Repealed.

(g) Tax benefit rule.

The Secretary may prescribe regulations under which differently treated items shall be properly adjusted where the tax treatment giving rise to such items will not result in the reduction of the taxpayer's regular tax for the taxable year for which the item is taken into account or for any other taxable year.

(h) Coordination with certain limitations.

The limitations of sections 704(d) , 465 , and 1366(d) (and such other provisions as may be specified in regulations) shall be applied for purposes of computing the alternative minimum taxable income of the taxpayer for the taxable year with the adjustments of sections 56 , 57 , and 58 .

(i) Special rule for amounts treated as tax preference.

For purposes of this subtitle (other than this part), any amount shall not fail to be treated as wholly exempt from tax imposed by this subtitle solely by reason of being included in alternative minimum taxable income.

(j) Treatment of unearned income of minor children.

(1) In general.

In the case of a child to whom section 1(g) applies, the exemption amount for purposes of section 55 shall not exceed the sum of-

(A) such child's earned income (as defined in section 911(d)(2)) for the taxable year, plus

(B) $5,000.

(2) Inflation adjustment.

In the case of any taxable year beginning in a calendar year after 1998, the dollar amount in paragraph (1)(B) shall be increased by an amount equal to the product of-

(A) such dollar amount, and

(B) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting "1997" for "2016" in subparagraph (A)(ii) thereof.

If any increase determined under the preceding sentence is not a multiple of $50, such increase shall be rounded to the nearest multiple of $50.

(k) Applicable corporation.

For purposes of this part-

(1) Applicable corporation defined.

(A) In general. The term "applicable corporation" means, with respect to any taxable year, any corporation (other than an S corporation, a regulated investment company, or a real estate investment trust) which meets the average annual adjusted financial statement income test of subparagraph (B) for one or more taxable years which-

(i) are prior to such taxable year, and

(ii) end after December 31, 2021.

(B) Average annual adjusted financial statement income test. For purposes of this subsection-

(i) a corporation meets the average annual adjusted financial statement income test for a taxable year if the average annual adjusted financial statement income of such corporation (determined without regard to section 56A(d)) for the 3-taxable-year period ending with such taxable year exceeds $1,000,000,000, and

(ii) in the case of a corporation described in paragraph (2) , such corporation meets the average annual adjusted financial statement income test for a taxable year if-

(I) the corporation meets the requirements of clause (i) for such taxable year (determined after the application of paragraph (2)), and

(II) the average annual adjusted financial statement income of such corporation (determined without regard to the application of paragraph (2) and without regard to section 56A(d)) for the 3-taxable-year-period ending with such taxable year is $100,000,000 or more.

(C) Exception. Notwithstanding subparagraph (A), the term "applicable corporation" shall not include any corporation which otherwise meets the requirements of subparagraph (A) if-

(i) such corporation-

(I) has a change in ownership, or

(II) has a specified number (to be determined by the Secretary and which shall, as appropriate, take into account the facts and circumstances of the taxpayer) of consecutive taxable years, including the most recent taxable year, in which the corporation does not meet the average annual adjusted financial statement income test of subparagraph (B) , and

(ii) the Secretary determines that it would not be appropriate to continue to treat such corporation as an applicable corporation.

The preceding sentence shall not apply to any corporation if, after the Secretary makes the determination described in clause (ii) , such corporation meets the average annual adjusted financial statement income test of subparagraph (B) for any taxable year beginning after the first taxable year for which such determination applies.

(D) Special rules for determining applicable corporation status. Solely for purposes of determining whether a corporation is an applicable corporation under this paragraph, all adjusted financial statement income of persons treated as a single employer with such corporation under subsection (a) or (b) of section 52 shall be treated as adjusted financial statement income of such corporation, and adjusted financial statement income of such corporation shall be determined without regard to paragraphs (2)(D)(i) and (11) of section 56A(c) .

(E) Other special rules.

(i) corporations in existence for less than 3 years. If the corporation was in existence for less than 3-taxable years, subparagraph (B) shall be applied on the basis of the period during which such corporation was in existence.

(ii) Short taxable years. Adjusted financial statement income for any taxable year of less than 12 months shall be annualized by multiplying the adjusted financial statement income for the short period by 12 and dividing the result by the number of months in the short period.

(iii) Treatment of predecessors. Any reference in this subparagraph to a corporation shall include a reference to any predecessor of such corporation.

(2) Special rule for foreign-parented multinational groups.

(A) In general. If a corporation is a member of a foreign-parented multinational group for any taxable year, then, solely for purposes of determining whether such corporation meets the average annual adjusted financial statement income test under paragraph (1)(B)(ii)(I) for such taxable year, the adjusted financial statement income of such corporation for such taxable year shall include the adjusted financial statement income of all members of such group. Solely for purposes of this subparagraph, adjusted financial statement income shall be determined without regard to paragraphs (2)(D)(i) , (3) , (4) , and (11) of section 56A(c) .

(B) Foreign-parented multinational group. For purposes of subparagraph (A) , the term "foreign-parented multinational group" means, with respect to any taxable year, two or more entities if-

(i) at least one entity is a domestic corporation and another entity is a foreign corporation,

(ii) such entities are included in the same applicable financial statement with respect to such year, and

(iii) either-

(I) the common parent of such entities is a foreign corporation, or

(II) if there is no common parent, the entities are treated as having a common parent which is a foreign corporation under subparagraph (D) .

(C) Foreign corporations engaged in a trade or business within the United States. For purposes of this paragraph, if a foreign corporation is engaged in a trade or business within the United States, such trade or business shall be treated as a separate domestic corporation that is wholly owned by the foreign corporation.

(D) Other rules. The Secretary shall, applying the principles of this section, prescribe rules for the application of this paragraph, including rules for the determination of-

(i) the entities (if any) which are to be to be treated under subparagraph (B)(iii)(II) as having a common parent which is a foreign corporation,

(ii) the entities to be included in a foreign-parented multinational group, and

(iii) the common parent of a foreign parented multinational group.

(3) Regulations or other guidance.

The Secretary shall provide regulations or other guidance for the purposes of carrying out this subsection, including regulations or other guidance-

(A) providing a simplified method for determining whether a corporation meets the requirements of paragraph (1) , and

(B) addressing the application of this subsection to a corporation that experiences a change in ownership.

(l) Corporate AMT foreign tax credit.

(1) In general.

For purposes of this part, if an applicable corporation chooses to have the benefits of subpart A of part III of subchapter N for any taxable year, the corporate AMT foreign tax credit for the taxable year of the applicable corporation is an amount equal to sum of-

(A) the lesser of-

(i) the aggregate of the applicable corporation's pro rata share (as determined under section 56A(c)(3)) of the amount of income, war profits, and excess profits taxes (within the meaning of section 901) imposed by any foreign country or possession of the United States which are-

(I) taken into account on the applicable financial statement of each controlled foreign corporation with respect to which the applicable corporation is a United States shareholder, and

(II) paid or accrued (for Federal income tax purposes) by each such controlled foreign corporation, or

(ii) the product of the amount of the adjustment under section 56A(c)(3) and the percentage specified in section 55(b)(2)(A)(i) , and

(B) in the case of an applicable corporation that is a domestic corporation, the amount of income, war profits, and excess profits taxes (within the meaning of section 901) imposed by any foreign country or possession of the United States to the extent such taxes are-

(i) taken into account on the applicable corporation's applicable financial statement, and

(ii) paid or accrued (for Federal income tax purposes) by the applicable corporation.

(2) Carryover of excess tax paid.

For any taxable year for which an applicable corporation chooses to have the benefits of subpart A of part III of subchapter N, the excess of the amount described in paragraph (1)(A)(i) over the amount described in paragraph (1)(A)(ii) shall increase the amount described in paragraph (1)(A)(i) in any of the first 5 succeeding taxable years to the extent not taken into account in a prior taxable year.

(3) Regulations or other guidance.

The Secretary shall provide for such regulations or other guidance as is necessary to carry out the purposes of this subsection.