
PA Public Utility	
Commission	
v.	
Columbia Gas of	
Pennsylvania, Inc.	
In-Person Evidentiary	
Hearing	

Pages 510 - 552	

Judge's Chambers
Keystone Building
400 North Street
Harrisburg, PA

INDEX TO EXHIBITS

Docket No. R-2025-3053499

Hearing Date: August 7, 2025

<u>NUMBER</u>	<u>FOR IDENTIFICATION</u>	<u>IN EVIDENCE</u>
OCA Statement 1	517	518

Direct Testimony of

Michael Deupree with

Appendix A, Exhibits MWD-1

through MWD-11 and

Verification		
OCA Statement 1-SR	517	518
Surrebuttal Testimony of		
Michael Deupree with		
Verification		
OCA Statement 2	531	532
Direct Testimony of		
Dante Mugrace, Public and		
Confidential Versions,		
with Appendix A, Exhibits		
DM-1 through DM-34 and		
Verification		
OCA Statement 2-SR	532	532
Surrebuttal Testimony of		
Dante Mugrace with		
Exhibits DM-SR-1 through		
DM-SR-34 and Verification		
OCA Statement 3	521	522
Direct Testimony of		

David J. Garrett with
Appendices A through E,
Exhibits DJG-1 through
DJG-24 and Verification

OCA Statement 3-SR	521	522

Surrebuttal Testimony of
David J. Garrett with
Verification

Columbia Hearing Exhibit 1	542	543

Response to I&E RE-11

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission :
: Docket No.: R-2025-3053499
v. :
:
Columbia Gas Of Pennsylvania, Inc. :

DIRECT TESTIMONY

**OF
Michael Deupree
On behalf of the
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE
OCA Statement 1**

Date Served: June 18, 2025

Table of Contents

I. INTRODUCTION 1

II. SUMMARY OF RECOMMENDATIONS 2

III. REGULATORY LAG 3

IV. REVENUE DECOUPLING AND THE PROPOSED RNA..... 17

A. The Company has not proven a need for the RNA..... 26

B. Proposed RNA provides no customer benefits..... 30

C. RNA shifts risks from Company shareholders to ratepayers. 40

D. RNA does not include any ratepayer protections. 45

V. WEATHER NORMALIZATION PROPOSAL..... 50

VI. ECONOMIC DEVELOPMENT DISTRIBUTION SERVICE RATE SCHEDULE 58

VII. CONCLUSIONS AND RECOMMENDATIONS 61

1 **I. INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?**

3 A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place
4 Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

5 **Q. PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF**
6 **EMPLOYMENT?**

7 A. I am a Senior Research Consultant with the Acadian Consulting Group (“ACG”), a
8 research and consulting firm that specializes in the analysis of regulatory, economic,
9 financial, accounting, statistical, and public policy issues associated with regulated and
10 energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is
11 located in Baton Rouge, Louisiana.

12 **Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS.**

13 A. I hold a Bachelor of Arts degree in Business Economics from Buena Vista
14 University in Storm Lake, Iowa, and a Master of Arts degree in Economics from the
15 University of Kansas in Lawrence, Kansas. I began my professional career with the Staff
16 of the Kansas Corporation Commission in 2008 while in graduate school conducting
17 analyses of topics related to energy and economy as a Research Assistant, eventually
18 being promoted to a Research Analyst and later Senior Research Economist after
19 graduation. I left the Kansas Corporation Commission to take a position with ACG in late
20 2011, where I have been promoted to positions of increasing responsibility since,
21 including my current position which I started earlier this year. Appendix A provides my
22 professional resume, which includes a listing of my publications, presentations, pre-filed
23 expert witness testimony, expert reports, and expert legislative testimony.

1 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2 A. I have been retained by the Pennsylvania Office of Consumer Advocate (“OCA”)
3 to address certain regulatory and policy issues related to the general rate case filed by
4 Columbia Gas of Pennsylvania (“Company”). I specifically have been asked to address
5 the Company’s proposed revenue decoupling mechanism, called the Revenue
6 Normalization Adjustment (“RNA”), the Company’s proposed change to its Weather
7 Normalization Adjustment (“WNA”), and the Company’s proposed Economic
8 Development Distribution Service (“EDDS”) and place each of those proposals within the
9 context of general regulatory and public policy principles.

10 **II. SUMMARY OF RECOMMENDATIONS**

11 **Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY’S**
12 **PROPOSED RNA?**

13 A. I recommend that the Commission reject the Company’s proposed Revenue
14 Normalization Adjustment. The proposal represents a full revenue decoupling
15 mechanism that would guarantee the Company recovery of its authorized base
16 distribution revenue regardless of actual sales, including usage declines due to weather,
17 conservation, energy efficiency, electrification, or economic factors. The Company has
18 not demonstrated that its current ratemaking tools such as the Fully Projected Future Test
19 Years (“FPFTY”) and frequent base rate filings are insufficient to manage revenue
20 variability. The RNA provides no ratepayer benefits, includes no consumer protections,
21 and would shift nearly all usage-related business risk from shareholders to ratepayers.
22 The proposal is one-sided, lacks any tie to energy efficiency outcomes, and could lead to

1 frequent surcharges with no corresponding benefits to customers. For these reasons, the
2 RNA should be rejected.

3 **Q. WHAT IS YOUR POSITION ON THE COMPANY'S WNA RATEMAKING**
4 **MECHANISM?**

5 A. I recommend that the Commission affirmatively discontinue the current WNA
6 mechanism. Despite operating the WNA on a pilot basis for over a decade, the Company
7 has not identified clear criteria for evaluating its performance or demonstrated that the
8 mechanism has produced balanced outcomes for ratepayers. Additionally, if the
9 Commission were to approve the Company's proposed RNA, continuing the WNA would
10 introduce overlapping and duplicative recovery of weather-related revenue shortfalls.

11 **Q. WHAT IS YOUR POSITION ON THE COMPANY'S PROPOSED EEDS TARIFF?**

12 A. I recommend that the Commission reject the Company's proposal to establish the
13 EEDS tariff. The proposed tariff is ill-defined, establishing a service the Company itself
14 admits its customers have not sought. If the Commission does decide to approve the
15 proposed EEDS tariff, I recommend that the Commission review the tariff performance in
16 future rate cases to ensure that non-EEDS jurisdictional customers are not subsidizing
17 EEDS service.

18 **III. REGULATORY LAG**

19 **Q. PLEASE DISCUSS THE COMPANY'S REGULATORY LAG CONCERNS.**

20 A. The Company claims that regulatory lag impairs its ability to recover costs and
21 maintain earnings stability as it undertakes extensive infrastructure investment.¹ The

¹ See, Direct Testimony of Mark Kempic, Company Statement No. 1 at 5:16-6:2 and 14:4-7.

1 Company's filing includes a proposed Revenue Normalization Adjustment ("RNA") to
2 mitigate variations in usage-driven revenues² and a request to make its Weather
3 Normalization Adjustment ("WNA") permanent.³ It argues that these proposals, along
4 with continued use of the Fully Projected Future Test Year ("FPFTY"), are needed to
5 improve revenue predictability and support system modernization.⁴

6 **Q. DOES THE COMPANY ALREADY HAVE MECHANISMS IN PLACE THAT**
7 **REDUCE REGULATORY LAG?**

8 A. Yes. The Company regularly utilizes Fully Projected Future Test Years ("FPFTY")
9 to better align revenues with projected costs and has filed five base rate cases since 2020
10 (Docket Nos. R-2020-3018835, R-2021-3024296, R-2022-3031211, R-2024-3046519,
11 and R-2025-3053499).⁵ The Company also has an approved Distribution System
12 Improvement Charge ("DSIC"), which allows for interim recovery of qualifying capital
13 investments between rate cases.⁶ These tools provide the Company with multiple
14 avenues to manage regulatory lag and ensure timely cost recovery. The proposed RNA
15 and continuation of the WNA would further enhance this framework.

² See, Direct Testimony of John Taylor, Company Statement No. 17 at 43:7-16.

³ See, Direct Testimony of John Taylor, Company Statement No. 17 at 28:2-3.

⁴ See, Direct Testimony of Mark Kempic, Company Statement No. 1 at 5:4-10.

⁵ See, Direct Testimony of Mark Kempic, Company Statement No.1 at 5:20-5:2.

⁶ See, Direct Testimony of Mark Kempic, Company Statement No.1 at 6:11-17.

**Q. ARE THESE THE ONLY MECHANISMS THE COMPANY HAS IN PLACE TO
REDUCE REGULATORY LAG?**

A. No. The Company already recovers a significant portion of its fixed costs through monthly customer charges, and in this proceeding, it proposes to increase those charges even further⁷ as part of a misguided continual transition toward Straight Fixed Variable (“SFV”) rate design.⁸

Q. PLEASE EXPLAIN SFV RATES.

A. SFV rate design attempts to separate all fixed and variable costs to provide service to each class of utility customer. SFV rates assigns all rate responsibility for fixed costs on fixed charges such as monthly customer and peak demand charges, while rate responsibility for all variable costs are assigned to variable volumetric charges.⁹ Since nearly all non-fuel costs associated with a local distribution company (“LDC”) are fixed in nature, SFV rate design has the effect of shifting nearly all LDC base rates to fixed charges. This would significantly reduce the Company’s risks from revenue fluctuations over time, as the Company recognizes,¹⁰ but results in exceptionally high monthly customer charges that are detrimental to ratepayers as explained in the Direct Testimony of OCA Witnesses Jerry Mierzwa and Roger Colton.

⁷ See, Direct Testimony of John Taylor, Company Statement No. 17 at 9:13-10:2.

⁸ See, Direct Testimony of John Taylor, Company Statement No. 17 at 42:9-11.

⁹ Lazar, Jim, “The Specter of Straight Fixed/Variable Rate Designs and the Exercise of Monopoly Power,” Smart Rate Design for a Smart Future, Appendix D.

¹⁰ See, Direct Testimony of John Taylor, Company Statement No. 17 at 29:3-7.

1 **Q. DO CHANGES IN CUSTOMER USAGE NECESSARILY REFLECT**
2 **REGULATORY LAG?**

3 A. No. Declines in usage can result from a range of factors, including efficiency
4 measures, economic conditions, or customer behavior. These changes are not inherently
5 problematic and do not, by themselves, create regulatory lag. Moreover, if usage declines
6 are accompanied by stable or declining costs, there may be no mismatch that requires
7 correction.

8 **Q. DO YOU AGREE WITH THE COMPANY THAT REGULATORY LAG HAS LED**
9 **TO THE SIGNIFICANT UNDER-RECOVERY OF REVENUES IN RECENT YEARS?**

10 A. No. While the Company has cited under-collections of \$20.2 million in 2023 and
11 \$22.6 million in 2024,¹¹ those figures should be viewed in context. First, some degree of
12 revenue variation between rate cases is inherent in traditional ratemaking and does not
13 automatically indicate that the system is broken or unjust. Second, the Company has
14 successfully used FPFTY and rate filings at regular intervals to mitigate revenue
15 erosion.¹² Third, the Commission has authorized the Company to utilize a Distribution
16 System Improvement Charge ("DSIC") to further reduce the effects of regulatory lag
17 between rate cases.¹³ These existing tools already provide significant flexibility for the
18 Company to address financial needs in a timely manner.

¹¹ See, Direct Testimony of John Taylor, Company Statement No. 17 at 38, Table 6.

¹² See, Direct Testimony of Mark Kempic, Company Statement No.1 at 5:20-5:2.

¹³ See, Direct Testimony of Mark Kempic, Company Statement No.1 at 6:11-17.

1 **Q. PLEASE DEFINE REGULATORY LAG.**

2 A. Regulatory lag can be defined in a number of different ways. One definition holds
3 that regulatory lag is the time period between when a utility's rates go into effect, after the
4 course of an evidentiary hearing process and its next rate case.¹⁴ Another definition holds
5 that regulatory lag can be represented as the period between when a utility investment is
6 undertaken and the time it enters into rates.¹⁵ Yet another definition holds that regulatory
7 lag is the time period in which a utility's achieved rate of return differs from that allowed
8 by regulators.¹⁶ At the heart of all these definitions is one theme: the frequency and
9 timing of rate cases can impact, positively or negatively, utility earnings.

10 **Q. IN UTILITY RATE REGULATION, WHICH PARTY CONTROLS REGULATORY**
11 **LAG OR THE DURATION OF TIME BETWEEN RATE CASES?**

12 A. Typically, utilities control the duration between rate cases. In most states, utilities
13 have the statutory ability to request rate increases if they believe that their rates are not
14 affording them the opportunity to earn a fair return on and of their investments and
15 prudently incurred costs. While state utility commissions and other stakeholders can, in
16 theory, request a utility be "brought in" for a rate case, my experience is, and research
17 indicates, that this event rarely happens. For instance, research on the topic of regulatory
18 lag conducted in the early 1980s by Ronald Braeutigam and James Quirk, surveyed state
19 utility rate cases during the period 1948 to 1978 and found that over 350 of the 363

¹⁴ Scott E. Atkinson and Clifford Nowell. (1994). "Explaining Regulatory Commission Behavior in the Electric Utility Industry." *Southern Economic Journal*. Vol. 60, No. 3: 634-643.

¹⁵ Elizabeth E. Bailey and Roger D. Coleman.(1971). "The Effect of Lagged Regulation in an Averch-Johnson Model." *Bell Journal of Economics and Management Sciences*. 2 (Spring): 278-292.

¹⁶ A.K. Klevorick. (1973). "The Behavior of a Firm Subject to Stochastic Regulatory Review," *Bell Journal of Economics and Management Science* 4 (Spring): 82.

1 surveyed rate cases (96 percent) were brought by a regulated utility, with the smaller
 2 number attributable to regulators or consumer groups. While this is an older, dated study,
 3 the results are likely to ring true even over the past two decades.

4 **Q. DOES A UTILITY'S ABILITY TO DETERMINE THE TIMING OF A RATE CASE**
 5 **SHIFT A CERTAIN DEGREE OF REGULATORY RISK ONTO RATEPAYERS?**

6 A. Yes. When the timing of a rate case is left in the hands of the utility, it has the
 7 ability to effectively shift the risk of regulation and regulatory lag away from itself and onto
 8 ratepayers. The option to request higher rates by utilities, in effect, creates a price floor
 9 that buttresses a utility's value.¹⁷ This price floor allows shareholders to retain benefits
 10 created by regulatory lag (*i.e.*, earning an actual rate of return that is higher than the
 11 authorized rate of return or over-earning), as well as the option to defend against
 12 challenges to those benefits through the timing of a rate case. Paul Joskow, writing as
 13 early as 1973, concluded in a frequently referenced regulatory article, that utility
 14 commissions tend to defend against rate increases, but are less aggressive in pursuing
 15 rate decreases when rates are stable or decreasing in real terms.¹⁸ This outcome has
 16 often been thought to have occurred in the post-war period until about the late 1960s, and
 17 arguably throughout the 1990s.

18 **Q. IS REGULATORY LAG UNFAIR OR CONFISCATORY TO UTILITIES?**

19 A. No. The premise that regulatory lag is somehow unfair is simply antithetical to
 20 most of the research in utility regulation over the past 50 years. Regulatory lag has long

¹⁷ Graeme Guthrie. (2006) "Regulating Infrastructure: The Impact on Risk and Investment." *Journal of Economic Literature*. 44 (December):925-972.

¹⁸ Paul L. Joskow. (1973) "Pricing Decisions of Regulated Firms: A Behavioral Approach." *The Bell Journal of Economics and Management Science*. 4 (Spring):118-140.

1 been recognized as a key component of the overall regulatory compact given the
2 discipline it can impose on utility operational and investment decisions. Regulation acts
3 as a substitute for the disciplines of competition.¹⁹ Regulatory lag prevents utility
4 regulation from devolving into a “cost-plus” approach that simply passes through costs on
5 a dollar-for-dollar basis to ratepayers and can lead to cost and investment inefficiencies.
6 The cost-plus regulatory approach also shifts a considerable amount of performance-
7 related risk away from utilities and onto ratepayers and leads to inefficient outcomes,
8 which was recognized as early as the 1960s and has come to be known as the “Averch-
9 Johnson” or “A-J” effect.

10 **Q. HOW ARE THE CONCLUSIONS REGARDING REGULATORY LAG RELATED**
11 **TO WHAT IS COMMONLY REFERRED TO AS THE “A-J EFFECT”?**

12 A. In the early 1960s, a seminal article was published that dramatically influenced the
13 theory and practice of utility regulation and economic thinking regarding the optimal
14 regulation of natural monopolies. This article, authored by Professors Harvey Averch and
15 Leland Johnson, and published in the *American Economic Review* in 1962, posited that
16 rate of return regulation creates an incentive for regulated utilities to overcapitalize,
17 resulting in an inefficient utilization of resources and higher-than-optimal rates.²⁰ This
18 finding; however, was premised upon a model with a number of assumptions, one of
19 which presumed there was no regulatory lag and that rates were set on a period-to-period
20 basis: in other words, rates were set on a “cost-plus” regulatory approach.

¹⁹ Charles F. Phillips, *The Regulation of Public Utilities: Theory and Practice*, (Arlington, VA: Public Utilities Reports, Inc., 1984), p. 154.

²⁰ H. Averch and L. Johnson. (1962) “Behavior of the Firm under Regulatory Constraint,” *American Economic Review*. 52:1052-1069.

Q. HOW IS REGULATORY LAG RELATED TO THIS RESEARCH?

A. Soon after its publication, Averch's and Johnson's article was met with a flurry of scholarly research attempting to empirically verify the A-J effect, as well as examining the conditions under which the effect would, and would not, be sustained.²¹ Rejoinders to the research noted that two characteristics of the regulatory process tended to temper the likelihood and prevalence of the A-J effect: (1) the possibility of disallowances through the prudence review process²² and (2) the positive efficiency incentives created by regulatory lag.²³ In fact, a series of articles published soon afterwards noted that regulatory lag typically creates incentives for utilities to seek efficiency opportunities between rate cases since the gains (profits) from those investments inure to shareholders instead of ratepayers.²⁴

²¹ These works are surveyed in Graeme Guthrie. (2006). "Regulating Infrastructure: The Impact on Risk and Investment." *Journal of Economic Literature*. 44 (December):925-972.

²² A.K. Klevorick. (1973). "The Behavior of a Firm Subject to Stochastic Regulatory Review," *Bell Journal of Economics and Management Science*. 4 (Spring): 82. P. Joskow. (1974). "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Regulation." *Journal of Law and Economics*, Vol. 17: 291-327. R.J. Gilbert and D.M. Newbery.(1988). *Regulation Games*. Working Paper 8879, University of California Berkeley, June 16.T.P. Lyons. (1991.) "Regulation with 20-20 Hindsight: 'Heads I Win, Tails You Lose'?" *Rand Journal of Economics*. Vol. 22 (Winter): 581-595.

²³ Elizabeth E. Bailey and Roger D. Coleman.(1971). "The Effect of Lagged Regulation in an Averch-Johnson Model." *Bell Journal of Economics and Management Sciences*. 2 (Spring): 278-292.

²⁴ W.K. Viscusi, J.M. Vernon, J.R. Harrington, Jr. (1997) *Economics of Regulation and Antitrust*, Second Edition. Cambridge: MA: MIT Press, 380. See also the works surveyed in Graeme Guthrie. (2006). "Regulating Infrastructure: The Impact on Risk and Investment." *Journal of Economic Literature*. 44 (December):925-972.

Q. HOW DID THE FINDINGS IDENTIFYING THE BENEFITS OF REGULATORY LAG ARISE?

A. One of the earliest works on the impact of regulatory lag was published in 1971 by William Baumol and Alvin Klevorick.²⁵ Their work was the first of what was to become a series of articles showing that regulatory lag actually diminished incentives for overcapitalization, since the earnings gained by avoiding these inefficient actions passed directly to shareholders. Soon after, Klevorick, writing separately from Baumol, built upon this model by explaining how multi-year regulatory lags, coupled with demand and cost uncertainty, created strong incentives for efficiency to maintain profitability.²⁶ One of his additional findings at the time, however, was that these incentives might also discourage regulated firms from investing in research and development.

Q. HOW IS THIS DISCUSSION RELEVANT TO THE COMPANY'S CURRENT FILING?

A. The Company's filing attempts to portray regulatory lag as a structural impairment to cost recovery and earnings stability, particularly in the context of its infrastructure investments. However, as discussed above, regulatory lag can and does serve a beneficial regulatory function. The Company's ability to file rate cases at will, utilize FPFTYs, and recover infrastructure costs through the DSIC already provide mechanisms

²⁵ William J. Baumol and Alvin K. Klevorick. (1970). "Input Choices and Rate-of-Return Regulation: An Overview of the Discussion." *The Bell Journal of Economics and Management Science*. 1 (Autumn):162-190.

²⁶ A.K. Klevorick. (1973). "The Behavior of a Firm Subject to Stochastic Regulatory Review," *Bell Journal of Economics and Management Science*. 4 (Spring): 82.

1 to reduce lag. As such, the Company's portrayal of lag as a barrier to fair return is
2 inconsistent with both its regulatory tools and academic literature.

3 **Q. HAS THE COMPANY DEMONSTRATED THAT REGULATORY LAG IS**
4 **UNMANAGEABLE UNDER CURRENT RATEMAKING PRACTICES?**

5 A. No. The Company has repeatedly made use of Pennsylvania's ratemaking tools
6 to address regulatory lag.²⁷ The Company has filed five base rate cases in the past five
7 years, employed FPFTYs, and utilized the DSIC to recover capital costs between rate
8 cases. Moreover, the Company exceeded the level of capital investments that it had
9 forecasted in its last rate case by \$13 million.²⁸ These facts show that the Company is
10 not constrained by regulatory lag and is already leveraging available mechanisms to
11 maintain revenue adequacy.

12 **Q. HAS THE COMPANY'S PARENT, NISOURCE, DEMONSTRATED THAT**
13 **REGULATORY LAG IS UNMANAGEABLE?**

14 A. No. In fact, the parent company of Columbia, NiSource Inc., presents a very
15 different picture to investors. In its quarter 1, 2025 earnings calls, NiSource has
16 emphasized the constructive nature of its regulatory jurisdictions and noted that at least
17 three-quarters of its planned capital investments over the next four years are expected to
18 begin recovery within twelve months.²⁹ NiSource's financial strategy explicitly relies on
19 minimizing regulatory lag through efficient capital deployment and the strategic
20 sequencing of rate cases. The Company's ability to achieve sustained earnings growth

²⁷ See, Direct Testimony of Mark Kempic, Company Statement No.1 at 14:4-7.

²⁸ See, Direct Testimony of Mark Kempic, Company Statement No.1 at 6:9-11.

²⁹ "Supplemental Slides 1Q 2025 Results" (May 7, 2025), Q1 2025 NiSource Earnings Conference Call.

1 and raise dividends annually demonstrates that regulatory lag is being successfully
2 managed within the existing regulatory framework.

3 **Q. DOES REGULATORY LAG, WHILE ENCOURAGING EFFICIENCY,**
4 **DISCOURAGE INNOVATION?**

5 A. No. Interestingly, this notion is a myth that arises in the practice of public utility
6 regulation but is debunked by several academic articles. Elizabeth Bailey, who also
7 served as an economic researcher at Bell Laboratories, addressed this issue originally
8 raised by Klevorick during this active period of regulatory scholarship in the 1960s and
9 1970s. Bailey found that regulatory lag helped to facilitate, not reduce, the incentives for
10 cost-reducing innovations.³⁰ Bailey's work built upon earlier work that she did with Roger
11 Coleman in 1971 that further supported the conclusions of Baumol and Klevorick, that
12 regulatory lag induces profit-maximizing firms to adopt minimum-cost production
13 alternatives.³¹

14 **Q. ARE THERE ANY PARALLELS AMONG REGULATORY LAG, INNOVATION,**
15 **RELIABILITY, AND SAFETY?**

16 A. Yes, and these are important to recognize since the perceived concern of
17 regulatory lag in the presence of increased capital investments required to meet
18 increased safety, reliability, and security demands is a key element backing the
19 Company's proposal.³² However, it should be recognized that the key benefits of

³⁰Elizabeth E. Bailey. (1974). "Innovation and Regulation." *Journal of Public Economics*. 3: 285-295.

³¹Elizabeth E. Bailey and Roger D. Coleman.(1971). "The Effect of Lagged Regulation in an Averch-Johnson Model." *Bell Journal of Economics and Management Sciences*. 2 (Spring): 278-292.

³² See, Direct Testimony of Mark Kempic, Company Statement No. 1 at 5:16-18.

1 regulatory lag are the weakening of the natural incentive for a utility to over-capitalize and
2 the strengthening of the natural incentive for a utility to minimize production costs in order
3 to increase shareholder profits. Several of the Company's proposed cost recovery riders,
4 and other regulatory lag mitigation proposals, that will be discussed in the following
5 section of my testimony, diverge considerably from the principles of traditional regulation,
6 and could lead to over-capitalization biases identified by Averch and Johnson over 60
7 years ago and not induce cost-reducing innovations as identified by Bailey.

8 **Q. PLEASE EXPLAIN THE TERM "REGULATORY COMPACT".**

9 A. The regulatory compact, as it is generally referred to in a regulatory policy context,
10 allows utilities the opportunity to earn a fair rate of return of and on their investments as
11 well as their prudently incurred costs. In return, utilities are expected to provide safe,
12 adequate, efficient, and reasonable service and facilities.

13 **Q. HAVE ANY STUDIES LOOKED AT THE IMPACT OF REGULATORY LAG**
14 **FROM A BROAD INDUSTRY-WIDE PERSPECTIVE DURING THESE PAST**
15 **PERIODS?**

16 A. Yes, there have been a few studies that have examined regulatory lag during the
17 inflationary period of the 1970s. The conclusions are mixed. Seth Norton, for instance,
18 conducted empirical research examining 45 utilities over a period from 1945 to 1974. The
19 period spans both the high growth, high productivity, low-cost periods for the industry prior
20 to 1970 and the inflationary low growth periods throughout the 1970s. According to

1 Norton, there were no significant financial impediments or opportunities created by
2 regulatory lag in any of these periods.³³

3 **Q. WILL THE COMPANY'S PROPOSALS SHIFT ANY RISKS AWAY FROM**
4 **ITSELF AND ONTO RATEPAYERS?**

5 A. Yes. The Company's proposals are designed to insulate the Company from
6 fluctuations in usage and weather-related variability. By guaranteeing recovery of
7 authorized revenues regardless of actual customer consumption, these mechanisms
8 significantly reduce the Company's exposure to traditional business risks. As a result,
9 the risk of revenue underperformance due to declining sales, conservation, economic
10 conditions, or unseasonably warm weather is shifted entirely onto ratepayers.
11 Importantly, the Company has not proposed any corresponding ratepayer protections
12 such as earnings tests, revenue caps, or performance incentives. This asymmetric risk
13 allocation leaves ratepayers exposed to upward rate adjustments without any assurance
14 of offsetting benefits or improved utility performance.

15 **Q. PLEASE EXPLAIN HOW REGULATORY RISK IS SHIFTED TO RATEPAYERS.**

16 A. As I discussed above, utilities typically control the timing of rate case filings.
17 Accordingly, utilities enjoy the ability to request higher rates, as well as the protection
18 afforded by a price floor that allows shareholders to retain benefits (*i.e.*, over-earning)
19 created by regulatory lag. Thus, in times of over-earning, risk is shifted to ratepayers
20 because utilities are not likely to elect to file a rate case. In times where a utility is under-
21 earning, risk also is shifted to ratepayers because the utility can file for a rate increase.

³³Seth W. Norton. (1987). "In Search of Regulatory Lag." *Quarterly Journal of Business and Economics*. Vol. 26 No. 4 (Autumn):3-16.

Q. DOES THE PRESENCE OF REGULATORY LAG CREATE ANY POLICY SUPPORT FOR THE COMPANY'S PROPOSALS?

A. No. The presence of regulatory lag in and of itself does not create policy justification for the Company's proposals. Regulatory lag can lead to both costs and benefits for a regulated utility. The Company's proposals are incorrectly premised upon a presumption that regulatory lag is bad and always will be bad. Regulatory lag creates opportunities for utilities to achieve gains as well as losses. The simple fact that regulatory lag creates "opportunities" and not guarantees, is one of the reasons why regulatory lag is considered efficiency enhancing. There is a long and rich history in the practice and theory of utility regulation supporting these efficiency-enhancing conclusions. Thus, there is no inherent nor *a priori* policy rationale supporting the Company's proposals. If anything, past thought and practice in utility regulation supports rejection of proposals of this nature on a policy basis.

Q. WHAT IS YOUR OVERALL RECOMMENDATION REGARDING REGULATORY LAG?

A. The Company has not demonstrated that the existing regulatory framework in Pennsylvania is failing to support timely and adequate cost recovery. Rather, the evidence, including statements made by its parent company, suggests that regulatory lag is already being effectively managed. The Commission should reaffirm the value of regulatory lag as a structural feature of traditional ratemaking and recognize that further erosion of this principle is neither necessary nor justified in this case.

**Q. HAS THE COMMISSION ADOPTED A STATEMENT OF POLICY REGARDING
ALTERNATIVE RATEMAKING MECHANISMS LIKE THE RNA AND WNA?**

A. Yes. In 52 Pa. Code § 69.3302(a) the Commission established 14 separate distribution rate considerations in determining just and reasonable alternative ratemaking distribution mechanisms and rate design. Exhibit MWD-1 presents these 14 considerations, along with the relevant effect of the RNA and WNA on each consideration.

IV. REVENUE DECOUPLING AND THE PROPOSED RNA

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED RNA MECHANISM.

A. The Company is proposing a Revenue Normalization Adjustment ("RNA") mechanism that functions as a revenue decoupling tool. Under the Company's proposal, the RNA would compare actual base rate revenue per customer to the benchmark revenue per customer established in this proceeding.³⁴ Any differences would be tracked monthly, adjusted for actual customer counts, and reconciled annually through a charge or credit to customers.³⁵ Unlike the existing Weather Normalization Adjustment ("WNA"), which only addresses usage variations attributable to deviations from normal weather,³⁶ the proposed RNA would allow the Company to recover revenue shortfalls regardless of cause. This includes revenue losses due to non-weather factors such as increased energy efficiency, economic conditions, federal appliance standards, or customer conservation efforts.

³⁴ See, Direct Testimony of John Taylor, Company Statement No. 17 at 43:7-10.

³⁵ See, Direct Testimony of John Taylor, Company Statement No. 17 at 44:10-16.

³⁶ See, Direct Testimony of John Taylor, Company Statement No. 17 at 46:1-2.

1 **Q. HOW WOULD THE COMPANY’S PROPOSED RNA BE CALCULATED?**

2 A. The Company proposes to calculate the RNA by comparing actual per customer
 3 base revenue to a benchmark revenue per customer (“BRPC”) established in this rate
 4 case.³⁷ The BRPC is determined by dividing the fully projected future test year (“FPFTY”)
 5 revenue requirement approved by the Commission for each eligible rate class by the
 6 projected number of customer bills over a twelve-month period.³⁸ At the end of each
 7 calendar year, the Company would calculate the actual revenue per customer (“ARPC”),
 8 inclusive of any WNA adjustments for the residential class.³⁹ If the ARPC falls short of
 9 the BRPC, the difference would be recovered from customers through a surcharge.⁴⁰ If
 10 the ARPC exceeds the BRPC, the excess would be refunded through a credit.⁴¹ These
 11 adjustments would be applied over a 12-month period beginning the following April and
 12 would roll forward any unresolved balance from prior periods.⁴² The Company is
 13 proposing to apply the RNA to non-CAP residential and C&I customers.⁴³

14 **Q. HAVE REVENUE DECOUPLING MECHANISMS BEEN PART OF THE**
 15 **RATEMAKING LANDSCAPE FOR SOME TIME?**

16 A. Yes. The advent of revenue decoupling mechanisms began in earnest in the late
 17 1980s and was boosted by inclusion as a regulatory review requirement in the Energy

³⁷ See, Direct Testimony of John Taylor, Company Statement No. 17 at 43:7-10.

³⁸ See, Direct Testimony of John Taylor, Company Statement No. 17 at 43:18-20.

³⁹ See, Direct Testimony of John Taylor, Company Statement No. 17 at 44:10-13.

⁴⁰ See, Direct Testimony of John Taylor, Company Statement No. 17 at 44:15-16.

⁴¹ See, Direct Testimony of John Taylor, Company Statement No. 17 at 44:13-15.

⁴² See, Direct Testimony of John Taylor, Company Statement No. 17 at 44:16-19.

⁴³ See, Direct Testimony of John Taylor, Company Statement No. 17 at 43:3-4.

1 Policy Act of 1992.⁴⁴ During this period, revenue decoupling initiatives were driven
2 primarily by the electric utility industry, as well as many of the same energy efficiency and
3 environmental advocates promoting the mechanism today. Most revenue decoupling
4 mechanisms adopted during this period were eliminated during the electric restructuring
5 process that began in the early 1990s and accelerated through the better part of the
6 decade.

7 **Q. CAN REVENUE AND COST TRACKER MECHANISMS LEAD TO ANY**
8 **REGULATORY PROBLEMS OR DISINCENTIVES?**

9 A. Yes. Trackers of all types eliminate the positive incentives typically afforded
10 through regulatory lag. It is a basic economic fact that rational utility management has
11 little incentive to enhance efficiency (operational and capital) if it has no effect on the
12 utility's profits.⁴⁵ This is precisely the situation that can arise when a utility is guaranteed
13 revenues and can pass higher costs through to ratepayers with minimal consequences
14 on sales and profits. Such an approach is completely at odds with traditional regulatory
15 principles and ratemaking practices.

16 **Q. HOW DOES THE PROPOSED RNA APPLY TO THIS VIEW OF TRACKER**
17 **MECHANISMS?**

18 A. The Company's RNA proposal is imbalanced and one-sided. Under the proposal,
19 the Company will receive all the benefits while ratepayers bear all the risk. Specifically,
20 the proposal guarantees revenue recovery rather than providing an opportunity to earn

⁴⁴ Energy Policy Act of 1992 § 115(b)(4), Pub. L. No. 102-486.

⁴⁵ See Alfred Kahn, *The Economics of Regulation: Principles and Institutions*, p. 48 (1988) Cambridge, MA: MIT Press: Vol. 2 (Institutional Issues).

those revenues as a reward for quality service and cost efficiencies. The more revenues are guaranteed, the more rates are in conflict with maintaining affordability.

Q. HOW DO TRACKERS UNDO EFFICIENCY-CREATING INCENTIVES?

A. Trackers reduce resource efficiency incentives in two ways. First, if trackers do in fact reduce the tendency for rate cases, as many of its proponents suggest, then the mechanism will reduce the potential use of disallowances in tempering bad expenditure and investment decisions. Second, if utilities are given the ability to change, and generally increase their rates, then the discipline typically imposed by the regulatory process until a utility's next base rate case (i.e., regulatory lag) is removed. The theory and practice of public utility regulation is based upon the well-recognized observation that regulatory lag gives utilities an incentive to reduce costs between rate cases and become more efficient since the benefits of those efficiencies will typically inure to shareholders.⁴⁶

Q. ARE REVENUE DECOUPLING MECHANISMS OFTEN PROPOSED BY UTILITIES TO REDUCE THROUGHPUT INCENTIVE?

A. Yes. Utilities frequently justify revenue decoupling proposals by pointing to the throughput incentive, which refers to the fact that under traditional ratemaking, utility revenues increase with sales volumes, creating a financial disincentive to promote energy efficiency or conservation. Decoupling mechanisms are designed to sever the link between revenues and sales, thereby removing any perceived conflict between utility earnings and reduced customer usage. However, mechanisms like the Company's proposed RNA often go well beyond addressing the throughput incentive by guaranteeing

⁴⁶ *Id.*

revenue recovery for all usage declines, regardless of cause, without requiring meaningful utility commitments to expand efficiency programs or deliver customer benefits.

Q. WHAT IS THE THROUGHPUT INCENTIVE?

A. Proponents of revenue decoupling argue that utility revenues are proportional to utility sales of supply (of electricity, natural gas, or water), while many utility costs do not vary with utility sales given the capital-intensive nature of utility operations. It is therefore believed by these proponents that utilities have an incentive to seek increased sales even in the face of public policy initiatives to encourage more efficient use of natural resources through consumer efficiency, presenting a significant barrier to effective utility efficiency programs.⁴⁷

Q. HAVE YOU PREPARED AN EXHIBIT THAT DEPICTS THE CURRENT STATUS OF REVENUE DECOUPLING ADOPTION ACROSS THE COUNTRY?

A. Yes. Exhibit MWD-2 presents a map indicating which states have electric and natural gas utility revenue decoupling. This map can distort the popularity of revenue decoupling mechanisms, since it depicts information on a statewide, versus utility-specific, basis. On a utility-specific basis, only 23 electric utilities, out of the nation's 158 investor-owned electric utilities⁴⁸ have an active revenue decoupling mechanism (15 percent of total electric utilities), and only 41 natural gas utilities nationwide, out of 147 investor-owned gas utilities⁴⁹ have similar mechanisms (28 percent of total gas utilities). This data reveals that: (a) despite a history of revenue decoupling that exceeds 30 years,

⁴⁷ See, "Utility Rate Decoupling," Alliance to Save Energy, October 24, 2013.

⁴⁸ "Adjustment Clauses – A State-by-State Overview," S&P Global, July 18, 2022.

⁴⁹ *Id.*

1 the number of electric and gas utilities with revenue decoupling riders is still in the
2 minority; and (b) the mere fact that a revenue decoupling mechanism has been approved
3 in a particular jurisdiction does not mean that it is appropriate for all electric and gas
4 utilities in that jurisdiction or other jurisdictions.

5 **Q. ARE THERE OTHER DETAILS ASSOCIATED WITH APPROVAL OF**
6 **DECOUPLING MECHANISMS THAT IS NOTEWORTHY?**

7 A. Yes. As shown by Exhibit MWD-3, a substantial portion of historic decoupling
8 mechanisms were approved in the late 2000s and very early 2010s. This period was
9 characterized by highly volatile and often elevated wholesale natural gas prices in which
10 the future outlook for natural gas supply was uncertain. In fact, at one time, the U.S.
11 anticipated being a net importer of natural gas supplies and several large-scale facilities
12 along the Gulf Coast and Atlantic seaboard were announced to support these large
13 imports. Energy policies during this time period were strongly oriented towards
14 encouraging greater levels of fuel switching and energy efficiency. Revenue decoupling
15 was seen as a tool to not only facilitate this transition, but to financially insulate natural
16 gas utilities from the effects of volatile natural gas markets. This circumstance simply no
17 longer exists: almost every year, the U.S. reports record levels of natural gas production,
18 relatively low natural gas prices, and relatively low natural gas price volatility.

19 **Q. ARE YOU AWARE OF ANY INSTANCES WHERE A REVENUE DECOUPLING**
20 **PILOT HAS BEEN SO DISAPPOINTING THAT REGULATORS HAVE TAKEN STEPS**
21 **TO TERMINATE IT EARLY?**

22 A. Yes. As will be discussed below, the Maine Public Utilities Commission took the
23 dramatic step of opening hearings to consider the suspension of Central Maine Power's

1 (“CMP”) decoupling mechanism during its trial period,⁵⁰ and ultimately opted to terminate
 2 the decoupling mechanism at a later date, following a period of extremely poor outcomes
 3 for ratepayers.⁵¹

4 **Q. HAS THE NEGATIVE INTERACTION OF DECOUPLING WITH ECONOMIC**
 5 **DISRUPTIONS CAUSED OTHER REGULATORS TO PAUSE THE IMPLEMENTATION**
 6 **OF PROPOSED DECOUPLING MECHANISMS?**

7 A. Yes. The Montana Public Service Commission (“MPSC”) authorized the fixed cost
 8 recovery mechanism (“FCRM”) for NorthWestern Energy on a four-year pilot basis in
 9 2019.⁵² In 2020, the COVID-19 pandemic caused massive economic disruptions and
 10 disruptions in working conditions as more workers began to work from home. The MPSC
 11 twice approved requests to delay implementation of the pilot due to the pandemic; as
 12 such, the pilot was never implemented⁵³ before the MPSC ultimately discontinued it.⁵⁴

⁵⁰ Leslie Hudson and Stephanie Seguino, *Assessing Maine’s ERAM experiment*, 3 MAINE POLICY REV. at 82 (1994).

⁵¹ *Id.* at 83.

⁵² See In the Matter of NorthWestern Energy’s Application for Authority to Increase Retail Electric Utility Service Rates and for Approval of Electric Service Schedules and Rules and Allocated Cost of Service and Rate Design, Montana Public Service Commission, Docket No. D2018.02.012, Order No. 7604u, dated Dec. 20, 2019, p. 35, para. 105.

⁵³ In the Matter of NorthWestern Energy’s Application for Authority to Increase Retail Electric and Natural Gas Utility Rates and For Approval of Electric and Natural Gas Service Schedules and Rules and Allocated Cost of Service and Rate Design, Montana Public Service Commission Docket No. 2022.07.078, Direct Testimony of Cynthia Fang (Priority Regulatory Mechanisms) at 37:2-14.

⁵⁴ *Id.*, Final Order 7860y at ¶ 302.

**Q. ARE YOU AWARE OF OTHER INSTANCES WHEREBY REGULATORS HAVE
ISSUED A WITHDRAWAL OF REVENUE DECOUPLING?**

A. Yes. In January 2022, the Massachusetts Department of Public Utilities (“MDPU”) directed all electric distribution companies (“EDCs”) in the Commonwealth to end electric revenue decoupling. The MDPU explained its decision as follows:

In order to pursue a clean energy future consistent with the Massachusetts 2050 Decarbonization Roadmap, broad electrification achieved through the Program Administrator’s strategic electrification efforts combined with even more significant electrification efforts outside the Three-Year Plans is necessary. However, these efforts will require expanding the use of electric generation and will place more stress on the electric distribution system. These factors lead the Department to conclude that we must discontinue full revenue decoupling for electric distribution companies.⁵⁵

It further added:

The Department does not come to this decision lightly, but there are many reasons that it is appropriate to make this policy change immediately. First, the Department finds that it is in ratepayers’ best interests to no longer make the electric distribution companies whole for lost sales if that is no longer in line with the Commonwealth’s energy policy. Second, timely implementation of a transition away from revenue decoupling is necessary to align the business interests of the electric distribution companies to embrace strategic electric load growth in a safe, reliable, affordable, and equitable manner, as the Department is considering several policies to advance the clean energy future. Last, implementing this policy change now will shift the risk associated with changes in lost revenues from customers to electric distribution company shareholders, while simultaneously increasing the incentive for the electric distribution companies to pursue and enable electrification.⁵⁶

⁵⁵ Massachusetts D.P.U. 21-120 through D.P.U. 21-129, Order, January 31, 2022, at pp. 231-232.

⁵⁶ D.P.U. 21-120 through D.P.U. 21-129, Order, January 31, 2022, at pp. 232-233.

1 **Q. HAS THE COMPANY PROPOSED A SIMILAR DECOUPLING MECHANISM IN**
2 **THE PAST?**

3 A. Yes. In its 2024 base rate case, the Company proposed a Revenue Normalization
4 Adjustment, which was a revenue decoupling mechanism intended to recover differences
5 between actual and projected revenue per customer, regardless of the reason for the
6 variation. However, the proposal was withdrawn without prejudice as part of the
7 settlement approved by the Commission. The Commission adopted the settlement terms,
8 including the Company's withdrawal of the RNA proposal, and concluded that this
9 resolution was in the public interest.⁵⁷ Accordingly, the Commission did not rule on the
10 merits of the RNA but acknowledged the ALJ's finding that "the Company's agreement to
11 withdraw its proposed RNA, without prejudice, to be in the public interest, finding that this
12 will provide all Parties, including the Company's ratepayers, with regulatory certainty."⁵⁸

13 **Q. HAVE YOU EVALUATED THE PROPOSED RNA TO THE COMMISSION'S**
14 **DISTRIBUTION RATE CONSIDERATIONS?**

15 A. Yes. Exhibit MWD-1, pages 1 and 2, evaluates the proposed RNA to the
16 Commission's 14 consideration criteria for alternative regulation. My review of the
17 Commission's consideration criteria finds that the Company's proposal either will not
18 impact the Commission's areas of concern, or will potentially worsen the areas of
19 concern.

⁵⁷ Pa. P.U.C. v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2024-3046519, Opinion and Order (entered November 21, 2024) at 29.

⁵⁸ *Id.*

Q. WOULD APPROVAL OF THE PROPOSED RNA BE APPROPRIATE AND IN THE PUBLIC INTEREST?

A. No. The proposed RNA suffers from at least four major shortcomings that require its rejection: (1) the Company has not proven it needs an RNA; (2) the Company provides no customer benefits and is not in the public interest; (3) the RNA shifts risk from Company shareholders to ratepayers; and (4) the proposed RNA includes no ratepayer protection mechanisms.

A. The Company has not proven a need for the RNA.

Q. HOW HAS REGULATORY PRACTICE TRADITIONALLY EVALUATED REVENUE AND COST RECOVERY RIDER (OR “TRACKER”) REQUESTS?

A. Regulators often use three separate criteria to evaluate revenue and cost recovery mechanism requests that include determining whether or not the revenues/costs included in the requested mechanism are: (1) largely outside the control of a utility; (2) unpredictable and volatile; and (3) substantial and recurring.⁵⁹ These criteria resulted from a popular research paper published by the National Regulatory Research Institute (“NRRI”), the research organization supporting the National Association of Regulatory Utility Commissioners. It is important to note that the NRRI-recommended evaluation criteria are the minimum criteria, as they pertain to the threshold issue regarding the characteristics of revenues or costs suitable for recovery via a tracker. Thus, in the event that the NRRI-recommended criteria are satisfied, the next step is to determine whether

⁵⁹ Costello, Ken (September 2009), “How Should Regulators View Cost Trackers?” National Regulatory Research Institute at 8.

1 the tracker proposal contains flaws unrelated to the characteristics of the revenues/costs
2 intended for recovery.

3 **Q. ARE THERE ANY OTHER PROBLEMS WITH THE COMPANY'S REVENUE**
4 **DECOUPLING PROPOSAL?**

5 A. Yes. The Commission should recognize that the Company's proposals run afoul
6 of the three traditional factors I discussed earlier that regulators have considered in
7 approving revenue and cost recovery mechanisms. First, the Company has not shown
8 that revenue variances are creating financial hardships and are large relative to its overall
9 cost structure. Second, the Company has not shown, and evidence I have provided
10 shows that revenue variances are not "volatile." Lastly, the Company has considerable
11 control over how it influences sales and revenue growth: this is not entirely out of the
12 utility's hands. Thus, the RNA proposal fails to meet the three NRRI-recommended
13 criteria for the use of revenue and cost recovery riders.

14 **Q. DO THE COMPANY'S HISTORIC EARNINGS TRENDS SHOW THAT**
15 **REVENUE ATTRITION IS COMPROMISING ITS OPPORTUNITY TO EARN A RETURN**
16 **ON AND OF ITS INVESTMENTS?**

17 A. No. Exhibit MWD-4 presents historic return on equity ("ROE") for the Company
18 dating back to 2010. Page 1 of this exhibit calculates the Company's achieved ROE
19 relative to its net plant in service. While there are instances where the Company has had
20 challenges earning at its allowed ROE, the table shows this is clearly a cost-related issue,
21 not one attributable to revenue attrition. If anything, the challenge for the Company has
22 been, and continues to be, its cost-efficiencies. Thus, the RNA is simply a solution in
23 search of a problem: revenues are not the problem and offering the Company any form

of revenue cushion or insulation only makes it whole for continued cost inefficiencies. Page 3 of the exhibit charts the Company's achieved ROEs and its annual capital investments on a year-end basis clearly indicating that capital investment discipline, or lack thereof, has more to do with its ROE challenge than insulating its revenue stream.

Q. HAVE YOU EXAMINED THE RELATIONSHIP BETWEEN CHANGES IN THE COMPANY'S USE PER CUSTOMER, TOTAL USAGE, AND REVENUES?

A. Yes. That analysis is provided in Exhibit MWD-5 and shows that changes in total sales (usage) are a function of (1) the changes in existing customers' average use (*i.e.*, use per customer or "UPC") and (2) the new usage arising from new customers (or customer growth). If usage increases from customer growth outpace UPC decreases (from existing customers), then total usage will increase. The inverse would occur if usage from customer growth was less than the total decreases created by reduced use per customer. If prices and costs are held constant, then earnings will continue to increase if new customer-related usage growth outpaces the decrease in use per customer for existing customers. The inverse would occur if new customer-created usage was less than the decreases in UPC for existing customers; again, holding other factors constant. Thus, the negative financial impacts of UPC decreases can be offset for a utility serving a growing service territory. Utilities that serve stagnant, or very slow growing service territories (in terms of customer growth), could see earnings attrition if UPC falls. These relationships are based upon the premise that other factors are held constant.

Q. WHAT DO THESE TRENDS SHOW FOR COLUMBIA?

A. Exhibit MWD-5 (page 1) shows that residential UPC has fallen from 86 MCF per customer in 2011 to 69 MCF per customer in 2023. This is an average decline of 1.6

1 percent per year. However, total residential sales volumes have decreased from 24.8
2 million MCF in 2011 to 24.7 million MCF in 2023. Thus, as I noted earlier, the problem
3 with the Company earning its allowed ROE has little to do with revenues, and more to do
4 with costs. The RNA is simply a solution in search of a problem.

5 **Q. HOW DO THESE USAGE CHANGES TRANSLATE INTO CHANGES IN**
6 **COMPANY REVENUES?**

7 A. Exhibit MWD-5 (page 2) shows that declines in gas usage do not necessarily
8 translate into declining revenues. Over the past several years, the Company has seen
9 growth in its residential RPC and growth from new customers added to its system. These
10 combined elements led to strong non-fuel revenue growth per customer ranging from
11 \$220 per customer in 2011 to \$1,144 per customer in 2023. Exhibit MWD-5 (page 4)
12 shows similar trends in commercial RPC.

13 **Q. HAS THE COMPANY DEMONSTRATED THAT THE RNA IS NEEDED TO**
14 **ADDRESS UNDER-RECOVERY?**

15 A. No. While the Company claims it has experienced recent under-recoveries of its
16 authorized revenue requirement, this is not evidence of a systemic problem that justifies
17 a new decoupling mechanism. In fact, the Company's use of FPFTY, regular rate filings,
18 and its WNA already provide substantial tools to manage revenue risk. Furthermore, the
19 Company's parent company, NiSource, has communicated to investors that its regulated
20 utilities operate in supportive jurisdictions with efficient recovery mechanisms and
21 predictable earnings.⁶⁰

⁶⁰ "Supplemental Slides 1Q 2025 Results" (May 7, 2025), Q1 2025 NiSource Earnings Conference Call.

1 **B. Proposed RNA provides no customer benefits.**

2 **Q. WHAT RATIONALE DOES THE COMPANY PROVIDE FOR ITS RNA**
3 **PROPOSAL?**

4 A. The Company asserts that even with the WNA in place, residual revenue volatility
5 persists due to changes in customer usage patterns not driven by weather.⁶¹ The
6 Company contends that the RNA will address this gap by “breaking the link” between
7 sales and revenue recovery and ensuring it fully recovers its Commission-approved
8 revenue requirement regardless of actual sales volume.⁶²

9 **Q. IS THE COMPANY’S ARGUMENT CONCERNING BREAKING THE LINK**
10 **BETWEEN EARNINGS AND VOLUMETRIC SALES UNIQUE?**

11 A. No. Many energy efficiency advocates, as well as certain (but not all) utilities, often
12 argue that current regulatory pricing practices discourage utility-sponsored energy
13 efficiency programs.⁶³ These advocates argue that energy efficiency reduces sales
14 thereby reducing a utility’s ability to recover its fixed costs. Revenue decoupling removes
15 the relationship between sales and revenues, and in doing so, theoretically removes the
16 claimed disincentive utilities have for promoting end-user energy efficiency.⁶⁴

⁶¹ See, Direct Testimony of John Taylor, Company Statement No. 17 at 46:15-21.

⁶² See, Direct Testimony of John Taylor, Company Statement No. 17 at 46:2-5.

⁶³ NRDC’s Fourth Annual Energy Report: *Accelerating Into a Clean Energy Future*, (2016).

⁶⁴ *Id.*

Q. DOES THE COMPANY PROPOSE TO EXPAND ITS DEMAND-SIDE MANAGEMENT AND ENERGY EFFICIENCY OFFERS IN CONJUNCTION WITH THE PROPOSED RNA?

A. No. While the Company proposes to continue to expand its voluntary residential energy efficiency program and introduce a new commercial offering,⁶⁵ these proposals are not meaningfully tied to the RNA. The Company does not condition its decoupling proposal on any mandatory energy savings targets or performance metrics. Instead, the RNA is framed solely as a revenue stabilization tool and is not designed to support or be driven by measurable demand-side outcomes. As such, the proposal lacks the kind of integrated framework that other jurisdictions have adopted when approving decoupling mechanisms in conjunction with robust, performance-based energy efficiency commitments.

Q. HAS THE COMPANY ASSESSED ITS HISTORIC EARNINGS AND THE EFFECTS OF THE PROPOSED RNA ON THESE EARNINGS?

A. No. The Company confirmed it has not conducted any analysis of how its historical earnings would have changed had the proposed RNA been in place.⁶⁶ It has not simulated or modeled the retroactive effects of the RNA on past periods. Additionally, the Company has also stated that no supporting documentation or workpapers were prepared to justify the benchmark revenue per customer levels proposed under the RNA.⁶⁷

⁶⁵ Columbia EE Report, 2024.

⁶⁶ Response to Discovery Request OCA 13-004.

⁶⁷ Response to Discovery Request OCA 13-008.

Q. PLEASE DISCUSS THE COMPANY'S HISTORIC ENERGY EFFICIENCY PROGRAM SAVINGS.

A. The Company launched its current three-year Energy Efficiency and Conservation ("EE&C") portfolio in August 2023, following Commission approval of its plan in Docket No. R-2022-3031211.⁶⁸ The Company offers two voluntary non-low-income residential programs: (1) the Online Audit and Kit ("OAK") Program, and (2) the Residential Prescriptive ("RP") Program.⁶⁹ Through the end of 2024, the Company achieved approximately 748,583 Dth in lifetime natural gas savings, representing 61 percent of its three-year goal.⁷⁰ The RP Program accounted for 480,448 Dth, while the OAK Program contributed 54,032 Dth in lifetime savings for 2024.⁷¹ Combined, the programs yielded over \$3.4 million in net present value benefits, with a portfolio-wide benefit-cost ratio of 2.87 under the Total Resource Cost test.⁷² While these results reflect significant activity in the early stages of the portfolio, participation remains voluntary and untethered to the Company's proposed RNA, and the programs do not include mandatory savings targets or performance incentives.

⁶⁸ Columbia EE Report, 2024 at 2.

⁶⁹ Columbia EE Report, 2024 at 3.

⁷⁰ Columbia EE Report, 2024 at 3.

⁷¹ Columbia EE Report, 2024 at 4.

⁷² Columbia EE Report, 2024 at 4.

1 **Q. PLEASE DISCUSS THE COMPANY'S HISTORIC ENERGY EFFICIENCY**
2 **PROGRAM COSTS.**

3 A. The Company's EE&C portfolio was approved with a total budget of \$5 million
4 through 2025. As of the end of 2024, the Company has spent approximately \$1.9 million,
5 or 49 percent of its three-year budget.⁷³ In 2024 alone, total portfolio spending was \$1.3
6 million, representing 94 percent of that year's revised budget.⁷⁴ The RP Program
7 accounted for the majority of these costs, with \$1 million spent.⁷⁵ Notably, the RP
8 Program exceeded its individual budget by 61 percent, largely due to high customer
9 participation, while the OAK Program underspent at 31 percent of its allocated budget.⁷⁶

10 **Q. IS RECOVERY OF LOST REVENUE A COMPONENT OF THE COMPANY'S**
11 **PUC-APPROVED VOLUNTARY ENERGY EFFICIENCY & CONSERVATION (EE&C)**
12 **PROGRAM?**

13 A. No.

14 **Q. ARE SALES DECREASES DUE TO ENERGY EFFICIENCY THE ONLY**
15 **SOURCE OF DIFFERENCES BETWEEN TEST YEAR (ALLOWED) AND ACTUAL**
16 **REVENUES?**

17 A. No. A variety of factors can influence sales between rate cases and lead to
18 situations where retail sales and revenues will differ from those observed in a utility's test
19 year. Consider that test year retail sales and revenues in a rate case are usually based

⁷³ Columbia EE Report, 2024 at 6.

⁷⁴ Columbia EE Report, 2024 at 6.

⁷⁵ Columbia EE Report, 2024 at 12.

⁷⁶ Columbia EE Report, 2024 at 9.

1 upon a “typical” year, and as such, are based upon typical factors such as the unexplained
2 weather trends, the economy, and prices, among other things. In any given year, the
3 actual performance of the economy may differ from the test year. The differences in sales
4 created by the economy, commodity prices, and other factors usually account for greater
5 changes in revenue than those resulting from utility-sponsored energy efficiency
6 programs.

7 **Q. WILL THE RNA ALLOW THE COMPANY TO RECOVER LOST REVENUES**
8 **FROM FACTORS NOT ASSOCIATED WITH ENERGY EFFICIENCY OR**
9 **DISTRIBUTED GENERATION?**

10 A. Yes. The RNA will allow monthly differences between actual and allowed RPC to
11 be trued up for each of the applicable rate classes on an annual basis. The proposed
12 RNA, if approved, will not be adjusted to account for revenue variations that are created
13 by such factors as changes in energy prices, the economy, or other factors.

14 **Q. YOU STATED ABOVE THAT THE COMPANY IS CONTINUING TO EXPAND**
15 **ITS EE&C OFFERINGS. WHAT DOES THIS SHOW?**

16 A. This shows three important things. First, the entire premise for the RNA, to the
17 extent it is even allowed, should be to remove a disincentive to aggressively pursue
18 energy efficiency activities. While the Company currently has various EE&C programs,
19 the Company also appears to have adequate incentives in promoting these programs
20 since they were initiated without revenue decoupling. Further, and more importantly, the
21 Company has not proposed any new incremental offerings to accompany the RNA
22 proposal. Approving the RNA alone, without any new or incremental energy efficiency
23 program commitments, effectively “decouples” the problem from the solution. Second,

1 this omission shifts the entire regulatory and performance-related risk associated with the
2 Company's future energy efficiency activities entirely onto ratepayers since there is
3 nothing to assure that the RNA, in fact, will lead to enhanced energy efficiency efforts.
4 Third, the proposal itself suggests the Company's EE&C activity is not adequate, yet the
5 Company does not quantify or provide any other record evidence to show how it could be
6 doing more than it is already doing with regards to its EE&C service offerings.⁷⁷

7 **Q. EXPLAIN HOW PERFORMANCE-RELATED RISKS OF THE PROPOSED**
8 **DECOUPLING MECHANISM ARE SHIFTED AWAY FROM THE COMPANY AND**
9 **ONTO RATEPAYERS.**

10 A. The proposed RNA will allow the Company to recover lost revenues regardless of
11 the source and regardless of its energy efficiency performance. There are no penalties if
12 the Company fails to deliver its anticipated energy efficiency participation levels or
13 savings. Yet, despite this shortcoming, the RNA would still be in place insulating the
14 Company from revenue shortcomings that will have little to nothing to do with its EE&C
15 activities. The RNA, therefore, will be decoupling not only revenues and sales, but will
16 also decouple utility energy efficiency performance from its financial returns.

17 **Q. ARE YOU AWARE OF ANY REGULATORY COMMISSIONS THAT HAVE TIED**
18 **REVENUE DECOUPLING APPROVAL TO EFFICIENCY PROGRAM**
19 **COMMITMENTS?**

20 A. Yes. The Washington Utilities and Transportation Commission ("WUTC"), in its
21 review of extending Avista Corporation's decoupling mechanism, found:

⁷⁷ Note that OCA Witness Stacy Sherwood (OCA St. 7) discusses in her testimony the Company's expanded EE&C offerings, and presents OCA's recommendations thereto.

1 The regulatory construct for decoupling in Washington has
 2 centered on the utility's performance relative to conservation.
 3 Our approval of decoupling in our two pilot programs was
 4 founded on the premise that lost margins affected the utility's
 5 appetite for offering additional conservation programs. Thus,
 6 both pilots required the companies to account for lost margin
 7 due to conservation, and to discriminate between the various
 8 causes of lost margin. In that more limited context, we
 9 conclude that the recovery of lost margin attributable to
 10 Avista's programmatic and non-programmatic conservation
 11 endeavors is sufficient to encourage Avista's [Demand Side
 12 Management] DSM efforts. We seek to avoid guaranteed
 13 recovery of lost margin that would occur should lost margin
 14 from other causes be included in the mechanism.⁷⁸

15 The WUTC reiterated this principle again in its 2010 investigation into utility
 16 conservation incentives stating that "revenue recovery by the company under the
 17 mechanism will be conditioned upon a utility's level of achievement with respect to its
 18 conservation target."⁷⁹

19 **Q IS THE RNA LIKELY TO RESULT IN ANY RATE DECREASE BENEFITS FOR**
 20 **RATEPAYERS?**

21 A. No. Under the Company's proposal, the RNA is designed to ensure that Columbia
 22 recovers its full Commission-approved revenue requirement each year, regardless of
 23 actual customer usage. As a result, any deviation below the benchmark revenue per
 24 customer would trigger a surcharge to make up for the shortfall. Given the Company's

⁷⁸ Washington Utilities and Transportation Commission v. Avista Corporation, d./b./a. Avista Utilities, Docket UE 090134 and UG 090135, consolidated, Order 10: Final Order Rejecting Tariff Filing; Approving and Adopting Multi-Party Partial Settlement Stipulation; Deferring Lancaster Costs; Extending Decoupling Mechanism; Authorizing Tariff Filing; and Requiring Compliance Filing, December 22, 2009. Final Order at p. 114, ¶291, emphasis added.

⁷⁹ In the Matter of the Washington Utilities and Transportation Commission's Investigation into Energy Conservation Incentives. Washington State Utilities and Transportation Commission. Docket U-100522, Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed Their Conservation Targets, November 4, 2010. ¶28.

underlying justification for the RNA, that usage per customer is steadily declining, it is far more likely that the mechanism will operate in the form of surcharges rather than credits. The proposed RNA is structured to shield the Company from downside risk, not to produce net rate reductions for customers.

Q HAVE ANY EMPIRICAL STUDIES FOUND THAT REVENUE DECOUPLING MECHANISMS LIKE THE RNA CONSISTENTLY LEAD TO RATE INCREASES?

A. Yes. Exhibit MWD-6 provides a summary of the results provided in a report purportedly designed to support the adoption of revenue decoupling. This report was prepared on the behalf of several energy advocacy groups in the Pacific Northwest by Graceful Systems and hereafter will be referred to as the “Lesh Report.”⁸⁰ The table provides the number of instances in which there were observed rate increases or rate decreases for electric and gas utilities under revenue decoupling. The table shows 72 percent of the gas utilities in the sample and 57 percent of all the electric utilities in the same had reconciliations resulting in rate increases instead of rate decreases over the past decade. This stands in stark contradiction to the typical utility assertion that decoupling will yield results that are symmetrical (i.e., will lead to equal rate increases and decreases). Furthermore, 19 percent of all gas decoupling surcharges were of an amount greater than three percent whereas all reconciliations resulting in refunds greater than three percent were themselves a mere three percent of all reconciliations: a 6-to-1 ratio of an extreme rate increase versus extreme rate decrease. Again, such a finding suggests a very highly skewed outcome against ratepayers.

⁸⁰ See Pamela Lesh, Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review (2009).

Q. DO THESE GENERIC FINDINGS MASK SOME OTHER EXTREME OBSERVATIONS ABOUT THE RATE IMPACTS FROM DECOUPLING?

A. Yes. There are a number of noticeably extreme rate increases created by revenue decoupling that have been highlighted in the study, assuming its representations are accurate. Consider for instance, the decoupling adjustments reported for Pacific Gas and Electric (PG&E). Decoupling-induced rate increases between 2006 and 2007 went from a level of \$24.64 million to \$148.9 million or some 504 percent. Likewise, the 2008 to 2009 increase from \$11.4 million to \$103.55 (or 808 percent) is considerable. Over the time period presented in the table, PG&E ratepayers saw an average annual increase, each and every year, of \$77.6 million.

Q. HAVE ANY MORE RECENT ACADEMIC STUDIES RAISED QUESTIONS ABOUT THE RATEPAYER BENEFITS ARISING FROM REVENUE DECOUPLING?

A. Yes. A relatively recent study conducted by the Centre for Climate Change Economics and the Grantham Research Institute on Climate Change and the Environment found that revenue decoupling adoption resulted in negative ratepayer outcomes.⁸¹ The empirical analysis used monthly data for the period January 2000 to November 2012 on 160 unique electric utilities. The study found that states with revenue decoupling had ten percent higher electricity prices within a two-year, post-adoption period than states without revenue decoupling.⁸² The study also found that, contrary to

⁸¹ Arlan Brucal and Nori Tarui (2019). "Revenue decoupling for electric utilities: impacts on prices and welfare. Centre for Climate Change Economics and Policy Working Paper No. 343 and Grantham Research Institute on Climate Change and the Environment Working Paper No. 309. ISSN 2515-5709, ISSN 2525-5717.

⁸² *Id.*

popular belief and advocacy, those states with revenue decoupling did not have meaningful changes in output due to efficiency.⁸³ Indicating that price increases result in pure increases of revenue to the adopting utility and its shareholders.⁸⁴ Equally important is the fact that revenue decoupling had more significantly negative impacts for lower-income households than higher income households: in other words, revenue decoupling is regressive.⁸⁵

Q ARE ADDITIONAL RATE INCREASES A CONCERN GIVEN COLUMBIA'S CURRENT RATES?

A. Yes. Exhibit MWD-7 provides a comparison of Columbia's residential retail base rates (estimated average total revenues). Columbia's rates are not only far above average, but higher than all but one peer utility in the grouping of comparable mid-Atlantic natural gas utilities. Columbia ranks among the most expensive utilities providing natural gas service on a retail basis to residential customers. Thus, any regulatory mechanism that has the potential to actually increase residential rates further should lead to some alarm for the Commission and underscore the need to reject the Company's RNA proposal. The Commission simply cannot adopt regulatory policies and strategies that offer zero ratepayer benefits and run the further risk of making Columbia's already worse-in-class retail natural gas rates any worse.

⁸³ *Id.*

⁸⁴ *Id.*

⁸⁵ *Id.*

1 **C. RNA shifts risks from Company shareholders to ratepayers.**

2 **Q. WOULD THE RNA PROVIDE ADDITIONAL GUARANTEED REVENUE**
 3 **RECOVERY FOR THE COMPANY?**

4 A. Yes. The Company's RNA proposal would sever the link between revenues and
 5 sales altogether. As such, the Company would face little to no risk associated with
 6 revenue variability (often referred to as "business risk").

7 **Q. HAVE OTHER REGULATORY COMMISSIONS PREVIOUSLY RECOGNIZED**
 8 **THE RELATIONSHIP BETWEEN RISK REDUCTION AND A UTILITY'S AUTHORIZED**
 9 **ROE?**

10 A. Yes. In denying a proposed revenue normalization adjustment by Washington Gas
 11 Light, the D.C. Public Service Commission ("DC PSC") noted its historic policy of
 12 reflecting decreases in utility risk through corresponding reductions in allowed ROE.⁸⁶
 13 Indeed, in earlier proceedings before it, the DC PSC noted that, because decoupling
 14 mechanisms provide benefits such as "reduced risk" for the utility, "it is imperative that on
 15 the other side of the ledger that the customers receive an offsetting benefit."⁸⁷ Such
 16 offsetting benefits could include "imposing [a] reduction in the utility's ROE, imposition of
 17 certain reporting requirements, establishment of specified energy efficiency performance
 18 requirements and benchmarking requirements, as well as the creation of reliability
 19 standards with attendant penalties for failure to meet said standards."⁸⁸ Accordingly, the

⁸⁶ D.C. Public Service Commission *Formal Case No. 1137*, Order No. 18712 ¶ 229 (citing *Formal Case No. 1079*, Order No. 15738 ¶ 8).

⁸⁷ *Formal Case No. 1053*, Order No. 15556 ¶ 26, rel. Sept. 28, 2009.

⁸⁸ *Id.*

1 DC PSC approved a 50 basis point reduction in ROE when approving a bill stabilization
 2 adjustment “as part of the approval of the BSA to balance the ledger by providing a benefit
 3 to consumers in exchange for the benefit to the Company and shareholders of reaping
 4 lowered business risk.”⁸⁹

5 Additionally, in the application of Aquarion Water Company of Connecticut
 6 (“Aquarion”), the Public Utilities Regulatory Authority (“Authority”) of Connecticut
 7 addressed Aquarion’s revenue adjustment mechanism, which reconciles in rates the
 8 difference between actual revenues and allowed revenues.⁹⁰ The Authority found that
 9 there “must be a reduction in risk from the revenue adjustment mechanism”⁹¹ and
 10 deducted 10 basis points from the company’s allowed ROE accordingly.⁹²

11 **Q. ARE THERE ANY REAL-WORLD EXAMPLES OF HOW REVENUE**
 12 **DECOUPLING CAN LEAD TO SERIOUS PROBLEMS DURING AN ECONOMIC**
 13 **RECESSION OR CONTRACTION?**

14 A. Yes, as referenced earlier, one of the more widely recognized failures of revenue
 15 decoupling occurred in Maine during the early 1990’s. The program, known as “ERAM”
 16 (“Electric Revenue Adjustment Mechanism”), was put into place for a three-year trial
 17 period to encourage CMP to promote energy efficiency.⁹³ The adoption of the ERAM
 18 coincided with a recession that resulted in lower sales levels and substantial revenue

⁸⁹ *Id.* ¶ 29.

⁹⁰ Decision, Docket No. 13-02-20 before the Public Utilities Regulatory Authority of Connecticut, Sep. 24, 2013, p. 110.

⁹¹ *Id.*

⁹² *Id.* at 115.

⁹³ Order, Maine Public Utilities Commission Docket No. 90-085, rel. May 7, 1991.

1 deferrals. CMP was entitled to recover these deferrals under the provisions of the ERAM
 2 mechanism, which by the end of 1992 had already reached a staggering \$52 million, an
 3 amount equal to more than six percent of CMP's annual revenues, causing the Maine
 4 Public Utilities Commission to take the dramatic step of opening hearings to consider the
 5 suspension of the ERAM during its trial period.⁹⁴ The ERAM was ultimately terminated
 6 on November 30, 1993.⁹⁵ In later assessing the reasons for the ERAM's failure, observers
 7 noted:

- 8 • The large accruals resulted primarily from the economic recession and were
 9 exacerbated by the inaccurate revenue forecast of the preceding rate case, the
 10 withdrawal of the 1991 rate case filing, warm weather, and the test year choice.⁹⁶
- 11 • By being shielded from the recession, CMP may not have had the same incentives
 12 to operate efficiently in the way that other companies were at that time.⁹⁷
- 13 • The ERAM failed in providing CMP with a sufficient incentive to pursue demand
 14 side management and other conservation measures.⁹⁸

15 **Q. ARE THERE CONCERNS THAT DECOUPLING COULD LEAD TO**
 16 **SURCHARGES DURING ECONOMIC CONTRACTIONS LIKE THE ONE CREATED BY**
 17 **THE COVID-19 PANDEMIC?**

18 A. Yes. As noted earlier, revenue decoupling mechanisms, like the RNA, allow
 19 utilities to recover sales losses, including those associated with such recent sales
 20 downturns like the ones created by the recent pandemic, regardless of the reason. Such

⁹⁴ Leslie Hudson and Stephanie Seguino, *Assessing Maine's ERAM experiment*, 3 MAINE POLICY REV. at 82 (1994), <https://digitalcommons.library.umaine.edu/mpr/vol3/iss2/9>.

⁹⁵ *Id.* at 83.

⁹⁶ *Id.* at 84.

⁹⁷ *Id.* at 85.

⁹⁸ *Id.*

an outcome is particularly concerning given the large economic dislocation that arose during the crisis and the challenges many households and businesses had paying bills for basic services. The proposed RNA would hold the Company harmless for revenue shortfalls resulting from any exogenous event like a pandemic or economic recession.

Q. CAN YOU POINT TO ANY EXAMPLES WHERE UTILITY MANAGEMENT HAS RECOGNIZED THE REVENUE PROTECTION CHARACTERISTICS OF REVENUE DECOUPLING?

A. Yes. In late 2019, the Ohio Legislature debated an amendment to proposed legislation that would allow electric utilities to adopt revenue decoupling. In an unsealed federal indictment involving bribery charges it was revealed that the Chief Executive Officer (“CEO”) of First Energy Corporation (a large Ohio electric utility) discussed the amendment with investors, noting:

[Decoupling] fixes our base revenues and essentially it takes about one-third of our company and I think makes it somewhat recession-proof. So, I get a question a lot about where I’m worried about a future recession. It’s 2 million customers in Ohio that this is going to help make sure that that doesn’t impact us.⁹⁹

Q. ARE THERE ANY OTHER EXAMPLES OF UTILITY MANAGEMENT RECOGNIZING THE RISK MANAGEMENT BENEFITS ARISING FROM REVENUE DECOUPLING?

A. Yes. In a July 30, 2020 investor earnings call, just a few months after the declared state of emergency concerning the COVID-19 pandemic, the Chief Financial Officer

⁹⁹ Affidavit in Support of a Criminal Complaint ¶ 169, United States v. Larry Householder, Jeffrey Longstreth, Neil Clark, Matthew Borges, Juan Cespedes, and Generation Now, Case No. 1:20-MJ-00526 (S.D. Ohio July 21, 2020).

1 (“CFO”) at AltaGas Ltd. reminded investors that a substantial portion of its regulated utility
 2 earnings were “protected” through decoupling and fixed customer charges.

3 Normalized EBITDA within the Utilities segment was \$80
 4 million for the quarter, slightly below Q2 2019. As I previously
 5 mentioned, growth at our regulated utilities was driven by our
 6 2019 settled rate cases, ARP spending and strong operational
 7 execution, which was partially overshadowed by COVID-19
 8 related impacts, including lower margins in our retail business.

9 As a reminder, approximately 70 percent of our regulated
 10 utilities earnings are protected through decoupling and fixed
 11 billing charges. In all the jurisdictions where we operate have
 12 (sic) approved the creation of regulatory assets to allow for
 13 the recovery of incremental costs related to COVID-19. We
 14 are tracking these costs and our lost revenue due to the
 15 pandemic and we will continue to work with our regulators on
 16 the definition and treatment of recoverable impacts within
 17 those regulatory assets.¹⁰⁰

18 **Q DOES NISOURCE REGULARLY COMMUNICATE ITS PROGRESS ON**
 19 **SECURING TRACKER MECHANISM APPROVALS WITH ITS SHAREHOLDERS?**

20 A. Yes. NiSource, Columbia’s parent, has provided periodic updates to its
 21 shareholders over the past several years regarding its state-level efforts at minimizing
 22 financial risk through the use of periodic cost and revenue recovery mechanisms, or
 23 trackers. Examples of these are provided in Exhibit MWD-8 and come from investor-
 24 relations presentations provided to investors in 2024, 2022, 2020, and 2018. Each survey
 25 presentation provides slides discussing NiSource’s attempts at securing risk-reducing
 26 regulatory mechanisms across all their electric and natural gas utilities in Ohio, Indiana,
 27 Virginia, Kentucky, Maryland, and Pennsylvania. This survey is not limited to revenue
 28 decoupling but includes a variety of other tracker mechanisms, particularly investment

¹⁰⁰ AltaGas Ltd., *Second Quarter 2020 Financial Results Conference Call*, at 11 (July 30, 2020) (emphasis added)

1 cost/pipeline replacement trackers such as the Distribution System Improvement Charge
2 (“DSIC”) available to the Company since 2012 with approval of a Long-Term
3 Infrastructure Plan (“LTIP”).¹⁰¹

4 **D. RNA does not include any ratepayer protections.**

5 **Q. HAS COLUMBIA PROPOSED SUFFICIENT RATEPAYER PROTECTIONS AS**
6 **PART OF THE RNA?**

7 A. No. The Company proposes no ratepayer protection mechanisms typically
8 approved as part of a decoupling mechanism. These include a limit on annual
9 adjustments through the proposed RNA to protect ratepayers from excessive rate
10 volatility. Also, unlike other utilities that have received authorization to implement a
11 revenue decoupling mechanism, the Company has not proposed ratepayer protections in
12 the form of performance guarantees, a pilot program to first prove the promised ratepayer
13 benefits, and/or a check on over earnings. Exhibit MWD-9 presents a comprehensive
14 survey of decoupling mechanisms approved in other jurisdictions and the ratepayer
15 protection mechanisms that have been approved as part of the mechanism’s adoption.

16 **Q. DOES THE COMPANY’S PROPOSED RNA INCLUDE ANY RATEPAYER**
17 **PROTECTIONS?**

18 A. No. While the proposed RNA would provide the Company with assured recovery
19 of its authorized revenue per customer, the Company offers no meaningful protections
20 for ratepayers in return. The proposal lacks common safeguards such as caps on annual
21 adjustments, deadbands to limit volatility, or performance-based conditions tied to

¹⁰¹ 66 Pa.C.S. §§ 1352-1353.

1 efficiency outcomes. These types of protections are routinely used by utilities and
2 regulators in other jurisdictions to ensure that decoupling mechanisms do not impose
3 excessive or unfair burdens on customers. The Company's filing includes none of these
4 measures, instead presenting the RNA as a one-sided tool that mitigates business risk
5 for the Company without offering ratepayers any corresponding benefit or protection.

6 **Q. HAVE YOU PREPARED A TABLE THAT SUMMARIZES COMMON**
7 **DECOUPLING MECHANISMS RATEPAYER PROTECTIONS?**

8 A. Yes. Exhibit MWD-9 has three pages that summarize electric, gas, and combined
9 electric and gas utility revenue decoupling mechanisms ratepayer protections. Utilities
10 are listed, along with the decision date for revenue decoupling. To the right are columns
11 identifying major types of ratepayer protections including whether the mechanism
12 includes any limited recovery or revenue caps, whether there is an earnings test to limited
13 over-earnings, whether incremental energy efficiency targets are included, whether the
14 mechanism was adopted on a trial or pilot basis, and whether a compliance evaluation or
15 program review is part of the process.

16 **Q. CAN YOU PLEASE EXPLAIN WHAT YOU MEAN BY LIMITED RECOVERY**
17 **PROTECTIONS?**

18 A. Limited recovery protections are safeguards that place boundaries on the amount
19 of revenue a utility can recover through a decoupling mechanism in any given period.
20 These protections often take the form of hard caps, such as a percentage limit on annual
21 revenue recovery or rate increases, designed to prevent excessive or unexpected
22 charges to customers. In some frameworks, amounts above the cap can be deferred to
23 future periods, while in others, the utility simply absorbs the difference. The Company's

1 proposal includes no such revenue or rate caps, exposing ratepayers to the risk of
2 significant year-over-year increases without any mechanism to moderate or phase in
3 recovery.

4 **Q. CAN YOU PLEASE EXPLAIN HOW EARNINGS TESTS ARE INCORPORATED**
5 **AS RATEPAYER PROTECTIONS?**

6 A. Earnings tests assure that a utility with revenue decoupling does not exceed their
7 authorized return on equity at the expense of ratepayers. These tests typically rely on
8 annual or quarterly earnings reports to determine whether the utility is operating within its
9 approved ROE range, often referred to as a “deadband.” If the utility is already earning
10 at or above its authorized ROE, it may be prohibited from recovering additional revenues
11 through its decoupling mechanism. Despite the widespread use of earnings tests in other
12 jurisdictions, the Company’s RNA proposal does not include any such limitation, leaving
13 ratepayers unprotected.

14 **Q. HOW DO NEW INCREMENTAL ENERGY EFFICIENCY TARGETS OR GOALS**
15 **SERVE AS RATEPAYER PROTECTIONS?**

16 A. These targets help to ensure that utilities use the stability afforded by decoupling
17 to deliver tangible customer benefits. Many utilities, both electric and gas, have paired
18 revenue decoupling proposals with commitments to expand energy efficiency efforts,
19 recognizing that the removal of the throughput incentive should be accompanied by
20 proactive investment in demand-side savings. These commitments help ensure that
21 ratepayers see measurable outcomes in return for assuming greater revenue risk on
22 behalf of the utility. The Company, however, has made no such commitment. The

1 Company has not proposed any new savings targets or program expansions that would
2 demonstrate good-faith use of the mechanism to advance customer efficiency goals.

3 **Q. HOW ARE PILOTS USED TO “TEST-DRIVE” A DECOUPLING MECHANISM?**

4 A. A large number of revenue decoupling mechanisms that have been adopted
5 across the U.S. have been done on a temporary or pilot basis. Often these pilots run
6 from three to five years to understand and examine how decoupling works before its full-
7 scale adoption. While the Company agreed to the WNA on a pilot basis, obviously
8 recognizing the benefits from such a measure, it has failed to make a similar proposal in
9 this proceeding for the RNA despite its broader scope and potentially greater customer
10 impact.

11 **Q. DISCUSS HOW COMPLIANCE REVIEWS ARE INCLUDED.**

12 A. These reviews are usually held at the end of a pilot or review period to assess
13 whether the goals of revenue decoupling have been achieved. These reviews assure
14 that the regulatory risks of adopting revenue decoupling are not entirely shifted onto
15 ratepayers and that utilities have some performance accountability in the form of
16 minimizing bill volatility, meeting certain incremental energy efficiency targets, reducing
17 administrative costs, maintaining cost efficiencies, among other goals. These reviews
18 “re-couple” performance back into the regulatory process. However, Columbia has made
19 no such proposal in this proceeding.

20 **Q. HAS THE COMPANY OFFERED ANY STAY-OUT PROVISIONS AS A QUID**
21 **PRO QUO FOR REVENUE DECOUPLING?**

22 A. No. Utilities frequently argue that revenue decoupling mitigates regulatory lag by
23 stabilizing earnings between rate cases. The underlying theory is that, by ensuring

1 recovery of authorized revenues, decoupling reduces the frequency and urgency of rate
2 filings, thereby lowering overall regulatory costs. In recognition of this, some utilities have
3 committed to “stay-out” provisions as a form of ratepayer protection. The Company has
4 made no such commitment in connection with its proposed RNA. This omission
5 underscores the one-sided nature of the proposal. While the Company seeks the benefits
6 of guaranteed revenue recovery, it offers no reciprocal commitments that would share
7 those benefits with customers or reduce regulatory burdens.

8 **Q. HAS THE COMPANY OFFERED ANY REDUCTIONS TO ITS ALLOWED ROE**
9 **IN RETURN FOR REVENUE DECOUPLING?**

10 A. No. Exhibit MWD-10 shows that a number of states, as well as the Federal Energy
11 Regulatory Commission (“FERC”), have made adjustments to the allowed rate of return
12 in recognition of the fact that revenue neutrality programs change the risk profiles of
13 regulated utilities. Some of these adjustments have actually been proposed by utilities,
14 and in a number of cases, these adjustments have been adopted. Adjustments range
15 from 10 to 50 basis points on a utility’s allowed ROE. The proposed RNA would inherently
16 reduce the Company’s financial risk, shifting these risks onto ratepayers. Other
17 jurisdictions that have recognized this risk-shifting have reduced allowed ROEs by as
18 much as 50 basis points, yet no such offer has been made in the current proceeding.

19 **Q. ARE THERE OTHER CONCERNS ASSOCIATED WITH THE PROPOSED RNA?**

20 A. Yes. OCA Witnesses Barbara Alexander and Roger Colton discuss in their
21 testimonies concerns associated with the proposed RNA as it relates to customer
22 understandability and negative effects on low-income customers, respectively. OCA
23 Witness Alexander finds that the Company’s proposed RNA is deficient in that the

Company has failed to develop any education materials to explain and educate customers about the proposed mechanism. Likewise, OCA Witness Colton finds that the proposed RNA will have adverse impacts on low-income customers.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RNA?

A. The Commission should reject the Company's RNA proposal. The Company has not demonstrated that existing ratemaking tools such as the WNA, FPFTY, and frequent rate cases are insufficient to address revenue variability. The RNA would represent an unnecessary and unjustified shift in regulatory risk from the utility to its customers.

V. WEATHER NORMALIZATION PROPOSAL

Q PLEASE DISCUSS THE COMPANY'S WNA.

A. The Company's WNA is a ratemaking mechanism that adjusts customer bills during the winter heating season (November through May) based on deviations from what the Company defines as "normal" weather.¹⁰² Specifically, it applies a formula using the ratio of normal heating degree days ("HDDs") to actual HDDs, multiplied by a customer-specific heating usage factor, to generate either a credit or a surcharge on the bill.¹⁰³ The WNA is limited to weather-related usage changes and applies to residential customers only.¹⁰⁴

¹⁰² See, Direct Testimony of John Taylor, Company Statement No. 17 at 28:5-8.

¹⁰³ See, Direct Testimony of Michael Girata, Company Statement No. 2 at 3:11-18.

¹⁰⁴ See, Direct Testimony of John Taylor, Company Statement No. 17 at 30:20-22.

Q. WHY ARE WEATHER NORMALIZATION ADJUSTMENTS TYPICALLY USED BY GAS UTILITIES?

A. Weather normalization adjustments are generally used to reduce revenue volatility that results from fluctuations in weather which can lower customer gas usage and thus reduce a utility's recovery of fixed costs through volumetric rates. The intent is to provide more predictable revenues for the utility while smoothing customer bills. However, this goal must be balanced with customer protections to ensure the mechanism does not systematically overcharge customers or remove all utility risk.

Q. WHAT IS THE COMPANY PROPOSING IN THIS CASE WITH RESPECT TO THE WNA?

A. The Company is proposing to convert its WNA from a pilot program to a permanent, ongoing ratemaking mechanism without making any structural changes such as modifying the three percent deadband.¹⁰⁵ The Company simply proposes to retain the existing formula and incorporate it permanently into its tariff without providing new analysis, customer impact data, or evaluative metrics.

Q. HAVE YOU EVALUATED THE WNA TO THE COMMISSION'S DISTRIBUTION RATE CONSIDERATIONS?

A. Yes. Exhibit MWD-1, pages 3 and 4, evaluates the current WNA to the Commission's 14 consideration criteria for alternative regulation. My review of the Commission's consideration criteria finds that the current WNA either does not impact the Commission's area of concern, or will potentially worsen the area of concern.

¹⁰⁵ See, Direct Testimony of John Taylor, Company Statement No. 17 at 28:2-3.

Q. WHAT DID THE COMMISSION DECIDE REGARDING THE WNA IN THE COMPANY'S PRIOR RATE CASE?

A. In its Final Order, the Commission adopted a settlement in which the Company agreed to withdraw its proposal to eliminate the three percent deadband from the WNA.¹⁰⁶ The Commission did not rule on the merits of that proposal but, the Order also confirms that the WNA's continuation, structure, and justification remain subject to further review in future proceedings.¹⁰⁷

Q. WHAT IS THE EFFECT OF COLUMBIA'S PROPOSAL IN THIS PROCEEDING TO MODIFY THE WNA PILOT INTO A PERMANENT RATEMAKING MECHANISM?

A. The Company's proposal would lock in place a ratemaking mechanism that has never been subject to formal evaluation, has consistently produced surcharges for customers, and operates without key safeguards such as reconciliation, earnings tests, or weather trend adjustments. By seeking to convert the WNA from a pilot into a permanent ratemaking mechanism, the Company is effectively attempting to shield itself from weather-driven sales risk indefinitely, while continuing to recover fixed costs through volumetric charges. This conversion would institutionalize an asymmetric mechanism that benefits the utility without demonstrating corresponding benefits to ratepayers.

¹⁰⁶ Pennsylvania Public Utility Commission, *Opinion and Order*. Docket No. R-2024-3046519 at 29.

¹⁰⁷ Pennsylvania Public Utility Commission, *Opinion and Order*. Docket No. R-2024-3046519 at 30.

1 **Q. HAS THE COMPANY PROVIDED ANALYSIS TO SUPPORT ITS REQUEST**
2 **FOR A PERMANENT WNA MECHANISM?**

3 A. No. The Company has not provided any new study, metric, or performance
4 evaluation to support its request for permanent adoption.¹⁰⁸ The Company has not
5 demonstrated how customers have benefitted from the mechanism, nor has it addressed
6 concerns about the asymmetry and lack of safeguards embedded in the WNA design.¹⁰⁹
7 The current proposal to make the pilot permanent, without modification or review,
8 disregards the Commission's directive to justify the mechanism in future proceedings with
9 a meaningful record.

10 **Q. DOES THE MECHANISM'S DESIGN CONTRIBUTE TO THIS ASYMMETRY?**

11 A. Yes. A key issue is the Company's use of a backward-looking 20-year average to
12 define "normal" weather. Given recent warming trends, this definition may overstate the
13 expected number of heating degree days in a typical year. As a result, actual HDDs often
14 fall short of "normal," which triggers automatic surcharges. This results in a structurally
15 biased mechanism that consistently benefits the utility at the expense of ratepayers.

16 **Q. HAS THE COMPANY JUSTIFIED THE CONTINUED USE OF THIS WEATHER**
17 **NORMALIZATION METHODOLOGY?**

18 A. Not persuasively. While the Company argues that the 20-year average HDD is a
19 better predictor of future weather than a 30-year average, it has provided no analysis of
20 the impact this choice has had on customer bills.¹¹⁰ More importantly, it has not

¹⁰⁸ Response to Discovery Request OCA 13-022.

¹⁰⁹ See, Direct Testimony of John Taylor, Company Statement No. 17 at 39:19-40:1.

¹¹⁰ See, Direct Testimony of Michael Girata, Company Statement No. 2 at 5:18-21.

1 addressed whether that methodology, when embedded in a ratemaking formula with
2 either reconciliation or an earnings test, has produced just and reasonable outcomes for
3 customers. A predictive model may be statistically valid but still produce inequitable
4 results if it is used in a rigid surcharge formula with no safeguards.

5 **Q. HAS THE COMPANY IDENTIFIED HOW THE MERITS OF THE WNA WOULD**
6 **BE EVALUATED?**

7 A. No. Despite operating the WNA on a pilot basis for over a decade, the Company
8 has never identified criteria or performance metrics by which the WNA would be
9 evaluated.¹¹¹ The Company has not defined what would constitute success under the
10 pilot, nor has it conducted any assessment of customer bill stability, fairness, or long-term
11 cost impacts. Without such evaluative benchmarks, the Commission and stakeholders
12 are left with no meaningful way to determine whether the WNA has functioned as intended
13 or delivered any benefits to ratepayers. The Company's current request to make the
14 WNA permanent underscores the Company's disregard for the evidentiary and
15 procedural standards typically expected in ratemaking.

16 **Q. WHAT HAS BEEN THE ACTUAL IMPACT OF THE WNA ON RATEPAYERS?**

17 A. The actual impact of the WNA on residential customers has been consistently
18 negative, resulting in substantial bill surcharges. The Company has filed annual WNA
19 reports since 2014 with the Commission that summarize the total dollar amount of WNA
20 charges and credits issued to residential customers during each heating season.¹¹²

¹¹¹ Response to Discovery Request OCA 13-022.

¹¹² Response to Discovery Request OCA 13-22

Exhibit MWD-11 includes a summary of the over/under collections from these reports for each of the past 12 heating season since the WNA's first year covering the 2013-2014 heating season. Over the most recent five heating seasons, from the 2020-2021 through 2024-2025 heating seasons, the Company has collected approximately \$71.3 million in net WNA revenues from residential customers. Each of those years resulted in a net surcharge to consumers. During this period, the Company *never* issued a refund to consumers under the WNA despite claiming that the mechanism is symmetrical. This pattern reveals that the WNA has functioned as one-sided charge, imposing consistent financial burdens on ratepayers while failing to deliver measurable bill stability or balance.

Q. HAS THE WNA EVER RESULTED IN NET REFUNDS TO CUSTOMERS?

A. Yes, but only in earlier years. The WNA produced net credits in four of the first seven heating seasons it was in effect, specifically 2013-2014, 2014-2015, 2017-2018, and 2018-2019. However, for each year since the 2019-2020 heating season, the WNA has consistently resulted in net surcharges to customers every year. In total, only four of the 12 historic heating seasons for which the WNA has been in place did customers see net credits under the mechanism.

Q. ARE ONE-WAY SURCHARGE MECHANISMS CONSISTENT WITH SOUND REGULATORY POLICY?

A. No. Regulatory policy disfavors mechanisms that allow utilities to recover lost revenues or costs from customers without also exposing the utility to comparable downside risk or performance standards. The WNA, as designed and applied by the Company, operates as a one-way ratchet: imposes surcharges but has failed to provide

1 meaningful refunds, due to its design. This violates basic ratemaking principles of
2 fairness and reciprocity between ratepayers and shareholders.

3 **Q. IS THE COMPANY'S CLAIMED NEED FOR A WNA SUPPORTED BY ITS OWN**
4 **REVENUE PERFORMANCE?**

5 A. No. While the Company points to year-over-year revenue under-recovery as
6 justification for the WNA,¹¹³ the facts reveal a different story. The WNA has produced
7 recurring surcharges, yet the Company continues to experience shortfalls in overall
8 revenue recovery. This disconnect suggests that the WNA fails to do what it is intended
9 to do, which is to stabilize revenue. The Company's own filing in this case reinforces that
10 conclusion by proposing an entirely separate RNA to address non-weather-related
11 revenue volatility. In effect, the Company admits that the WNA is insufficient and then
12 uses that insufficiency as justification for layering on a second, broader decoupling
13 mechanism.

14 **Q. HOW DOES THE COMPANY'S RNA PROPOSAL AFFECT ITS CLAIMS ABOUT**
15 **THE WNA?**

16 A. The Company's proposed RNA undermines the claim that the WNA provides
17 sufficient revenue stability. Columbia admits that even with the WNA in place, it continues
18 to experience revenue volatility. This contradiction raises serious concerns about the
19 effectiveness of the WNA and whether it serves any practical purpose beyond creating a
20 one-sided revenue stream for the utility.

¹¹³ See, Direct Testimony of John Taylor, Company Statement No. 17 at 30:13-15.

1 **Q. ARE THERE OTHER CONCERNS REGARDING THE WNA?**

2 A. Yes. OCA Witness Colton discusses the negative impacts the current WNA has
3 on ratepayers, particularly low-income ratepayers. As he notes, that the WNA has
4 resulted in consistent surcharges contributes to the growing unaffordability of rates in the
5 Company's service territory. He also criticizes the idea that the WNA protects residential
6 customers from bill volatility due to weather variability noting that programs like budget
7 billing provide better protection to residential customers from bill volatility than the WNA.
8 OCA Witness Colton also discusses public testimony offered at Public Input Hearings
9 ("PHI") as it pertains to customer concerns related to the rates. In general, these
10 customers attested to the real life impacts of macro-economic issues such as inflation
11 and economic uncertainty, and how growing bill unaffordability contributes to these
12 hardships. Customers also noted that the WNA, and the Company's proposed RNA, add
13 to these concerns by reducing the ability of customers to control their utility bill during
14 these economic hardships by reducing the impact of efforts to reduce utility bills by
15 reducing energy consumption.

16 OCA Witness Alexander also discusses Columbia's customer communications
17 concerning the WNA. Ms. Alexander criticizes the Company's handling of customer
18 inquiries about WNA charges on their bill, including failing to provide the customer with
19 specific information on how their WNA was calculated. She finds that Columbia's reliance
20 on providing the WNA calculation in its tariff is misplaced, as customer communications
21 do not refer to the tariff and include no formula for the calculation is included in customer-
22 facing materials, including Columbia's website and other communications. Ms. Alexander
23 also found that Columbia does not disclose to customers that the actual operation of the

WNA has favored the Company's revenues, instead of acting symmetrically as described on Columbia's website or in other communication materials.

Q. WHAT IS YOUR POSITION ON THE COMPANY'S WNA RATEMAKING MECHANISM?

A. I recommend that the Commission affirmatively discontinue the current WNA mechanism. Despite operating the WNA on a pilot basis for over a decade, the Company has not identified clear criteria for evaluating its performance or demonstrated that the mechanism has produced balanced outcomes for ratepayers. Indeed, the mechanism has functioned as an asymmetric surcharge on customers bills for the past six heating seasons, even though the mechanism was designed to symmetrically provide both surcharges and credits to customers.

VI. ECONOMIC DEVELOPMENT DISTRIBUTION SERVICE RATE SCHEDULE

Q. PLEASE DESCRIBE THE COMPANY'S EDDS RATE SCHEDULE.

A. The proposed EDDS grants additional flexibility to new large load customers seeking to locate to the Company's service territory. Under the EDDS, the Company proposes to treat these large load customers as non-jurisdictional customers, providing the opportunity for the Company to enter into individual contracts with these customers, allowing for billing rates that reflect the costs of their individual needs without the potential for these customers to be subsidized by jurisdictional customers.¹¹⁴

¹¹⁴ Direct Testimony of Nicole M. Paloney at 41:7-15.

Q. WHY IS THE COMPANY PROPOSING THE EDDS RATE SCHEDULE IN THE CURRENT PROCEEDING?

A. The Company references the January 2024 strategic plan for economic development in Pennsylvania released by Governor Shapiro and the Department of Community and Economic Development (“DCED”), as outlining a desire to make Pennsylvania a national leader in innovation, job creation, and economic development.¹¹⁵ The Company states that its proposed EDDS rate schedule will provide a pathway for large volume customers to work collaboratively with the Company to accelerate investment in the Commonwealth.¹¹⁶ The Company notes that these entities will require large amounts of electricity and are willing to develop capabilities to use natural gas to generate electricity.¹¹⁷

Q. DOES THE COMPANY CURRENTLY HAVE CUSTOMERS THAT HAVE EXPRESSED INTEREST IN THE PROPOSED EDDS RATE SCHEDULE?

A. No. The Company admits that it “currently does not have customers that have expressed an interest in the service that would be provided by this rate schedule...”¹¹⁸ However, the Company still proposes the EDDS under the assumption that there may be a need for such a service in the foreseeable future.¹¹⁹ Specifically, the Company notes that the electric industry is facing a constrained environment regarding transmission and

¹¹⁵ *Id.* at 40:18 to 41:3.

¹¹⁶ *Id.* at 41:3-6.

¹¹⁷ *Id.* at 41:18 to 42:3.

¹¹⁸ *Id.* at 42:5-6.

¹¹⁹ *Id.* at 42:6-7.

1 generation development that may make large volume customers turn to on-site natural
 2 gas generation as an alternative to meet their electricity needs.¹²⁰

3 **Q. DOES THE COMPANY'S PROPOSAL TO TREAT EDDS CUSTOMERS AS**
 4 **NON-JURISDICTIONAL CUSTOMERS INSULATE OTHER JURISDICTIONAL**
 5 **CUSTOMERS FROM THE POTENTIAL TO SUBSIDIZE THESE CUSTOMERS?**

6 A. Yes. The Company's proposal means that facilities constructed for the benefit of
 7 these individual customers will not be included in the Company's retail revenue
 8 requirement, meaning that retail customers should be protected from having to pay for
 9 these facilities.¹²¹ However, upgrades to jurisdictional facilities required to maintain safe,
 10 reliable service for retail customers with the inclusion of EDDS large volume customers
 11 would still be included in retail revenue requirement.¹²² In these cases the Company
 12 states that EDDS customers would pay their share of these facilities costs so that retail
 13 customers are not burdened by EDDS customers.¹²³

14 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE PROPOSED EDDS**
 15 **RATE SCHEDULE?**

16 A. The proposed EDDS rate schedule appears to be a solution to a non-existent
 17 problem, with no customer that have expressed interest in the proposed program.
 18 However, if the Commission decides to approve the proposed EDDS, I recommend that
 19 the Commission review the program in future rate cases to ensure that EDDS customers

¹²⁰ *Id.* at 42:13-17.

¹²¹ *Id.* at 43:3-8.

¹²² *Id.* at 43:18-19.

¹²³ *Id.* at 43:19 to 44:1.

are not being subsidized by retail ratepayers. This is consistent with the program's design as laid out by the Company.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSED RNA?

A. I recommend that the Commission reject the Company's proposed Revenue Normalization Adjustment. The proposal represents a full revenue decoupling mechanism that would guarantee the Company recovery of its authorized base distribution revenue regardless of actual sales, including usage declines due to weather, conservation, energy efficiency, electrification, or economic factors. The Company has not demonstrated that its current ratemaking tools such as the FPFTY and frequent base rate filings are insufficient to manage revenue variability. The RNA provides no ratepayer benefits, includes no consumer protections, and would shift nearly all usage-related business risk from shareholders to ratepayers. The proposal is one-sided, lacks any tie to energy efficiency outcomes, and could lead to frequent surcharges with no corresponding benefits to customers. For these reasons, the RNA should be rejected.

Q. WHAT IS YOUR POSITION ON THE COMPANY'S WNA RATEMAKING MECHANISM?

A. I recommend that the Commission affirmatively discontinue the current WNA mechanism. Despite operating the WNA on a pilot basis for over a decade, the Company has not identified clear criteria for evaluating its performance or demonstrated that the mechanism has produced balanced outcomes for ratepayers. Additionally, if the

1 Commission were to approve the Company's proposed RNA, continuing the WNA would
2 introduce overlapping and duplicative recovery of weather-related revenue shortfalls.

3 **Q. WHAT IS YOUR POSITION ON THE COMPANY'S PROPOSED EEDS TARIFF?**

4 A. I recommend that the Commission reject the Company's proposal to establish the
5 EEDS tariff. The proposed tariff is ill-defined, establishing a service the Company itself
6 admits its customers have not sought. If the Commission does decide to approve the
7 proposed EEDS tariff, I recommend that the Commission review the tariff performance in
8 future rate cases to ensure that non-EEDS jurisdictional customers are not subsidizing
9 EEDS service.

10 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

11 A. Yes.

Appendix A

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EDUCATION

M.A. in Economics, Kansas University, 2009

B.A. in Business Economics, Buena Vista University, 2007

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

Spring 2025 – Present	Senior Research Consultant
Summer 2021 – Spring 2025	Research Consultant
Summer 2016 – Summer 2021	Research Associate
Winter 2011 – Summer 2016	Senior Research Analyst

Kansas Corporation Commission, Topeka, Kansas

Utilities Division

Summer 2011 – Winter 2011	Senior Research Economist

Research Division

Spring 2009 – Summer 2011	Research Analyst

Kansas Energy Council

Summer 2008 – Spring 2009	Research Assistant

PUBLICATIONS AND REPORTS

1. The challenges of the regulatory review of diversification mergers. With Dr. David E. Dismukes. *The Electricity Journal* 29 (2016) 8-14. (May 2016)

PROFESSIONAL AND CIVIC PRESENTATIONS

1. “Development Trends, Issues, and Challenges with Clean Hydrogen Production” (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 15, 2025.
2. “Status and Future of Natural Gas Supply and Infrastructure” (2025). Prepared for the Michigan State University, Institute of Public Utilities, Annual Regulatory Studies Program. April 8, 2025.

3. "Observed Impact of Formula Rate Plans Across the United States" (2024). Prepared for Arizona Corporation Commission Formula Rate Plan Workshop. October 3, 2024.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Cause No. 46120. (2025). Before the Indiana Utility Regulatory Commission. *Verified Petition of NIPSCO Generation LLC for Certain Determinations by the Commission with Respect to its Jurisdiction Over Petitioner's Activities as a Non-Retail Generator of Electric Power*. On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.
2. Expert Testimony. Case No. U-21859. (2025). Before the Michigan Public Service Commission. *In the matter of the application of Consumers Energy Company for Ex Parte Approval of Certain Amendments to Rate GPD*. On Behalf of the Michigan Attorney General. Issues: Rate Design, Large Data Center Loads.
3. Expert Testimony. Docket No. R-2025-3053112. (2025). Before the Pennsylvania Public Utilities Commission. *Pennsylvania Public Utility Commission v. Philadelphia Gas Works*. On Behalf of the Pennsylvania Office of Consumer Advocate. Issues: Decoupling, Regulatory Lag.
4. Expert Testimony. Docket No. E-01773A-24-0220. (2025). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Electric Power Cooperative, Inc. for a Hearing to Determine the Fair Value of its Property for Ratemaking Purposes, to Fix a Just and Reasonable Return Thereon and To Approve Rates Designed to Develop Such Return*. On Behalf of Arizona Corporation Commission Staff. Issues: Cost of Service, Qualifying Facilities.
5. Expert Testimony. Case No. U-21816. (2025). Before the Michigan Public Service Commission. *In the matter of Consumer Energy Company's application for the regulatory reviews, revisions, determinations, and/or approvals necessary to fully comply with Public Act 295 of 2008, as amended by Public Act 235 of 2023*. On Behalf of the Attorney General. Issues: Capital Expense, Cost Recovery
6. Expert Testimony. Cause No. 46120. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42.4, 8-1-2-61 and 8-1-2.5-6 for (1) Authority to Modify its Retail Rates and Charges for Electric Utility Service Through a Phase in of Rates; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders (both Existing and New); (3) Approval of Revised Common and Electric Depreciation Rates Applicable to its Electric Plant in Service; (4) Approval of Necessary and Appropriate Accounting Relief, Including, but*

Limited to, Authority to Capitalize as Rate Base All Expenditures for Improvements to Petitioner's Information Technology Systems through the Design, Development, and Implementation of a Work and Asset Management ("WAM") Program, to the Extent Necessary; and (5) Approval of Alternative Regulatory Plans for the Partial Waiver of 170 IAC 4-1-16(f) and Proposed Remote Disconnection and Reconnection Process and, to the Extent Necessary, Implementation of a Low Income Program. On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Cost of Service, Rate Design.

7. Expert Testimony. Cause No. 46097. (2024). Before the Indiana Utility Regulatory Commission. *In the Matter of the Verified Petition of Indiana Michigan Power Company for Approval of Modifications to its Industrial Power Tariff – Tariff I.P.* On Behalf of the Indiana Office of Utility Consumer Counselor. Issues: Rate Design, Large Data Center Loads.
8. Expert Report. Docket No. AHD-00000J-23-0273. (2024). Before the Arizona Corporation Commission. *In the Matter of the Application of the Arizona Corporation Commission's Exploration of Changes to the Up to 10% Annual Reduction in the Export Rate and the 10-Year Export Rate Effective Period Under the Resource Comparison Proxy Methodology Approved in the Value and Cost of Distributed Generation Docket (E-00000J-14-0023).* On Behalf of the Arizona Corporation Commission Staff. Issues: Value of Solar.
9. Expert Testimony. Case No. U-21585. (2024). Before the Michigan Public Service Commission. *In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and Other Relief.* On Behalf of the Attorney General. Issues: Capital Expenses.
10. Expert Report. *Review of LPSC Rules Regarding Distributed Generation: Report on Phase II of Rule-Making.* Docket No. R-33929. (2019). *In Re: Review of Policies Related to Customer-owned Solar Generation and Possible Modification of the Commission's Current Net Metering Rules.* On behalf of Louisiana Public Service Commission. Issues: Solar Net Metering.
11. Expert Report. (2011). *2011 Kansas Generation Planning Survey.* On behalf of the Kansas Corporation Commission Staff.
12. Expert Testimony. Docket No. 11-KCPE-581-PRE. (2011). Before the Kansas Corporation Commission. *In the Matter of the Petition of Kansas City Power & Light Company ("KCP&L") for Determination of the Ratemaking Principles and Treatment That Will Apply to the Recovery in Rates of the Costs to be Incurred by KCP&L for Certain Electric Generation Facilities Under K.S.A. 66-1239.* On Behalf of the Kansas Corporation Commission Staff. Issues: System Planning, Predetermination.

13. Expert Testimony. Docket No. 10-KCPE-795-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas City Power & Light Company for Approval to Implement a Portfolio of Demand Side Management Programs Including Affordability, Energy Efficiency, Demand Response and Educational Programs, and to Implement a Rider for Recovery of Program Costs and Incentives Associated with this Portfolio.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.
14. Expert Testimony. Docket No. 10-WSEE-775-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Westar Energy, Inc. and Kansas Gas and Electric Company for an Order Authorizing them to participate in Efficiency Kansas, Approve the SimpleSavings Program Rider, and related cost recovery.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.
15. Expert Testimony. Docket No. 10-BHCG-639-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Black Hills/Kansas Gas Utility Company, LLC, d/b/a Black Hills Energy for Approval to Implement Black Hills Energy's Five-Year Energy Efficiency Plan Consisting of Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate About Efficient Energy Usage, to Provide for Program Cost Recovery Through a Rider Mechanism, Permit the Implementation of a Revenue Normalization Mechanism to Replace the Weather Normalization Adjustment, a Performance Incentive Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.
16. Expert Testimony. Docket No. 10-EPDE-497-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of the Empire District Electric Company for Approval to Implement its Portfolio of Energy Efficiency and Demand Response Programs for its Kansas Customers, to Provide for Program Cost Recovery and Lost Revenue Through a Rider Mechanism, to Obtain any Necessary Waivers for the Commission, and for Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.* On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.
17. Expert Testimony. Docket No. 10-KGSG-421-TAR. (2010). Before the Kansas Corporation Commission. *In the Matter of the Application of Kansas Gas Service, a Division of ONEOK, Inc., for Approval to Implement the Efficiency Kansas Energy Efficiency Program, to Implement Natural Gas Energy Efficiency Programs to Improve Building and Equipment Efficiency and to Educate about Efficient Energy Usage, To Provide for Program Cost Recovery Through a Rider Mechanism, to Establish Administrative Charges and a Program Initiation Fee, Permit the*

Implementation of a Revenue Decoupling Mechanism, and Appropriate Accounting Authority to Defer Expenses and Revenues Associated with the Filing.
On Behalf of the Kansas Corporation Commission Staff. Issues: Demand Side Management, Cost-Benefit Analyses.

EXHIBITS

Table of Exhibits

Title	Exhibit
Commission Alternative Regulation Considerations (§ 69.3302)	Exhibit MWD-1
Map of States with Decoupling Programs	Exhibit MWD-2
Decoupling Program Adoption by Year	Exhibit MWD-3
Columbia Gas Historic ROE (2010-2024)	Exhibit MWD-4
Analysis of Consumption and Customer Trends	Exhibit MWD-5
Summary of Lesh Report	Exhibit MWD-6
Peer Comparison of Average Total Revenues	Exhibit MWD-7
NiSource Investor Relations Presentations	Exhibit MWD-8
Survey of Ratepayer Protection Mechanisms	Exhibit MWD-9
ROE Adjustments in States with Revenue Decoupling	Exhibit MWD-10
Summary of WNA Annual Reports	Exhibit MWD-11

Commission Alternative Regulatory Considerations (§ 69.3302), Revenue Normalization Adjustment (RNA)

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-1
Page 1 of 4

Commission Consideration Criteria		Discussion
§ 69.3302(a)(1)	How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.	The Company's proposed RNA does not address the Commission's consideration criteria aligning revenues with cost causation. The proposed RNA is premised on ensuring the Company will recover its annual fixed costs of providing gas distribution service; while the proposed RNA adjustment however is applied as a variable charge to customer's bills.
§ 69.3302(a)(2)	How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.	Proposed RNA will not impact capacity utilization.
§ 69.3302(a)(3)	Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption level.	Proposed RNA will incorporate forecasted volumes included in a projected test year. These forecasts however are prone to errors which can bias future RNA surcharges. Furthermore, the proposed RNA allows for increased rates between rate cases due to reductions in consumption due to energy efficiency, potentially discouraging adoption of energy efficiency measures.
§ 69.3302(a)(4)	How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.	A separate RNA will be calculated for each class and, therefore, there will be no inter-class cost shifting. However, with respect to intra-class cost shifting, the RNA could shift revenue within the Residential class from customers who are financially able to invest in energy efficiency and conservation measures to low-income customers who are not financially able to make those same investments.
§ 69.3302(a)(5)	How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.	The Company has not proven that it is materially disadvantaged from pursuing energy efficiency programs currently. Moreover, the Company, like nearly all gas utilities, has historically seen declining use per customer without the proposed RNA.
§ 69.3302(a)(6)	How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.	Proposed RNA may disincentivizing customers to pursue energy efficiency programs since revenue savings that would ordinarily be achieved through usage reductions will be offset by higher usage charges under the RNA. This differs from traditional ratemaking where all customer-achieved usage reductions accrue to ratepayers until the filing of the utility's next rate case.
§ 69.3302(a)(7)	How the ratemaking mechanism and rate design impact low-income customers and support customer assistance programs.	Proposed RNA may lead to intraclass subsidies from less advantaged residential ratepayers to more advantaged residential ratepayers to the extent decreases in sales are due to implementation of energy efficiency measures. Low-income customers are generally viewed as having limited ability to pursue energy efficiency initiatives due to limited resources.

Commission Alternative Regulatory Considerations (§ 69.3302), Revenue Normalization Adjustment (RNA)

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-1
Page 2 of 4

Commission Consideration Criteria		Discussion
§ 69.3302(a)(8)	How the ratemaking and rate design impact customer rate stability principles.	The Company fails to include a cap on surcharges under the proposed RNA. Therefore, the proposed RNA may result in extraordinary reconciliation charges. Furthermore, on a more basic level, under traditional regulation the utility retains the ability to seek changes in rates within the context of a full rate case if a utility experience revenue shortfalls due to declining sales. The proposed RNA, on the other hand, will add an additional surcharge to ratepayer bills without any demonstration from the Company that the proposed RNA will reduce the frequency of future rate filings.
§ 69.3302(a)(9)	How weather impacts utility revenue under the ratemaking mechanism and rate design.	The proposed RNA proposes to extend the existing WNA designed to recover revenue changes due to fluctuations in weather to all other non-weather factors affecting month-to-month revenue changes.
§ 69.3302(a)(10)	How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.	It is unlikely that the inclusion of the proposed RNA will not prevent the Company from seeking additional rate increases in the future. This is because the proposed RNA does not affect future revenue requirements that are incurred above that approved by the Commission. Therefore, if future rate cases are driven by future investment needs or higher expenses and associated cost recovery, the RNA would not reduce the need for such cases.
§ 69.3302(a)(11)	If or how the ratemaking mechanism and rate design interact with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa. C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa. C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa. C.S. § 1353 (relating to distribution system improvement charge).	The proposed RNA applies only to base rates and does not impact surcharges.
§ 69.3302(a)(12)	Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.	The proposed RNA does not include any consumer protections. These include caps on RNA charges, checks on over-earnings, or specific energy efficiency targets.
§ 69.3302(a)(13)	Whether the alternative ratemaking mechanism and rate design are understandable to consumers.	Customers may find the proposed RNA confusing since it allows for the utility to increase rates to offset negative changes in natural gas sales such as customer-initiated energy efficiency measures. It is also impossible for customers to forecast RNA charges in advance as the mechanism is premised on Company recovery of its allowed revenue requirement, which is unknowable in advance. This will add to customer confusion.
§ 69.3302(a)(14)	How the ratemaking mechanism and rate design will support improvements in utility reliability.	The proposed RNA will not lead to changes in the Company's quality of service, either positively or negatively. The proposed RNA is not tied to achievement of any energy efficiency or service reliability performance, but will reduce the positive incentive of regulatory lag for the Company to control costs. The Company also retains the ability to file rate cases in the future using a projected future test year to address concerns associated with capital improvements required to facilitate reliable delivery of natural gas.

Commission Alternative Regulatory Considerations (§ 69.3302), Weather Normalization Adjustment (WNA)

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-1
Page 3 of 4

Commission Consideration Criteria		Discussion
§ 69.3302(a)(1)	How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.	The WNA does not address the Commission's consideration criteria aligning revenues with cost causation. The WNA is premised on ensuring the Company will recover its annual fixed costs of providing gas distribution service; however, the WNA adjustment is applied as a variable charge to customer's bills.
§ 69.3302(a)(2)	How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.	Proposed WNA does not impact capacity utilization, as the determining metric for the charge is weather, not utilization.
§ 69.3302(a)(3)	Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption level.	The WNA adjustment mechanism creates the anomaly where customers see rate increases when they reduce consumption and rate decreases when they increase consumption. If the WNA is generating revenue, then it inherently does not reflect the level of demand associated with the customer's anticipated consumption levels, because the WNA only generates revenue if the demand is less than anticipated.
§ 69.3302(a)(4)	How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.	The WNA may have led to intraclass cost shifting to the extent that smaller use residential customers typically have a greater percentage of natural gas use that is temperature-sensitive compared to larger use residential customers.
§ 69.3302(a)(5)	How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.	The WNA does not limit or eliminate disincentives for the promotion of energy efficiency. The WNA is solely tied to adjustment in customer usage attributed to changes in heating requirements and is not impacted by a reduction in customer use due to energy efficiency initiatives. The Company has not demonstrated that the lack of a WNA would present a major obstacle for the promotion of energy efficiency programs.
§ 69.3302(a)(6)	How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.	The WNA may be perceived as a disincentive to employ energy efficiency measures for customers whose energy efficiency initiative takes place during periods of warmer than normal weather. These customers will see increased WNA charges after reducing usage through implementing energy efficiency initiatives.
§ 69.3302(a)(7)	How the ratemaking mechanism and rate design impact low-income customers and support customer assistance programs.	The WNA may harm low-income customers as these customers have less ability to weatherize homes to reduce impact of weather fluctuations on consumption.
§ 69.3302(a)(8)	How the ratemaking and rate design impact customer rate stability principles.	The WNA adds another surcharge to customers' bills without any showing that the WNA would reduce the frequency of base rate case filings. It therefore does not improve rate stability.

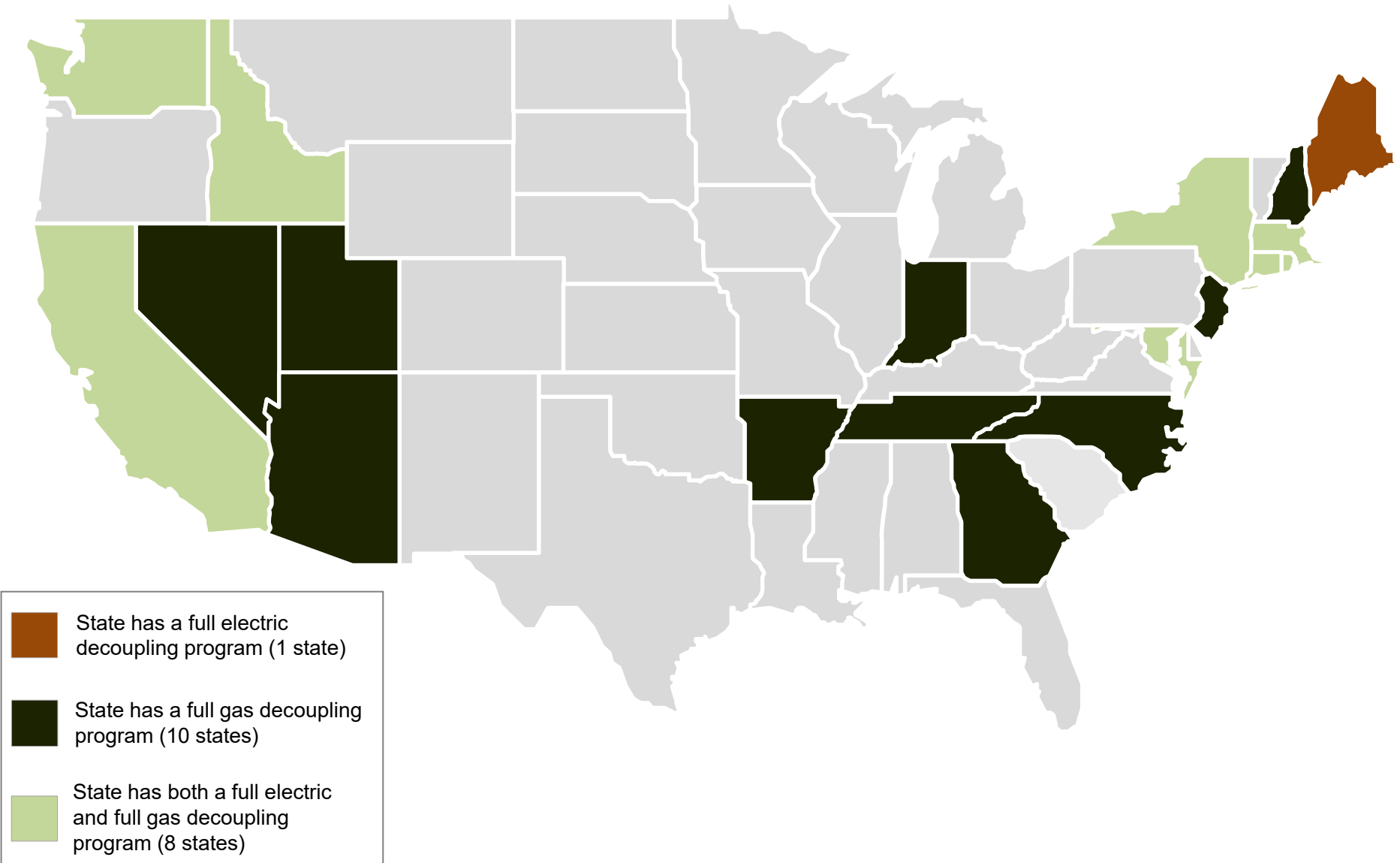
Commission Alternative Regulatory Considerations (§ 69.3302), Weather Normalization Adjustment (WNA)

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-1
Page 4 of 4

Commission Consideration Criteria	Discussion
§ 69.3302(a)(9) How weather impacts utility revenue under the ratemaking mechanism and rate design.	While the WNA is premised on reducing risks to the Company revenue stability caused by fluctuations in weather conditions, in practice it is not a revenue neutral mechanism. Of the 12 heating seasons 2013-2014 through 2024-2025, only 4 (33 percent) have included WNA credits to ratepayers. Indeed, over these 12 heating seasons the Company has collected on net nearly \$71.6 million from ratepayers through the WNA.
§ 69.3302(a)(10) How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.	Historically the Company has filed multiple rate case over the last decade, despite possessing the WNA. This is unlikely to change and the WNA does not prevent the Company from seeking additional rate increases driven by future investment needs or higher expenses and associated cost recovery. The WNA does, however, weaken the positive impacts regulatory lag has on promoting cost containment between rate cases. Regulatory lag has long been recognized as a key component of the overall regulatory compact that disciplines utility operational and investment decisions between rate cases. Regulatory lag in particular diminishes incentives for utilities to overcapitalize since the inefficiencies associated with overcapitalization are passed directly to shareholders until reviewed by the Commission in the utility's next rate case.
§ 69.3302(a)(11) If or how the ratemaking mechanism and rate design interact with other revenue sources, such as Section 1307 automatic adjustment surcharges, 66 Pa. C.S. § 1307 (relating to sliding scale of rates; adjustments), riders such as 66 Pa. C.S. § 2804(9) (relating to standards for restructuring of electric industry) or system improvement charges, 66 Pa. C.S. § 1353 (relating to distribution system improvement charge).	The WNA applies only to base rates and does not impact surcharges.
§ 69.3302(a)(12) Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.	The WNA does not include sufficient consumer protections. These include checks on over-earnings to prevent overall rate increases through WNA reconciliations.
§ 69.3302(a)(13) Whether the alternative ratemaking mechanism and rate design are understandable to consumers.	Customers have no means of anticipating future WNA changes as it is impossible for customers to forecast WNA charges in advance and likely difficult for customers to calculate even after the fact. For these reasons elements of the WNA likely not understandable to customers and effectively is viewed as just another surcharge present on the customer's bill.
§ 69.3302(a)(14) How the ratemaking mechanism and rate design will support improvements in utility reliability.	The WNA has not lead to changes in the Company's quality of service, either positively or negatively. The WNA is not tied to achievement of increased service reliability performance, but has reduced the positive incentive of regulatory lag for the Company to control costs and led to customer confusion. The Company retains the ability to file rate cases using a projected future test year to address concerns associated with capital improvements required to facilitate reliable delivery of natural gas.

Map of States with Decoupling Programs

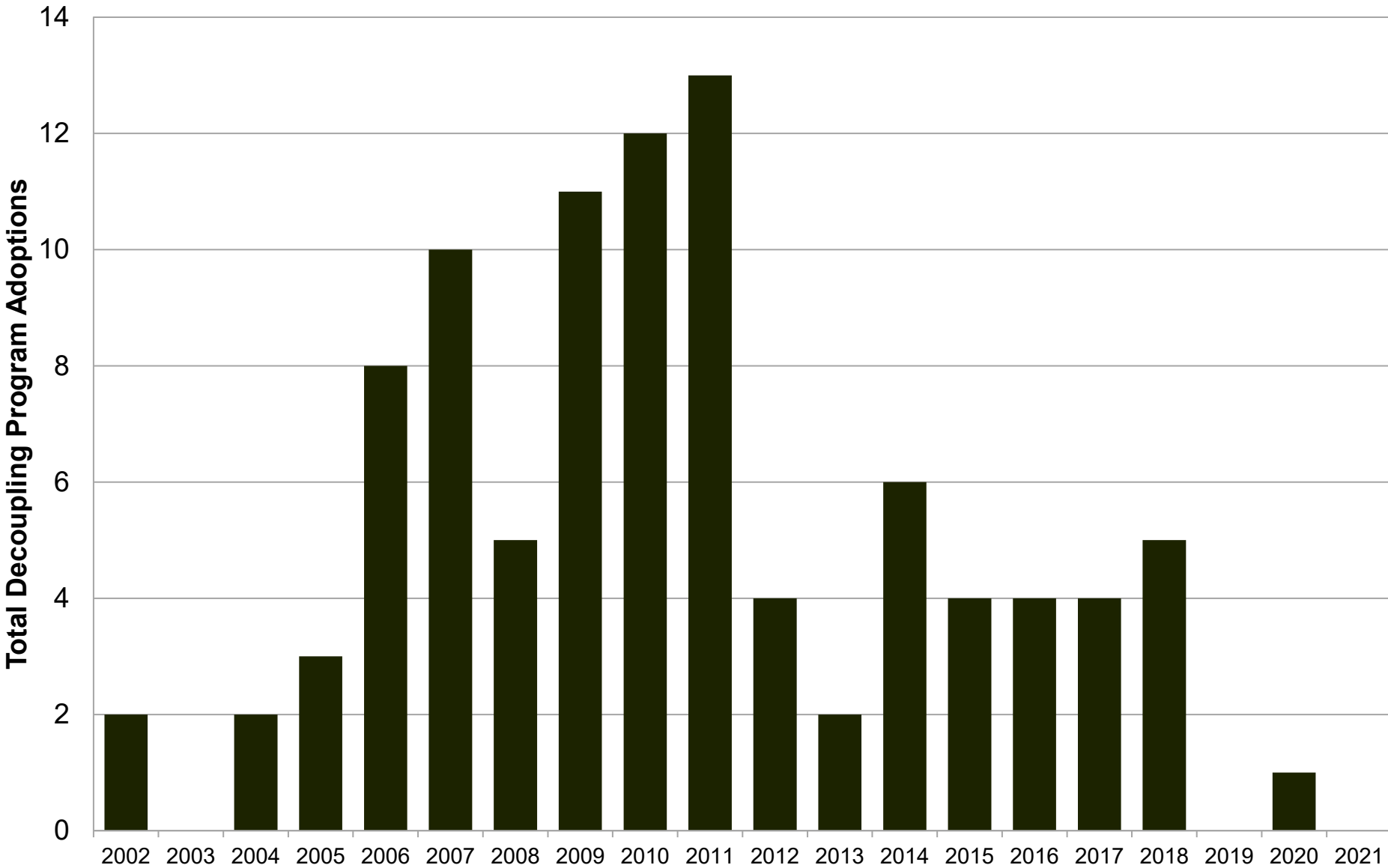
Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-2



Source: S&P Global.

Decoupling Program Adoption by Year

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-3



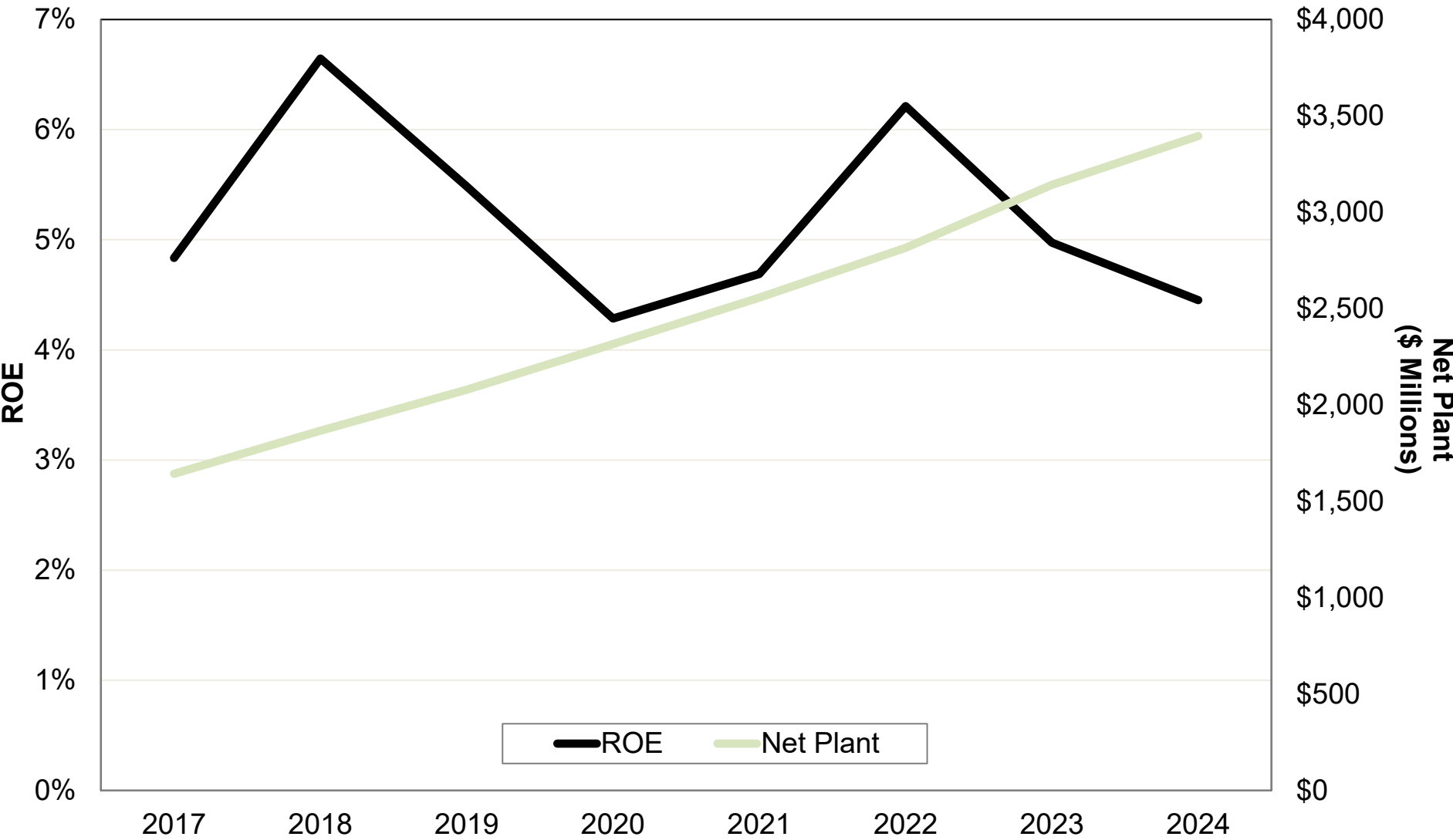
Columbia Gas Historic ROE (2010-2024)

	2010	2011	2012	2013	2014	2015	2016
	----- (\$000) -----						
Total Proprietary Capital	\$ 346,344	\$ 328,631	\$ 426,407	\$ 474,867	\$ 538,530	\$ 602,947	\$ 669,776
Total Long-term Debt	313,215	248,390	356,390	411,390	394,040	495,515	540,515
Total Capitalization	\$ 659,559	\$ 577,021	\$ 782,797	\$ 886,257	\$ 932,570	\$ 1,098,462	\$ 1,210,291
Revenue	\$ 559,163	\$ 504,751	\$ 406,292	\$ 512,312	\$ 563,310	\$ 536,212	\$ 493,930
Operating Expenses	495,688	445,078	341,626	434,859	478,471	445,191	400,158
Other Operating Income	-	-	-	-	-	-	-
Other Income	5,286	3,368	5,391	3,465	4,627	2,123	3,254
Other Income Deductions	623	667	530	733	393	749	390
Taxes on Other Income & Deductions	(1,566)	(588)	(1,919)	(1,317)	(1,564)	(1,530)	(1,182)
Interest Charges	16,385	20,247	20,900	22,416	23,880	26,617	28,624
Extraordinary Items	-	-	-	-	-	-	-
Net Income	\$ 50,187	\$ 41,539	\$ 46,708	\$ 56,452	\$ 63,629	\$ 64,248	\$ 66,830
Equity Percentage of Total Capitalization	52.5%	57.0%	54.5%	53.6%	57.7%	54.9%	55.3%
Net Income Available to Equity	\$ 26,354	\$ 23,658	\$ 25,443	\$ 30,248	\$ 36,744	\$ 35,266	\$ 36,984
Net Plant in Service	\$ 694,591	\$ 776,735	\$ 886,050	\$ 1,007,076	\$ 1,152,812	\$ 1,287,276	\$ 1,458,889
Return on Equity	7.61%	7.20%	5.97%	6.37%	6.82%	5.85%	5.52%

Columbia Gas Historic ROE (2010-2024)

	2017	2018	2019	2020	2021	2022	2023	2024
	----- (\$000) -----							
Total Proprietary Capital	\$ 735,601	\$ 886,397	\$ 983,420	\$ 1,125,005	\$ 1,320,480	\$ 1,483,215	\$ 1,628,137	\$ 1,768,525
Total Long-term Debt	625,515	705,515	785,515	895,515	1,035,515	1,135,515	1,285,515	1,385,515
Total Capitalization	\$ 1,361,116	\$ 1,591,912	\$ 1,768,935	\$ 2,020,520	\$ 2,355,995	\$ 2,618,730	\$ 2,913,652	\$ 3,154,040
Revenue	\$ 562,611	\$ 590,241	\$ 602,397	\$ 555,341	\$ 666,569	\$ 867,641	\$ 821,141	\$ 759,726
Operating Expenses	467,064	450,185	466,781	427,249	510,452	654,515	617,237	558,679
Other Operating Income	-	-	-	-	-	-	-	-
Other Income	3,719	1,156	(213)	615	(920)	(604)	(76)	3,376
Other Income Deductions	486	377	599	624	1,542	851	2,291	292
Taxes on Other Income & Deductions	(1,020)	(124)	281	(53)	1,284	730	356	976
Interest Charges	31,935	34,916	38,062	41,445	44,464	49,665	56,972	64,720
Extraordinary Items	-	-	-	-	-	-	-	-
Net Income	\$ 65,825	\$ 105,795	\$ 97,023	\$ 86,585	\$ 110,475	\$ 162,736	\$ 144,921	\$ 140,387
Equity Percentage of Total Capitalization	54.0%	55.7%	55.6%	55.7%	56.0%	56.6%	55.9%	56.1%
Net Income Available to Equity	\$ 35,574	\$ 58,908	\$ 53,939	\$ 48,210	\$ 61,919	\$ 92,172	\$ 80,981	\$ 78,717
Net Plant in Service	\$ 1,643,093	\$ 1,866,780	\$ 2,079,108	\$ 2,315,526	\$ 2,556,420	\$ 2,815,330	\$ 3,141,815	\$ 3,395,303
Return on Equity	4.84%	6.65%	5.48%	4.29%	4.69%	6.21%	4.97%	4.45%

Columbia Gas Historic ROE (2010-2024)



Source: Gas Annual Reports

Analysis of Consumption and Customer Trends, Residential Volumes

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-5
Page 1 of 4

	MCF Sold	Number of Customers	MCF Per Customer	Change in Use		Percent Change	
				Use from Existing Customers	Use from New Customers	Number of Customers	MCF Per Customer
2011	24,878,520	289,405	86.0				
2012	19,026,460	272,778	69.8	(4,692,315)	(1,159,745)	-5.7%	-18.9%
2013	22,692,644	273,342	83.0	3,619,361	46,823	0.2%	19.0%
2014	25,007,023	279,362	89.5	1,775,500	538,879	2.2%	7.8%
2015	23,830,378	287,713	82.8	(1,868,333)	691,688	3.0%	-7.5%
2016	23,352,930	312,033	74.8	(2,297,586)	1,820,138	8.5%	-9.6%
2017	24,435,279	314,761	77.6	870,571	211,778	0.9%	3.7%
2018	28,383,510	331,837	85.5	2,487,644	1,460,587	5.4%	10.2%
2019	27,423,413	337,268	81.3	(1,401,694)	441,597	1.6%	-4.9%
2020	25,804,402	341,302	75.6	(1,924,005)	304,994	1.2%	-7.0%
2021	26,981,983	349,583	77.2	538,426	639,155	2.4%	2.1%
2022	29,123,768	360,154	80.9	1,286,964	854,821	3.0%	4.8%
2023	24,736,323	358,458	69.0	(4,270,408)	(117,037)	-0.5%	-14.7%

Analysis of Consumption and Customer Trends, Residential Revenues

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-5
Page 2 of 4

		Non-Fuel Revenue	Number of Customers	Non-Fuel Revenue Per Customer	Change in Revenue		Percent Change	
					Revenue from Existing Customers	Revenue from New Customers	Number of Customers	Non-Fuel Revenue Per Customer
2011	\$	63,799,136	289,405	\$ 220				
2012		108,525,545	272,778	398	\$ 51,341,511	\$ (6,615,102)	-5.7%	80.5%
2013		79,468,364	273,342	291	(29,221,152)	163,971	0.2%	-26.9%
2014		132,228,704	279,362	473	49,910,930	2,849,410	2.2%	62.8%
2015		189,550,607	287,713	659	51,820,110	5,501,792	3.0%	39.2%
2016		207,928,646	312,033	666	2,171,982	16,206,057	8.5%	1.1%
2017		216,229,382	314,761	687	6,426,699	1,874,037	0.9%	3.1%
2018		349,049,068	331,837	1,052	114,857,970	17,961,716	5.4%	53.1%
2019		264,317,796	337,268	784	(88,987,560)	4,256,289	1.6%	-25.5%
2020		265,299,372	341,302	777	(2,154,115)	3,135,691	1.2%	-0.8%
2021		272,191,351	349,583	779	444,250	6,447,729	2.4%	0.2%
2022		293,491,257	360,154	815	12,685,547	8,614,360	3.0%	4.7%
2023	\$	409,909,992	358,458	\$ 1,144	\$ 118,358,173	\$ (1,939,439)	-0.5%	40.3%

Analysis of Consumption and Customer Trends, Commercial Volumes

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-5
Page 3 of 4

	MCF Sold	Number of Customers	MCF Per Customer	Change in Use		Percent Change	
				Use from Existing Customers	Use from New Customers	Number of Customers	MCF Per Customer
2011	9,653,102	29,855	323.3				
2012	7,710,630	29,111	264.9	(1,745,409)	(197,063)	-2.5%	-18.1%
2013	9,073,789	28,845	314.6	1,446,835	(83,676)	-0.9%	18.8%
2014	10,044,618	29,132	344.8	871,872	98,957	1.0%	9.6%
2015	9,186,432	28,977	317.0	(809,047)	(49,139)	-0.5%	-8.1%
2016	7,793,895	26,063	299.0	(521,133)	(871,404)	-10.1%	-5.7%
2017	8,317,864	28,477	292.1	(181,138)	705,107	9.3%	-2.3%
2018	9,423,908	26,078	361.4	1,972,980	(866,936)	-8.4%	23.7%
2019	8,654,771	24,782	349.2	(316,527)	(452,610)	-5.0%	-3.4%
2020	7,324,676	24,933	293.8	(1,374,455)	44,360	0.6%	-15.9%
2021	8,073,555	25,689	314.3	511,283	237,596	3.0%	7.0%
2022	9,197,289	26,571	346.1	818,438	305,296	3.4%	10.1%
2023	7,783,414	26,320	295.7	(1,339,649)	(74,226)	-0.9%	-14.6%

Analysis of Consumption and Customer Trends, Commercial Revenues

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-5
Page 4 of 4

		Non-Fuel Revenue	Number of Customers	Non-Fuel Revenue Per Customer	Change in Revenue		Percent Change	
					Revenue from Existing Customers	Revenue from New Customers	Number of Customers	Non-Fuel Revenue Per Customer
2011	\$	5,039,282	29,855	\$ 169				
2012		26,085,531	29,111	896	\$ 21,712,926	\$ (666,677)	-2.5%	430.9%
2013		11,345,320	28,845	393	(14,635,587)	(104,623)	-0.9%	-56.1%
2014		24,244,327	29,132	832	12,660,159	238,848	1.0%	111.6%
2015		40,519,248	28,977	1,398	16,491,661	(216,740)	-0.5%	68.0%
2016		36,367,753	26,063	1,395	(85,361)	(4,066,133)	-10.1%	-0.2%
2017		34,726,738	28,477	1,219	(4,584,807)	2,943,791	9.3%	-12.6%
2018		78,720,696	26,078	3,019	51,235,731	(7,241,773)	-8.4%	147.5%
2019		44,120,644	24,782	1,780	(32,292,718)	(2,307,334)	-5.0%	-41.0%
2020		39,151,700	24,933	1,570	(5,206,056)	237,112	0.6%	-11.8%
2021		38,999,961	25,689	1,518	(1,299,467)	1,147,727	3.0%	-3.3%
2022		42,081,994	26,571	1,584	1,685,159	1,396,873	3.4%	4.3%
2023	\$	76,713,636	26,320	\$ 2,915	\$ 35,363,220	\$ (731,578)	-0.9%	84.0%

Summary of Lesh Report

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-6

Refund/Surcharge	Number of Reconciliations			Share of All Reconciliations		
	Gas	Electric	Total	Gas	Electric	Total
Refund Percent						
Greater than 3 percent	2	0	2	3.1%	0.0%	2.3%
Less than or equal to 3 percent	1	3	4	1.5%	13.0%	4.5%
Less than or equal to 2 percent	2	1	3	3.1%	4.3%	3.4%
Less than or equal to 1 percent	13	6	19	20.0%	26.1%	21.6%
Total				27.7%	43.5%	31.8%
Surcharge Percent						
Less than 1 percent	23	7	30	35.4%	30.4%	34.1%
Less than 2 percent	7	4	11	10.8%	17.4%	12.5%
Less than 3 percent	5	2	7	7.7%	8.7%	8.0%
Greater than 3 percent	12	0	12	18.5%	0.0%	13.6%
Total				72.3%	56.5%	68.2%
Total Decoupled Utilities	65	23	88	100.0%	100.0%	100.0%

Peer Comparison of Average Total Revenues: Average Residential Sales Revenue per Mcf

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-7
Page 1 of 3

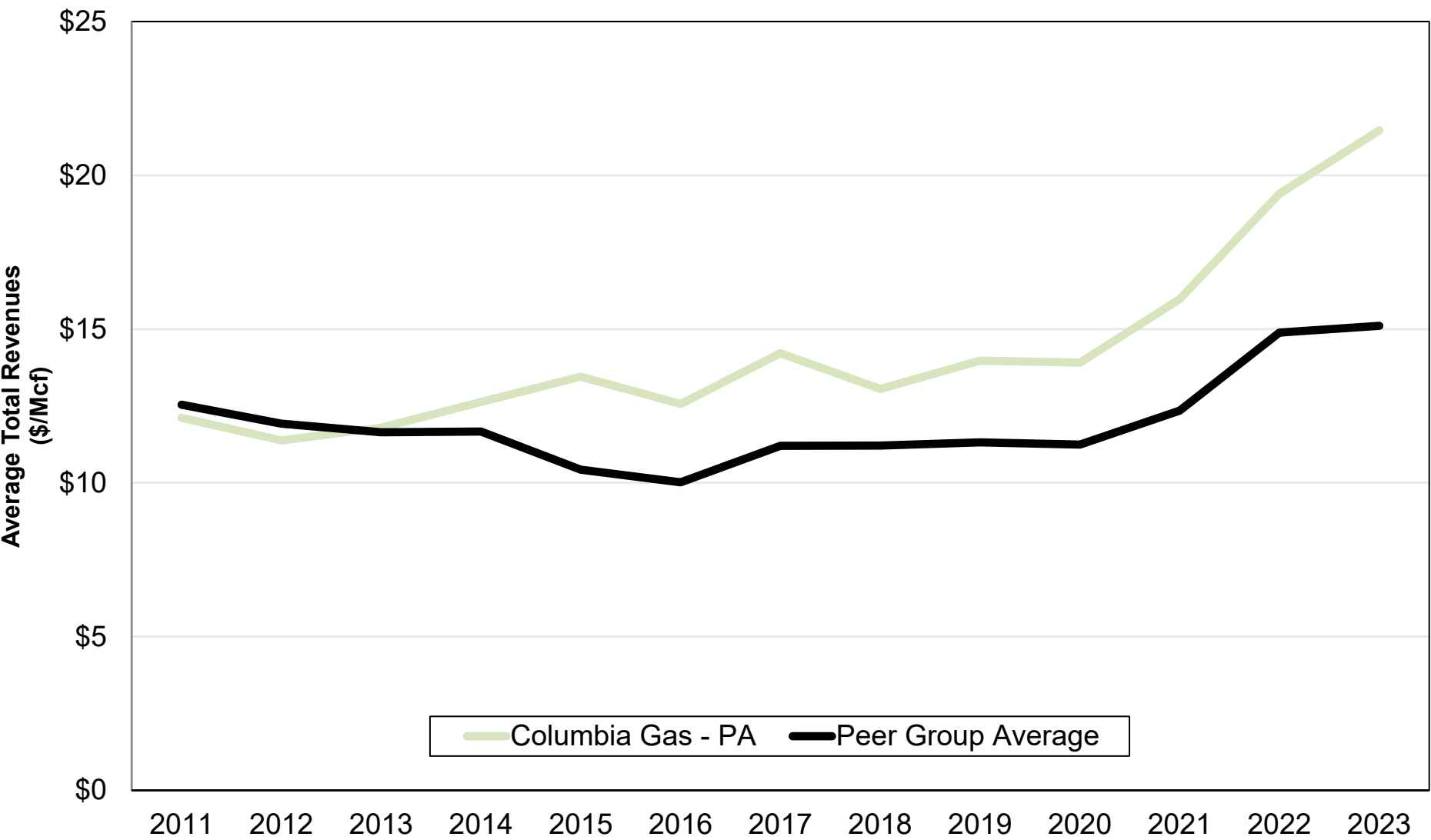
State Company		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
		-----(\$/Mcf)-----												
PA	Columbia Gas of Pennsylvania	\$12.12	\$11.38	\$11.79	\$12.63	\$13.46	\$12.57	\$14.21	\$13.05	\$13.98	\$13.91	\$15.98	\$19.40	\$21.46
MD	Baltimore Gas & Electric	\$11.74	\$12.21	\$11.92	\$11.61	\$12.17	\$12.19	\$14.01	\$12.78	\$13.26	\$14.66	\$16.25	\$17.99	\$19.25
NJ	New Jersey Natural Gas	\$13.48	\$11.44	\$12.90	\$11.66	\$10.42	\$9.40	\$10.96	\$11.00	\$11.35	\$12.37	\$12.66	\$15.52	\$16.00
NJ	Elizabethtown	\$11.92	\$11.56	\$11.38	\$10.78	\$8.12	\$8.16	\$8.49	\$8.89	\$9.38	\$10.49	\$10.26	\$12.30	\$11.53
NJ	Public Service Electric & Gas	\$11.21	\$10.51	\$9.86	\$8.39	\$6.81	\$7.47	\$8.09	\$7.70	\$8.48	\$8.21	\$8.62	\$10.53	\$11.61
NJ	South Jersey Gas Company	\$11.95	\$13.61	\$12.92	\$12.88	\$13.98	\$11.27	\$12.70	\$14.02	\$14.44	\$14.83	\$15.45	\$18.29	\$19.19
NY	Central Hudson Gas & Electric	\$17.72	\$16.39	\$15.35	\$17.01	\$14.67	\$14.51	\$16.28	\$17.23	\$17.07	\$17.90	\$19.57	\$22.87	\$24.41
NY	Consolidated Edison NY	\$18.49	\$17.78	\$17.96	\$16.78	\$13.95	\$13.97	\$15.46	\$16.76	\$17.44	\$18.65	\$20.80	\$24.82	\$26.83
NY	Liberty Utilities - St. Lawrence	\$12.84	\$13.22	\$12.73	\$12.29	\$12.45	\$10.96	\$11.64	\$11.51	\$10.74	\$10.57	\$11.07	\$13.31	\$13.26
NY	National Fuel Gas Dist - NY	\$10.89	\$10.34	\$9.62	\$10.11	\$7.84	\$6.83	\$8.07	\$8.16	\$7.88	\$7.74	\$8.55	\$10.88	\$10.66
NY	New York State Elec & Gas	\$12.70	\$12.35	\$11.07	\$10.84	\$9.74	\$9.49	\$10.43	\$10.27	\$10.15	\$9.57	\$10.70	\$12.96	\$12.92
NY	Niagara Mohawk	\$12.14	\$11.26	\$10.50	\$9.66	\$8.41	\$8.18	\$8.98	\$9.00	\$8.77	\$7.89	\$9.94	\$12.20	\$12.19
NY	Orange & Rockland Utilities Inc	\$15.33	\$14.52	\$13.82	\$13.41	\$10.35	\$11.03	\$14.27	\$14.63	\$13.71	\$12.76	\$14.52	\$16.99	\$17.41
NY	Rochester Gas and Elec	\$11.63	\$11.34	\$10.38	\$9.95	\$8.67	\$8.26	\$9.08	\$9.51	\$8.77	\$8.17	\$9.46	\$11.48	\$10.68
NY	The Brooklyn Union Gas Co	\$13.10	\$11.84	\$11.61	\$11.87	\$10.94	\$11.11	\$12.99	\$13.40	\$14.15	\$14.40	\$14.74	\$17.57	\$18.20
OH	Columbia Gas of Ohio	\$10.13	\$7.68	\$9.00	\$10.60	\$9.31	\$9.31	\$10.60	\$9.98	\$10.15	\$10.22	\$12.74	\$15.09	\$13.93
OH	Duke Energy Ohio	\$12.00	\$12.09	\$11.49	\$12.41	\$12.86	\$12.76	\$13.18	\$12.11	\$11.11	\$10.75	\$13.45	\$16.28	\$16.16
OH	East Ohio Gas Co	\$9.56	\$7.80	\$7.71	\$8.23	\$6.59	\$6.02	\$7.13	\$6.85	\$7.22	\$6.58	\$8.90	\$11.50	\$10.06
OH	Northeast Ohio Natural Gas	\$9.56	\$8.62	\$9.32	\$10.05	\$6.77	\$6.27	\$6.82	\$7.18	\$8.45	\$7.93	\$9.42	\$11.88	\$10.95
OH	Suburban Natural Gas Co	\$11.85	\$11.65	\$12.68	\$11.98	\$10.17	\$10.63	\$11.96	\$10.89	\$9.83	\$9.07	\$11.24	\$12.86	\$10.78
PA	Peco Energy Co	\$11.58	\$11.44	\$11.13	\$11.33	\$10.25	\$8.82	\$9.24	\$9.89	\$11.16	\$10.18	\$10.04	\$13.17	\$14.14
PA	Peoples Gas Co	\$12.69	\$12.11	\$11.61	\$13.67	\$11.66	\$11.85	\$13.53	\$13.05	\$13.04	\$11.33	\$12.23	\$15.16	
PA	Peoples Natural Gas Co	\$12.15	\$11.04	\$10.97	\$11.17	\$9.93	\$8.55	\$10.17	\$9.94	\$10.41	\$9.64	\$10.52	\$13.38	\$11.23
PA	Philadelphia Gas Works	\$14.81	\$15.44	\$14.69	\$14.27	\$13.69	\$13.95	\$14.90	\$14.35	\$15.03	\$15.27	\$15.29	\$18.32	\$18.39
PA	UGI Utilities	\$12.72	\$11.37	\$10.78	\$10.54	\$10.01	\$9.37	\$11.16	\$10.98	\$10.65	\$11.40	\$11.38	\$14.38	\$17.05
WV	Mountaineer Gas Co	\$11.26	\$10.53	\$9.79	\$10.23	\$11.01	\$10.06	\$10.01	\$10.21	\$10.21	\$10.58	\$10.95	\$12.49	\$15.70
Peer Group Average		\$12.54	\$11.92	\$11.65	\$11.67	\$10.43	\$10.02	\$11.21	\$11.21	\$11.31	\$11.25	\$12.35	\$14.89	\$15.11

Peer Comparison of Average Total Revenues: Average Residential Sales Revenue per Mcf, Ranking

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-7
Page 2 of 3

State Company		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
		(Ranking)												
PA	Columbia Gas of Pennsylvania	14	11	17	20	22	22	22	19	21	20	23	24	23
MD	Baltimore Gas & Electric	9	19	18	14	19	21	21	18	19	22	24	21	22
NJ	New Jersey Natural Gas	22	12	21	15	15	12	13	15	17	18	16	17	15
NJ	Elizabethtown	11	14	13	10	5	5	5	5	7	12	8	7	7
NJ	Public Service Electric & Gas	5	5	6	2	3	4	4	3	4	6	2	1	8
NJ	South Jersey Gas Company	12	22	22	21	25	19	17	22	23	23	22	22	21
NY	Central Hudson Gas & Electric	25	25	25	26	26	26	26	26	25	25	25	25	24
NY	Consolidated Edison NY	26	26	26	25	24	25	25	25	26	26	26	26	25
NY	Liberty Utilities - St. Lawrence	20	21	20	18	20	16	15	16	14	13	12	12	11
NY	National Fuel Gas Dist - NY	4	4	4	6	4	3	3	4	2	2	1	2	2
NY	New York State Elec & Gas	18	20	11	11	9	13	11	12	9	8	10	10	10
NY	Niagara Mohawk	15	8	8	3	6	6	6	6	5	3	6	6	9
NY	Orange & Rockland Utilities Inc	24	23	23	22	14	17	23	24	20	19	19	19	18
NY	Rochester Gas and Elec	8	9	7	4	7	7	7	7	6	5	5	3	3
NY	The Brooklyn Union Gas Co	21	16	15	16	16	18	18	21	22	21	20	20	19
OH	Columbia Gas of Ohio	3	1	2	9	8	10	12	10	10	11	17	15	12
OH	Duke Energy Ohio	13	17	14	19	21	23	19	17	15	15	18	18	16
OH	East Ohio Gas Co	1	2	1	1	1	1	2	1	1	1	3	4	1
OH	Northeast Ohio Natural Gas	2	3	3	5	2	2	1	2	3	4	4	5	5
OH	Suburban Natural Gas Co	10	15	19	17	12	15	16	13	8	7	13	9	4
PA	Peco Energy Co	7	13	12	13	13	9	8	8	16	10	7	11	13
PA	Peoples Gas Co	17	18	16	23	18	20	20	20	18	16	15	16	
PA	Peoples Natural Gas Co	16	7	10	12	10	8	10	9	12	9	9	13	6
PA	Philadelphia Gas Works	23	24	24	24	23	24	24	23	24	24	21	23	20
PA	UGI Utilities	19	10	9	8	11	11	14	14	13	17	14	14	17
WV	Mountaineer Gas Co	6	6	5	7	17	14	9	11	11	14	11	8	14

**Peer Comparison of Average Total Revenues:
Average Residential Sales Revenue per Mcf**

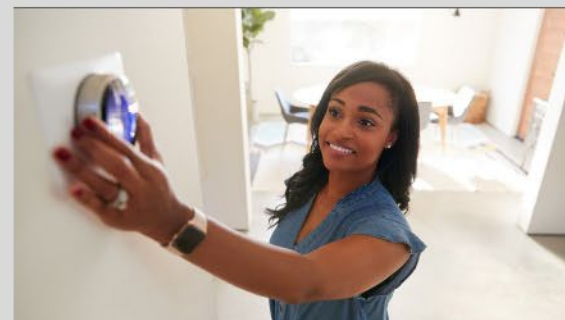




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SUPPLEMENTAL SLIDES YEAR END 2023 RESULTS

February 21, 2024



SUPERIOR REGULATORY AND STAKEHOLDER FOUNDATION

		2021			2022				2023				2024
		Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1
NIPSCO Electric	Rate Case						Filed		Settled +\$292M		Approved In Rates		
	Trackers		TDSIC 8 Approved		TDSIC 9 Approved		TDSIC 1 Approved		TDSIC 2 +\$7M				
NIPSCO Gas	Rate Case		Filed		Settled +\$72		Approved Step 1 Rates		Step 2 Rates			Filed +\$162M	
	Trackers	TDSIC 2 Approved	FMCA 6 Approved	TDSIC 3 Approved	FMCA 7 Approved	TDSIC 4 Approved	FMCA 1 Approved			FMCA 2 +\$4M	TDSIC 6	TDSIC 7 FMCA 1&2	
Columbia Gas of Ohio	Rate Case	Filed						Settled +\$68M	Approved In Rates				
	Trackers	IRP Approved	CEP Approved			IRP Approved	CEP Approved			IRP +\$38M	CEP +\$31M		
Columbia Gas of Pennsylvania	Rate Cases		Settled	Approved In Rates	Filed		Settled	Approved In Rates					
Columbia Gas of Virginia	Rate Case					Filed	Rates Effective	Settled +\$26M		Approved			
	Trackers			SAVE Approved				SAVE +\$5M				SAVE +\$8M	
Columbia Gas of Kentucky	Rate Case	Filed		Settled Approved	In Rates								
	Trackers	SMRP Approved						SMRP +\$2M					SMRP +\$5M ⁽¹⁾
Columbia Gas of Maryland	Rate Cases	Filed	Settled	Approved In Rates		Filed	Settled +\$4M	Approved In Rates		Filed	Settled +\$4M	Approved In Rates	
	Trackers			STRIDE Approved				STRIDE Approved	In Rates +\$1M				

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1) Rates implemented subject to refund
See appendix for detailed regulatory program names
Select capital trackers shown; does not include expense trackers

SAFETY AND INFRASTRUCTURE INVESTMENT AND TRACKER FILINGS

COMPANY	MECHANISM	INCREMENTAL INVESTMENTS		RECOVERY
		PERIOD	AMOUNT (\$M)	EFFECTIVE DATE
Columbia Gas of Ohio	Infrastructure Replacement Program (IRP)	FY 2022	\$316	May 2023
	Capital Expenditure Program (CEP)	FY 2022	\$265	Sep 2023
Columbia Gas of Virginia	Steps to Advance Virginia's Energy Plan (SAVE)	FY 2023	\$46	Jan 2023
		FY 2024	\$69	Jan 2024
Columbia Gas of Kentucky	Safety Modification and Replacement Program (SMRP)	FY 2023	\$42	Jan 2023
		FY 2024	\$40	Jan 2024
Columbia Gas of Maryland	Strategic Infrastructure Development and Enhancement (STRIDE)	FY 2023	\$18	Jan 2023
NIPSCO – Gas	Transmission, Distribution and Storage System Improvement Charge (TDSIC)	TDSIC 6: Jan 2022 – Feb 2023	\$150	Sep 2023
		TDSIC 7: Mar 2023 – Aug 2023	\$207	Mar 2024
	Federally Mandated Cost Adjustment Rider (FMCA)	FMCA 2: Apr 2022 – Sep 2022	\$38	Apr 2023
NIPSCO – Electric	Transmission, Distribution and Storage System Improvement Charge (TDSIC)	TDSIC 2: Feb 2022 - Jul 2022	\$144	Feb 2023
		TDSIC 3: Jan 2023 – Aug 2023	\$145	Sep 2024

We exist to deliver safe, reliable energy that drives value to our customers

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NiSource – A Premium Utility Company

November 7, 2022



NiSource[®]



REGULATORY / LEGISLATIVE ENVIRONMENT

NiSource's six constructive jurisdictions recognize the value of gas and electric service to customers

	IN	OH	PA	VA	KY	MD
Legislation protecting customers from gas bans	✓	✓			✓	
Commodity cost pass through	✓	✓	✓	✓	✓	✓
Revenue/bill stabilization		✓	✓	✓	✓	✓
Bad debt/low-income assistance	✓	✓	✓	✓	✓	✓
Customer gas supplier choice	✓	✓	✓	✓	✓	
Infrastructure tracking and recovery mechanisms	✓	✓	✓	✓	✓	✓
Energy efficiency programs	✓	✓	✓	✓	✓	✓

Significant economic development and growth opportunities across jurisdictions

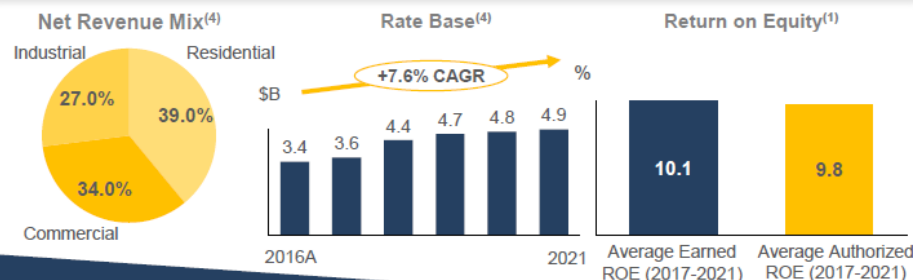
NORTHERN INDIANA PUBLIC SERVICE COMPANY (NIPSCO ELECTRIC)

Business Profile

- 490K Customers
- ~3,100 Employees⁽¹⁾
- 0.7% Annual Customer Growth⁽²⁾
- 13,000 Miles of Distribution/Transmission
- 3,000 MW of Generation Capacity



Unique Insights/Opportunities



Regulatory Landscape

- TDSIC recovers new or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development
- Design of rate 831 insulates NIPSCO from potential year-to-year variability of industrial electric load
- Fully Forward Test Year and CWIP in Rate Base
- ~\$550M FERC Regulated Electric Transmission Rate Base

Constructive Legislation

- **SB 560** – Forward test year, timely rate cases and infrastructure tracking
- **HB 1470** – Increased flexibility for inclusion of future projects in TDSI
- **HB 1221** – build-out of electric vehicle public charging infrastructure

Economic Outlook

- NIPSCO continues to work with customers impacted by the pandemic with extended payment plans

Key Riders/Constructs	Weighted Avg. Regulatory Lag
Transmission, Distribution, and Storage System Improvement Charge(TDSIC)	12 Months ⁽⁶⁾ (80% of Investment)
Federally Mandated Cost Adjustment (FMCA)	11 Months ⁽⁶⁾
Bad Debt	Base Rates
RTO	Forecasted with a True-Up to Actual
Energy Efficiency	Forecasted with a True-Up to Actual
Fuel Costs	Forecasted with a True-Up to Actual
Pension/OPEB	WACC / Base Rate Return
Resource Adequacy	10 Months

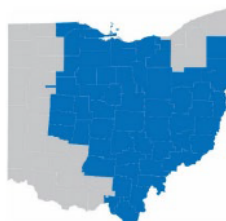
Footnotes:

- (1) Inclusive of both Gas & Electric
(2) Compound annual growth between 2018 actuals and 2021 estimate
(3) Represents complaints justified by the Indiana Utility Regulatory Commission (IURC)
(4) Revenue mix based on net revenues for the year ending 2021
(5) NIPSCO rate base includes deferred taxes in capital structure
(6) Under TDSIC/FMCA 20% of investment is deferred with carrying cost for recovery in next rate case

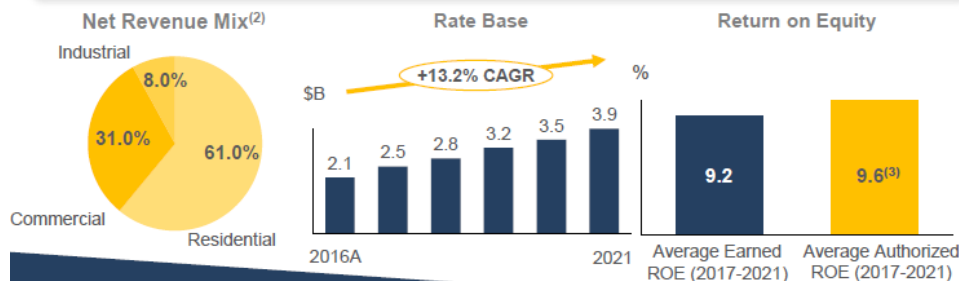
COLUMBIA GAS OF OHIO (COH)

Business Profile

- 1.5M Customers
- ~2,300 Employees
- 0.5% Annual Customer Growth⁽¹⁾
- 20,514 Miles of Pipeline



Unique Insights/Opportunities



Regulatory Landscape

- Fully tracked annual Infrastructure Replacement Program (IRP) and Capital Expenditure Program (CEP)
- Public policy provides tools supporting investment for economic development and deferral of pipeline safety costs
- Straight fixed variable rate design

Constructive Legislation

- HB 95** – authorization of utility modernization capital programs
- SB 319** – Annual infrastructure cost recovery of up to \$25.5M for economic development projects
- SB 378** – Underground protection & enforcement
- HB 201** – Codifies consumers' right to fuel diversity

Economic Outlook

- Intel's investment in 2 new chip fabrication facilities is the largest economic development project for Ohio

Key Riders/Constructs	Weighted Avg. Regulatory Lag
Capital Expenditure Program (CEP)	14 Months
Infrastructure Replacement Program (IRP)	10 Months
Bad Debt	10 Months (SGS/GS) Base Rates (LGS)
Environmental	Deferral / Base Rates
Energy Efficiency	10 Months
Fuel Costs	Forecasted with a True-Up to Actual
Low Income	11 Months
Pipeline Safety	Deferral / Base Rates

Footnotes:

- (1) Compound annual growth between 2018 actuals and 2021 estimate
(2) Revenue mix based on net revenues for the year ending 2021
(3) Authorized return within settlement stipulation filed 10/31/22 for case 21-0637-GA-AIR

COLUMBIA GAS OF PENNSYLVANIA (CPA)

Business Profile

- 443K Customers
- 0.6% Annual Customer Growth⁽¹⁾
- ~800 Employees
- 7,756 Miles of Pipeline



Unique Insights/Opportunities

1.1K Miles

Of remaining priority pipe

100%

Of capital recovered with zero lag

#2

In customer satisfaction based on 2021 JD Power Survey

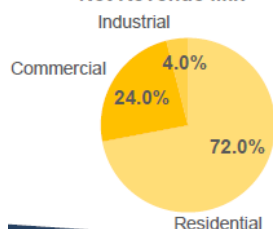
9

Of the last 10 base rate proceedings have been settled

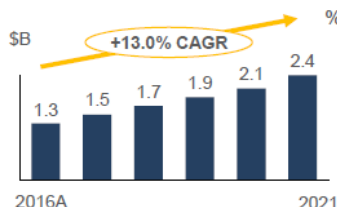
\$375M

In annual investment opportunity

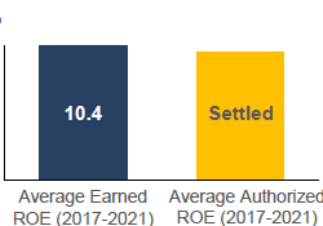
Net Revenue Mix⁽²⁾



Rate Base



Return on Equity



Regulatory Landscape

- Fully projected Future Test year allows for capital and expense recovery with zero lag
- Authorized Weather Normalized Adjustment of residential bills during winter period stabilizes revenue for CPA and bills for customers
- State leader in universal services, low-income initiatives, choice and energy efficiency programs

Constructive Legislation

- Act 11 – Allows for filing of a Distribution Service Improvement Charge (DSIC) and a rate case with a fully forecasted rate year

Economic Outlook

- Pennsylvania is the second largest producer of natural gas in the US, and CPA is geographically situated on top of the Marcellus/Utica shale.

Key Riders/Constructs	Weighted Avg. Regulatory Lag
Rate Case	0 Months (Fully Projected Future Test Year)
DSIC	3 - 6 Months
USECP Rider	0 Months
Environmental	Deferred to Rate Case
Energy Efficiency ⁽³⁾	Deferral/Surcharge
Fuel Costs (inc. Bad debt)	Deferred
Pension/OPEB	Deferred
Low Income	Deferral/Surcharge

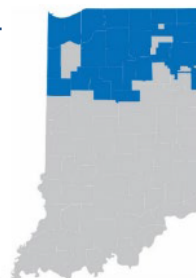
Footnotes:

- (1) Compound annual growth between 2018 actuals and 2021 estimate
- (2) Revenue mix based on net revenues for the year ending 2021
- (3) CPA's energy efficiency program for non-low income customers is currently pending before the PA utility commission

NORTHERN INDIANA PUBLIC SERVICE COMPANY (NIPSCO GAS)

Business Profile

- 853K Customers
- ~3,100 Employees⁽¹⁾
- 0.8% Annual Customer Growth⁽²⁾
- 18,437 Miles of Pipeline



Unique Insights/Opportunities

\$130.29

Average residential bill over the last 5 years – the lowest in the state

Lowest

Number of complaints⁽³⁾ in the state over the past 5 years

100%

Of distribution rate cases settled since 1987

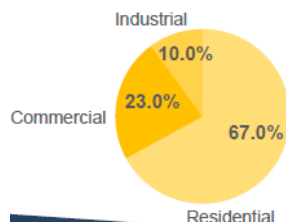
Largest

LDC in the state of Indiana

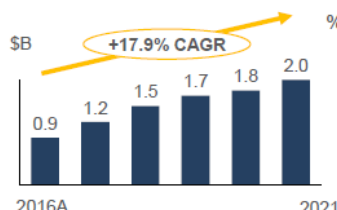
\$150-\$250M

In annual investment opportunity

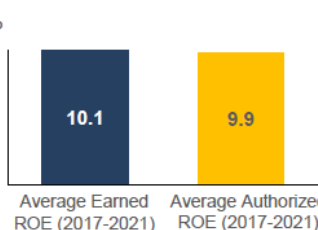
Net Revenue Mix⁽⁴⁾



Rate Base⁽⁵⁾



Return on Equity⁽¹⁾



Regulatory Landscape

- TDSIC recovers new or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development
- FMCA offers capital recovery for federally mandated costs, including adherence to PHMSA
- Fully Forward Test Year available for base rate case

Constructive Legislation

- SB 560 – Forward test year, timely rate cases and infrastructure tracking
- HB 1470 – Increased flexibility for inclusion of future projects in TDSIC
- HB 1197 – Codifies consumers' right to fuel diversity

Economic Outlook

- NIPSCO continues to work with customers impacted by the pandemic with extended payment plans
- Stellantis and Samsung SDI are forming a joint venture to invest more than \$2.5B to build an electric vehicle battery facility in Kokomo, IN

Key Riders/Constructs	Weighted Avg. Regulatory Lag
Transmission, Distribution, and Storage System Improvement Charge(TDSIC)	12 Months ⁽⁶⁾ (80% of Investment)
Federally Mandated Cost Adjustment (FMCA)	11 Months ⁽⁶⁾
Bad Debt	Base Rates / Fuel Costs
Energy Efficiency	Forecasted with a True-Up to Actual
Fuel Costs	Forecasted with a True-Up to Actual
Low Income	Deferral with a True-Up to Actuals
Pension/OPEB	WACC / Base Rate Return

Footnotes:

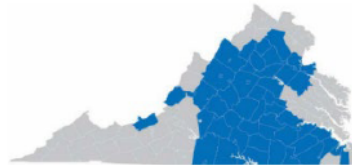
- (1) Inclusive of both Gas & Electric
- (2) Compound annual growth between 2018 actuals and 2021 estimate
- (3) Represents complaints justified by the Indiana Utility Regulatory Commission (IURC)

- (4) Revenue mix based on net revenues for the year ending 2021
- (5) NIPSCO rate base includes deferred taxes in capital structure
- (6) Under TDSIC/FMCA 20% of investment is deferred with carrying cost for recovery in next rate case; a future test year is utilized to recover operating expenses

COLUMBIA GAS OF VIRGINIA (CVA)

Business Profile

- 288K Customers
- ~500 Employees
- 1.5% Annual Customer Growth⁽¹⁾
- 5,506 Miles of Pipeline



Regulatory Landscape

- Forward-looking annual modernization/safety infrastructure investment tracker filings
- Tracker filings supplemented by rate case filings with forward test year

Constructive Legislation

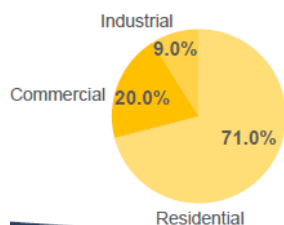
- **DIMP Act**– Allows deferral of incremental O&M related to pipeline safety
- **SAVE Act**– Allows recovery of investment on infrastructure replacement
- **CARE Act**– Provides for energy efficiency programs and a revenue decoupling adjustment
- **Energy Innovation Act**– Provides regulatory pathways to procure substitute/supplemental gas (RNG/Hydrogen), promotes biogas supply and expends energy efficiency

Economic Landscape

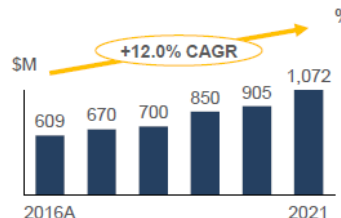
- Plenty Limited Vertical Farming investing over \$300M in Chesterfield County
- U.S. Navy partnering in major pipeline expansion at Portsmouth facility for combined heat and power project

2nd Nationally in overall CSAT ⁽⁴⁾ through 3Q2022 (among 85 brands)	Top Decile Nationally in damage prevention	Awarded For energy efficiency and community service by Virginia DOE	1st Amongst major VA LDC's in customer growth rate ⁽²⁾	\$45-\$70M In annual investment opportunity

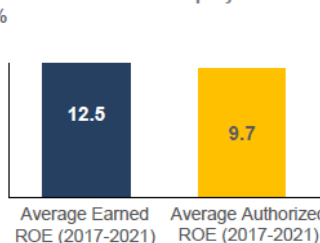
Net Revenue Mix⁽³⁾



Rate Base



Return on Equity⁽⁵⁾



Key Riders/Constructs	Weighted Avg. Regulatory Lag
Steps to Advance Virginias Energy Plan (SAVE)	0 Months (Forward Looking Test Year)
Energy Efficiency (CARE)	Deferral/Surcharge
Bad Debt	Rate Case – non tracked
Fuel Costs (inc. Bad debt)	Deferral/Surcharge
Pipeline Safety (DIMP)	O&M Above baseline Deferred to Rate Case

Footnotes:

- (1) Compound annual growth between 2018 actuals and 2021 estimate
- (2) Based on customer growth reported in 2016 -2020 annual LDC filings (2021 not yet available), excludes LDC's with less than 5,000 customers
- (3) Revenue mix based on net revenues for the year ending 2021

COLUMBIA GAS OF KENTUCKY (CKY)

Business Profile

- 138K Customers
- ~200 Employees
- 0.3% Annual Customer Growth⁽¹⁾
- 2,681 Miles of Pipeline



3rd
Consecutive year (20,21,22) on Kentucky's best place to work list

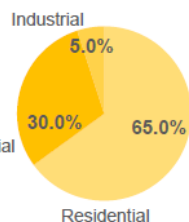
\$50M
In annual investment opportunity

#1
In Customer Satisfaction based on 2021 JD Power Survey⁽²⁾

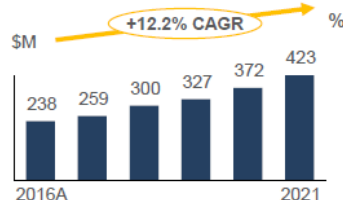
Recognized
For Leadership in Emerging Energy/Transition Environment⁽³⁾

AGA
Safety achievement award winner in 2021

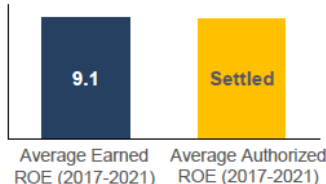
Net Revenue Mix⁽⁴⁾



Rate Base



Return on Equity



Regulatory Landscape

- SMRP allows for full cost recovery of eligible pipeline replacement/safety related initiatives via forward looking test year
- Commission has authorized economic development extension tariff for high potential sites requiring natural gas
- Performance based incentives for gas supply management
- Base rate recovery is weather normalized

Constructive Legislation

- HB 207 – Codifies consumers' right to fuel diversity
- HB 100 – Governments may create and assess for special energy efficiency project districts

Economic Landscape

- Buffalo Trace Distillery is completing a \$1.2B investment in their bourbon facility in Frankfort, KY
- Baptist Health investing \$225M in new surgery center and campus

Key Riders/Constructs	Weighted Avg. Regulatory Lag
Safety Modification & Replacement Program (SMRP)	0 Months (Forward Looking Test Year)
Energy Efficiency	Base Rates
Gas Costs	Forecasted with a True-Up to Actual

Footnotes:

- (1) Compound annual growth between 2018 actuals and 2021 estimate
- (2) JD Power Scores – CKY does not meet residential customer threshold for syndicated survey but ranked #1 in Midwest Midsize Segment
- (3) Recognized at Governor's Conference on Energy & Environment
- (4) Revenue mix based on net revenues for the year ending 2021

COLUMBIA GAS OF MARYLAND (CMD)

Business Profile

- 35K Customers
- ~70 Employees
- 0.8% Annual Customer Growth⁽¹⁾
- 669 Miles of Pipeline



Rates

Of residential customers are below the state average for other LDC's⁽²⁾

102

Miles of cast Iron/Bare Steel pipeline replaced since 2008

0

PHMSA/DOT reportable incidents in 2021

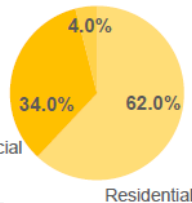
Revenue

Normalization enables full recovery of distribution revenue (residential)

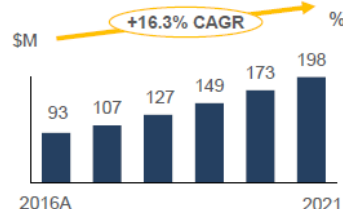
\$25-\$35M

In annual investment opportunity

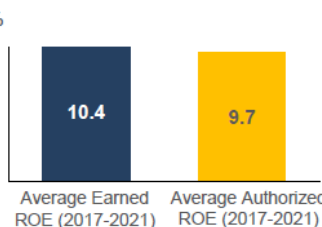
Net Revenue Mix⁽³⁾



Rate Base



Return on Equity



Regulatory Landscape

- Forward-looking annual infrastructure replacement and improvement surcharge (IRIS) recovers age and condition investment
- IRIS filings supplemented by periodic rate cases

Constructive Legislation

- STRIDE Act– Prospective cost recovery for age and condition investment.

Economic Landscape

- Eastern operations are now attracting commuters from Washington DC, supporting customer growth
- Tariff provisions allow for modest customer growth
- Grow West Cannabis Company investing \$20M in an expansion of their medical marijuana production in Cumberland, Maryland

Key Riders/Constructs	Weighted Avg. Regulatory Lag
Strategic Infrastructure Development & Enhancement (STRIDE)	0 Months
Energy Efficiency Rider	Deferral/Surcharge
Bad Debt	Base Rates
Fuel Costs (inc. Bad Debt)	Deferral
Environmental	Deferral / Base Rates

Footnotes:

- (1) Compound annual growth between 2018 actuals and 2021 estimate
- (2) Based on information available in public LDC filings, based on 2016-2020 (2021 was not yet available for all MD LDCs)
- (3) Revenue mix based on net revenues for the year ending 2021



SUPPLEMENTAL SLIDES
THIRD QUARTER 2020 EARNINGS

November 2, 2020



GAS DISTRIBUTION OPERATIONS

- Rate case settlement reached in Maryland, case pending in Pennsylvania
- Continuing to execute infrastructure modernization designed to enhance system safety, reliability and environmental performance

Highlight	Key Components	Status
Columbia Gas of Kentucky Safety Modification and Replacement Program (SMRP) Annual Rider Update	◦ Supports continued replacement of aging pipelines and adoption of pipeline safety upgrades ◦ Request covers \$50.0M for 2021 capital investments	◦ Filed Oct. 15, 2020 ◦ Order expected Q1 2021 ◦ New rates effective Q1 2021
NIPSCO Gas System Modernization Program	◦ Long-term infrastructure modernization program ◦ TDSIC1 filing covers \$26.0M in incremental capital investments made between January and June 2020	◦ Filed Aug. 25, 2020 ◦ Order expected Dec. 2020
Columbia Gas of Virginia Steps to Advance Virginia's Energy (SAVE) Annual Rider Update	◦ Supports continued replacement of aging pipelines and adoption of pipeline safety upgrades guided by SMS risk prioritization ◦ Request covers \$46.4M for 2021 capital investments	◦ Filed July 24, 2020 ◦ Order expected Nov. 2020 ◦ New rates effective Jan. 2021
Columbia Gas of Maryland Base Rate Case	◦ Supports continued replacement of aging pipelines and adoption of pipeline safety upgrades ◦ Settlement includes \$3.3M total annual revenue increase; \$2.0M net of infrastructure trackers	◦ Filed May 15, 2020 ◦ Order expected Nov. 2020 ◦ New rates effective Dec. 2020
Columbia Gas of Pennsylvania Base Rate Case	◦ Supports continued replacement of aging pipelines and adoption of pipeline safety upgrades ◦ Requests \$100.4M total annual revenue increase	◦ Filed Apr. 24, 2020 ◦ Order expected Q1 2021 ◦ New rates effective Jan. 2021
Columbia Gas of Ohio Capital Expenditure Program (CEP) Annual Rider Update	◦ Allows for recovery of capital investments and related deferred expenses that are not recovered through IRP tracker ◦ Application covers ~\$185M in 2019 capital investments	◦ Filed Feb. 28, 2020 ◦ Order received Aug. 12, 2020 ◦ New rates effective Sep. 2020

~\$40B IN IDENTIFIED LONG-TERM GAS AND ELECTRIC INFRASTRUCTURE INVESTMENT OPPORTUNITIES

ELECTRIC OPERATIONS

- Three new solar JV projects announced for coal-fired generation replacement capacity
- \$1.8 - \$2.0B incremental capital investment opportunities expected in 2022 and 2023
- Continued execution of seven-year ~\$1.2B electric system modernization program

Highlight	Key Components	Status
Renewable Generation JV Projects	◦ Construction continues on Rosewater and Indiana Crossroads wind projects ◦ Agreements executed on Dunns Bridge Solar I, Dunns Bridge Solar II and Cavalry Solar	◦ Rosewater expected in service YE2020 ◦ Indiana Crossroads expected in service YE2021 ◦ CPCN filing expected for Dunns / Cavalry Q42020
Renewable Generation PPA Projects	◦ Construction continues on Jordan Creek wind project ◦ Commercial terms reached on Brickyard Solar and Greensboro Solar + storage, PPAs filed with IURC	◦ Jordan Creek expected in service YE2020 ◦ Regulatory approval for Brickyard and Greensboro Solar expected by YE2020
Electric System Modernization Program	◦ Focused on electric transmission and distribution investments designed to improve system safety and reliability ◦ TDSIC 7 semi-annual tracker update covering \$122.3M in investments from July 2019 - July 2020	◦ Filed Sep. 29, 2020 ◦ Order expected Jan. 2021 ◦ Rates effective Feb. 2021

* Represents installed capacity of generation facilities.

~\$40B IN IDENTIFIED LONG-TERM GAS AND ELECTRIC INFRASTRUCTURE INVESTMENT OPPORTUNITIES

SAFETY AND INFRASTRUCTURE INVESTMENT AND TRACKER FILING DETAILS

Company	Mechanism	Incremental Investments		Recovery	
		Period	Amount (\$ Millions)	Filing Date	Effective Date
Columbia Gas of Ohio	Infrastructure Replacement Program (IRP)	FY 2018	\$199.6	Feb 2019	May 2019
		FY 2019	\$234.4	Feb 2020	May 2020
Columbia Gas of Ohio	Capital Expenditure Program (CEP)	FY 2018	\$121.7	Feb 2019	Sept 2019
		FY 2019	\$185.1	Feb 2020	Sept 2020
Columbia Gas of Pennsylvania	Distribution System Improvement Charge (DSIC)	Mar 2020 - May 2020	\$28.6	Jun 2020	Jul 2020
		Jun 2020 - Aug 2020	\$85.0	Sep 2020	Oct 2020
Columbia Gas of Virginia	Steps to Advance Virginia's Energy Plan (SAVE)	FY 2020	\$50.0	Aug 2019	Jan 2020
		FY 2021	\$46.4	Jul 2020	Expected - Jan 2021
Columbia Gas of Kentucky	Safety Modification and Replacement Program (SMRP)	FY 2020	\$40.4	Oct 2019	Jan 2020
		FY 2021	\$50.0	Oct 2020	Expected - Jan 2021
Columbia Gas of Maryland	Strategic Infrastructure Development and Enhancement (STRIDE)	FY 2020	\$15.0	Jan 2020	Feb 2020
		FY 2021	\$16.9	Oct 2020	Expected - Jan 2021
NIPSCO – Gas	Transmission, Distribution and Storage System Improvement Charge (TDSIC)	TDSIC 11: May 2019 - Dec 2019	\$38.7	Feb 2020	Jul 2020
		TDSIC 1: Jan 2020 - Jun 2020	\$26.0	Aug 2020	Expected - Jan 2021
NIPSCO – Electric	Transmission, Distribution and Storage System Improvement Charge (TDSIC)	TDSIC 6: Dec 2018 – Jun 2019	\$131.1	Aug 2019	Jan 2020
		TDSIC 7: Jul 2019 - Jul 2020	\$122.3	Sep 2020	Expected - Feb 2021

Supplemental Slides Third Quarter 2018 Earnings November 1, 2018



NiSource



Gas Distribution Operations - Third Quarter 2018

- Significant progress on regulatory initiatives inclusive of the impacts of federal tax reform across states
- Ongoing infrastructure modernization on track and delivering customer value, including enhanced system safety, reliability and environmental performance

Key Milestones:

<u>Highlight</u>	<u>Key Components</u>	<u>Status</u>
Columbia Gas of Virginia Base Rate Case	• Supports continued focus on pipeline safety and replacement of aging infrastructure • Requests \$22.2M total annual revenue increase; \$14.2M, net of infrastructure trackers	• Filed Aug. 28, 2018 • Rates in effect Feb. 1, 2019; subject to refund • Order expected in 2H2019
Columbia Gas of Maryland Base Rate Case	• Supports continued focus on pipeline safety and replacement of aging infrastructure • Settlement includes \$3.7M annual revenue increase; \$2.1M, net of infrastructure trackers	• Filed Apr. 13, 2018 • Settlement filed Jul. 31, 2018 • Rates in effect Nov. 2018 • Order expected in 4Q2018
Columbia Gas of Pennsylvania Base Rate Case	• Supports continued focus on pipeline safety and replacement of aging infrastructure • Settlement includes \$26.0M annual revenue increase	• Filed Mar. 16, 2018 • Settlement filed Aug. 31, 2018 • Rates in effect Dec. 2018 • Order expected in 4Q2018
Columbia Gas of Ohio Capital Expenditure Program (CEP) Rider	• Establishes annual rider to recover certain capital investments and related deferred expenses not recovered through the IRP tracker • Settlement includes \$74.5M annual revenue increase	• Filed Dec. 1, 2017 • Settlement filed Oct. 25, 2018
NIPSCO Gas Base Rate Case	• Supports continued focus on pipeline safety and replacement of aging infrastructure • First base rate increase request in more than 25 years • Settlement includes ultimate \$107.3M annual revenue increase	• Filed Sept. 27, 2017 • Settlement filed Apr. 20, 2018 • Settlement approved: Sept. 19, 2018 • Rates effective Oct. 1, 2018

~\$20B in Identified Long-Term Infrastructure Investment Opportunities

* Operating Earnings (non-GAAP); For a reconciliation of GAAP to non-GAAP earnings, see NiSource's November 1, 2018, supplemental segment and financial information accompanying this presentation and available on the investor section of www.nisource.com.

Electric Operations - Third Quarter 2018

- Continued execution of seven-year ~\$1.25B electric system modernization program
- 2018 Integrated Resource Plan submitted Oct. 31, 2018
- 2018 Base Rate Case filed Oct. 31, 2018
- Construction continues on environmental upgrades for Michigan City, R.M. Schahfer generating stations

Key Milestones:

<u>Highlight</u>	<u>Key Components</u>	<u>Status</u>
Base Rate Case	• Seeks changes to the company's depreciation schedules related to the early retirements of coal-fired generation plants called for in the IRP • Proposes changes to tariffs to provide service flexibility for industrial customers as they seek to remain competitive in the global marketplace • Requests \$21.4M annual revenue increase	• Filed Oct. 31, 2018 • Rates in effect Sept. 2019 • Order expected in 3Q2019
Integrated Resource Plan (IRP)	• Outlines NIPSCO's plans for meeting customers' long-term electricity needs • 2018 IRP included plans to retire nearly 80 percent of NIPSCO's coal-fired generation fleet by 2023 and the remaining coal-fired units by 2028 • Replacement options point toward lower-cost renewable energy resources such as wind, solar and battery storage technology	• Submitted Oct. 31, 2018
Electric System Modernization Program	• Focused on electric transmission and distribution investments designed to improve system reliability and safety • TDSIC 4 semi-annual tracker update covering ~\$72.2M in investments from December 2017 - May 2018; Settlement pending	• Filed Jul. 31, 2018 • Settlement filed Oct. 25, 2018 • Order expected in 4Q2018
Environmental Upgrades	• Address requirements under Effluent Limitation Guidelines (ELG) and Coal Combustion Residuals (CCR) rules • Costs to be recovered through Federally Mandated Cost Adjustment (FMCA) mechanism • Settlement covers CCR-related investments of ~\$193M; ELG-related investments moved to later proceeding	• Filed Nov. 1, 2016 • CCR settlement filed Jun. 9, 2017 • CCR settlement approved Dec. 13, 2017 • Construction underway, expected completion by YE2018

~\$10B in Identified Long-Term Infrastructure Investment Opportunities

Survey of Ratepayer Protection Mechanisms

Company	Utility Type - Gas/ Electric	Decoupling - Gas/ Electric	Date of Decision	Decision Type	Limited Recovery / Cap on Accruals	Check on Over Earnings	DSM or EE Targets	Pilot or Trial Period	Compliance Review
Arkansas Oklahoma Gas (AR)	Gas	Gas	11/20/2007	Settlement		XXX			
Black Hills Energy (AR) (former westar gas)	Gas	Gas	6/1/2007	Settlement		XXX		XXX	
CenterPoint Energy (AR)	Gas	Gas	10/25/07	Settlement		XXX			
Southwest Gas (AZ)	Gas	Gas	1/6/2012	Settlement	XXX	XXX			XXX
Pacific Gas & Electric (CA)	Electric & Gas	Electric & Gas	5/27/2004	Settlement		XXX	XXX		
San Diego Gas & Electric (CA)	Electric & Gas	Electric & Gas	3/17/2005	Settlement		XXX	XXX		
Southern California Gas (CA)	Gas	Gas	3/17/2005	Settlement		XXX	XXX		
Southern California Edison (CA)	Electric	Electric	4/22/2002	Order		XXX	XXX		
Southwest Gas (CA)	Gas	Gas	3/16/2004	Order		XXX	XXX		
PSC of Colorado (CO)	Electric	Electric	6/21/2017	Order	XXX			XXX	XXX
Connecticut Light & Power (CT)	Electric	Electric	12/17/2014	Order					
Connecticut Natural Gas (CT)	Gas	Gas	1/22/2014	Order					XXX
Southern Connecticut Gas (CT)	Gas	Gas	12/13/2017	Settlement					
United Illuminating (CT)	Electric	Electric	2/4/2009	Order	XXX		XXX		XXX
Potomac Electric Power Company (DC)	Electric	Electric	9/28/2009	Order	XXX				XXX
Atmos Energy/Liberty Utilities (GA)	Gas	Gas	12/27/2011	Settlement		XXX			XXX
HECO Companies (HI)*	Electric	Electric	8/31/2010	Order		XXX			XXX
Avista Utilities (ID)	Electric & Gas	Electric & Gas	12/18/2015	Settlement	XXX				XXX
Idaho Power (ID)	Electric	Electric	3/12/2007	Settlement	XXX		XXX	XXX	
Ameren Illinois (IL)	Electric & Gas	Gas	12/9/2015	Order					
Liberty Utilities (IL)	Electric & Gas	Gas	5/24/2017	Order					
North Shore Gas Company (IL)	Gas	Gas	7/15/2014	Order	XXX				XXX
Peoples Gas Light and Coke (IL)	Electric & Gas	Gas	7/15/2014	Order	XXX				XXX
Boonville Natural Gas Corporation	Gas	Gas	11/30/2011	Settlement			XXX	XXX	
Citizens Gas (IN)	Gas	Gas	8/29/2007	Settlement	XXX			XXX	
Citizens Gas of Westfield (IN)	Gas	Gas	3/10/2010	Order	XXX			XXX	
Community Natural Gas Company	Gas	Gas	11/30/2011	Settlement			XXX	XXX	
Fountaintown Gas (IN)	Gas	Gas	11/30/2011	Settlement	XXX		XXX	XXX	
Indiana Natural Gas (IN)	Gas	Gas	11/30/2011	Settlement	XXX		XXX	XXX	
Indiana Utilities Corporation (IN)	Gas	Gas	11/30/2011	Settlement			XXX	XXX	
Midwest Natural Gas Corporation (IN)	Gas	Gas	11/30/2011	Settlement			XXX	XXX	
South Eastern Indiana Natural Gas Company (IN)	Gas	Gas	11/30/2011	Settlement			XXX	XXX	
Switzerland County Natural Gas Company (IN)	Gas	Gas	11/30/2011	Settlement			XXX	XXX	
Vectren Southern Indiana Gas (IN)	Electric & Gas	Gas	12/1/2006	Settlement	XXX			XXX	
Vectren Indiana Gas (IN)	Electric & Gas	Gas	12/1/2006	Settlement	XXX			XXX	
Kansas City Power & Light (KS)	Electric	Electric	6/22/2017	Order					

Note: HECO Companies include Hawaiian Electric, Hawaii Electric Light, and Maui Electric Company.

Source: Commission Orders

Survey of Ratepayer Protection Mechanisms

Company	Utility Type - Gas/ Electric	Decoupling - Gas/ Electric	Date of Decision	Decision Type	Limited Recovery / Cap on Accruals	Check on Over Earnings	DSM or EE Targets	Pilot or Trial Period	Compliance Review
Bay State Gas (MA)	Gas	Gas	10/30/2009	Order	XXX				
Boston Gas dba National Grid (MA)	Gas	Gas	11/2/2010	Order	XXX				
Colonial Gas dba National Grid (MA)	Gas	Gas	11/2/2010	Order	XXX				
Fitchburg Gas & Electric (MA)	Electric & Gas	Electric & Gas	8/1/2011	Order	XXX				
Nantucket Electric/Massachusetts Electric dba National Grid (MA)	Electric	Electric	2/23/2018	Order	XXX	XXX			
NSTAR dba Eversource Energy (MA)	Electric & Gas	Electric & Gas	10/30/2015 & 1/5/2018	Order	XXX				
New England Gas (MA)	Gas	Gas	3/31/2011	Order	XXX				
Western Massachusetts Electric (MA)	Electric	Electric	1/11/2011	Order	XXX				
Baltimore Gas & Electric (MD)	Electric & Gas	Electric & Gas	2/27/1998 & 2013	Settlement					
Delmarva Power & Light (MD)	Electric	Electric	7/19/2007	Settlement					
PEPCO (MD)	Electric	Electric	7/19/2007	Settlement					
Washington Gas (MD)	Gas	Gas	8/11/2005	Settlement					
Central Maine Power (ME)	Electric	Electric	8/25/2014	Settlement	XXX				
Consumers Energy (MI)	Electric & Gas	Gas	4/21/2016	Settlement					
Detroit Edison (MI)	Electric	Electric	01/11/10	Order			XXX	XXX	XXX
Indiana Michigan Power (MI)	Electric	Electric	4/12/2018	Order	XXX				
Michigan Consolidated Gas (MI)	Gas	Gas	06/03/10	Order			XXX	XXX	XXX
Michigan Gas Utilities (MI)	Gas	Gas	07/01/10	Order			XXX	XXX	XXX
CenterPoint Energy (MN)	Gas	Gas	7/20/2018	Settlement	XXX		XXX	XXX	XXX
Great Plains Natural Gas (MN)	Gas	Gas	9/6/2016	Order	XXX			XXX	XXX
MERC (MN)	Gas	Gas	7/13/2012	Order	XXX			XXX	XXX
Northern States Power dba Xcel Energy (MN)	Electric & Gas	Electric	5/8/2015	Order	XXX		XXX	XXX	XXX
NorthWestern Energy (MT)	Electric & Gas	Electric	01/07/10	Order				XXX	XXX
Piedmont Natural Gas (NC)	Gas	Gas	10/24/2008	Settlement			XXX	XXX	
Public Service Co. of NC (NC)	Gas	Gas	10/24/2008	Settlement			XXX		
Liberty Utilities (EnergyNorth Natural Gas) (NH)	Gas	Gas	4/27/2018	Order					
South Jersey Gas (NJ)	Gas	Gas	10/12/06 & 1/21/10	Settlement	XXX	XXX	XXX	XXX	
New Jersey Natural Gas (NJ)	Gas	Gas	10/12/06 & 1/21/10	Settlement	XXX	XXX	XXX	XXX	
PSE&G (NJ)	Electric & Gas	Electric & Gas	9/23/2020	Order			XXX	XXX	
Nevada Power Co (NV)	Electric	Electric	9/27/2013						
Southwest Gas (NV)	Gas	Gas	11/3/2009	Order			XXX		
Consolidated Edison (NY)	Electric & Gas	Electric & Gas	9/25/07 & 3/25/08	Settlement			XXX	XXX	
National Gas Distribution (NY)	Gas	Gas	9/20/2007	Order			XXX		
Orange and Rockland (NY)	Electric & Gas	Electric & Gas	7/23/2008	Order					
Central Hudson Gas & Elec. (NY)	Electric & Gas	Electric & Gas	6/18/2010	Settlement					

Note: HECO Companies include Hawaiian Electric, Hawaii Electric Light, and Maui Electric Company.

Source: Commission Orders

Survey of Ratepayer Protection Mechanisms

Company	Utility Type - Gas/ Electric	Decoupling - Gas/ Electric	Date of Decision	Decision Type	Limited Recovery / Cap on Accruals	Check on Over Earnings	DSM or EE Targets	Pilot or Trial Period	Compliance Review
Coming Natural Gas (NY)	Gas	Gas	7/17/2009	Settlement					
National Grid - KEDNY & KEDLI (NY)	Gas	Gas	12/22/2009	Settlement					
NYSEG and Rochester G&E (NY)	Electric & Gas	Electric & Gas	9/21/2010	Settlement					
Niagara Mohawk (NY)	Electric & Gas	Electric & Gas	5/15/2009 & 1/24/2011	Settlement					
St. Lawrence Gas (NY)	Gas	Gas	12/18/2009	Order					
American Electric Power (OH)	Electric	Electric	12/14/2011	Settlement	XXX			XXX	
Dayton Power & Light (OH)	Electric	Electric	9/26/2018	Order					
Duke Energy (OH)	Electric	Electric	5/30/2012	Order	XXX			XXX	
Vectren (OH)	Gas	Gas	09/13/06	Settlement			XXX	XXX	XXX
Avista (OR)	Gas	Gas	2/29/2016	Order	XXX			XXX	XXX
Cascade Natural Gas (OR)	Gas	Gas	4/19/2006	Settlement		XXX	XXX	XXX	XXX
Northwest Natural (OR)	Gas	Gas	9/12/2002	Settlement	XXX		XXX	XXX	
Portland General Electric (OR)	Electric	Electric	1/22/2009	Order	XXX		XXX	XXX	XXX
National Grid (RI)	Electric & Gas	Electric & Gas	5/25/2012	Order					
Chattanooga Natural Gas (TN)	Gas	Gas	11/8/2010	Order	XXX			XXX	XXX
Questar Gas (UT)	Gas	Gas	10/5/06 & 11/5/07	Order			XXX	XXX	XXX
Virginia Natural Gas (VA)	Gas	Gas	12/23/2008	Settlement			XXX	XXX	XXX
Columbia Gas of Virginia (VA)	Gas	Gas	12/4/2009	Settlement			XXX	XXX	XXX
Washington Gas Light (VA)	Gas	Gas	3/26/2010	Order			XXX		
Green Mountain Power (VT)	Electric	Electric	12/22/2006	Order					
Avista (WA)	Electric & Gas	Electric & Gas	11/25/2014	Settlement					
Cascade Natural Gas (WA)	Gas	Gas	1/12/2007	Settlement		XXX	XXX	XXX	XXX
Pacific Power (WA)	Electric	Electric	9/1/2016	Order	XXX	XXX	XXX		XXX
Puget Sound Energy (WA)	Electric & Gas	Electric & Gas	6/25/2013	Order	XXX				
Wisconsin Public Service (WI)	Electric & Gas	Electric & Gas	12/30/08	Settlement	XXX		XXX	XXX	XXX
Questar Gas (WY)	Gas	Gas	6/17/2009	Order			XXX	XXX	XXX

Note: HECO Companies include Hawaiian Electric, Hawaii Electric Light, and Maui Electric Company.
Source: Commission Orders

ROE Adjustments in States with Revenue Decoupling

Company (Jurisdiction)	Docket/ Case	Revenue Decoupling Mechanism	Case Decided	Outcome
NATURAL GAS				
Arkansas Oklahoma Gas (AR)	Docket No. 07-026-U	Billing Determinant Adjustment	Settlement	ROE reduced 10 basis points
Arkansas Western (AR)	Docket No. 06-124-U	Billing Determinant Adjustment	Settlement	ROE reduced 25 basis points
North Shore Gas Company; and Peoples Gas Light and Coke (IL)	Docket No. 07-241 and 07-242	Volume Balancing Adjustment	Final Order	ROE reduced 10 basis points
Liberty Utilities/ EnergyNorth Natural Gas (NH)	Docket No. DG 17-048	Lost Revenues Adjustment Mechanism	Final Order	ROE reduced by 10 basis points
Southwest Gas (NV)	Docket No. 09-04003	Revenue Decoupling	Final Order	ROE reduced 25 basis points.
National Fuel Gas Distribution Co (NY)	Case No. 07-G-0141	Revenue Decoupling Mechanism (RDM)	Final Order	ROE reduced 10 basis points
St. Lawrence Gas Company, Inc. (NY)	Case 08-G-1392	Revenue Decoupling	Order	ROE reduced by 10 basis points
Chattanooga Gas (TN)	Docket No. 0900183	Alignment and Usage Adjustment	Final Order	ROE reduced by 25 basis points

Note: HECO Companies include Hawaiian Electric, Hawaii Electric Light, and Maui Electric Company.
Source: Commission Orders

ROE Adjustments in States with Revenue Decoupling

Company (Jurisdiction)	Docket/ Case	Revenue Decoupling Mechanism	Case Decided	Outcome
ELECTRIC				
Connecticut Light & Power (CT)	Docket No. 14-05-06	Revenue Decoupling	Order	Decoupling was adopted with a one-year ROE penalty of 15 basis points.
Potomac Electric Power Company (DC)	Formal Case No. 1076; Order No. 15710	Revenue Decoupling	Final Order	ROE reduced 50 basis points
Potomac Electric Power Company (DC)	Formal Case No. 1087; Order No. 16930	Bill Stabilization Adjustment	Final Order	50 basis point downward adjustment maintained
Potomac Electric Power Company (DC)	Case No. 1053-E-549	Bill Stabilization Adjustment	Order	Decoupling was adopted, ROE reduced 50 basis points
HECO Companies (HI)*	Docket No. 2013-0141	Revenue Balancing Account Rate Adjustment	Order	ROE reduced 50 basis points
Western Massachusetts Electric Company (MA)	D.P.U. 10-70	Revenue Decoupling Mechanism	Final Order	No specific adjustment for decoupling, but ROE set below Company's requested ROE
Baltimore Gas and Electric Company	Order No. 83907; Case No. 9230	Bill Stabilization Adjustment	Settlement	ROE adjusted downward by 50 basis points
Delmarva Power and Light (MD)	Case No. 9093	Bill Stabilization Adjustment	Settlement	ROE reduced 50 basis points
Potomac Electric Power Company (MD)	Order No. 83516; Case No. 9217	Bill Stabilization Adjustment	Settlement	ROE adjusted downward by 50 basis points
Potomac Electric Power Company (MD)	Case No. 9092	Bill Stabilization Adjustment	Settlement	ROE reduced 50 basis points
Portland General Electric Company (OR)	Order 09-020	Sales Normalization Adjustment	Final Order	ROE adjusted downward by 10 basis points

Note: HECO Companies include Hawaiian Electric, Hawaii Electric Light, and Maui Electric Company.
Source: Commission Orders

Summary of WNA Annual Reports

Witness: Deupree
Docket No. R-2025-3053499
Exhibit MWD-11

Heating Season	Revenue Impact
2013-2014	\$ (9,356,200)
2014-2015	(10,981,225)
2015-2016	11,522,044
2016-2017	13,904,914
2017-2018	(6,052,270)
2018-2019	(3,734,377)
2019-2020	4,979,367
2020-2021	5,327,158
2021-2022	2,530,224
2022-2023	17,441,275
2023-2024	36,341,358
2024-2025	9,653,083
Total	\$ 71,575,351

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

Columbia Gas of Pennsylvania, Inc.

:
:
:
:
:
:
:

Docket No. R-2025-3053499

VERIFICATION

I, Michael Deupree, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 1, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 18, 2025

Signature: /s/ Michael Deupree
Michael Deupree

Address: 5800 One Perkins Place Drive,
Suite 5-F
Baton Rouge, Louisiana 70808

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	:	
	:	Docket No.: R-2025-3053112
v.	:	
	:	
Columbia Gas Of Pennsylvania, Inc.	:	

**SURREBUTTAL TESTIMONY
OF
Michael Deupree
On behalf of the
PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE
OCA Statement 1SR**

Date Served: July 31, 2025

1 **I. INTRODUCTION**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A. My name is Michael W. Deupree. My business address is 5800 One Perkins Place
4 Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

5 **Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN THIS PROCEEDING?**

6 A. Yes. I filed direct testimony in this proceeding on June 18, 2025 on behalf of the
7 Pennsylvania Office of Consumer Advocate (“OCA”).

8 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

9 A. The purpose of my testimony is to respond to elements of the rebuttal testimony
10 of Vincent V. Rea and John D. Taylor on behalf of Columbia Gas of Pennsylvania, Inc.
11 (“CGP,” or the “Company”). In particular, I will respond to arguments raised by CGP
12 related to regulatory lag, the proposed revenue normalization adjustment (“RNA”), and
13 the current weather normalization adjustment (“WNA”).

14 **II. REGULATORY LAG**

15 **Q. PLEASE SUMMARIZE THE COMPANY’S ARGUMENTS SURROUNDING**
16 **REGULATORY MECHANISMS AND REGULATORY LAG.**

17 A. The Company disagrees with my discussion on regulatory lag and the beneficial
18 impact of regulatory lag in the overall regulatory process. Instead, the Company argues
19 that my discussion of academic theorems first promulgated in the 1960s and 1970s are
20 largely outdated since the utility industry has changed significantly over the past 50-60
21 years.¹ The Company furthermore points to Baumol and Klevorick’s 1970 conclusion that

¹ Rebuttal Testimony of Vincent V. Rea at 20:11-12.

“regulatory lag induces profit maximizing firms to adopt minimum-cost production alternatives,” as somehow detracting from application to CGP’s pipeline infrastructure replacement initiatives.²

Q. DO YOU AGREE THAT DISCUSSIONS REGARDING THE BENEFICIAL IMPACT OF REGULATORY LAG ON THE REGULATORY PROCESS ARE OUTDATED?

A. No. The Company fails to provide any evidence disputing the fact that regulatory lag disciplines utility investment decisions between rate cases. Indeed, contrary to the Company’s assertion, these early discussions on the importance of regulatory lag gave rise to discussions of alternative regulation mechanisms in the 1980s and 1990s centered around what is known as incentive or performance-based regulation.³ Indeed, these discussions continue to inform contemporary thought on alternative regulation design.⁴

Q. DID THE COMPANY REFERENCE ARTICLES IT CLAIMS INDICATE LIMITED EMPIRICAL EVIDENCE IN SUPPORT OF REGULATORY LAG?

A. Yes. The Company references three studies conducted in the past few decades that the Company claims ‘refutes’ the existence of the Averch-Johnson Effect (“A-J Effect”) I discuss in my Direct Testimony.⁵ However, the Company applies the conclusions presented in these studies incorrectly.

² *Id.* at 20:12-18.

³ Paul L. Joskow, *Incentive Regulation in Theory and Practice: Electricity Distribution and Transmission Networks* (January 21, 2006), National Bureau of Economic Research Conference on Economic Regulation.

⁴ See, Herman K. Trabish, *Performance-based regulation: Seeking the new utility business model* (July 23, 2019), UtilityDive.

⁵ Rebuttal Testimony of Vincent V. Rea at 22:14-15.

Q. HAVE YOU REVIEWED THE ARTICLES REFERENCED BY THE COMPANY PERTAINING TO THE AVERCH-JOHNSON EFFECT?

A. Yes. These studies attempt to apply the theoretical underpinnings developed decades ago to observable utility operations and largely conclude that real-world dynamics are complicated, often obscuring theoretically anticipated behaviors. Noteworthy in these complicated dynamics are that regulators themselves are not ignorant of incentives for utilities to overcapitalize, and thus in the presence of dutiful regulators utilities are careful to guard against potential disallowances or other negative regulatory outcomes. As summarized by Law in his 2014 paper:

A few studies have carefully found evidence suggestive of the [A-J Effect]. Studies from the same period in different industries found no evidence and more recent papers have found no evidence of the [A-J Effect]. Either there never was a significant [A-J Effect] and/or regulators read the economic literature, too, and took steps to mitigate the [A-J Effect].⁶

Q. ARE THERE OBSERVATIONS MEANINGFUL TO DISCUSSIONS OF REGULATORY LAG?

A. No. The Company ignores that one means in which regulators guard against utility over-capitalization is by embedding regulatory lag in the regulatory process through mechanisms like stay-out provisions. Furthermore, as the Company itself recognizes,⁷ in international regulation incentive or performance-based regulation is commonplace which includes defined multi-year periods between rate cases and thus embeds regulatory lag

⁶ Stephen M. Law, *Assessing the Averch-Johnson-Wellisz Effect for Regulated Utilities*, International Journal of Economics and Finance (July 2014), p. 51 (*emphasis added*).

⁷ Rebuttal Testimony of Vincent V. Rea at 22:19-23.

into the regulatory process to promote efficient utility operations.⁸ Rather than ‘refute’ the existence of the positive benefits of regulatory lag, these observations merely indicate that regulators through diligent oversight of utility operations have largely prevented the negative impacts that was theorized could occur through lapse oversight.

Q. HAVE UTILITY REGULATORY COMMISSIONS AND STATE LEGISLATIVE BODIES ADOPTED COST RECOVERY MECHANISMS TO ENCOURAGE THE UPGRADE AND REPLACEMENT OF AGING NATURAL GAS PIPELINE INFRASTRUCTURE?

A. Yes. Regulators generally have determined that over-reliance on regulatory lag in the regulatory process would encourage utilities to make significant cuts to non-revenue generating investments and activities such as customer service and service reliability improvements.⁹ These cuts may not be in the public interest, especially in the natural gas sector where such cuts may lead to dangerous deterioration of the nation’s natural gas pipeline infrastructure. Rather than demonstrating that regulators and state legislatures disagree with the beneficial impact of regulatory lag on the regulatory process, this merely demonstrates the recognition that the beneficial impact of regulatory

⁸ See, Paul L. Joskow, *Regulation and Deregulation After 25 Years: Lessons Learned for Research in Industrial Organization*, Review of Industrial Organization, Volume 26, (March 2005), p. 31.

“Ironically, despite the extensive amount of research done by economists in the United States on mechanism design issues, the application of incentive regulation theories, including benchmarking and yardstick competition, have been much more extensive in Europe, Australia, New Zealand and several Latin American countries than it has been in the United States. Why this should be the case is unclear, but it is at least partially the legacy of a century of living with formal regulatory rules that may appear to restrict what regulators can do. Regulators in the United States have no problem cutting deals through informal regulatory arrangements, but the formal introduction of well designed incentive-based regulatory contracts has been difficult.”

⁹ Biewald, *et. al.*, *Performance-Based Regulation in a Restructured Electric Industry* (November 8, 1997), National Association of Regulatory Utility Commissioners, p. 37.

lag must be tempered by other processes that incentivize utilities to make investments in non-revenue generating improvements that are in the public interest.

Q. HAS PENNSYLVANIA ADOPTED PROCESSES TO INCENTIVIZE UTILITY INVESTMENT IN NEEDED INFRASTRUCTURE REPLACEMENT ACTIVITIES?

A. Yes. As the Company notes in its Direct Testimony,¹⁰ it has available to it the Distribution System Improvement Charge (“DSIC”) that would allow it to earn a return of and on qualifying capital investments made between rate cases that are designed to replacing aging pipeline facilities. Furthermore, in 2012 the Pennsylvania Legislature amended 66 PA. C.S. Section 315(e) to allow for utilities to utilize Fully Projected Future Test Years (“FPFTY”),¹¹ which the Company has utilized in each of its last five base rate case filings.¹² As I noted in my direct testimony,¹³ these mechanisms already address regulatory lag concerns without relying on the proposed RNA or continuation of the WNA.

III. WEATHER NORMALIZATION ADJUSTMENT

Q. PLEASE SUMMARIZE THE COMPANY’S RESPONSE TO PARTIES’ CONCERNS REGARDING THE COMPANY’S PROPOSAL TO MAKE THE WNA PERMANENT.

A. The Company argues that intervenor arguments against continuation of the WNA can be grouped into three general themes: (a) customer impact and fairness; (b) transparency and customer understanding; and (c) structural and methodological

¹⁰ Direct Testimony of Mark Kempic at 6:11-17.

¹¹ Act of February 14, 2012, P.L. 72, No. 11.

¹² Direct Testimony of Michael W. Deupree at 4:8-11.

¹³ *Id.* at 4:11-14.

concerns.¹⁴ With regards to customer impacts, the Company argues that the WNA will not undermine energy conservation efforts¹⁵ and possesses adequate customer protections.¹⁶ Regarding transparency and customer understanding, the Company argues that WNA mechanisms are common mechanisms for gas utilities and therefore not inherently complex for customers to understand.¹⁷ Finally, the Company argues that the WNA does not shift weather risks to customers, contrary to parties' statements to the contrary.¹⁸

Q. DO YOU AGREE WITH THE COMPANY'S ARGUMENT THAT THE WNA DOES NOT UNDERMINE EFFORTS TO CONSERVE ENERGY?

A. No. The Company argues that the WNA does not eliminate the price signals customers receive from their energy consumption, and references as an example a customer's April 2025 bill. Specifically, a customer who used 45 therms in April of 2025 would have seen \$6.27, or approximately 11.1 percent, savings by reducing consumption by 10 percent after application of the WNA. This compared to a \$4.70, or 10 percent, savings by reducing consumption by 10 percent without application of the WNA.¹⁹

The Company's hypothetical demonstrates the concern associated with the WNA undermining efforts to conserve energy. Under the WNA, a customer that used approximately 40 therms in the month of April 2025 (approximately 10 percent less than the base of 45 therms) would have seen a final monthly bill of \$50.14. This is more than

¹⁴ Rebuttal Testimony of John D. Taylor at 5:1-3.

¹⁵ *Id.* at 6:2-17.

¹⁶ *Id.* at 6:18 to 7:20.

¹⁷ *Id.* at 9:20 to 10:19.

¹⁸ *Id.* at 11:11 to 13:7.

¹⁹ *Id.* at 6:10-14.

1 the \$47.00 monthly bill the same customer using 45 therms would have seen in the
2 absence of the WNA. While a customer would still see savings on monthly utility bills
3 from reducing consumption, the WNA in this example still results in a customer
4 consuming less having a higher final monthly bill due to the imposition of the WNA. The
5 proposed RNA will exacerbate these concerns by creating higher RNA charges in cases
6 of widespread efforts to conserve energy.

7 **Q. DO YOU AGREE THAT THE WNA POSSESSES ADEQUATE CUSTOMER**
8 **PROTECTIONS?**

9 A. No. The Company points to the current 3 percent deadband present within the
10 WNA, and how the mechanism is restricted to the Residential class and therefore
11 presents no cross-subsidization concerns with other classes.²⁰ However, as I discussed
12 in my Direct Testimony, the WNA as currently designed does not provide important
13 ratepayer protections such as earnings tests, revenue caps, or performance incentives.²¹

14 **Q. DOES THE COMPANY MAKE ANY MISLEADING CLAIMS OF WNA**
15 **CUSTOMER PROTECTIONS?**

16 A. Yes. The Company claims that the current WNA is designed to only reflect the
17 revenues that would have been collected under normal weather, and therefore prevents
18 the Company from recovering additional distribution revenues due to colder than average
19 temperatures.²² This is misleading. As noted in my Direct Testimony, the WNA has in
20 practice been skewed towards generating revenue for the Company rather than providing
21 credits to customers, especially when examining recent operations of the WNA.

²⁰ *Id.* at 7:6-20.

²¹ Direct Testimony of Michael W. Deupree at 15:11-14.

²² Rebuttal Testimony of John D. Taylor at 5:1-3.

Furthermore, the statement that the Company is prevented from excess earning through the WNA than authorized by the Commission assumes that customer behavior is consistent with that modeled through the Company's models. Specifically, as it relates to determination of customer usage during normal weather as the Commission noted in its decision to reject a proposed WNA by PECO in Docket No. R-2024-3046932.²³

Q. IS THE WNA LIKELY UNDERSTANDABLE, OR VALUED, BY CGP RATEPAYERS?

A. No. Figure 1 presents the mathematical formula that is used to calculate monthly WNA charges or credits. This demonstrates that CGP's WNA is calculated on a per customer basis and includes several elements that are potentially confusing to customers.

²³ *Pennsylvania Public Utilities Commission et. al. v. PECO Energy Company – Gas Division*, Docket No. R-2024-3046932, Opinion and Order at 95.

1

Figure 1 – WNA Mathematical Formula**RIDER WNA – WEATHER NORMALIZATION ADJUSTMENT**

A Weather Normalization Adjustment (WNA) shall be applied to bills of Residential customers under Rate Schedules RSS, RDS, and CAP, for the heating season November through May. The WNA shall continue until a final Order is entered in the Company's first rate case filed after December 14, 2024. The WNA will be applied to November through May billing cycles and shall be calculated as follows:

$$\text{WNBT} = \text{BLMT} + [(\text{NHDD} / \text{AHDD}) \times (\text{AMT} - \text{BLMT})]$$

$$\text{WNAT} = \text{WNBT} - \text{AMT}$$

$$\text{WNA} = \text{WNAT} \times \text{Distribution Usage Charge}$$

- (a) Weather Normalized Billing Therms (WNBT) will be calculated as the Base Load Monthly Therms (BLMT) added to the product of the Normal Heating Degree Days (NHDD) divided by the Actual Heating Degree Days (AHDD) and the Actual Monthly Therms (AMT) less the Base Load Monthly Therms (BLMT).
- (b) Base Load Monthly Therms (BLMT) are established for each customer using the customer's actual average daily consumption from the billing system, measured in therms, for the two months with the lowest consumption per billing day for the three billing months of July, August and September. The average baseload per day information will be updated annually. If actual BLMT information is not available for the year, the Company will use the most recently available base load information for the premise. If no history is available, the Company shall use the overall base load average for the residential class reflected in the most recent rate case.
- (c) Normal Heating Degree Days (NHDD) shall be updated annually by September 1st using the same methodology established in the Company's most recent Rate Case. NHDD for any given day are based upon the 20 year average for the given day.
- (d) Actual Heating Degree Days (AHDD) are the actual experienced heating degree days for the billing cycle. The degree day data is provided by the National Oceanic and Atmospheric Administration (NOAA). Customers will be assigned to weather stations based on their geographic locations.
- (e) Actual Monthly Therms (AMT) are measured for each customer and billing cycle.
- (f) Actual Monthly Therms (AMT) will be subtracted from the Weather Normalized Billing Therms (WNBT) to compute the Weather Normalized Adjustment Therms (WNAT).
- (g) The WNAT is then multiplied by the residential Distribution Usage Charge to compute the WNA amount that will be charged or credited to each residential customer.

2

3 **Q. HOW MIGHT THE WNA BE CONFUSING TO CGP's RATEPAYERS?**

- 4 A. First, the WNA is applied only to the weather-sensitive portion of the customer's
- 5 usage, excluding base load usage that is non-temperature sensitive. It is unlikely that a
- 6 CGP customer would know the portion of their natural gas usage that is not associated
- 7 with natural gas space heating (as opposed to water heating, cooking, drying clothes, or

1 using outdoor grills or fireplaces), or have ready access to determine the average lowest
2 daily consumption for the two of the three summer months of July through September. A
3 customer's baseload usage for the purposes of calculating the WNA is furthermore not
4 included on their bill.²⁴ Second, the WNA applies relevant actual heating degree day
5 ("HDD") information against annually updated 20-year normal HDD prepared each
6 September 1st. While historical weather information is available through the National
7 Climatological Data Center ("NCDC") of the National Oceanic and Atmospheric
8 Administration ("NOAA"), verifying actual updated normal HDD information used in the
9 WNA calculation would require a ratepayer to access this weather information, presuming
10 the individual was even aware of the availability of historic weather information.

11 **Q. DOES FIGURE 1 CONTAIN THE FULL MATHEMATICAL FORMULA**
12 **REQUIRED TO CALCULATE THE WNA?**

13 A. No. Figure 1 is pulled from the Company's WNA tariff sheet, but it importantly does
14 not include the 3 percent deadband that is applied to WNA calculation. Specifically, a
15 billing adjustment only occurs if the ratio of NHDD/AHDD identified in Figure 1 is greater
16 than 103 percent, or less than 97 percent. While providing an important protection to
17 ratepayers from normal weather variations, this adds additional complexity for CGP
18 ratepayers to understand.

19 **Q. ARE THERE OTHER CONCERNS WITH THE UNDERSTANDABILITY OF THE**
20 **WNA TO AN AVERAGE RATEPAYER?**

21 A. Yes. HDD itself is a calculated value, specifically the difference between the
22 'average' temperature for a day and a given 'base' value, typically 65 degrees. In this

²⁴ OCA Exhibit BA-4, Columbia Response to OCA-3-020, Attachment A.

context, average temperature represents the median temperature for the day, or the middle value between the daily low and the daily high temperature. This additional calculation element could provide additional confusion for CGP ratepayers who are unfamiliar with meteorological calculations.

Q. DOES THE WNA DISPROPORTIONATELY AFFECT LOW-INCOME HOUSEHOLDS?

A. Yes. As discussed in the Direct Testimony of OCA Witness Colton, the WNA disproportionately affects low-income households in an adverse fashion since these customers respond less to cold weather than do higher income customers.²⁵

Q. DO YOU AGREE THAT THE WNA DOES NOT SHIFT WEATHER-RELATED RISKS FROM CGP SHAREHOLDERS TO CGP RATEPAYERS?

A. No. From a high level the Commission should recognize that the Company admits that utility investors in the CGP debt and equity instruments view mechanisms like the WNA and RNA favorably because “regulatory lag directly contributes to earnings attrition, which has negative implications for both bond investors and equity investors.”²⁶ Put another way, the WNA protects CGP from falling earnings attributed to weather-related revenue risks caused by warmer than expected winters. That the WNA protects CGP from these risks is not in dispute,²⁷ however, the Company argues that the WNA is designed to operate symmetrically and points to the fact that customers have received

²⁵ Direct Testimony of Roger Colton at 96:3-7.

²⁶ Rebuttal Testimony of Vincient V. Rea at 23:5-7.

²⁷ See, Rebuttal Testimony of John D. Taylor at 12:5-20.

1 credits under the WNA approximately 40 percent of the time since the mechanism's
2 inception.²⁸

3 **Q. DO YOU AGREE WITH THE COMPANY'S ARGUMENT THAT THE WNA HAS**
4 **BEEN OPERATING SYMMETRICALLY?**

5 A. No. The Company's analysis finds that during the period September 2013 through
6 April 2025, 36 out of 89 monthly billing periods saw credits provided to customers through
7 the WNA mechanism.²⁹ However, 14 of these monthly credits, or more than a third,
8 occurred during the first two years of operation of the WNA mechanism (2013-14 and
9 2014-15 winter periods), meaning that since October 2015 nearly 70 percent of WNA
10 monthly adjustments have been charges applied to customer's bills.³⁰ The Company's
11 analysis of historic WNA adjustments is also misleading in that it fails to recognize that
12 most historic monthly credits to ratepayers through the WNA have been small relative to
13 monthly WNA charges.

14 **Q. HAVE YOU ESTIMATED THE TOTAL AMOUNT OF REVENUE COLLECTED**
15 **BY THE COMPANY THROUGH THE WNA?**

16 A. Yes. In Exhibit MWD-11 attached to my Direct Testimony I examined the
17 Company's over/under collections through the WNA since the mechanism's inception for
18 the 2013-14 heating season. In the mechanism's 12 year life, the Company has collected
19 nearly \$71.6 million through the WNA, with the Company collecting nearly \$71.3 million
20 through the WNA in the last five years (2020-21 through 2024-25 heating seasons) alone.
21 This reality undermines arguments that the mechanism is symmetrical in nature. Indeed,

²⁸ *Id.* at 11:20 to 12:3.

²⁹ *Id.* at Exhibit JDT-1R.

³⁰ *Id.*

on an annual basis in only 4 of the 12 years the mechanism has been in existence did customers see a net credit on bills through the application of the WNA, with the last such occurrence being during the 2018-19 heating season.

Q. DOES YOUR OBSERVATION HOLD EVEN WHEN EXAMINING RECENT WNA OPERATIONS?

A. Yes. In the WNA period covering the most recent winter the Company has received on net more than \$9.6 million through the WNA during through April.³¹ This occurred while the Company's service territory experienced notably colder than usual temperatures during the months of January and February of this year.³²

Q. ARE COMPANY CUSTOMERS ACCURATELY INFORMED THAT THE WNA HAS GENERALLY CONTRIBUTED TO HIGHER RATES?

A. No. As discussed in the Direct Testimony of OCA Witness Alexander, the Company's communication materials do not reflect that the actual operations of the WNA has been favorable to the utility's revenues.³³

IV. REVENUE NORMALIZATION ADJUSTMENT

Q. PLEASE SUMMARIZE THE COMPANY'S RESPONSE TO INTERVENOR TESTIMONY RELATING TO THE RNA.

A. The Company continues to support its proposed RNA. With regards to my Direct Testimony, the Company argues that my argument that the RNA unfairly shifts business risk from shareholders to ratepayers is misleading because the RNA is not a guarantee

³¹ *Id.*

³² *Id.*

³³ Direct Testimony of Barbara R. Alexander at 25:14-16.

1 of earnings.³⁴ The Company also argues that the RNA will not disincentivize customers
2 to pursue energy efficiency.³⁵ Finally, the Company argues that its proposal of the RNA
3 is not intended to somehow invalidate the WNA.³⁶

4 **Q. DO YOU CONTINUE TO BELIEVE THE PROPOSED RNA UNFAIRLY SHIFTS**
5 **BUSINESS RISK FROM SHAREHOLDERS TO RATEPAYERS?**

6 A. Yes. As noted earlier, from a high level the Commission should recognize that the
7 Company admits that utility investors in the CGP debt and equity instruments view
8 mechanisms like the WNA and RNA favorably because “regulatory lag directly contributes
9 to earnings attrition, which has negative implications for both bond investors and equity
10 investors.”³⁷ The proposed RNA would insulate the Company from industry trends
11 showing declining natural gas use per customer by allowing it to increase rates between
12 rate cases to account for this revenue attrition, transferring this risk to ratepayers.

13 **Q. DO YOU AGREE THAT THE PROPOSED RNA WILL INSULATE CGP FROM**
14 **THE EFFECTS OF CHANGES IN USAGE DUE TO EFFECTS UNRELATED TO**
15 **ENERGY EFFICIENCY SUCH AS ECONOMIC DECLINE AND FUEL SWITCHING?**

16 A. Yes. As I discussed in my direct testimony, similar decoupling mechanisms to the
17 proposed RNA have been shown to insulate utilities from the impact of events unrelated
18 to energy efficiency such as the economic business cycle and economic recessions.³⁸
19 Indeed, I reference examples where utility management have referenced the presence of

³⁴ Rebuttal Testimony of John D. Taylor at 21:1 to 22:9.

³⁵ *Id.* at 22:10 to 23:7.

³⁶ *Id.* at 23:9 to 24:2.

³⁷ Rebuttal Testimony of Vincient V. Rea at 23:5-7.

³⁸ Direct Testimony of Michael W. Deupree at 41:11 to 42:14.

1 revenue decoupling mechanisms to protect utility revenue streams during large
2 macroeconomic upheaval such as the COVID-19 pandemic.³⁹ Rather than a positive for
3 ratepayers, this is decidedly a negative for ratepayers as the proposed RNA shifts these
4 macroeconomic risks from the utility onto ratepayers.

5 **Q. DOES THE COMPANY DISPUTE YOUR ARGUMENT THAT THE PROPOSED**
6 **RNA WILL RESULT IN ASYMMETRICAL SURCHARGES TO RATEPAYERS?**

7 A. Yes. The Company argues that the proposed RNA will be symmetrical, resulting
8 in both surcharges and credits for customers.⁴⁰ However, this assertion ignores the fact
9 that natural gas utilities as a whole have experienced falling use per customer trends for
10 decades as customers purchase more energy-efficient appliances. As I discuss in my
11 Direct Testimony, analyses of decoupling mechanisms introduced elsewhere in the
12 country have consistently found these mechanisms more often result in monthly
13 surcharges for customers rather than credits.⁴¹

14 **Q. DO YOU CONTINUE TO BELIEVE THAT THE RNA WOULD CREATE**
15 **DISINCENTIVES FOR CUSTOMERS TO PURSUE ENERGY EFFICIENCY?**

16 A. Yes. The Company should recognize that the RNA will result in greater monthly
17 charges for ratepayers to the extent more customers pursue energy efficiency measures.
18 This undoubtedly will create the impression in the public's mind that any pursuit of energy
19 efficiency for the purposes of lower monthly utility bills is meaningless since the RNA will
20 adjust monthly usage to the levels calculated in the Company's most recent base rate
21 case.

³⁹ *Id.* at 42:15 to 44:17.

⁴⁰ Rebuttal Testimony of John D. Taylor at 22:5-6.

⁴¹ Direct Testimony of Michael W. Deupree at 37:5-21.

1 **Q. IS THE PROPOSED RNA DUPLICATIVE OF THE EXISTING WNA?**

2 A. Yes. The proposed RNA would allow the Company to recover variances in
3 revenues regardless of the source. To this end the proposed mechanism would duplicate
4 the functions of the current WNA if the Commission decides to allow CGP to retain the
5 WNA. This would add confusion for customers including an additional annual
6 reconciliation for the RNA on top of the current monthly reconciliation for the WNA.

7 **V. IMPACT OF THE WNA AND RNA ON CGP'S RATE OF RETURN**

8 **Q. IN YOUR DIRECT TESTIMONY, DID YOU DESCRIBE HOW OTHER**
9 **REGULATORY COMMISSIONS HAVE RECOGNIZED THE RELATIONSHIP**
10 **BETWEEN RISK REDUCTION AND A UTILITY'S AUTHORIZED ROE?**

11 A. Yes. On pages 40 and 41 of my Direct Testimony, I included several examples of
12 regulatory commissions, when approving revenue normalization mechanisms, making
13 corresponding reductions in allowed ROE due to the decrease in utility risk associated
14 with such mechanisms.⁴²

15 **Q. HOW DID THE COMPANY RESPOND?**

16 A. The Company argues that if the WNA is discontinued and the Company's request
17 for the RNA is denied, then the Company will bear more risk relative to the Gas LDC
18 Group used by the Company and OCA witness Garrett is estimating the market-based
19 cost of equity.⁴³ Accordingly, the Company argues that its estimated cost of equity will

⁴² *Id.* at 40:7-41:10.

⁴³ Rebuttal Testimony of Vincent V. Rea at 17:17-21.

understate the market-required return if the Company's request to continue the WNA and implement the proposed RNA are denied.⁴⁴

Q. DID THE COMPANY PROVIDE ANY BASIS TO CONCLUDE THAT THE RISK REDUCTION ASSOCIATED WITH THE WNA AND RNA ARE ACCURATELY REFLECTED IN THE COST OF EQUITY ESTIMATES PROVIDED BY CGP?

A. No. In response to a discovery request, the Company stated that it "did not attempt to quantify the degree to which the implementation of revenue decoupling mechanisms by the Gas LDC Group companies impacted the cost of capital for these companies."⁴⁵ Rather, the Company's conclusion is entirely qualitative and supported by no analysis or review of market-based data.⁴⁶

Q. DOES THIS STATEMENT SUPPORT THE CONCLUSION THAT IT MAY BE APPROPRIATE TO ADJUST CGP'S ALLOWED RATE OF RETURN IN RECOGNITION OF ITS CHANGING RISK PROFILE DUE TO THE WNA AND/OR RNA?

A. Yes. While I did not submit testimony in this proceeding on the comparative risk profiles between CGP and the companies in the Gas LDC Group relied upon by the Company and OCA witness Garrett, the WNA and RNA clearly both shift risk from CGP onto its ratepayers. Because the WNA and RNA shift risks associated with revenue deficiencies from the utility to ratepayers, the Company's authorized ROE should reflect the reduced risks to its earnings, as other jurisdictions have previously recognized.⁴⁷

VI. CONCLUSIONS AND RECOMMENDATIONS

⁴⁴ Rebuttal Testimony of Vincent V. Rea at 17:22-20:2.

⁴⁵ Company's Response to Data Request OCA 2-015.

⁴⁶ Response to Discovery Request OCA 2-015.

⁴⁷ Direct Testimony of Michael Deupree, Exhibit MWD-10.

1 **Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.**

2 A. Having reviewed the rebuttal testimony filed by CGP in this proceeding, I continue
3 to recommend the Commission:

- 4 • Reject the proposed RNA mechanism. The proposed RNA shifts nearly all
5 volumetric risk, including that associated with weather, conservation, energy
6 efficiency, and electrification, from the utility to its customers. The mechanism also
7 lacks common consumer protection such as rate caps, earnings tests, or
8 performance incentives.
- 9 • Discontinue the WNA, or, at a minimum, impose significant structural reforms. The
10 WNA has produced consistent net charges to ratepayers over recent years,
11 reflecting a one-sided risk allocation. If the Commission decides to continue the
12 WNA, I recommend the Commission eliminate the month of October from the WNA
13 period.

14 **Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

15 A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

Columbia Gas of Pennsylvania, Inc.

:
:
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:
:
:
:

Docket No. R-2025-3053499

VERIFICATION

I, Michael Deupree, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 1SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 31, 2025

Signature: /s/ Michael Deupree
Michael Deupree

Address: 5800 One Perkins Place Drive,
Suite 5-F
Baton Rouge, Louisiana 70808

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2025-3053499
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF

DANTE MUGRACE

**ON BEHALF OF THE
COMMONWEALTH OF PENNSYLVANIA
OFFICE OF CONSUMER ADVOCATE**

June 18, 2025

PUBLIC VERSION

TABLE OF CONTENTS

	<u>PAGE</u>
I. STATEMENT OF QUALIFICATIONS	1
II. PURPOSE OF TESTIMONY	2
III. REVENUE REQUIREMENT ISSUES	
A. SUMMARY RECOMMENDATIONS	3
B. RATE BASE	
1. UTILITY PLANT IN SERVICE	4
2. ACCUMULATED DEPRECIATION	9
3. WORKING CAPITAL	10
4. DEFERRED INCOME TAXES	12
C. RATE OF RETURN	14
D. OPERATING INCOME	
1. OPERATING REVENUES	15
2. OPERATING AND MAINTENANCE EXPENSES	
a. Labor	16
b. Incentive Compensation	18
c. Pension Deferral	22
d. Other Employee Benefits	23
e. Outside Services	24
f. Corporate Insurance	27
g. Injury and Damages	27
h. Employee Expenses	28
i. Company Memberships	30
j. Utilities-Fuel Used in Co. Operations	32
k. Advertising	32
l. Materials and Supplies	33
m. NCSC	34
n. DEI/ESG costs	38
o. Rate Case Expenses	39
p. Uncollectible Expense – Unbundled - Gas	40
q. Rider USP and Rider EE41	41
3. DEPRECIATION and AMORTIZATION	42
4. TAXES OTHER THAN INCOME	43
5. INCOME TAXES	44
E. ACT-40 REQUIREMENTS (ACT 40 of 2016)	46

1 I. STATEMENT OF QUALIFICATIONS

2 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

3 A. My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD
4 20877.

5 Q. WHAT IS YOUR PRESENT OCCUPATION?

6 A. I am a Senior Consultant with the Economic and Management Consulting Firm of PCMG
7 and Associates, LLC. ("PCMG"). In my capacity as a Senior Consultant, I am responsible
8 for evaluating and examining rate and rate related proceedings before various
9 governmental entities, preparing expert testimony recommending revenue requirement, as
10 well as, offering opinions on economic policy and policy issues and methodologies used
11 to set a value on a utility's rate base and cost of service components of revenue requirement.

12 Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE.

13 A. PCMG is an association of experts in utility regulation and policy, economics, accounting
14 and finance. PCMG's members have over 75 years collective experience providing
15 assistance to counsel and expert testimony regarding the regulation of electric, gas, water
16 and wastewater utilities that operate under local, state and federal jurisdictions. PCMG
17 focuses on areas regarding revenue requirement, cost of service, rate design, cost of capital
18 and rate of return. Prior to my association with PCMG, I was employed as a Senior
19 Consultant with the consulting firm of Snavelly King Majoros and Associates ("SKM")
20 from 2013 to 2015, in the same capacity as PCMG. Prior to SKM I was employed by the
21 New Jersey Board of Public Utilities ("NJBPU") from 1983 to my retirement in 2011.
22 During my tenure at the NJBPU, I held various Accounting, Rate Analyst, Supervisory and
23 Management Positions. My last position was Bureau Chief of Rates in the Agency's Water
24 Division (Bureau Chief of Rates). I held this position for nearly 10 years. My resume is
25 attached as Appendix A.

1 **Q. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE**
2 **SETTING PROCEEDINGS AND OTHER UTILITY MATTERS?**

3 **A.** In my capacity as Bureau Chief of Rates at NJBPU, I was responsible for overseeing the
4 rate process regarding administrative, financial, and managerial functions of the Rates
5 Bureau. My primary duties were to ensure that the jurisdictional utilities had sufficient
6 revenues to cover their operating expenses, the ability to earn a reasonable rate of return
7 on plant investments, and to ensure that the provision of safe, adequate and proper service
8 at reasonable rates was met. During my time at the NJBPU, I was involved in hundreds of
9 rate and rate related proceedings. In my capacity as a Senior Consultant previously with
10 SKM and now with PCMG, I am and was involved in rate and rate related proceedings
11 before the Commissions in the Commonwealths of Massachusetts and Pennsylvania, and
12 the States of Arkansas, Hawaii, Georgia, Maine, Maryland, New Jersey, New York, North
13 Dakota, Ohio, and Wyoming. I was involved in the Generic Proceedings to Establish
14 Parameters for the Next Generation Performance Based Rate Plans before the Alberta
15 Utilities Commission.

16 **Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?**

17 **A.** I hold a Master of Business Administration (“MBA”) degree with a concentration in
18 Strategic Management from Pace University-Lubin School of Business in New York, New
19 York. I hold a Master of Public Administration (“MPA”) degree from Kean University in
20 Union, New Jersey. I hold a Bachelor of Science (“BS”) degree in Accounting from Saint
21 Peter’s University in Jersey City, New Jersey.

22 **II. PURPOSE OF TESTIMONY**

23 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

24 **A.** I am testifying on behalf of the Pennsylvania Office of Consumer Advocate (“OCA”).
25
26
27

1 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

2 **A.** The purpose of my testimony is to calculate and recommend Columbia Gas of
3 Pennsylvania, Inc. (Columbia, CPA or Company) Rate Base and Proforma Operating
4 Income at Present Rates for the Fully Projected Future Test Year Period Ending December
5 31, 2026. On March 20, 2025, Columbia filed a base rate case with the Pennsylvania Public
6 Utility Commission (PAPUC or Commission) requesting an overall increase in rates for its
7 gas distribution service of \$110.497 million or approximately 12.00% above current rates.¹
8 Included in my recommended position on Rate Base and Operating Income, I am also
9 incorporating the recommendations of OCA witness Mr. David Garrett on the overall rate
10 of return and for adjustments to the Company's depreciation expense. I am also including
11 a recommendation related to the Company's Rider USP balance as recommended by OCA
12 witness Roger Colton.

13 **III. REVENUE REQUIREMENT ISSUES**

14 **A. SUMMARY**

15 **Q. WHAT REVENUE DEFICIENCIES OR ADJUSTMENTS ARE YOU**
16 **RECOMMENDING?**

17 **A.** Based upon the use of the Company's proposed fully projected future test year ending
18 December 31, 2026, I have the following recommendations:

- 19 • My recommended Rate Base balance is \$3,883,435,478 which is \$38,053,763 higher
20 than the Company's proposed Rate Base balance of \$3,845,381,715.
- 21 • My overall Rate of Return is based upon OCA witness Mr. Garrett's recommendation
22 of 7.06%, which includes a Common Equity component of 8.90%. This incorporates
23 a Long-Term Debt ratio of 47.68%, a Short-Term Debt ratio of 2.32% and a Common
24 Equity ratio of 50%.
- 25 • My recommended Rate of Return on Rate Base is \$274,170,545, which is \$54,609,592
26 lower than the Company's Rate of Return on Rate Base of \$328,780,137.

¹ As per Company Exhibit 102 Schedule 3 page 3 of 6.

- My recommended Operating Revenue at Present Rates is computed at \$919,077,834 which is the same as Company's Present Rate Revenue of \$919,077,833.
- My recommended total for Operating Expenses is \$561,537,684 which is \$66,454,225 lower than the Company's proposed Operating Expenses of \$627,991,908.
- My recommended Income Tax expense is \$53,261,241, which is \$19,550,100 lower than the Company's proposed Income Taxes of \$72,811,341. I have accepted the Company's Proposed Investment Tax Credit of (\$78,757).
- Overall, I recommend a revenue requirement decrease of \$41,771,883 which is \$152,268,630 lower than the Company's proposed revenue requirement increase of \$110,496,797.

B. RATE BASE

1. Utility Plant in Service (UPIS)

Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS UTILITY PLANT IN SERVICE ("UPIS")?

A. The Company has proposed a UPIS balance in the amount of \$5,219,879,725 for the fully projected future test year of twelve months ending December 31, 2026. Included in that balance are plant additions the Company expects to place in service in the amount of \$436,529,280 for the Future period ending November 30, 2025, and an additional \$436,492,629 for the Fully Projected Future Test period ending December 31, 2026. (Company Exhibit 108, page 3 of 11). The Company stated that the primary drivers of this rate proceeding are the ongoing significant investment to modernize its distribution system through the replacement of pipe and related appurtenances that are reaching the end of their useful lives. (Kempic Statement No. 1 page 4).

Q. WHAT ARE THE REQUIREMENTS OF THE USE OF A FPFTY PERIOD?

A. With the enactment of Act 11 of 2012, CPA is allowed to use a fully projected future test year (FPFTY) to establish base rates. The FPFTY is defined as the 12-month period that begins with the first month that the new rates will be placed in service, after application of the full suspension period permitted under Section 1308(d).

1 **Q. HAS THE COMPANY CHOSEN TO BASE ITS RATE REQUEST UPON AN**
2 **FPFTY?**

3 **A.** Yes. (Covert Statement No. 11 page 3).

4 **Q. WHAT HAS THE COMPANY INCLUDED IN THE DEVELOPMENT OF ITS**
5 **UPIS?**

6 **A.** In response to OCA Set 9-14, the Company included capital expenditures related to growth,
7 betterments, infrastructure replacements, IT upgrades, facilities and security upgrades,
8 support service upgrades and replacement of aging and condition upgrades. These balances
9 total increases of \$445.386 million and \$415.721 million and \$461.280 million in the HTY,
10 the FTY and the FPFTY periods, respectively. With respect to IT investments in the FTY,
11 the Company has included about \$29 million related to the Company's Work and
12 Management Asset (WAM) program. These costs include software upgrades and cloud
13 upgrades (9-52). These costs have an expected in-service date of July 2025.

14 **Q. WHAT OTHER UPIS HAS THE COMPANY INCLUDED IN ITS FPFTY**
15 **BALANCE?**

16 **A.** The Company has included costs related to its pipeline replacement efforts to remove bare
17 steel, wrought iron and cast iron pipe that began in 2007. The Company stated that it has
18 replaced an average of 437,307 feet of pipe per year. (Brumley Statement No. 7 page 10).
19 The Company has continued to replace its bare steel pipe through its Distribution Integrity
20 Management Program (DIMP) because the scoring continues to rank external corrosion on
21 bare steel as its top system risks. (Brumley Statement No. 7 page 10). Finally, the
22 Company is continuing to focus on risk identification and mitigation and its third Long
23 Term Infrastructure and Improvement Plan (LTIIP) for the years 2023-2027 continues to
24 focus on replacing the remaining bare steel, and to expand its focus to include pre-1982
25 plastic (Adyl-A) and pre-1971 coated steel pipe. (Kempic Statement No. 1 page 13).

1 **Q. HOW DID THE COMPANY DEVELOP ITS PROJECTED PLANT ADDITIONS**
2 **THROUGH THE FPFTY PERIOD?**

3 **A.** The Company budgeted its Projected Plant Additions by reviewing its capital expenditures
4 related to distribution plant in the 2024-2028 time frame with planned spending program
5 of over \$300 million budgeted annually for replacement work, inclusive of mains, services
6 and measurement and regulation stations over the five-year period. (Brumley Statement
7 No. 7 page 3). The Company's budget included categories or classes of plant related to
8 age and condition, betterment and public improvement. (Brumley Statement No. 7 page 4
9 Table 1 and Table 2). Mr. Brumley stated that the replacement costs and restoration issues
10 are the cause that continue to be significant drivers to the overall unit cost increase when
11 replacing expenditures for mainline and service line replacement work. (Brumley
12 Statement No. 7 page 5).

13 **Q. WHAT OTHER COSTS HAS THE COMPANY INCLUDED IN ITS UPIS?**

14 **A.** According to Mr. Brumley, the Company has planned to install Advance Metering
15 Infrastructure (AMI) devices. 330,000 Automatic Meter Reading (AMR) devices are
16 expected to reach end of life over the next decade with most devices reaching the end of
17 life between 2029-2032. (Brumley Statement No. 7 page 7). Mr. Brumley stated that these
18 devices must be replaced as the Itron manufactured devices are being phased out by Itron
19 and will not be available in quantities sufficient to meet the Company's current or future
20 needs. (Brumley Statement No. 7 page 7). In response to OCA Set 9-33, Itron will stop
21 its IT support late 2028 with respect to AMR devices. The Company is awaiting
22 confirmation from the vendor on potential solutions and costs for extending support of the
23 existing AMR system.

24 **Q. WHAT HAS THE COMPANY STATED REGARDING INCREASED COSTS**
25 **RELATED TO CONTRACTOR PRICING INCREASES IN UNIT COST**
26 **EXPENDITURES FOR MAINLINE AND SERVICE LINE REPLACEMENTS?**

27 **A.** Mr. Brumley stated that the Company is projecting increases in these costs in 2025,
28 primarily due to anticipated increased contractor pricing. (Brumley Statement No. 7 page
29 5). Mr. Brumley stated that these increased costs include additional usage of flaggers and

1 staging vehicles on job sites to address increased work zone intrusions and the safety of
2 Company's employees and contractors. According to Mr. Brumley, Columbia has
3 experienced upward pressure for replacement projects over several years and the average
4 cost of main replacement has increased since Columbia began its accelerated main
5 replacement program. The average cost of main replacement when the Company began
6 its accelerated main replacement program over the past several years was \$81.25 per foot
7 while the average cost of main replacement in 2024 was \$355 per foot. (Brumley Statement
8 No. 7 page 17).

9 **Q. WHAT CHANGES DO YOU HAVE WITH RESPECT TO THE COMPANY'S**
10 **PROPOSED LEVEL OF UPIS FOR ITS FTY AND ITS FPFTY PERIODS?**

11 **A.** I have an adjustment to the Company's capital expenditures as related to its proposed
12 contractor cost increases. The Company stated that these increases are driven by
13 competition for resources as more natural gas distribution companies in Pennsylvania and
14 across the country undertake main replacement programs, increase training and
15 qualification requirements and compete for the availability of construction work with other
16 businesses inside and outside of the industry. (Brumley Statement No. 7 page 18). In
17 response to OCA Set 9-28, the Company stated that it has included an inflation rate of 4%
18 and 5% applied to the average unit costs for 2025 and 2026, respectively, related to
19 contractor pricing. These inflation increases were applied for an overall average unit cost.
20 I am recommending disallowance of these inflation related adjustments in the Company's
21 GPIS balance.

22 **Q. WHY ARE YOU RECOMMENDING THIS ADJUSTMENT?**

23 **A.** I am recommending disallowance of inflation related adjustments because these types of
24 adjustments or costs are not known and measurable in setting rates for service. These
25 types of cost adjustments should not be used for ratemaking purposes because they do not
26 provide a good index of cost increases, but rather reflect an overall broad, blanket-type
27 economic adjustment that are typically applied to baskets of goods and services that may
28 or may not be related or reflective to costs that are expected to be incurred by Columbia.
29 Inflation related adjustments do not address any particular or individual expense category.
30 These adjustments are simply forecasts or predictions that may or may not be realized. As

baskets of goods and services fluctuate over time, applying inflation adjustments even from a budgeting standpoint is not a proper approach that should be utilized in setting rates for utility services. While such inflation adjustments are normally used to develop economic data as in changes to consumer goods and services, utilizing an inflation related adjustment for ratemaking purposes is not reasonable.

Q. HOW DID YOU CALCULATE YOUR ADJUSTMENT?

A. I reviewed Mr. Brumley Statement No. 7 page 4 Table 1 which reflects the Company's plant additions expected to be placed in service through the FPFTY period related to capital expenditures by category or description. These balances reflect a total budget (plant additions) for the following periods:

	CAPEX	Contractor Costs 2024	OCA/Mugrace Ratio ²
2024 – Actual	\$364,652,157	\$178,243,845	48.88%
2025 - Projected	\$312,583,000	\$152,790,570	48.88%
2026 – Projected	\$343,538,800	\$167,921,765	48.88%

In response to OCA Set 9-34 the Company provided a breakdown of contractor costs for the periods 2020 through 2024. The Company stated that it did not have the 2025 or 2026 budget forecast broken down by contractor amount. According to the Company, the actual level of contractor costs for 2024 is \$178,243,845. For purposes of my adjustment I used a ratio of contractor costs to the Company's actual (2024) and budgeted (2025 and 2026) plant additions expected to be placed in service through the 2026 projected period and arrived at a ratio of 48.88%. This shows that about 48.88% of contractor costs are embedded in the Company's proposed capital addition replacements. I then calculated the Company's 2025 and 2026 projected capital additions by the contractor cost ratio of 48.88% to arrive at an estimated or projected contractors' costs of \$152,790,570 for 2025 and \$167,921,765 for 2026. I then took each of the estimated balances related to contractors' costs and multiplied these balances by the inflation rate of 4% in 2025 and 5%

² Contractor Amount of \$178,243,845 divided by the Company's Actual Costs for 2024 additions of \$364,652,157 or 48.88%. Source of inputs: OCA 9-34.

1 in 2026 and arrived at an inflation adjustment of \$6,111,623 for 2025 (\$152,790,570 times
2 4%) and \$8,396,088 for 2026 (\$167,921,765 times 5%). These two balances total
3 \$14,507,711. This is shown on my Exhibit DM-5.

4 **2. Accumulated Depreciation**

5 **Q. WHAT HAS THE COMPANY CALCULATED WITH RESPECT TO ITS**
6 **ACCUMULATED DEPRECIATION?**

7 **A.** The Company computed accumulated depreciation in the amount of \$927,212,098 as
8 shown on Company Exhibit 108, page 3 of 11 and Schedule No. 3 page 1. In the same
9 manner as the Company used in the calculation of its UPIS, the Company calculated its
10 accumulated depreciation using the FPFTY end of year balance as of December 31, 2026.
11 Company Exhibit No. 105 Page 9 reflects the detailed breakdown of the Company's
12 depreciable group and the associated depreciation rates that computes to the Company's
13 total Accumulated Depreciation balance of \$927,212,098.

14 **Q. DO YOU RECOMMEND ADJUSTMENTS TO THE COMPANY'S**
15 **ACCUMULATED DEPRECIATION BALANCE AS OF THE END OF THE**
16 **FPFTY?**

17 **A.** Yes, I do. I have two adjustments. My first adjustment relates to my recommended
18 disallowance of the Company's inflation increases to contractor costs which increased the
19 Company's UPIS claim for the FTY and FPFTY, as described above. As I have
20 recommended disallowance of \$14,507,711 (Exhibit DM-5) to reduce the Company's
21 UPIS claim and so remove inflation related capital costs related to contractor costs, a
22 corresponding adjustment to the Company's FPFTY Accumulated Depreciation expense
23 claim is also necessary. Since the Company has included inflation related adjustments in
24 its capital expenditure additions, depreciation is based upon total costs of Company capital
25 expenditures and therefore is the basis to the development of depreciation expenses. I
26 utilized OCA witness Mr. Garrett's recommended depreciation rate related to mains
27 (account 376) of 1.63% multiplied by the \$14,507,711. This results in an adjustment of
28 \$236,476. This adjustment is shown on my Exhibit DM-32 which flows into my
29 Accumulated Depreciation Reserve Exhibit DM-6.

1 **Q. WHAT IS YOUR SECOND ADJUSTMENT AND NET RECOMMENDED**
2 **REDUCTION TO THE COMPANY’S ACCUMULATED DEPRECIATION**
3 **CLAIM?**

4 **A.** My second adjustment incorporates the recommendation of OCA Witness Mr. Garrett with
5 respect to his depreciation adjustments. Mr. Garrett recommended an overall reduction to
6 the Company’s depreciation expense of \$45,802,423 as shown on Mr. Garrett’s Exhibit
7 DJG-17. I flowed through this adjustment to my Accumulated Depreciation adjustment
8 (Exhibit DM-6). The sum of these two OCA adjustments results in a total recommended
9 reduction of \$46,038,899 to the Company’s accumulated depreciation claim.

10 **3. Working Capital**

11 **Q. WHAT IS INCLUDED IN THE COMPANY’S WORKING CAPITAL?**

12 **A.** The Company is not making a claim for working capital allowance based upon a lead-lag
13 method. (Exhibit 108 Schedule No. 4 page 1). (I&E RE-43). The Company agreed that the
14 Settlement in the 2024 Rate Case in Docket No. R-2024-3046519 provided that the
15 Company agreed to file a cash working capital study in its first rate case filed after January
16 1, 2026. The Company has only included a cash working capital claim for its Materials and
17 Supplies, Prepayments and Gas Storage Underground balances, shown on Company
18 Exhibit 108, Page 3 in the total amount of:

19	Materials and Supplies -	\$ 948,060
20	Prepayments	\$ 5,577,551
21	Gas Storage Underground	<u>\$50,418,870</u>
22	Total	<u>\$56,944,481</u>

23 **Q. DO YOU AGREE WITH THE COMPANY’S WORKING CAPITAL CLAIM?**

24 **A.** No I do not. The Company’s claim is overstated by the application of inflation adjustments
25 to certain components of the Company’s claim particularly its Materials and Supplies and
26 its Prepayments.

1 **Q. HOW DID YOU CALCULATE YOUR RECOMMENDED WORKING CAPITAL?**

2 **A.** In calculating my recommended working capital, I also removed the Gross Domestic
3 Product (GDP) inflation factor of 2.93% (11/30/2025) and 3.05% (12/31/2026) related to
4 the Company's Materials and Supplies and Prepayments. (OCA Set 9-46) There were no
5 inflation factors used to compute the Company's Gas Storage Underground balances. My
6 balances compute as follows:

	<u>Company</u>	<u>PAOCA</u>
Materials and Supplies	\$ 948,060 – inflation =	\$891,083
Prepayments	\$ 5,577,551 – inflation =	\$5,315,070
Gas Storage Underground	<u>\$50,418,870</u>	<u>\$50,418,870</u>
Subtotal	\$56,944,481	\$56,625,024

12 **Q. WHAT IS YOUR REASONING FOR REMOVING THE COMPANY'S**
13 **INFLATION FACTORS FOR THE FTY AND THE FPFTY PERIODS?**

14 **A.** As I indicated above in my adjustments related to the Company's UPIS, I believe that
15 including inflation type factors to adjust for costs are not reasonable because these types of
16 increase adjustments are not known and measurable and they do not reflect the true costs
17 of providing service. Inflation adjustments do not provide a good index of cost increases
18 but rather an overall broad blanket-type economic adjustment that are typically applied to
19 goods and services that may not be directly rated to costs incurred by the Company.
20 Inflation adjustments do not address any particular or individual expense category. These
21 are simple forecasts and predictions of cost estimates. As goods and services fluctuate over
22 time, applying escalating or inflation factors to adjust costs is not a proper approach that
23 should be utilized in setting rates for service. While such inflation types adjustments are
24 used to develop economic data as in changes to broad baskets of consumer goods and
25 services such as housing, clothing, food, etc., utilizing adjustments for ratemaking purposes
26 is not reasonable. More definitive types of increases are contractually related increases or
27 escalation increases that are included in agreements or services contracts.

1 **Q. WHAT IS THE ADJUSTED WORKING CAPITAL BALANCE YOU ARE**
2 **RECOMMENDING?**

3 **A.** My adjusted Working Capital balance is a reduction for Materials and Supplies of \$56,977
4 and a reduction of Prepayments of \$262,481 for a net decrease of \$319,457. This reduces
5 the Company's Working Capital balance to \$56,625,024. This is shown on my Exhibit
6 DM-3.

7 **4. Accumulated Deferred Income Taxes**

8 **Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS**
9 **ACCUMULATED DEFERRED INCOME TAXES (ADIT)?**

10 **A.** The Company proposed in its initial filing an ADIT balance of \$503,051,382 as shown on
11 Company Exhibit 108, Schedule 8, page 1. The Company identified its ADIT by deferred
12 income taxes, depreciation related taxes, and the regulatory liability Excess ADIT.
13 Company witness Ms. Harding stated that the deferred taxes on customer advances and
14 inventory has been normalized in rate base for federal and state tax purposes in that it
15 remeasured the accumulated deferred state taxes from 9.99% over the 9-year reduction to
16 4.99% in 2031 and recognized the deficient deferred tax of \$1,782,085 before gross up
17 recorded in a regulatory asset. (Harding Statement No. 10 page 4). The Company also
18 included deferred taxes for the Federal Net Operating Loss (NOL), customer advances,
19 inventory and other book versus tax timing differences related to the reduction in the tax
20 rate from 35% to 21% through the Tax Cuts and Jobs Act of 2017 (TCJA). (Harding
21 Statement No. 10 page 6). The Company included the recovery of the deficient deferred
22 taxes over the estimated remaining life of the assets of 42 years based upon the composite
23 book depreciation rate of 2.4% as included in the last base rate case and projects to record
24 higher tax expense of \$571,391 for the FPFTY. (Harding Statement No. 10, page 6). For
25 the non-property related deferred taxes on customer advances and inventory that are
26 included in the calculation of rate base, the Company projected to record higher tax expense
27 in its federal tax provision by \$626,961 using a ten-year amortization period. (Harding
28 Statement No. 10 page 6). The remaining non-property deferred taxes on the book versus
29 tax timing differences are a net deferred tax asset with results in net deficient taxes because
30 of TCJA. (Harding Statement No. 10 page 6).

1 **Q. WHAT HAS THE COMPANY STATED WITH RESPECT TO THE SAFE**
2 **HARBOR METHOD AND WHETHER THE COMPANY INTENDS TO**
3 **RECOGNIZE A CHANGE IN ACCOUNTING METHOD?**

4 **A.** Ms. Harding stated that the Company is in the process of reviewing and quantifying the
5 provisions of the safe harbor method for taxpayers with natural gas transmission and
6 distribution property. (Harding Statement No. 10 page 7). Columbia's parent company
7 NiSource expects to elect the change in tax accounting method on its 2024 consolidated
8 tax return filing due on or before October 15, 2025. (Harding Statement No. 10 page 7).
9 In response to OCA Set 9-40, the Company does not expect a material difference when the
10 natural gas safe harbor method for accounting for repairs is adopted on its 2024
11 consolidated tax return. The Company will determine if it is necessary to supplement its
12 filing due to a change in the state tax expense due to the flow-through accounting for the
13 gas repairs deduction that is already captured in the filing.

14 **Q. DO YOU RECOMMEND AN ADJUSTMENT TO THE COMPANY'S ADIT**
15 **BALANCE AS OF THE END OF THE FPFTY?**

16 **A.** Yes, I do. I have calculated a reduction to correspond with my disallowance related to the
17 Company's inclusion of inflation related adjustments to calculate the Company's plant
18 additions in the 2025 and 2026 periods. As I have recommended downward adjustments
19 to the Company's UPIS balance and the related accumulated depreciation reserve, I am
20 making a corresponding downward adjustment to flow through my adjustments related to
21 the deferred income taxes associated with my disallowance of the UPIS additions related
22 to inflation adjustments. I utilized my balance in the accumulated depreciation reserve
23 balance of \$236,476 and calculated this balance by the composite tax rate (federal and
24 state) of 28.49% to arrive at an adjustment of \$67,372 . This is shown on my Exhibit DM-
25 7.

26 **Q. DID YOU MAKE AN ADJUSTMENT WITH RESPECT TO OCA WITNESS MR.**
27 **GARRETT AS TO HIS DEPRECIATION ADJUSTMENTS?**

28 **A.** Yes I did. I flowed through the adjustments from Accumulated Depreciation to the
29 Accumulated Deferred Income Taxes. Using the Company's composite rate of 28.49%, I

1 calculated my recommended adjustment of \$46,038,899 to arrive at an overall balance of
2 \$13,116,482. This is shown on my Exhibit DM-7.

3 **C. RATE OF RETURN**

4 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS OVERALL**
5 **RATE OF RETURN?**

6 **A.** As shown on Company Exhibit No. 400 page 1, the Company proposed an overall Rate of
7 Return of 8.55% including a Return on Equity of 11.35%. The Company has included a
8 management performance adjustment of 25 basis points. (Mr. Rea Statement No. 8 page
9 4).

10 **Q. WHAT HAS OCA WITNESS MR. GARRETT PROPOSED WITH RESPECT TO**
11 **HIS RECOMMENDED OVERALL RATE OF RETURN?**

12 **A.** Mr. Garrett has recommended an overall Rate of Return of 7.06% with a Return on Equity
13 of 8.90%. His overall Weighted Cost of Capital is as follows:

	Ratio	Cost Rate	Weighted Cost
Long-Term Debt	47.68%	5.20%	2.50%
Short-Term Debt	2.32%	5.00%	0.10%
Common Equity	<u>50.00%</u>	<u>8.90%</u>	<u>4.50%</u>
Total	100%		7.06%

19 **Q. WHAT EFFECT DOES MR. GARRETT'S REMOVAL OF MR. REA'S**
20 **MANAGEMENT PERFORMANCE ADJUSTMENT PREMIUM OF 25 BASIS**
21 **POINTS HAVE ON THE COMPANY'S REVENUE REQUIREMENT?**

22 **A.** The effect of removing the 25 basis points for the Management Performance adjustment
23 from the Company's cost of equity would be a reduction from 11.35% to 11.10%, or an

overall Rate of Return of 8.42%. The revenue requirement impact would be a reduction of \$6,933,505.³

D. OPERATING INCOME

1. Operating Revenues

Q. WHAT HAS THE COMPANY PROPOSED AS ITS OPERATING REVENUE AT PRESENT RATES AND PROPOSED RATES?

A. As shown on Company Exhibit 102, Schedule 3, page 3 of 6, and Exhibit 103, page 8 of 15, the Company has projected pro-forma revenues at present rates in the amount of \$916,958,770. The Company also included revenues related to Forfeited Discounts, Miscellaneous Revenues and Other Gas Revenues totaling \$2,049,064. The total proposed present rate revenues are calculated at \$919,007,833. In computing its present rate revenues, the Company used a 20-year weather normalization period to normalize the revenues for the historic test year ending December 31, 2024 (Girata Statement No. 2 page 5). Consistent with the Company's approach since 2008 and in the last base rate case proceeding, the Company has proposed to use the most recent 20-year average to normalize sales and usage. The Company calculated its Operating Revenues at proposed rates by adding its proposed revenue requirement increase of \$110,496,797 (Exhibit 102, Schedule 3, page 3 of 6) to arrive at its FPFTY Operating Revenues at proposed rates of \$1,029,504,630.

Q. DID THE COMPANY UPDATE ITS OPERATING REVENUE SUBSEQUENT TO THE INITIAL FILING?

A. No.

Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S PRESENT RATE REVENUE?

A. No. I do not. I am accepting the Company's Present Rate Revenues.

³ Rate Base of \$3.845 billion times the rate of return of 8.42% equals \$323.781 million or a reduction from the Company's proposed income requirement of \$328.780 million or a difference of \$4.999 million multiplied by the gross revenue factor of 1.38697964 equals \$6.934 million.

2. OPERATION AND MAINTENANCE EXPENSES (O&M)⁴

a. Labor

Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS LABOR EXPENSE?

A. As shown on Company Exhibit 104, Schedule 1, page 2, the Company proposed to increase Labor Expenses to \$38,770,674. (OCA Set 9-20). Adjustments were made to annualize and normalize payroll for employees as of the end of the HTY. (Vassalotti Statement No. 4 page 7). The Company has projected total employee count of 715 as of the end of the FPFTY period. (Gas RR-026 Attachment A- Public). The Company applied an O&M Expense percentage of 50.57% to annualized the Labor costs under the FTY and the FPFTY periods, as well as removed Lobbying costs of \$12,415 and \$12,787 under the FTY and the FPFTY periods, respectively. (Company Exhibit No. 104 Schedule No. 2 page 1). Included in this amount are general payroll increases of 3% and 4% for the FTY for its various employees. (Exhibit No. 4 Schedule No. 5). (Gas RR-025). The Company adjusted its headcount from 728 in the Pre-TY 11/30/2023 to 715 through the FPFTY period (a reduction of 13).

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO THE LEVEL OF EMPLOYEES IN THE FPFTY PERIOD?

A. As shown on Company's GAS-RR-026 and in response to I&E RE-11 the Company had an actual employee count of 728 as of the month ending (TME) November 30, 2023. The Company stated that it had a level of employees of 715 in the HTY and the Company uses the same level of employee headcount for the FTY and the FPFTY periods. This is a reduction of 13 employees from the November 30, 2023 period.

Q. WHAT HAS BEEN THE LEVEL OF VACANCIES IN THE PAST?

A. In response to I&E RE-11 Attachment B (Public), the Company has had the following vacancies:

⁴ For those O&M expenses I did not address, I am accepting the Company's balances in the FPFTY period.

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2021	60	(December 2021)
2022	57	(year-end)
2023	64	(year-end)
2024	65	(year-end)

Utilizing the above vacancy levels for 2022-2024, a three-year average computes to 62 average employee vacancies. Applying the Company’s 50.57% (O&M percentage) results in an average net vacancy of 31 employees.

Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY’S TOTAL LABOR EXPENSE CLAIM OF \$38,770,673 AS FAR AS VACANCIES?

A. I have reviewed the response to I&E RE–11 Attachment A (Public) and in Company Exhibit GAS-RR-026. I took the Company’s average level of employees as shown in those responses and prepared the following:

HTY	715
FTY	715
FPFTY	715
Four-Year Average	715

I then calculated a ratio of 4.3812% by taking the average historic vacancy rate of 31 employees and divided by the three-year average of 715 employees. I then took the ratio of 4.3812% and multiplied that ratio by the Company’s proposed labor balance of \$38,770,674 to arrive at an adjustment of \$1,698,606.

Q. WHAT IS THE RATIONALE FOR EMPLOYING A VACANCY RATE RATIO TO THE COMPANY’S LABOR BALANCE?

A. In all organizations there will always be a certain level of vacancies that will not be filled out at any given point in time. This is inherent in all companies and is a natural order of business. Given that, throughout a typical calendar period, the number of employees vary due to retirement, termination, layoffs and management policies. The Company’s prior level of vacancy levels show that in the past, a number of vacancies were present. The

number or level of employees is determined based upon the need to perform the work assignments, the level of productivity needed to be achieved and the areas in which staff levels appear to be over or under worked and the replacement of employees who are underperforming. Absent a vacancy rate ratio to adjust employee count in the FPFTY period, there could be a situation that arises in which the Company could over-earn in the event no additional employees were to be hired in the test year period.

Q. WHAT ARE YOUR OVERALL RECOMMENDATIONS RELATED TO LABOR COSTS?

A. My overall adjustment to the Company's Labor costs are my adjustment related to the vacancy rate ratio of 4.3548% which results in a reduction to labor of \$1,698,621 and is shown on my Exhibit DM-10.

b. Incentive Compensation

Q. WHAT DID THE COMPANY PROPOSE TO INCLUDE REGARDING ITS INCENTIVE COMPENSATION?

A. The Company has proposed to include total Incentive Compensation of \$2,568,807 for the FPFTY period as shown on Exhibit 104, Schedule 1, pages 3 and 4 of 6. The Company began with an Incentive Compensation Balance of \$3,823,624 (GAS-RR-026 and Company Exhibit 104 Schedule 1) for the HTY normalized period. The Company adjusted this balance in the FTY budget period to \$2,067,046. The Company normalized the FTY period balance to \$2,742,912 (Company Exhibit 104 Schedule 1). Finally, the Company adjusted this balance by \$174,105 to arrive at a FPFTY period of \$2,568,807.

Q. PLEASE DESCRIBE THE COMPANY'S INCENTIVE COMPENSATION PROGRAM.

A. In GAS-RR-027 Attachment B, the Company's Incentive Compensation is based upon NiSource, Inc. 2020 Omnibus Incentive Plan, which in part states that the Committee may grant Cash-Based Awards to employees. The 2020 Omnibus Incentive Plan may be paid for performance beginning January 1, 2025 and ending December 31, 2025. The Company

has identified the following performance measures, weightings and target opportunities as follows:

Financial – adjusted earnings per share	70%
Operational Excellence Operations/Process Failure	10%
Safety- Dart	5%
Safety PVC	5%
Customer Experience	<u>10%</u>
Total	100%

Q. PLEASE DESCRIBE AND EXPLAIN THE ABOVE PERFORMANCE MEASURES.

A. The Financial Metrics – Earnings per share at a weighing of **70%** is based upon the Corporation’s achievements of net operating earnings per share. The Corporation shall have full discretion and authority to determine whether this measure has been achieved and whether any adjustments shall be made in the calculation of Adjusted EPS to reflect unusual or non-recurring events.

Operational Excellence – Reflects a weighing of **10%** and is based upon the number of significant injuries or fatalities or PHMSA reportable incidents due to operations or process failures (employees).

Safety – DART – Reflects a weighing of **5%** and is based upon days away, restricted or transferred (DART(incident rate for all injuries meeting OSHA reportability that require an employee to not report to work, to restrict their duties or transfer to another role as a result of the injury.

Safety – PVC – Reflects a weighing of **5%** and is based upon Preventable Vehicle Collisions (PVC) rate for all vehicle crashes deemed to be the responsibility of the company-employed driver.

Customer Satisfaction - Reflects a weighing of **10%** and is based upon Post-transactional / customer relationship satisfaction survey; score companies five post-transactional customer channels (CSR, Field Service, IVR, Online and Project Work/Site Restoration) and one customer relationship measure.

1 **Q. DID YOU REVIEW THE COMPANY'S RESPONSES THAT PROVIDE**
2 **INFORMATION RELATED TO PERFORMANCE TARGETS AND CASH-**
3 **BASED AWARDS PAYOUTS?**

4 **A.** Yes. In responses to OCA Set 9-4, the Company provided its 2024 and 2025 cash – based
5 awards and its 2020 Omnibus Incentive Plan. In response to I&E RE-13 all active
6 employees are eligible to receive incentive compensation. The Company stated that the
7 terms and conditions of the Company's Cash Based Awards Program are very similar to
8 the prior year's 2023-2024 Cash Based Awards Program. The 2026 Cash -Based Awards
9 Program design will not be available until early 2026 and the Company anticipates that the
10 terms and conditions will be essentially the same as the 2025 program.

11 **Q. HOW MUCH OF INCENTIVE COMPENSATION IS INCLUDED IN THIS**
12 **FILING RELATED TO COVERED OFFICERS, OFFICER PARTICIPANTS AND**
13 **PARTICIPANTS?**

14 **A.** In response to OCA Set 9-9, the Company included LTI compensation stock awards in the
15 form of performance share units (PSU) and restricted stock units (RSU) to employees at
16 the level of director and above.

17 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE LEVEL OF**
18 **INCENTIVE COMPENSATION TO BE INCLUDED IN REVENUE**
19 **REQUIREMENT?**

20 **A.** In Gas-RR-027 the financial metrics related to cash-based award performance measures
21 the Company's Incentive Compensation is predominately geared towards the Company's
22 achievement of its Net Operating Earnings Per Share ("NOEPS") at 70% with the
23 remaining 30% geared towards Occupational Health and Safety, Customer Care, Customer
24 Satisfaction and Customer Safety. I am recommending that only those incentive
25 compensation costs that are geared toward customer-oriented benefits of 30% be allowed
26 for recovery in rates. I believe these types of incentives benefit ratepayers because the
27 metrics reflect costs that are specifically related to provide customer related benefits.
28 Therefore I am recommending that 30% or \$770,642 should be recovered from ratepayers.

1 **Q. WHY ARE YOU RECOMMENDING DISALLOWANCE OF COSTS RELATED**
2 **TO FINANCIAL PERFORMANCE?**

3 **A.** I am recommending that the Incentive Compensation that was paid out for achieving an
4 Earnings Per Share (“EPS”) metric be disallowed from the Company’s revenue
5 requirement increase (70%). My recommendation is based upon the fact that the majority
6 of the Company’s Incentive Compensation payments are aligned with the Company’s
7 financial goals and earnings per share growth with minimal being attributable to the benefit
8 of customers. I do not believe that ratepayers should pay for incentive compensation,
9 which promotes shareholders’ interest and the alignment of shareholder growth. I do not
10 see a nexus between shareholder interest and the alignment of shareholder growth and
11 customer-oriented benefits in the area of safe and reliable utility service. The shareholder
12 should be required to fund these costs if they believe it benefits ratepayers. My adjustment
13 reduces the Company’s incentive compensation by \$1,798,165.

14 **Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE COMPANY’S**
15 **RESTRICTED STOCK AND LONG TERM INCENTIVE (LTI)?**

16 **A.** In response to OCA Set 9-9 (Restricted Stock, Stock Options and Stock Awards) the
17 Company has included Stock Awards in its Labor Costs of \$855,882 and \$754,446, for the
18 FTY and the FPFTY, respectively. I disallowed the costs for the FPFTY period of
19 \$754,446 because I believe that ratepayers should not be charged costs related to stock
20 awards. The Company has not provided any reason that these stock awards benefit
21 ratepayers or provide customer-oriented services. These payments are paid to directors
22 and above (OCA Set 9-9), and vest over three years. I do not see any benefits incurred to
23 ratepayers that are customer-oriented or customer satisfaction in the payments of restricted
24 stock and long-term incentive (“LTI”). Rather these types of costs are typically aligned
25 with the Company’s financial goals, and earnings per share growth with minimal benefits
26 attributable to customers with respect to customer performance, measures, safety and
27 environmental issues. These types of payments promote shareholders’ interest and align
28 with shareholder growth. The Company’s shareholders should be responsible for these
29 payments.

1 **Q. WHAT ARE YOUR ADJUSTMENTS RELATED TO THE COMPANY'S FPFTY**
2 **INCENTIVE COMPENSATION?**

3 **A.** My total adjustments related to the Company's incentive compensation costs is a reduction
4 of \$1,798,165 related to financial performance and \$754,446 related to restricted stock
5 units for a total disallowance of \$2,552,612. These adjustments are shown on my Exhibit
6 DM-11. The Company has not identified where the restricted stock units of \$754,446 are
7 accounted for so I am including my recommended disallowance in the Company's total
8 incentive compensation category. With respect to capitalized restricted stock units my
9 adjustments is a reduction of \$719,400 of which \$225,510 is related to the Columbia LTI
10 and \$493,890 is related to the allocated NCSC costs to Columbia and is shown on my
11 Exhibit DM-3.

12 **c. Pension Deferral Amortization**

13 **Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS PENSION**
14 **DEFERRAL AMOUNT?**

15 **A.** According to Columbia witness Vassalotti, the Commission permitted the Company to
16 recover the deferred prepaid pension O&M Expenses of \$8,449,772 over a ten-year period
17 starting December 16, 2018 with an annual recovery amount of \$844,977 for amortization
18 expense. (Vassalotti Statement No. 4 page 10). In response to OCA Set 9-21, the
19 \$8,449,772 represents the one-time pension prepayment expenses amortized over a ten-
20 year period.

21 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S**
22 **PENSION PREPAYMENT?**

23 **A.** Given that the Commission has permitted the Company to recover these pension costs in
24 the Settlement document R-2018-2647577, I am accepting the balance of \$8,449,772 and
25 the amortization period of 10-years for an annual recovery of \$844,977.

d. Other Employee Benefits

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS OTHER EMPLOYEE BENEFITS?

A. The Company is proposing a level of Other Employee Benefits of \$8,915,459 as shown on Company Exhibit 104 Schedule 1. The Company has not specifically identified the development of these costs nor has provided a breakdown of these costs in its revenue requirement schedules. The Company began with a balance from \$8,139,063 in the HTY and adjusted this balance by \$235,749 to arrive at a FTY balance of \$8,374,812. (Exhibit 104 Schedule 1). The Company adjusted this \$8,374,812 balance by \$540,647 in the FTY to arrive at a balance of \$8,915,459 in the FPFTY period. (Exhibit 104 Schedule 1).

Q. WHAT IS INCLUDED IN THE COMPANY'S OTHER EMPLOYEE BENEFITS?

A. In response to I&E RE-16, the Company has included costs associated with Employee Medical Health Insurance, 401K Plan, Dental, Long-Term Disability, Profit Sharing and other costs related to Company Health and Medical costs. The Company provided a breakdown of the FTY and the FPFTY period balances as reflected in I&E RE-16 Attachment A. The Company also provided forecasted balances through 2029.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending disallowance of the Company's Profit Sharing costs (net amount) for the FPFTY - \$406,864. I am disallowing this expense in the FPFTY period, because there is no breakdown or further information that indicates to whom these Profit Sharing benefits go to or accrue to. Also, the Company has not identified whether these Profit Sharing costs are attributable to employees in what they were required to do or to perform to get or obtain these Profit Sharing costs. In response to I&E RE-16 and OCA Set 14-1 the Company also included capitalized costs related to profit sharing. I am also recommending disallowance of the capitalized cost of \$337,136 which are shown on my Exhibit DM-3.

Q. WHAT OTHER ADJUSTMENTS DO YOU HAVE?

A. Since I incorporated a vacancy rate ratio of 4.3812% for the Company's Labor costs, I am also adjusting Columbia's Other Employee Benefits in the FPFTY period. I took the

1 Company's FPFTY benefits balance of \$8,915,459 and divided that by Columbia's
2 proposed Labor costs of \$38,770,673 to arrive at a ratio of 22.995%. I then took my
3 recommended Labor costs of \$37,072,052 and multiplied that amount by 22.995% to arrive
4 at a recommended Other Benefits of \$8,524,718 or an adjustment of \$390,741. My total
5 recommended adjustment to the Company's Other Employee Benefits are \$406,864 for
6 profit sharing plus \$390,741 or a total adjustment of \$797,605 and a balance of \$8,117,854.
7 This is shown on my Exhibit DM-13.

8 **e. Outside Services**

9 **Q. WHAT DID THE COMPANY PROPOSE RELATED TO ITS OUTSIDE**
10 **SERVICES?**

11 **A.** The Company has proposed a level of Outside Services of \$18,013,909 for the FPFTY
12 Period December 31, 2026, a decrease of \$1,000,282 from the Company's FTY period
13 ending November 30, 2025. (Exhibit 104, Schedule 1, page 2). The Company's HTY
14 balance was \$16,852,517 to which it adjusted this balance by \$2,161,517 to arrive at the
15 FTY balance of \$19,014,191. (Exhibit 104 Schedule 1 page 2). The Company stated that
16 the balance of \$2,161,517 from the HTY to the FTY period was due to underspending in
17 Turn backs and Maximum Allowable Operating Pressure (MAOP) related activities within
18 the operations during the HTY. (I&E RE-19). The Company stated that the balance
19 decrease of \$1,000,282 from the FTY to the FPFTY period was due to reallocation of spend
20 by various departments to other cost categories within their budgets based upon updated
21 assumptions and resource needs. (I&E RE-19). The Company has provided a breakdown
22 of the FTY and the FPFTY cost balances in response to I&E RE-20.

23 **Q. HOW DID THE COMPANY ADJUST ITS OUTSIDE SERVICES BALANCES**
24 **FROM THE FTY PERIOD TO THE FPFTY PERIOD?**

25 **A.** As shown on Company Exhibit 104 Schedule 2 page 4, the Company adjusted its Outside
26 Services balance by including an Inflation Index of 2.93% (FTY) and 3.05% (FPFTY)
27 related to non-recoverable consulting costs (lobbying) of \$121,175 and to report \$4,105
28 related to RP1162 Public Awareness costs as Advertising to arrive at a balance adjustment
29 of (\$128,529).

Q. WHAT IS YOUR ADJUSTMENT RELATED TO THE COMPANY’S INCLUSION OF AN INFLATION / DEFLATION ADJUSTMENT?

A. As I previously stated, I believe that including inflation/deflation types factors to adjust for costs are not reasonable because these types of increase adjustments are not known and measurable and they do not reflect the true costs of providing service. These types of costs are basically blanket type increases/decreases which do not directly relate to actual costs expected to be incurred by the Company in the period for which rates are to be set. Costs should be predicated on evidence or documentation that supports the Company’s proposed ratemaking adjustments. Costs should not be adjusted based upon a blanket type of increase and applied to all costs. My adjustment increases the Company’s Outside Services – Ratemaking Adjustments for the FTY and the FPFTY periods to \$3,550 and \$3,804, respectively.

Q. WHAT IS INCLUDED IN THE COMPANY’S OUTSIDE SERVICES?

A. As shown on Company’s GAS-RR-052 Attachment A, the Company provided a schedule showing a breakdown of its Outside Services from 2021-2024. In response to I&E RE-18, the Company provided a further detailed breakdown of Outside Services for the periods ending November 2022 through 2024.

Q. WHAT IS YOUR RECOMMENDATION?

A. I reviewed the Company’s Exhibit GAS RR-052 which shows the level of Outside Services for the periods 2021 through 2024. I compared that level to the Company level for its 2025 FTY and its 2026 FPFTY periods. For the periods 2021-2024 the Company’s Outside Services have increased/decreased as follows:

2021-2022	4.52% decrease or \$1,100,482
2022-2023	10.16% increase or \$2,363,643
2023-2024	31.36% decrease or \$8,127,134
2025 FTY	12.83% increase or \$2,161,674
2026 FPFTY	5.26% decrease or \$1,000,282
Three-year average 2022-2024 = (8.57%)- reduction	

1 The Company's Outside Services budgeted decreased by approximately 8.57% during the
2 2022-2024 period. In its FTY period, the Company stated that it is increasing this expense
3 by \$2,161,674 related to underspending activities. In its FPFTY period the Company stated
4 that it is decreasing this expense related to allocation of costs to other departments. In my
5 opinion, an 8.57% decrease seems to be the normalized level of work activity based upon
6 activities and costs in the past historical activities.

7 Given this information, I am recommending that a three-year average which reduces this
8 balance of the Company's HTY of \$16,852,517 by 8.57% or a reduction of \$1,444,261,
9 (HTY balance of \$16,852,517 times 8.57%) be used to set the Company's Outside Services
10 work plan budget. Outside Services can fluctuate widely depending on the pool of
11 contractors, materials and costs needed, and resources allocated. Not all the work may be
12 performed as planned and within the time frame stated by the Company.

13 **Q. WHAT ARE YOUR ADJUSTMENTS RELATED TO THE COMPANY'S**
14 **OUTSIDE SERVICES?**

15 **A.** My adjustments to the Company's Outside Services included disallowing the deflation
16 adjustments results in a reduction of \$1,437,457. This is shown on my Exhibit DM-14.

17 **f. Corporate Insurance**

18 **Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS CORPORATE**
19 **INSURANCE?**

20 **A.** The Company proposed a level of Corporate Insurance of \$4,452,228 as shown on Exhibit
21 104, Schedule 1, pages 2 and Schedule 2 page 7. The Company has included a budget
22 adjustment of \$4,320,454 for the FTY period and added \$131,774 for the FPFTY period.
23 The Company stated that this account includes insurance for property, casualty, workers
24 compensation, medical stop loss and other miscellaneous general liability. (Vassalotti
25 Statement No. 4 page 12). The Company provided a breakdown of its Corporate Insurance
26 on Exhibit 4 Schedule 2 page 10 for the twelve months ending November 30, 2024.

1 **Q. WHAT IS YOUR RECOMMENDATION?**

2 **A.** I disallowed the 3.05% inflation factor that the Company included to calculate its FPPTY
3 period. This results in a decrease of \$131,774 shown on Company Exhibit 104 Schedule 2
4 page 7. As I stated previously in my testimony, I believe inflation related increases /
5 adjustments are not known and measurable and do not reflect the true costs of expenses.
6 My adjustment recommends a balance of \$4,320,454 and is shown on my Exhibit DM-17.
7 My adjustment is shown on my Exhibit DM-17.

8 **g. Injury and Damages (I&D)**

9 **Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS INJURY AND**
10 **DAMAGES?**

11 **A.** The Company proposed an Injury and Damage (“I&D”) expense of \$405,057 as shown on
12 Exhibit 104, Schedule 1, pages 2. The Company stated that this balance represents
13 expenses for claims paid, accruals for claims anticipated to be paid and other accounting
14 adjustments. (Vassalotti Statement No. 4 page 13). The Company made a downward
15 adjustment of \$3,880 to normalize the level of I&D based upon a five-year average actual
16 cash paid for claims in today’s dollars using an Inflation Factor of 3.05% to arrive at a
17 proforma level of expenses of \$381,879. (Vassalotti Statement No. 4 page 13).

18 **Q. WHAT IS YOUR RECOMMENDATION?**

19 **A.** I reviewed the response to OCA Set 9-22 Attachment A, which reflect the calculation of
20 the Company’s five-year average of I&D to arrive at a balance of \$381,879 for the HTY
21 period. I am accepting the Company’s five-year average to calculate its HTY balance, but
22 I am disallowing the inflation related adjustments for those five-year periods for the reasons
23 set forth above regarding blanket inflation related adjustments. My adjustments reflect a
24 balance of \$353,800 a reduction of \$51,257 from the Company’s proposed balance of
25 \$405,057.

26 **Q. WHAT OTHER ADJUSTMENTS DID YOU MAKE?**

27 **A.** I also disallowed the Inflation Adjustments reflected on Company Exhibit 104 Schedule 2
28 page 8 of 2.93% in the FTY and 3.05% in the FPPTY periods, which is included in the

1 balance above of \$353,800. The Company's five-year average is a good indicator of costs
2 without the use of inflation factors. My argument for disallowing inflation related
3 adjustments is the same as in my section on Corporate Insurance. My adjustment is shown
4 on my Exhibit DM-18.

5 **h. Employee Expenses**

6 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS EMPLOYEE**
7 **EXPENSES?**

8 **A.** The Company proposed a level of Employee Expenses in the amount of \$1,275,033 for the
9 FPFTY period as shown on Exhibit 104, Schedule 1, pages 2 . Company witness Vassalotti
10 stated that a downward adjustment of \$187,192 was made to the HTY expense balance
11 (Company Exhibit 4 Schedule 2 page 12) to remove non-recoverable employee expenses.
12 Included in the Company's adjustments are Inflation/Deflation Adjustments of 2.93% in
13 the FTY and 3.05% in the FPFTY periods. (Company Exhibit 104 Schedule 2 page 9).

14 **Q. DID THE COMPANY PROVIDE A BREAKDOWN OF THESE COSTS?**

15 **A.** Yes. In response to I&E RE-28 the Company provided a breakdown of its HTY balance
16 of \$1,474,438. The Company made adjustments to this HTY balance by reducing this
17 balance by \$187,192 (Company Exhibit 4 Schedule 2 page 12) indicating that it was
18 previously reported as an Other Employee Benefit rather than in Employee Expenses.

19 **Q. WHAT ARE YOUR ADJUSTMENTS TO THE COMPANY'S EMPLOYEE**
20 **EXPENSES?**

21 **A.** I have several. I first disallowed the Inflation Adjustments reflected on Company Exhibit
22 104 Schedule 2 page 9 of 2.93% in the FTY and 3.05% in the FPFTY periods, which is
23 included in the balance above of \$187,192. My argument for disallowing inflation related
24 adjustments is the same as in my previous sections.

25 **Q. WHAT ARE YOUR NEXT ADJUSTMENTS?**

26 **A.** With respect to Employee Expenses of \$554,925 in the HTY and \$637,383 in the FPFTY
27 the Company stated that these costs include employee recognition gifts, event tickets used
28 for employee morale or team building purposes and other entertainment expenses that

support employee engagement. (OCA Set 14-3). The Company removed \$198,554 related to gifts and entertainment in the FPFTY period (OCA Set 14-3). The net balance is \$438,829. My last adjustment is to the Company's Meals/Entertainment expenses of \$84,567 in the HTY and \$48,166 in the FPFTY period. A summary of my adjustments is as follows:

<u>Description</u>	<u>FTY Amount</u>	<u>FPFTY Amount</u>	<u>OCA</u>
Meals / Entertainment	\$84,567	\$48,166	\$24,083
Employee Expenses (net)	\$362,248	\$438,829	\$0

Q. WHAT IS YOUR RECOMMENDATION RELATED TO MEALS/ENTERTAINMENT?

A. I am recommending that 50% of the Company's Meals and Entertainment or \$24,083 be allowed in rates. The Company has not broken-down these costs related to either and it is difficult to segregate out which expenses are meal-related, and which are entertainment-related. Also, I do not believe ratepayers should be paying for entertainment-related costs, company sponsored events for the benefit of the employees which may include entertainment related expenses, or other sports related entertainment. Therefore, I believe that allowing 50% of the Company's Meal and Entertainment is reasonable.

Q. WHAT IS YOUR RECOMMENDATION RELATED TO EMPLOYEE EXPENSES?

A. I recommend disallowance of these costs of \$438,829 for ratemaking purposes. I believe these types of expenses do not benefit ratepayers but rather boosts morale and provides for a camaraderie among and between employees. As the Company stated in response to OCA Set 14-3, these costs are used for employee morale and team-building purposes and other entertainment expenses that support employee engagement. My adjustments are shown on my Exhibit DM-19. I believe that ratepayers should not be required to pay for costs associated with employee morale boosting and team engagement as these costs are outside the spectrum of utility service. These are not the sort of expenses that ratepayers should pay for in the area of safe and reliable utility service.

1 **Q. WHAT ARE YOUR TOTAL ADJUSTMENTS?**

2 **A.** My total adjustments is a disallowance of \$451,550 and is shown on my Exhibit DM-19.

3 **i. Company Memberships**

4 **Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS COMPANY**
5 **MEMBERSHIPS?**

6 **A.** The Company proposed a Company Membership expense of \$682,796 for the FPFTY
7 period as shown on Exhibit 104, Schedule 1, pages 2. Mr. Vassalotti stated that the HTY
8 expense for Company Memberships has been adjusted to annualize the American Gas
9 Association dues to reflect known and measurable current payments for calendar year
10 2024. (Vassalotti Statement No. 4 page 14). Mr. Vassalotti stated that the Company
11 removed costs identified as lobbying. (Statement No. 4 page 14).

12 **Q. DID THE COMPANY PROVIDE A BREAKDOWN OF THESE COSTS?**

13 **A.** Yes. In Gas-RR-032 and Company Exhibit 4 Schedule 2 page 13; the Company provided
14 an HTY period balance of \$688,085. With respect to costs related to dues and memberships
15 to national, regional and community utility-based organizations, the Company stated these
16 costs provide vital links for the Company on industry trends and expertise including
17 innovative solutions and partnerships in providing safety education in the communities that
18 it serves. (I&E RE-30).

19 **Q. WHAT ARE YOUR RECOMMENDATIONS?**

20 **A.** I am accepting the Company's costs related to the American Gas Association of \$407,424
21 - \$101,856 x 4 quarters). I am recommending disallowance of about \$260,661 of Company
22 Membership costs identified in the HTY period. In reviewing GAS-RR-030 and Company
23 Exhibit 4 Schedule 2 page 13, most of these Membership dues reflect business network
24 advocacy groups, fraternal, social service clubs, and chambers of commerce that promote
25 the Company in a particular territory or service area and do not reflect any benefits to
26 customers. With respect to Chamber of Commerce (COC) Membership Fees, these relate
27 to helping small businesses connect with potential customers and promoting economic
28 power in the communities. I note that in 66 Pa. C.S. Section 1316.1, recovery of these

1 types of club dues, “no public utility may charge to its customers as a permissible operating
2 expense for ratemaking purposes membership fees, dues or charges to fraternal, social or
3 sports clubs or organization.” Ratepayers should not pay for costs that appear to be related
4 to contributions, pledges, sponsorships and donations and in accordance with the statute
5 identified above. These types of costs mainly benefit Columbia as being good corporate
6 citizens, advocacy on policy issues before various agencies and civic related initiatives.

7 **Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY’S**
8 **BUDGET ADJUSTMENTS TO ITS FTY AND FPFTY PERIODS?**

9 **A.** I am recommending disallowance of the Company’s Inflation Adjustments of 2.93% and
10 3.05% for the FTY and the FPFTY periods, respectively. My reasoning for disallowance
11 of Inflation related adjustments are discussed previously above.

12 **Q. WHAT IS YOUR TOTAL ADJUSTMENT TO THE COMPANY’S COMPANY**
13 **MEMBERSHIP?**

14 **A.** My adjustment is an overall reduction of \$258,217 and is shown on my Exhibit DM-20.

15 **j. Utilities – Fuel Used in Company Operations**

16 **Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS UTILITIES AND**
17 **FUEL USED IN COMPANY OPERATIONS?**

18 **A.** The Company proposed a balance of \$2,075,819 related to its Utilities and Fuel used in
19 Company Operations for the FPFTY period as shown on Exhibit 104, Schedule 1, pages 2.
20 In response to I&E RE-31, the Company provided a breakdown of these costs as of
21 November 30, 2024 of \$2,573,883 on a normalized basis. Mr. Vassalotti stated that the
22 Company reduced this amount by \$473,830 to eliminate costs associated with the contra
23 gas cost expense account 812 for activity related to Company-used gas recovered through
24 its annual purchased gas cost case. The remaining level of other utility costs such as
25 electric and telecommunications represents costs not recovered through Section 1307(f)
26 process. (Statement No. 4 page 15).

1 **Q. WHAT ADJUSTMENTS DO YOU HAVE?**

2 **A.** I am recommending disallowance of the deflation factors of 2.93% (FTY) and 3.05%
3 (FPFTY) to arrive at an adjustment of \$28,758, an increase over the Company's HTY
4 balance. To be consistent with removing inflation factors, I am also making adjustments
5 related to deflation or increases in the Company's adjustments. My arguments with respect
6 to the disallowance of Inflation related adjustments have been previously discussed in my
7 testimony.

8 **Q. WHAT IS YOUR RECOMMENDATION?**

9 **A.** My adjustment increases the Company's costs related to Utilities – Fuel Used in Company
10 Operations by \$28,758 or \$2,104,577 and is shown on my Exhibit DM-21.

11 **k. Advertising**

12 **Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS ADVERTISING**
13 **EXPENSE?**

14 **A.** The Company has proposed a level of Advertising Expense of \$391,359 for the FPFTY
15 period as shown on Exhibit 104, Schedule 1, pages 2. The Company made adjustments to
16 its HTY period by removing non-recoverable brand advertising, misclassified items and
17 reflect Public Awareness expenses inadvertently classified as Outside Services, Materials
18 and Supplies and Other O&M as Advertising. (Statement No. 4 page 15-16). In response
19 to I&E RE-33 the Company provided a breakdown of these costs for the period ending
20 November 30, 2024 of \$505,077.

21 **Q. WHAT IS YOUR RECOMMENDATION?**

22 **A.** The only adjustment I have with respect to the Company's Advertising Expense is the
23 disallowance of the Company's deflation factors for the FTY and the FPFTY periods of
24 2.93% and 3.05%, respectively. My reasons for the removal of deflation factors are stated
25 previously in my testimony with respect to my disallowance of my inflation factors. My
26 adjustments adds \$11,366 to the Company's Advertising Expense from \$391,358 to
27 \$402,724 and is shown on my Exhibit DM-22.

I. Materials and Supplies

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS MATERIALS AND SUPPLIES?

A. The Company proposed a level of Materials and Supplies in the amount of \$6,080,827 for the FPFTY period as shown on Exhibit 104, Schedule 1 page 2. The Company made adjustments to remove lobbying materials and supplies and to include Public Awareness costs as Advertising. (Statement No. 4 page 16). The Company included Inflation Adjustments to adjust the Materials and Supplies balances by 2.93% in the FTY and 3.05% in the FPFTY periods, respectively.

Q. HAS THE COMPANY PROVIDED A BREAKDOWN OF THESE COSTS?

A. Yes, in response to I&E RE-35, Attachment A the Company provided a breakdown of its HTY period expense balance of \$7,622,402. In response to OCA Set 14-5 the Company provided a breakdown of certain of its expenses for the 2022-2024 period.

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. In reviewing the response to OCA Set 14-5, I noticed that account 2020 Facilities Maintenance and Repairs Materials have expenses of \$42,478 in 2022, \$174,598 in 2023 and \$946,461 in 2024. A three-year normalization of these costs results in a balance of \$387,846 or an adjustment of \$558,615. This is an increase of 59% over prior years costs.

Q. WHAT IS YOUR RECOMMENDATION?

A. I am recommending a reduction of account 2020 by \$558,615 and a balance in the HTY of \$7,063,787. A three-year normalization provides for a smoothing of expenses based upon prior actual costs. Operating costs incurred from prior years typically show a trend that can be utilized to set costs in the future. In response to OCA Set-14-5 the Company has not provided a reason for these increased costs over the years. My recommendation is shown on my Exhibit DM-24.

1 **m. NCSC-Shared Services**

2 **Q. WHAT DID THE COMPANY PROPOSE RELATED TO ITS NCSC-SHARED**
3 **SERVICES?**

4 **A.** The Company proposed a NiSource Corporate Services Company (NCSC) balance of
5 \$79,191,883 for the FPFTY period as shown on Company Exhibit 104 Schedule 1 page 2.
6 The Company began with an HTY balance of \$81,633,879 and made a budget adjustment
7 in the FTY of \$929,824 and a ratemaking adjustment of \$(309,385) to arrive at a FTY
8 balance of \$82,254,318. The Company made an FPFTY budget adjustment of
9 (\$2,680,225) and a ratemaking adjustment of (\$382,209) to arrive at its FPFTY balance of
10 \$79,191,883. (Company Exhibit 104 Schedule 1 page 3 and 4).

11 **Q. PLEASE PROVIDE THE ADJUSTMENTS THE COMPANY CALCULATED TO**
12 **ARRIVE AT ITS HTY BALANCE OF \$81,633,879?**

13 **A.** As shown on Company Exhibit 4 Schedule 2 page 19 the Company calculated the
14 following adjustments to arrive at its HTY balance of \$81,633,879:

15	NCSC Contract Billing O&M	\$83,618,250
16	Short-Term Incentive	(\$2,273,944)
17	HTY Labor and Benefits	\$ 1,395,748
18	Non-Recoverable Adjustments	(\$ 502,751) ⁵
19	Smithfield Customer Care Facility Charges	(\$ 602,699)
20	NCSC Expense – R-2024-3046519 Rate Case	<u>(\$ 725)</u>
21	Total	\$81,633,879

22 **Q. PLEASE BRIEFLY DESCRIBE HOW THE COMPANY’S PARENT, NISOURCE,**
23 **ALLOCATES AND PROVIDES SUPPORT SERVICES TO ITS SUBSIDIARIES,**
24 **PARTICULARLY TO COLUMBIA.**

25 **A.** NCSC is a subsidiary of NiSource and an affiliate of Columbia within the NiSource
26 corporate organization. NSCS was established to provide centralized services to the

⁵ These costs related to Lobbying charges of \$58,468; Advertising of \$43,578; Charitable Contributions of \$72,033 and Other Non-Recovery Charges of \$328,672)

individual operating companies with NiSource and to coordinate the allocation and the billing of charges to the NiSource operating companies for services provided by both NSCS directly and by third-party vendors. (Statement No. 4 page 17-18). The rendering of services on a centralized basis enables the affiliates to realize benefits of personnel with specialized areas of expertise as well as the use of assets without bearing the full cost of each individually as the costs are shared among the affiliates. (Statement No. 4 page 18). The NCSC offers Columbia as well as the other NiSource distribution companies access to the depth and breadth of professional experience that may not be otherwise available or that may be available from consultants at much higher costs. (Statement No. 4 page 18).

Q. DOES COLUMBIA HAVE A CONTRACT BETWEEN IT AND NCSC?

A. Yes. NCSC has executed an individual service agreement with each affiliate which designates the types of services to be performed and the method of calculating the charges for these services. The current service agreement between NCSC and Columbia became effective on January 1, 2025. (Statement No. 4 page 18).

Q. HOW ARE NCSC'S COST BILLED TO AFFILIATES?

A. According to Mr. Vassalotti, there are two types of billings made to affiliates: (1) contract billing and (2) convenience billing. Contract billing represents NCSC labor and costs billed to the respective affiliate and are identified by billing pools. Contract billing may be direct or allocated depending on the nature of the costs. (Statement No. 4 page 19). Convenience billing reflects payments that are routinely made by NCSC on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing and external audit fees. Convenience billing is intended as a convenience because it eliminates the need for vendors to separately invoice each affiliate entity receiving the same services. (Statement No. 4 page 19).

Q. HOW ARE THE COSTS DETERMINED RELATED TO COLUMBIA?

A. In accordance with FERC Order 684, centralized service companies like NCSC must use a cost accumulation system provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. NCSC uses a billing pool system to collect costs that are applicable and billable

1 to affiliates, including Columbia. (Statement No. 4 page 19). NCSC directs all personnel
2 to charge an affiliate directly whenever possible so that costs associated with services
3 rendered to affiliates can be directly billed, allowing a user to directly bill a single company
4 for costs incurred. (Statement No. 4 page 19-20). NCSC's charges for services are billed
5 at cost. (Statement No. 4 page 20). System controls are in place that restrict certain
6 departments or groups to only use billing pools that allocate to companies benefitting from
7 the services those departments provide. (Statement No. 4 page 20).

8 **Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE**
9 **COMPANY'S SHARED SERVICES FOR THE FPFTY PERIOD?**

10 **A.** I have several adjustments related to the Company's Shared Services. I reviewed the
11 Company's breakdown of its HTY period balance 11/30/2024 of \$81,633,879, which is
12 shown on Company Exhibit 4 Schedule 2 page 19 and 23. In response to OCA Set 9-9, the
13 Company included long-term incentive (LTI) compensation and stock awards in the form
14 of Performance Share Units (PSU) and Restricted Stock Units (RSU) to employees at the
15 level of Director and above. The balances were shown in the amount of \$3,356,377 in the
16 HTY, \$4,320,459 in the FTY and \$4,012,229 in the FYFTY. In my opinion I believe that
17 PSU and RSU costs appear to be predominately geared towards executive pay with no
18 value accruing to the ratepayers of Columbia. These types of incentive costs are typically
19 geared toward the achievement of financial performance, earnings growth and aligning
20 with the goals of the Company's shareholders. I do not see any benefit accruing to the
21 ratepayer in the area of customer-oriented goals related to safety, environmental, or
22 satisfaction. Therefore, I am recommending that the FPFTY costs of \$4,012,229 for PSU
23 and RSU be disallowed for ratemaking purposes. I do not believe that ratepayers should
24 pay for incentive compensation which promotes NCSC's shareholders' interest and the
25 alignment of NCSC's shareholder growth. As the performance metrics are the same for
26 direct allocation to CPA, these types of costs should not be included, and they provide no
27 benefit to ratepayers but rather to the benefit of shareholders.

1 **Q. WHAT IS YOUR NEXT ADJUSTMENT TO THE COMPANY'S NCSC'S SHARED**
2 **SERVICES?**

3 **A.** My next adjustment is to the Company's inclusion of Supplemental Executive Retirement
4 Plan ("SERP") costs in rates. In OCA 9-10, the Company included \$136,102 of SERP
5 costs totaling \$133,954 in the HTY, \$145,608 in the FTY and \$136,102 in the FPFTY
6 period. In my opinion, I believe that SERP related costs should be disallowed for
7 ratemaking purposes and there are no discernable benefits accruing to ratepayers. These
8 types of costs benefit and accrue to the Company by retaining key employees and are used
9 as rewards for the benefit of key employees. Under a SERP, the Company retains the
10 benefits in the event an employee dies, leaves or quits the Company. The Company has
11 access to the dollars in the SERP and gets the cash value of the plan. Ratepayers should
12 not be burdened with costs that eventually inure to the shareholders of the Company. The
13 Company should have the burden to and responsibility for the attraction and retention of
14 key employees.

15 **Q. WHAT IS YOUR NEXT ADJUSTMENT RELATED TO THE COMPANY'S NCSC**
16 **SHARED SERVICES?**

17 **A.** In response to OCA Set 14-7, the Company provided a breakdown of costs included in the
18 NCSC balance in the HTY of \$81,833,879. Included in those costs \$105,630 were for
19 discretionary bonuses. I am recommending disallowance of these costs as they do not
20 reflect any kind of goal or performance related to customer service or customer-oriented
21 goals.

22 **Q. WHAT IS YOUR FINAL ADJUSTMENT?**

23 **A.** In response to OCA Set 14-8 which referred to I&E RE-38 Attachment B, the Company
24 reflected a balance of \$4,220,133 of Capital incentive costs that was allocated to Columbia
25 paid in 2025 for the 2024 incentive program. The Company reflected \$6,977,626 of
26 incentive compensation expense that was allocated to Columbia that was paid in 2025 for
27 the 2024 incentive program.

1 **Q. WHAT IS YOUR RECOMMENDATION?**

2 **A.** I am recommending an additional disallowance of the NCSC incentive costs of \$4,884,338
3 (6,977,626 times 70%). As stated previously in my testimony, the 70% Performance
4 Metrics is related to Financial achievement with respect to net operating earnings per share
5 as identified in Company Gas RR-027 Attachment A. In response to OCA Set 14-9, the
6 Company stated that the performance goals and metrics are the same for Columbia and
7 NSCS. Given that I recommended disallowance of 70% of the total costs of incentive for
8 the Columbia employees, I am recommended only 30% or \$2,093,288 be included for
9 NSCS incentive compensation. This is a disallowance of \$4,884,338 that I believe are
10 related to costs that support and promote shareholder interest and shareholder growth. My
11 recommendation is shown on my Schedule DM-27 and is a total disallowance of
12 \$9,138,299. I am also disallowing the capitalized incentive costs of \$4,220,133 by 70%
13 or \$2,954,093 as I disallowed under my adjustment related to incentive compensation
14 expenses which are geared toward the support and promotion of shareholder interests and
15 shareholder growth as I expenses in my incentive compensation section above. This is
16 reflected on my Exhibit DM-3 (Rate Base).

17 **n. DEI /ESG Costs**

18 **Q. WHAT HAS THE COMPANY INCLUDED IN ITS FILING RELATED TO**
19 **DIVERSITY, EQUITY AND INCLUSION COSTS (DEI) and ENVIRONMENTAL,**
20 **SOCIAL AND GOVERNANCE COSTS (ESG)?**

21 **A.** In response to OCA Set 9-13 the Company included a net balance of \$130,450 of DEI
22 costs. The Company has not specifically identified the level of costs related to ESG stating
23 that these costs are not separately identified in the budget as the costs are integrated into
24 the comprehensive NiSource ESG strategy.

25 **Q. WHAT ADJUSTMENTS DO YOU HAVE?**

26 **A.** I am recommending disallowance of DEI costs for ratemaking purposes. I believe these
27 types of costs do not benefit ratepayers in the provision of safe and reliable utility service.
28 These types of costs reflect organizational frameworks which seek to promote the fair
29 treatment and full participation of all people who have been subject to discrimination. I do

not see a nexus between DEI costs and customer-oriented benefits. These types of costs should be recovered and borne by the Company or its shareholders if it believes they provide a benefit. This adjustment is reflected on my Exhibit DM-9.

o. Rate Case Expenses

Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS RATE CASE EXPENSES?

A. The Company proposed a total level of Rate Case Expenses of \$1,321,000 with a normalization period of 1 year. (Exhibit 104, Schedule 2, page 16). The Company calculated this level based upon a normalized level of rate case expenses and based the one-year amortization period due to prior experience and the expectation of future rate filings. (Statement. No. 4, page 23).

Q. WHAT ADJUSTMENTS DO YOU HAVE?

A. I reviewed the response to OCA Set 9-24 which asked for the level of rate case expenses incurred by the Company for the past five base rate proceedings along with the normalization periods associated with the rate case expenses. The Company provided the following rate case costs:

<u>Case Year</u>	<u>Amount Requested</u>
(BEGIN CONFIDENTIAL)	
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED] (END CONFIDENTIAL)
2025	\$1,321,000

In this instant proceeding (2025) the Company proposed a rate case expense balance of \$1,321,000.

1 **Q. WHAT IS YOUR RECOMMENDATION?**

2 **A.** The Company has filed rate case petition about every 2 years, with the exception being the
3 filing dates of 2021 and 2022. The Company did not file a rate case petition in 2023. The
4 Company filed a rate case petition in 2024 and in this instant 2025 rate case petition. In
5 this case, I am recommending a 1.16 year normalization period (7 years divided by 6 rate
6 case proceedings or 1.16). This computes to an annual recovery expense of \$1,138,793
7 (\$1,321,000/1.16) . While the Company claims that it is expected to file more frequent rate
8 case filings, prior experiences indicate that, on average, the Company has been filing rate
9 case every two years. My adjustment is shown on my Exhibit DM-28.

10 **p. Uncollectible Expense**

11 **Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS**
12 **UNCOLLECTIBLE EXPENSE?**

13 **A.** The Company has proposed total Uncollectible Expenses – Base Rates of \$9,459,959 and
14 Unbundled Uncollectible Expenses of \$1,169,096 under the HTY period. (Exhibit 104,
15 Schedule 2, page 17). The Company adjusted these balances by \$26,770 for the Base Rate
16 uncollectible and \$11,865 for the Unbundled uncollectible expenses under the FTY period.
17 The Company adjusted these balances by \$995 for the Base Rate uncollectible and \$6,689
18 for the Unbundled uncollectible expenses under the FPFTY period. The total proposed
19 uncollectible balances results in a \$9,487,724 for the Base Rate uncollectible and
20 \$1,187,650 for the Unbundled uncollectible expenses. The Company utilized a three-year
21 average of net write-offs which is developed on Company Exhibit 4 Schedule 2 page 24
22 and the Unbundled (Customer Assistance Program or CAP) is recovered through the Rider
23 USP (Statement No. 4 page 23).

24 **Q. WHAT ARE YOUR RECOMMENDATIONS?**

25 **A.** I am accepting the Company's FPFTY revenues at present rates and the methodology used
26 to compute the Company's level of Uncollectible Expense. What I am adjusting is my
27 recommended revenue requirement adjustment related to my recommended overall
28 revenue requirement decrease of \$41,771,833 using the Company's uncollectible rate of
29 .0134613 of average write-offs (Company Exhibit 104 Schedule 2 page 17). My

1 recommendation is a balance of (\$562,303) shown on my Exhibit DM-29. (OCA Set 14-
2 10).

3 **q. Rider USP and Rider EE**

4 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO RIDER USP**
5 **AND RIDER EE COSTS?**

6 **A.** The Company proposed recovery of \$31,862,500 in the FPFTY related to its Rider USP
7 for its universal service program reconciling mechanism, and \$1,235,965 in the FPFTY
8 related to its Rider EE for its energy efficiency program reconciling mechanism.
9 (Company Exhibit 104 Schedule 1 page 2). The adjustments are a result of the matching
10 of expenses to revenues as Rider USP and Rider EE are fully reconciling. Mr. Vassalotti
11 stated that the net impact to operating income is zero with the expense offsetting present
12 rate revenue and do not impact the base rate increase requested in this case. (Statement
13 No. 4 page 44).

14 **Q. WHAT COSTS ARE INCLUDED IN THE COMPANY'S RIDER ACCOUNTS?**

15 **A.** In response to OCA Set 9-53, the Company proposed \$100,000 of costs annually related
16 to a two-year CAP Pilot. The Company proposed \$300,000 related to Speech Analytics
17 Pilot Program. The Company proposed \$225,136 related to Energy Assistant Team (EAT).
18 (Vassalotti Statement No. 4 page 44). The breakdown of the EAT costs are shown in
19 Confidential Attachment 1 to OCA Set 9-25.

20 **Q. WHAT ADJUSTMENTS DO YOU HAVE?**

21 **A.** As more fully identified in Mr. Roger's Colton's testimony, page 111, he recommended a
22 disallowance of \$220,000 of administrative costs being switched from base rates to the
23 Rider USP. I am including this adjustment in my Rider USP balance. My recommendation
24 is shown on my Exhibit DM-31.

1 **3. DEPRECIATION AND AMORTIZATION EXPENSE**

2 **Q. WHAT DID THE COMPANY PROPOSE WITH RESPECT TO ITS**
3 **DEPRECIATION AND AMORTIZATION EXPENSE?**

4 **A.** The Company proposed a Depreciation and Amortization Expense of \$149,371,200 as
5 shown on Exhibit 104 Schedule 3 page 3 and on Exhibit 105, page 9 of 10. The Company
6 proposed a Five Year Amortization of Net Negative Salvage of \$5,484,681 as shown on
7 Exhibit 104 Schedule 3 page 3 and on Exhibit 105 page 10.

8 **Q. DID THE COMPANY HAVE A DEPRECIATION STUDY PERFORMED FOR**
9 **USE IN THIS RATE PROCEEDING?**

10 **A.** Yes. In Mr. Spanos' testimony, Statement. No. 5, page 2 and 3, a 2024 depreciation study
11 was performed to calculate depreciation expense as related to the original cost at November
12 30, 2024. Mr. Spanos stated that the depreciation study included the results of the original
13 cost as of November 30, 2025 and the results of the study related to gas plant as of
14 December 31, 2026. (Statement No. 5 page 3).

15 **Q. WHAT ARE YOUR RECOMMENDATIONS RELATED TO THE COMPANY'S**
16 **DEPRECIATION AND AMORTIZATION EXPENSE?**

17 **A.** As more fully identified in Mr. Garrett's testimony, I am incorporating his adjustments
18 here. Mr. Garrett recommended an overall reduction to the Company's Depreciation
19 expense of \$45,802,423 (Garrett Exhibit DJG-17). I am also including my recommended
20 adjustments to the Company's UPIS with respect to my disallowance of inflation
21 adjustments as previously identified in my testimony. This results in a reduction of
22 \$236,476 that includes the recommended depreciation rates as shown on Mr. Garrett's
23 Exhibit DJG-17. My overall adjustment is a reduction of \$46,038,898. My
24 recommendations is shown on my Exhibit DM-33.

25 **Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S NEGATIVE NET**
26 **SALVAGE VALUE OF \$5,484,681?**

27 **A.** No. I do not believe Mr. Garrett proposed any adjustment to the Company's Negative Net
28 Salvage Value of \$5,484,681. My recommendation is shown on my Exhibit DM-33.

1 **4. TAXES OTHER THAN INCOME**

2 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO TAXES OTHER**
3 **THAN INCOME TAXES?**

4 **A.** The Company proposed total Taxes Other Than Income in the amount of \$4,500,883 as
5 shown on Exhibit 102, Schedule 2, page 3 with a breakdown shown on Exhibit 106
6 Schedule 2 page 2. These taxes are comprised of related payroll taxes, property taxes,
7 license and franchise, sales and use taxes and other. The balance of \$4,500,883 is a
8 decrease of \$101,205 over the Company's FTY period of \$4,602,038.

9 **Q. WHAT IS YOUR RECOMMENDED LEVEL OF TAXES OTHER THAN INCOME**
10 **TAXES?**

11 **A.** I am accepting the Company's Taxes Other than Income with the exception of the Payroll
12 Taxes, mainly Social Security (FICA), With respect to the Company's proposed balance
13 of Federal Unemployment Tax Act ("FUTA") and State Unemployment Tax Act
14 ("SUTA") of \$97,544, these balances are not affected since the maximum limitation for
15 FUTA and SUTA is \$7,000 in 2025. Since I adjusted labor and incentive compensation, I
16 am making the associated adjustments to reflect my recommended levels using the
17 Company's Payroll Tax Rate of 7.2234% (Exhibit 106, Schedule 2, page 3). My Payroll
18 Tax balance is \$2,798,543, a reduction of \$187,573. I also adjusted the Property Taxes to
19 reflect the changes in my recommended UPIS balance. I used the Company's Property tax
20 level of \$1,372,160 to the Company's proposed UPIS balance of \$5,219,879,723 and
21 calculated a composite tax rate of 0.00026287%. Using my recommended UPIS balance
22 of \$5,205,372,014 times the composite tax rate of 0.00026287%, I computed a Property
23 Tax expense of \$1,368,336, a reduction of \$3,824. My total adjustment to the Company's
24 Taxes Other Than Income is a reduction of \$191,397 and a balance of \$4,309,435. My
25 recommendation is shown on my Exhibit DM-33.

1 **5. INCOME TAXES**

2 **Q. WHAT DID THE COMPANY CALCULATE WITH RESPECT TO ITS INCOME**
3 **TAXES?**

4 **A.** The Company proposed total Income Taxes of \$72,811,341. This is comprised of Net
5 Federal Income Taxes of \$34,759,235, State Income Taxes of \$12,777,404, Deferred
6 Income Taxes of \$34,757,235 offset by the flow back of Excess Deferred Income Taxes of
7 \$2,498,191. (Company Exhibit 107 page 8). The Company also included \$78,757 related
8 to the Amortization of Investment Tax Credit. (Company Exhibit 107 page 8). Company
9 witness Ms. Harding utilized the Federal Income Tax Rate of 21% in developing its FPPTY
10 Federal Income Tax expense. Ms. Harding utilized the State Income Tax Rate of 7.49%
11 effective in 2026 to calculate its FPPTY State Income Tax expense. (Statement No. 10
12 page 3).

13 **Q. DID THE COMPANY ADJUST ITS PROPOSED REVENUE REQUIREMENT TO**
14 **ACCOUNT FOR THE TAX CUTS AND JOBS ACT OF 2017 (TCJA)?**

15 **A.** Yes. The Company is refunding its excess accumulated deferred income taxes (EDIT) as
16 a result of the enactment of the TCJA which is being refunded under the Average Rate
17 Assumption Method (ARAM). (Statement No. 10 page 5). (See OCA Set 9-39)

18 **Q. HAS THE COMPANY ADDRESSED THE CHANGE IN ACCOUNTING**
19 **METHOD TO ADOPT THE NATURAL GAS SAFE HARBOR METHOD (NGSH)?**

20 **A.** According to Ms. Harding, yes. NiSource expects to elect the change in tax accounting
21 method in its 2024 consolidated tax return filing due on October 15, 2025. (Statement No.
22 10 page 7). The Company is in the process of reviewing and quantifying the provisions of
23 the safe harbor method for taxpayers with natural gas transmission and distribution
24 property. The federal repairs will be normalized under deferred tax accounting so there
25 will be no impact on federal tax expense. The repairs deduction has not been normalized
26 for state income tax purposes based on prior Commission orders and is expected to be
27 recognized as flow-through for state tax purposes and is reflected in the state tax expense.
28 (Statement No. 10 page 7).

1 **Q. HAS THE COMPANY UTILIZED THE PENNSYLVANIA NET OPERATING**
2 **LOSS (NOL) CARRYFORWARD IN THE HTY?**

3 **A.** Yes. The Company had \$144,975,996 of NOL for 2008 and was carried forward to future
4 years. The Company reflected a balance of this NOL in the HTY period as reflected on
5 Company Exhibit 7 page 20 of \$11,063,419 (Statement No. 10 page 9).

6 **Q. WHAT IS YOUR RECOMMENDED INCOME TAXES FOR FEDERAL AND**
7 **STATE?**

8 **A.** I reviewed the methodology that the Company used to compute its Federal and State
9 Income Taxes, as well as the Company's Deferred Income Taxes. Using the Company's
10 methodology shown on the Company's Exhibit 107 Page 8, with a Federal Income Tax
11 Rate (FIT) of 21% and a PA State Income Tax Rate (SIT) of 7.49%, I utilized the flow
12 through of my Rate Base and Operating Income adjustments to compute my State and
13 Federal Income Tax balance and the Deferred Tax adjustments. In response to OCA 9-42
14 the Company updated its excess tax depreciation over book depreciation by \$2,834,217
15 and a balance of \$32,331,282. With respect to the Company's Statutory Adjustments of
16 (\$223,215,150), I made an adjustment to the Company's Interest Expense, in that I used
17 my recommended Rate Base Balance of \$3,883,435,478 times the recommended weighted
18 Cost of Short-Term and Long-Term Debt of 2.60%, as recommended by Mr. Garrett which
19 equals \$100,789,131. This is \$9,422,861 greater than the Company's proposed Interest
20 Expense balance of \$91,366,270. I have accepted the Company's balance related to its
21 EDIT of \$2,498,191. My total recommended State Income Tax is \$16,023,187; my total
22 recommended Federal Income Tax is \$69,205,671 and my total Deferred Income Taxes
23 are (\$38,689,948).

24 **Q. WHAT IS YOUR RECOMMENDED STATUTORY ADJUSTMENTS BALANCE**
25 **USING YOUR RECOMMENDED RATE BASE BALANCE AND WEIGHTED**
26 **COST OF SHORT-TERM AND LONG-TERM DEBT?**

27 **A.** My recommended Statutory Adjustments balance is \$184,237,847. This reflects my
28 adjustment to Depreciation Expense as recommended by OCA witness Mr. Garrett and my
29 adjustments to the Company's Interest Expense. This is shown on my Exhibit DM-34.

1 **E. Act 40 Requirements (Act 40 of 2016)**

2 **Q. WHAT ARE THE ACT 40 REQUIREMENTS?**

3 **A.** Act 40 changes the way that federal income tax expense is computed for ratemaking
4 purposes for many Pennsylvania utilities that participate in a consolidated federal income
5 tax return. In part, Act 40 states:

6 If an expense or investment is allowed to be included in a public utility's
7 rates for ratemaking purposes, the related income tax deductions and credits
8 shall also be included in the computation of current or deferred income tax
9 expense to reduce rates. If an expense or investment is not allowed to be
10 included in a public utility's rates, the related income tax deductions and
11 credits, including tax losses of the public utility's parent or affiliated
12 companies, shall not be included in the computation of income tax expense
13 to reduce rates. The deferred income taxes used to determine the rate base
14 of a public utility for ratemaking purposes shall be based solely on the tax
15 deductions and credits received by the public utility and shall not include
16 any deductions or credits generated by the expenses or investments of a
17 public utility's parent or any affiliated entity. The income tax expense shall
18 be computed using the statutory income tax rates.

19 Act 40 further states:

20 REVENUE USE- If a differential accrues to a public utility resulting from
21 applying the ratemaking methods employed by the commission prior to the
22 effective date of subsection (a) for ratemaking purposes, the differential
23 shall be used as follows:

- 24 (1) Fifty percent to support reliability or infrastructure related to the rate-base
25 eligible capital investment as determined by the commission; and
26 (2) Fifty percent for general corporate purposes.

27
28 **Q. HAS THE COMPANY CALCULATED A CONSOLIDATED TAX EXPENSE**
29 **ADJUSTMENT?**

30 **A.** No. According to Ms. Harding's testimony, Statement No.10, page 10, the Company has
31 not included a Consolidated Tax Adjustment in accordance with Act 40 which became
32 effective on August 10, 2016. Act 40 and eliminated the consolidated tax adjustment in
33 ratemaking. Title 66 of the Pennsylvania Consolidated Statutes Section 1301.1 stated that
34 for the computation of income tax expense for ratemaking purposes, if an expense or

investment is not allowed to be included in a public utility's rates, the tax losses of a public utility's parent or affiliated companies should not be included in the computation of income tax expense to reduce rates (Statement No. 10, page 10).

Q. HAS THE COMPANY SATISFIED THE FIRST REQUIREMENT UNDER ACT 40 OF THE DIFFERENTIAL SPENT ON INFRASTRUCTURE PROJECTS?

A. Yes. The Company is expected to invest \$316.8 million of infrastructure projects in the FTY and an additional \$329.3 million in the FPFTY period. (Statement No. 10 page 11). This expenditure is greater than the \$2.26 million (50% of the \$4.53 million differential) that would have been a consolidated tax adjustment prior to Act 40.

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO THE OTHER 50% OF THE DIFFERENTIAL WHICH SECTION 1301.1 (b) STATES MUST BE USED FOR GENERAL CORPORATE PURPOSES?

A. Ms. Harding stated that Columbia's pro forma operating and maintenance expense budget is \$227.1 million in the FTY and \$223.6 million in the FPFTY. These expenditure levels are greater than the \$2.26 million that would have been a consolidated tax adjustment prior to Act 40.

Q. WHAT DO YOU CONCLUDE FROM COLUMBIA WITH RESPECT TO 50% OF THE DIFFERENTIAL RELATED TO GENERAL CORPORATE PURPOSES?

A. Columbia has not specifically identified how it has satisfied 50% of the differential for General Corporate purposes. Columbia has identified no specific ways in which that 50% of the differential would be used in any way to benefit Pennsylvania ratepayers. One might conclude from this that Columbia therefore basically intends to use that money for the benefit of its stockholders and not apply it in any manner to provide a quantifiable ratepayer benefit or in a manner that directly benefits service to Pennsylvania customers.

Q. WHAT DOES "GENERAL CORPORATE PURPOSES" AS USED IN ACT 40 MEAN?

A. Because Columbia is a regulated utility in Pennsylvania, its "general corporate purpose" is to provide regulated utility service in the Commonwealth of Pennsylvania. While the term

1 “general corporate purposes” is rather vague, consistent with that general corporate
2 purpose of regulated utilities, general corporate purposes would include uses for such
3 “differential” revenues as supporting capital expenditures necessary to execute utility
4 business plans, paying off debt, funding construction projects, paying dividends, paying
5 for maintenance and operating expenses, investing in utility plant in Pennsylvania, and
6 providing a source of working capital. Many of these uses for “general corporate purposes”
7 would have a quantifiable benefit to Pennsylvania ratepayers. As I read the entirety of Act
8 40, the "revenue use differential" addressed in the Act for “general corporate purposes”
9 should mean public utility purposes and uses that result in having some identifiable and
10 quantifiable benefit to Pennsylvania and Peoples ratepayers, rather than just resulting in a
11 windfall of \$2.263 million annually.

12 **Q. WHAT SPECIFIC RECOMMENDATION DO YOU HAVE FOR APPLYING THE**
13 **50% OF THE “REVENUE USE” DIFFERENTIAL THAT ACT 40 REQUIRES TO**
14 **BE FOR “GENERAL CORPORATE PURPOSES”?**

15 **A.** I have reflected the 50% differential for general corporate purposes as a source of non-
16 investor-supplied funding for utility working capital, which is a Rate Base reduction. This
17 is a balance of \$2,263,821 and shown on my Exhibit DM-3.

18 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

19 **A.** Yes, it does.

APPENDIX A - Resume of Dante Mugrace

PCMG and Associates LLC

DANTE MUGRACE

Education

Master Business Administration, MBA Strategic Management, Pace University, Lubin School of Business, New York, NY, 2010

Master Public Administration, MPA, Kean University, Union, NJ, 2001

Bachelor of Science, BS. Accounting, St. Peter's University, Jersey City, NJ, 1983

Position

Senior Consultant – PCMG and Associates	2014 – present
Senior Consultant – Snavelly King Majoros and Associates	2013 – 2014
Independent Consultant	2012 – 2013
Bureau Chief/Administrative Analyst/Accountant – New Jersey Board of Public Utilities	1983 – 2011

Professional Experience

Mr. Mugrace has 35 years' experience in all aspects of regulatory accounting and policy including processing, analyzing and evaluating utility rate case petitions before Public Service Commissions. Mr. Mugrace examines and evaluates rate filings, contracts, agreements and rate matters regarding utility operations and provides recommendations as to best course of action. Additionally, Mr. Mugrace analyzes and reviews utility regulatory matters and sets forth recommendations for resolution of issues, calculates total revenue requirement needed to cover operating expenses and rate of return; researches and evaluates regulatory utility matters to assess impact on various classes of customers, regarding rates, service, compliance and cost of service provisions, as well as annual true-up and tracking mechanisms.

Prior to undertaking consulting assignments, Mr. Mugrace was the Bureau Chief Utility Rate Manager for the New Jersey Board of Public Utilities, in which role he managed and assigned tasks to a staff of 12 professionals and supervisory personal in the daily administrative, financial and managerial functions of the Division. Mr. Mugrace's primary duties were to determine whether the utility had sufficient revenues to cover its operating expenses and earn a return on its plant investment and to ensure that the utility provided safe, reliable and continuing utility service to its customers. Mr. Mugrace set rates and charges for utility companies, which had revenues of up to \$500 million, and ensured that the revenue requirement provided for recovery of all operating expenses, return on investment and depreciation. Mr. Mugrace was also responsible for reviewing and verifying that the companies' property, plant and equipment (up to \$2.5 billion) were used and useful in providing service to its customers. Mr. Mugrace coordinated and met with the New Jersey State Department of Environmental Protection to

PCMG and Associates LLC

determine whether water and wastewater utilities were complying with state regulations and were adhering to any regulatory agency directives or orders. Mr. Mugrace developed ways to minimize the rising costs of water utility services by investigating alternative rate structures, analyzing engineering mechanisms and techniques, looking into the feasibility of mergers and acquisitions within the water industry and reviewing financing, and rate alternatives to minimize the impact on ratepayers. Mr. Mugrace was responsible for ensuring that the rate-case process adhered the statutory timeframe for preparing, reviewing and recommending findings to the Board Commissioners on financial operations, costs, revenues and operating expenses, prior to the litigation proceedings. Mr. Mugrace also examined alternative rate recovery mechanisms and clauses, phase-ins of revenue requirements, deferral mechanisms and pass-through of rate charges. Mr. Mugrace assumed the role of Director during transition periods and Administrative changes. Finally, Mr. Mugrace conducted the recruitment and hiring of employees for placement within the Division and the Board.

Professional and Business Affiliations

- Institute of Public Utilities (IPU) Michigan State University (MSU), National Association of Regulatory Utility Commissioners (NARUC), National Association of State Utility Consumer Advocates (NASUCA)

References

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PCMG and Associates LLC

Regulatory Projects and Appearances

1. In Re: Northern States Power Company for Approval of a 2024 Natural Gas Rate Increase.
(Appearance: Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff).
North Dakota Public Service Commission – Docket No. PU-23-367.
2. In Re: FirstEnergy Pennsylvania Electric Company for Approval of a General Base Rate Case increase for Electric Distribution rates for service.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2024-3047068
3. In Re: Duquesne Light Company for Approval of a General Base Rate Case to increase Electric Distribution rates for service.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No.- R-2024-3046523
4. In Re: Peoples Natural Gas Company, LLC for Approval of a General Base Rate Case increases in Natural Gas Service.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2023-3044549
5. In Re: Black Hills Energy Arkansas, Inc. (BHEA) and Summit Utilities Arkansas, Inc. (SUA) for a General Change, or Modification in its Rates, Charges and Tariffs
(Appearance: Incentive Compensation Proposals on behalf of the Attorney General Office)
Arkansas Public Service Commission – Docket No. (BHEA) - 23-074-U and Docket No. (SUA) - 23-079-U.
6. In Re: Montana Dakota Utilities Co. for Approval to increase Gas Rates for Natural Gas Service in North Dakota
(Appearance- Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff)
North Dakota Public Service Commission – Docket No. PU-23-341
7. In Re: Otter Tail Power Company for Approval to increase Electric Rates in North Dakota.
(Appearance: Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff)
North Dakota Public Service Commission – Docket No. PU-23-342
8. In Re: New Jersey-American Water Company for Approval to change the level of its Purchased Water and Purchased Wastewater Treatment Adjustment Clause for 2023.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)

PCMG and Associates LLC

New Jersey Board of Public Utilities – Docket No. WR23110791

9. In Re: Verified Petition of Jersey Central Power & Light Company to establish a Rate for Rider Lost Revenue Adjustment Mechanism for Sales Losses incurred during Program Year 2 Pursuant to the Energy Efficiency and Peak Demand Reductions Programs (PY Rider LRAM Filing).
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23110865
10. In Re: Fitchburg Gas & Electric Company; The Berkshire Gas Company; Boston Gas Company d/b/a National Grid; Liberty Utilities; Eversource Gas of Massachusetts d/b/a Eversource Energy and; NSTAR Gas Company d/b/a Eversource Energy – 2023 Gas System Enhancement Program Plan Filings. (DPU GSEP-01; DPU GSEP-02; DPU GSEP-03; DPU GSEP-04; DPU GSEP-05; and DPU GSEP-06, respectively)
(Appearance: Accounting Issues on behalf of the Commonwealth of Massachusetts Office of the Attorney General)
Department of Public Utilities
11. In Re: Northern States Power Company – Advance Determination of Prudence – 345 kV Transmission Line – MN.
(Appearance: Accounting Issues and Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff.
North Dakota Public Service Commission – Docket No. PU-23-142.
12. In Re: Northern States Power Company – Advance Determination of Prudence- Brookings Second Circuit Project.
(Appearance: Accounting Issues and Revenue Requirement on behalf of the North Dakota Public Service Commission Advocacy Staff.
North Dakota Public Service Commission – Docket No. PU-23-295.
13. In Re: Northern States Power Company – Advance Determination of Prudence – 345 kV Big Stone to Sherburne.
(Appearance: Accounting Issues and Revenue Requirements on behalf of the North Dakota Public Service Commission Advocacy Staff.
North Dakota Public Service Commission – Docket No. PU-23-329.
14. In Re: Rockland Electric Company – Annual Conservation Incentive Program Filing – Reconciliation for the period July 1, 2022 – June 30, 2023.
(Appearance: Accounting Issues on behalf the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070471
15. In Re: Public Service Electric & Gas Company for Approval of Incremental COVID-19 Costs for Recovery through a New Special Purpose Clause and for Authorization to Recovery Uncollectible Costs for Gas Through the Societal Benefits Charge
16. (Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070448

PCMG and Associates LLC

17. In Re: Jersey Central Power & Light Company's Verified Petition Seeking Review and Approval of the Net Deferred Costs Included in its COVID-19 Regulatory Asset and Establishment of a COVID-19 Recovery Charge (JCP&L CRC-Filing)
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070453.
18. In Re: Aqua New Jersey, Inc. Petition for 2024 PSTAC Rate and True-up for 2021 and 2022 PSTAC.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR23080576
19. In Re: Public Service Electric & Gas Company for Approval of Changes in its Electric Tax Adjustment Credit and Gas Tax Adjustment Credit 2023 (2023 TAC Filing)
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23090634 and GR23090635
20. In Re: New Jersey – American Water Company for Deferral Accounting Authority for the Costs of Implementing the Clean Energy Act of 2018 Benchmarking Requirements.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WF23060346
21. In Re: Public Service Electric & Gas Company – Annual BGSS (2023-2024) Commodity Charge Filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for Changes in its Balancing Charge Rate.
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR23060331
22. In Re: Public Service Electric & Gas Company – Electric and Gas Green Programs Recovery Charges 2023. (GPRC).
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23070423 and GR23070424
23. In Re: Public Service Electric & Gas Company – Electric Solar Pilot Recovery Charge (SPRC) for its Solar Loan I Program (2023).
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER23060412
24. In Re: Middlesex Water Company for approval of Proposed Cost Recovery of Lead Service Line Replacement Program
(Appearance: Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR23050291
25. In Re: Black Hills Wyoming Gas, LLC d/b/a Black Hills Energy for Approval of a General Rate Increase of \$19,262,412 to the Retail Gas Rates.

PCMG and Associates LLC

(Appearance: Revenue Requirement on behalf of the Wyoming Office of Consumer Advocate)

Wyoming Public Service Commission – Docket No. 30026-78-GR-23

26. In Re: Pittsburgh Water and Sewer Authority for an Increase in Rates for Water Service, Wastewater Service and Stormwater Service
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2023-3039920 (water), R-2023-3039921 (wastewater), and R-2023-3039919 (stormwater)
27. In Re: Massachusetts Electric and Nantucket Electric Companies d/b/a National Grid – Request for recovery of Incremental Storm related expenses associated with fourteen weather events between February 2020 and December 2020.
(Appearance: Storm Cost recovery (Operating and Maintenance Expenses) on behalf of the Massachusetts Office of Attorney General.
Massachusetts Department of Public Utilities – DPU No. 22-43.
28. In Re: Philadelphia Gas Works – for approval of an Increase in rates for Distribution Gas Service for 2023
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2023-3037933
29. In Re: Lanai Water Company, Inc. for Review and Approval of Rate Increases, Revised Rate Schedules and Charges to its Tariff.
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2022-0233
30. In Re: Hawaii Water Service Company, Inc., For Approval of a General Rate Increase for Its Pukalani Wastewater Division and Certain Tariff Changes
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2022-0186
31. In Re: UGI Utilities – Electric Division for Review of an Electric Base Rate Case proceeding for 2023.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3037368
32. In Re: Southern Maryland Electric Cooperative, Inc. (SMECO) for Authority to Revise its Rates and Charges for Electric Service and Certain Rate Design Changes.
(Appearance: Revenue Requirement on behalf of the Maryland Office of People’s Counsel)

PCMG and Associates LLC

Maryland Public Service Commission – Case No. 9688

33. In Re: Public Service Electric and Gas Company – 2022 Electric and Gas Tax Adjustment Credit (TAC)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket Nos. ER22100667 and GR22100668
34. In Re: Public Service Electric and Gas Company – 2022 Green Program Recovery Charge.
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket Nos. ER22070413 and GR22070414
35. In Re: Rockland Electric Company – Annual Conservation Incentive Program Filing – Reconciliation for the Period July 1, 2021 – June 30, 2022.
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. ER22070469.
36. In Re: Atlantic City Electric Company for Implementation to its Conservation Incentive Program Rate Mechanism and Associated Customer Class Rate (2022)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. ER22070463
37. In Re: Public Service Electric and Gas Company – 2022/2023 Annual BGSS Commodity Charge filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for changes to its Balancing Charge.
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
NJ Board of Public Utilities – BPU Docket No. GR22060363
38. In Re: Citizens' Electric Company of Lewisburg, PA – 2022 Base Rate Case Proceeding for an Increase in Electric Distribution Rates.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3032369
39. In Re: Valley Energy, Inc. – 2022 Base Rate Case for an Increase in Gas Distribution Rates.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3032300
40. In Re: Berkshire Gas Company – 2021 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office)
Massachusetts Department of Public Utilities – D.P.U. 22-GREC-02

PCMG and Associates LLC

41. In Re: Liberty Utilities (New England Natural Gas Company) 2021 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office)
Massachusetts Department of Public Utilities – D.P.U. 22-GREC-04
42. In Re: Eversource Gas Company (Eversource Energy) 2021 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office)
Massachusetts Department of Public Utilities – D.P.U. 22-GREC-05
43. In Re: South Jersey Gas Company – 2022 Base Rate Case Proceeding for an Increase in rates for Distribution Gas Service.
(Appearance: Revenue Requirement, CWC and Consolidated Income Taxes on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GR22040253
44. In Re: Public Service Electric and Gas Company – 2022 Electric Conservation Incentive Program (CIP) for changes in its Electric CIP rate for 2022.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. ER22020035
45. In Re: PECO Energy Company-Gas Division – 2022 Base Rate Case Proceeding for an Increase in rates for Distribution Gas Service.
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3031113.
46. In Re: Nova Scotia Power Company- 2022-2024 General Rate Application for an Increase in Rates for Electric Service
(Appearance- Review of COSS – Subcontract with Synapse Energy Economics, Inc. on behalf of the Nova Scotia Utility Review Board)
Nova Scotia Utility and Review Board – Docket No. M10431
47. In Re: Georgia Power Company – 2022 Base Rate Case petition for an Increase in rates for Electric Distribution Service
(Appearance: Review of O&M Expenses for calendar years 2023-2025 on behalf of the Georgia Public Service Commission – Docket No. TBD)
48. In Re: UGI Utilities Inc, Gas Division – 2022 Base Rate Case petition for an Increase in Distribution Gas Service Rates
(Appearance: Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2022-3030218

PCMG and Associates LLC

49. In Re: Hawaii-American Water Company – Approval of Rate Increases and Revised Rate Schedules for Wastewater Services – 2021
(Appearances: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Service Commission – Case No. 2021-0063
50. In Re: Kalaeloa Water Company – Approval of a General Rate Increase / Adjustments for Water and Wastewater Services – 2021
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Service Commission – Case No. 2021-0005
51. In Re: Northern States Power Company – 2021 Natural Gas Rate Increase Application
(Appearance: Revenue Requirements on behalf of the Advocacy Staff of the North Dakota Public Service Commission – Case No. PU-21-381
52. In Re: Shore Water Company – Petition for an Increase in Rates for Water Service and Other Relief
(Appearance: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21091141
53. In Re: Atlantic City Sewerage Company – Petition for an Increase in Rates for Sewerage Service and other Tariff Changes
(Appearance: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21071006
54. In Re: Gordon’s Corner Water Company – Petition for an Increase in Rates and Charges for Water Service
(Appearance: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21070979
55. In Re: The Petition of HPBS Inc., for review and approval of Central Scheduling System (CSS) charge increase and revised CSS Schedule (2021)
(Appearance – Accounting and Revenue Requirement on behalf of the Hawaii Division of Commerce and Consumer Affairs)
Hawaii DCCA – Docket No. PTP-2021-001
56. In Re: The Berkshire Gas Company, 2020 Gas System Enhancement Program Reconciliation Filing
(Appearance – Massachusetts Attorney General’s Office – Accounting and Revenue Requirement)
Massachusetts Department of Public Utilities – DPU Docket No. 21-GREC-02

PCMG and Associates LLC

57. In Re: Eversource Gas Company of Massachusetts d/b/a Eversource Energy, 2020 Gas System Enhancement Program Reconciliation Filing
(Appearance – Massachusetts Attorney General’s Office – Account and Revenue Requirement)
Massachusetts Department of Public Utilities – DPU Docket No. 21-GREC-05
58. In Re: NSTAR Gas Company d/b/a Eversource Energy, 2020 Gas System Enhancement Program Reconciliation Filing
(Appearance: Massachusetts Attorney General’s Office – Accounting and Revenue Requirement)
Massachusetts Department of Public Utilities – DPU Docket No. 21-GREC-06
59. In Re: Joint Petition of New Jersey Natural Gas Company and Public Service Electric and Gas Company for Authorization and Approval of a Waiver of Certain Accounting Treatment Pursuant to the Clean Energy Order
(Appearance – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement.
New Jersey Board of Public Utilities – BPU Docket No. EO20030254
60. In Re: Public Service Electric and Gas Company – 2021/2022 Annual BGSS Commodity Charge Filing for its Residential Gas Customers under its Periodic Pricing Mechanism and for Changes in its Balance Charge.
(Appearance – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. GR21060878
61. In Re: Middlesex Water Company – Petition for Approval of an Increase in Rates for Water Service and Other Tariff Changes.
(Appearances – New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket No. WR21050813
62. In Re: New Jersey Natural Gas Company – Petition for an Increase in Gas Base Rates and Changes in its Tariff for Gas Service and for a Change to Depreciation Rates for Gas Property and for Approval of a Base Rate Adjustment Pursuant to the NJ RISE and SAFE II Programs.
(Appearances: New Jersey Division of Rate Counsel – Accounting and Revenue Requirement)
New Jersey Board of Public Utilities – BPU Docket Nos. GR21030679 and GR21030680.
63. In Re: PECO Energy Company – a division of Exelon Corp., for a General Base Rate Case Filing for Electric Operations
(Appearances: Accounting and Policy on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2021-3024601

PCMG and Associates LLC

64. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for Water, Wastewater and Stormwater services
(Appearance: Accounting and Policy, and Regulatory Policy on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2021-3024773 (Water) R-2021-3024774 (Wastewater) and R-2021-3024779 (Stormwater).
65. In Re: Northern States Power Company – 2021 Electric Base Rate Case Increase
(Appearance: Revenue Requirement on behalf of the Advocacy Staff of the North Dakota Public Service Commission)
North Dakota Public Service Commission – Case No. PUC-20-441
66. In Re: Public Service Electric and Gas Company – Approval of a Tax Adjustment Clause (TAC).
(Appearance; Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER20100685 and GR20100686.
67. In Re: Pike County Light and Power Company – Approval to increase base rates for Electric and Gas Service.
(Appearance: Revenue Requirement in behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2020-3022134 (Gas) and R-2020-3022135 (Electric)
68. In Re: Jersey Central Power and Light Company for Approval of JCP&L’s Energy Efficiency and Conservation Plan Including Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090620
69. In Re: Atlantic City Electric Company for Approval of an Energy Efficiency Program, Cost Recovery Mechanism, and Other Related Relief for Plan Years One Through Three.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090621
70. In Re: Rockland Electric Company for Approval of Its Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090623
71. In Re: Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charge and its Gas Green Programs Recovery Charge 2020 PSE&G Green Programs Cost Recovery filing

PCMG and Associates LLC

(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER20060467 and GR20060468

72. In Re: Public Service Electric and Gas Company's 2020/2021 Annual BGSS Commodity Charge filing for its Residential Gas Customers under its Pricing Mechanism and for Changes in its Balance Charge
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060379
73. In Re: Public Service Electric and Gas Company's 2020 Annual Margin Adjustment Clause (MAC)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060384
74. In Re: South Jersey Gas Company for Approval to Revise the Rider H Rate Associated with the Tax Cuts and Jobs Act of 2017
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060382
75. In Re: Berkshire Gas Company -2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts -Department of Public Utilities – DPU 20-GREC-02
76. In Re: Bay States Gas Company d/b/a Columbia Gas – 2019 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-05
77. In Re: NSTAR Gas Company – 2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-06
78. In Re: South Jersey Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
(Appearances: Revenue Requirement and Cash Working Capital) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. GR20030243
79. In Re: Jersey Central Power & Light Company for Review and Approval of Increased in, and Other Adjustments to Rates and Charges for Electric Services and approval of Other Proposed Tariff Revisions (Appearance: Revenue Requirement, Cash Working Capital,

PCMG and Associates LLC

Consolidated Income Taxes, LED Conversion and Reliability Roll-In) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. ER20020146

80. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for water and wastewater service and for approval of a multi-year rate plan. (Appearance: Accounting and Policy, Customer Service and Regulatory Policy) on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2020-3017951 and R-2020-3017970.
81. In Re: New Jersey-American Water Company, Inc. for approval of Increased Base Tariff Rates and Charges for Water and Wastewater Services and Other Tariff Revisions. (Appearance: Accounting and Revenue Requirement and Cash Working Capital / Consolidated Income Taxes) on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19121516
82. In Re: Hawaiian Electric Company, Inc., for approval of a General Rate Increase and Revised Rate Schedules and Rules. (Appearance: Accounting and Revenue Requirement on behalf of the Hawaiian Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2019-0085
83. In Re: Mount Olive Villages Water Company for approval of an Increase in Rates for Water Service and Other Tariff Changes. (Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060770
84. In Re: Mount Olive Villages Sewer Company for approval of an Increase in Rates for Sewer Service and Other Tariff Changes. (Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060769
85. In Re: Public Service Electric and Gas Company for approval of changes in its Electric Green Programs Recovery and its Gas Green Programs Recovery Charge (2019 PSE&G Green Programs Cost Recovery Filing). (Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER19070764 and GR19070765
86. In Re: Proposed Amendment to N.J.A.C. 14:9- Adoption by reference to the Uniform System of Accounts for Water Utilities and Wastewater Utilities. (Appearance: Consulting Services on behalf of the New Jersey Division of Rate Counsel)

PCMG and Associates LLC

New Jersey Board of Public Utilities- Docket Nos. WX19050612 (Water) and
WX19050613 (Wastewater)

87. In Re: Public Service Electric and Gas Company's 2019/2020 Annual BGSS Commodity Charge filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge.
(Appearance: Revenue Requirement and accounting/consulting services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR190600699
88. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-05
89. In Re: NSTAR Gas Company d/b/a Eversource Energy for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-06
90. In Re: Public Service Electric and Gas Company for Approval of Gas Rate Base Adjustments Pursuant to its Gas System Modernization Program (April 2019 GSMP)
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR19040522
91. In Re: Kalaeloa Water Company, LLC for Approval of General Rate Case and Revised Rules, Regulations and Rates.
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2019-0057
92. In Re: Elizabethtown Gas Company for Approval of an Increase in Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
(Appearance: Revenue Requirement and Other Accounting Issues on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – Docket No. GR19040586
93. In Re: Petition of Peoples Natural Gas Company for Approval of an Increase in Rates for Natural Gas Distribution Service.
(Appearance: Revenue Requirement and Other Accounting Issues on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2018-3006818

PCMG and Associates LLC

94. In Re: Petition of Aqua New Jersey, Inc. for Approval of an Increase in Rates for Water Service and other Tariff Changes.
(Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18121351
95. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Efficiency (CEF-EE) Program on a Regulated Basis.
(Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket Nos. GO18101112 and EO18101113.
96. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Vehicle and Energy Storage (CEF-EVES) Program on a Regulated Basis. (Appearance – Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. EO18101111.
97. In Re: Petition of New Jersey Natural Gas Company- Request for Deferred Accounting Authority for Costs Related to New Information Technology Systems. (Appearance: Impact on Revenues, prudence of costs on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GR18101096
98. In Re: Petition for Approval of An Indirect Change in Control of the New Jersey Public Utilities Subsidiaries of SUEZ Water Resources, Inc. and Other Related Approvals.
(Appearance: Impact on Rates, Service, Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WM18090982
99. In Re: The Matter of the Merger of Roxbury Water Company into New Jersey American Water Company (Appearance: Impact on Rates, Service and Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WM18080904
100. In Re: The Matter of the Application of Maryland-American Water Company for Authorization to Adjust its Existing Schedule of Tariffs and Rates.
(Appearance: Revenue Requirement on behalf of the Maryland Office of People’s Counsel)
Maryland Public Service Commission – Case No. 9487
101. In Re: The Matter of the Joint Petition for Approval of an Increase in Rates for Water and Wastewater Service and Other Tariff Changes for SUEZ Water NJ, Inc., Toms River, Inc., Arlington Hill, Inc., West Milford, Inc., Matchaponix, Inc., and Princeton Meadows, Inc.

PCMG and Associates LLC

(Appearance: Revenue Requirement and the development of Consolidated Income Taxes on behalf of the NJ Division of Rate Counsel)

New Jersey Board of Public Utilities – BPU Docket No. WR18050593

102. In Re: The Matter of the Application of Atlantic City Electric Company to Adjust the Level of its Rider RGGI Rate Associated with its Solar Renewable Energy Certificate Financing Program 2018 (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)

New Jersey Board of Public Utilities – BPU Docket No. ER18050543

103. In Re: The Matter of the Petition of New Jersey Natural Gas Company's Approval of the Cost Recovery Associated with Energy Efficiency Programs (Appearance; Revenue Requirement on behalf of the NJ Division of Rate Counsel)

New Jersey Board of Public Utilities – BPU Docket No, GR18050585

104. In Re: The Matter of Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2017 Gas System Enhancement Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy)

Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-05.

105. In Re; The Matter of NSTAR Gas Company d/b/a Eversource Energy, Gas System Enhancement Program Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy)

Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-06.

106. In Re: The Matter of the Merger of SUEZ Water NJ, SUEZ Water Toms River, SUEZ Water Arlington Hills, SUEZ Water West Milford, SUEZ Water Princeton Meadows and SUEZ Water Matchaponix (Appearance: Positive Benefits related to the Merger on behalf of the NJ Division of Rate Counsel)

New Jersey Board of Public Utilities – BPU Docket No. WR18030266

107. In Re: The Matter of the Columbia Gas of Pennsylvania for a General Rate Increase in Distribution Gas Service (Appearance; Accounting Issues and Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)

Pennsylvania Public Utility Commission – Docket No. R-2018-2647577

108. In Re: The Matter of the New Jersey Board of Public Utilities Consideration of the Tax Cuts and Jobs Act of 2017 – Generic Proceeding (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)

New Jersey Board of Public Utilities – BPU Docket No. AX18010001

109. In Re: Acquisition of Elizabethtown Gas, a Division of Pivotal Utilities Holdings, Inc. by ETG Acquisition Corp., a Division of South Jersey Industries, Inc., and Related

PCMG and Associates LLC

Transactions. (Appearance: Customer Service Issues/Employee and Labor Relations on behalf of the NJ Division of Rate Counsel)

New Jersey Board of Public Utilities – BPU Docket No. GM17121309.

110. In Re: Middlesex Water Company – Base Rate Case Proceeding for Water Service. (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. WR17101049.
111. In Re: Township of East Brunswick – Sewer Rate Study – (Evaluation of the existing sewer rate structure and examining and quantify costs for future expansion).
112. In Re: Montana-Dakota Utilities – Base Rate Case Proceeding for Gas Service. (Appearance: revenue requirement on behalf of the North Dakota Public Service Commission). NDPSC Docket No. PU-17-295.
113. In Re: Andover Utility Company – Base Rate Case Proceeding for Wastewater Services. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. WR17070726.
114. In Re: Public Service Electric and Gas Company- Approval of Changes in its Electric and Gas Green Programs Recovery Charges “2017 Public Service Electric & Gas Green Programs Cost Recovery Filing. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket Nos. ER17070724 and GR17070725.
115. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2016 Gas System Enhancement Program Reconciliation Filing, (Appearance: revenue requirement on behalf of the Massachusetts Attorney General’s Office of Ratepayer Advocacy).
Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-05.
116. In Re: NSTAR Gas Company d/b/a Eversource Energy, 2016 Gas System Enhancement Program Reconciliation Filing (Appearance: revenue requirement on behalf of the Massachusetts Attorney General’s Office of Ratepayer Advocacy).
Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-06.
117. In Re: Petition of Columbia Gas of Maryland – Increase in rates for Distribution Service – (Appearance: revenue requirement on behalf of the Office of People’s Counsel) Public Service Commission of Maryland – Case No. 9447
118. In Re: Petition of South Jersey Gas Company – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR17010071

PCMG and Associates LLC

119. In Re: Petition of UGI Penn Natural Gas – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utilities Commission Docket No. R-2016-2580030
120. In Re: Petition of PJM Interconnection, LLC. – Mid-Atlantic Interstate Transmission, LLC. Formula Rate Filing. (Appearance on behalf of the Pennsylvania Office of Consumer Advocate).
FERC Docket No. ER17-211-000
121. In Re: Petition of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company for approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. GR16090826
122. In Re: Petition of SUEZ Water New Jersey, et al – Approval of a Management and Services Agreement pursuant to N.J.S.A 48: 3-7.1 (Appearance on the reasonableness of contract agreements on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WO16080806
123. In Re: Petition of SUEZ Water Arlington Hills Inc. – Approval of an Increase in Rates for Wastewater Services and other Tariff Changes (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR16050510
124. In Re: Petition of Public Service Electric and Gas Company – 2016 Marginal Adjustment Clause (MAC) (Appearance; reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. GR16060484
125. In Re: Petition of Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charges and its Gas Green Program Recovery Charges 2016 PSEG Program Cost Recovery Filing
(Appearance: reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket Nos. ER16070613 and GR16070614
126. In Re: Petition of the Mount Olive Village Sewer Company, Inc., for Approval of an Increase in Rates for Service (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR16050391
127. In Re: Petition of the Mount Olive Village Water Company, Inc. for Approval of an Increase in Rates for Service (Appearance; revenue requirement on behalf of the New Jersey Division of Rate Counsel)

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New Jersey Board of Public Utilities Docket No. WR16050390

128. In Re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Advice to Counsel: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01
129. In Re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Appearance: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05
130. In Re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Analysis and Advice to Counsel: compliance with statutes and regulations, review of contract, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
NH Public Utilities Commission Docket No. DE 16-241
131. In Re: Central Maine Power Company, Annual Compliance Filing and Price Change (2016) - (Analysis and Advice to Counsel; tax normalization regulatory asset on behalf of the Maine Office of the Public Advocate)
ME Public Service Commission Docket No. 2016-00035
132. In Re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (Appearance: productivity adjustments/performance-based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
Alberta Utilities Commission Proceeding 20414
133. In Re: The Matter of Request by Emera Maine for Approval of a Rate Change (2016) - (Appearance: revenue requirement on behalf of the Maine Office of the Public Advocate)
Maine Public Utilities Commission Docket No. 15-00360)
134. In Re: the Matter of the Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Holdings, Inc. d/b/a Elkton Gas (2015-2016) - (Analysis and advice to counsel: customer service impacts, employee impacts, supplier diversity on behalf of the Maryland Office of People's Counsel)
MD PSC Case No. 9404
135. In Re: The Matter of the Merger of Southern Company and AGL Inc. (2015-2016) - (Appearance: customer service impacts and employee impacts on behalf of the NJ Division of Rate Counsel)
New Jersey BPU Docket No. GM15101196

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136. In Re: The Matter of the United Water New Jersey, Inc., for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2015-2016) - (Appearance: revenue requirements, rate base issues and operating income on behalf of the NJ Division of Rate Counsel)
New Jersey BPU Docket No. WR15101177
137. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-130
138. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Metro LNG, L.P.; and National Grid LNG (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-129
139. In Re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor (TIRF) Compliance Filing (2015) - (Appearance: computation of the revenue requirement impact on the TIRF on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-55
140. In Re: The Matter of the Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its Targeted Infrastructure Reinvestment Factor (TIRF) for CY 2013 (2014) - (Appearance: computation of the revenue requirement impact on the TIRF)
MA D.P.U. 14-83
141. In Re: The Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (Atlantic City Electric Company) (2014-2015) - (Appearance: customer service impacts)
New Jersey BPU Docket No. EM14060581
91. In Re: Public Utilities Commission of Ohio – In the Matter of the Application of Ohio Power Company (American Electric Power Ohio) (AEP Ohio) to Adopt a Final Implementation Plan for the Retail Stability Rider – (Appearance - Accounting Issues) (2014) on behalf of the Ohio Office of Consumer Counsel (OCC)
PUCO Case No. 14-1186-EL-RDR
92. In Re: Public Utilities Commission of Ohio - In the Matter of the Application of Aqua Ohio, Inc. to Increase its Rates and Charges for its Waterworks Service. – Revenue and Rates (2014) - (Appearance: operating income, certain rate base issues and income taxes on behalf of the Ohio Office of Consumer Counsel)
PUCO Case No. 13-2124-WW-AIR

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93. In Re: New York Public Service Commission, as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. Revenue Requirement (2013-2014) – (Appearance: revenue requirement, rate base issues and operating income on behalf of the Intervenor, the County of Westchester)
NYPSC Case Nos. 13-E-0030, 13-G-0031 and 13-S-0032, et al
94. In Re: North Dakota Public Service Commission, - Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, On-Going Revenue Requirement (2013) - (Appearance: revenue requirement and rate base, operating income, operating and maintenance expenses on behalf of the North Dakota Public Service Commission Staff)
North Dakota Case No. PU-12-813
95. In the Matter of the Petition of New Jersey American Water Company for Authorization to Implement a Distribution System Improvement Charge (DSIC) Order Denying Petition and Instituting Stakeholder Process (2008) - (Case manager on policy decision and revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WO08050358
96. In the Matter of the Joint Petition of the City of Trenton, New Jersey and New Jersey-American Water Company, Inc. for Authorization of the Purchase and Sale of the Assets of the Outside Water Utility System ("OWUS") of the City of Trenton, New Jersey and for Other Relief Order Adopting Initial Decision, (2008) - (Case manager on the revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM08010063
97. In the Matter of the Petition of United Water New Jersey, United Water Toms River, United Water Lambertville, United Water Mid-Atlantic and Gaz de France for Approval as Need for a Change in Ownership and Control (2007) - (Case manager on customer impact, employee impact and impact on rates on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM06110767
98. In the Matter of the Petition of United Water Arlington Hills Sewerage, Inc. for an Increase in Rates for Wastewater Service and Other Tariff Changes (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08100929
99. In the Matter of the Petition of United Water New Jersey Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes, (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08090710

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100. In the Matter of the Petition of United Water Toms River, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on the revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08030139
101. In the Matter of the Joint Petitioners of New Jersey-American Water Company, Inc., S.J. Services, Inc., South Jersey Water Company, Inc. and Pennsgrove Water Supply Company, Inc. for Among Other Things Approval of a Change in Control of South Jersey Water Supply Company, Inc. and Pennsgrove Water Supply Company, Inc. (2007) - (Case manager on the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM07020076
102. In the Matter of the Petition of Aqua, New Jersey, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on revenue requirement and the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR0712095
103. I/M/O the Joint Petition of Thames Water, Aqua Holdings GMBH, on Behalf of Itself and Its Parent Holdings Company, RWE Aktiengesellschaft, Thames Water Aqua US Holdings, Inc., American Water works Company Inc., Thames Water Holdings Incorporated, E 'town Corporation, New Jersey-American Water Company, Inc., Elizabethtown Water Company, the Mount Holly Water Company and Applied Wastewater Management, Inc. for Confirmation that the Board of Public Utilities Does Not Have Jurisdiction Over, or, Alternatively, for Approval of a Proposed Transaction Involving, Among Other Things, the Sale by Thames Water Aqua Holdings GMBH of Up to 100% of the Shares of the Common Stock of American Waterworks Company, Inc. in One or More Public Offerings (2007) - (Case manager on revenue requirement impacts, effect on rates and effect on service on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM06050388
104. In the Matter of the Petition of Elizabethtown Water Company for Approval of an Increase in Rates for Water Service (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR03070510
105. In the Matter of the Petition of New Jersey American Water Company, Inc. for Approval of Increased Tariff Rates and Charges for Water and Sewer Service; Increased Depreciation Rates and Other Tariff Revisions (2008) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08010020
106. In the Matter of Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes (2007) - (Case manager on overall revenue

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requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)

BPU Docket No. WR07040275

107. In the Matter of the Joint Petition of United Water New Jersey, Inc., United Water Arlington Hills, Inc., United Water Hampton, Inc., United Water Vernon Water Hills, Inc., and United Water Lambertville, Inc. for an Increase in Rates and Charges for Water Service and Other Tariff Changes and for Approval to Merge the Operations of the Joint Petitioners into and with United Water New Jersey, Inc. (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)

BPU Docket No. WR07020135

EXHIBITS

<u>REVENUE REQUIREMENT SUMMARY</u>	(1)			
	Company Proposed	Adjustments	PAOCA	References
Rate Base	\$ 3,845,381,715	\$ 38,053,763	\$ 3,883,435,478	
Rate of Return	8.55%		7.06%	
Operating Income	\$ 328,780,137	\$ (54,609,592)	\$ 274,170,545	
Operating Income at Present Rates	\$ 249,112,928	\$ 55,174,738	\$ 304,287,666	
Revenue Deficiency	\$ 79,667,209	\$ (109,784,330)	\$ (30,117,121)	
Revenue Conversion Factor	1.38697964		1.38697964	
Gross Revenue Requirement	\$ 110,496,797	\$ (152,268,630)	\$ (41,771,833)	
Current Rates	\$ 916,958,770		\$ 916,958,770	
% Increase	12.05%		-4.56%	
Prproposed Rates	\$ 1,027,455,567	\$ (152,268,630)	\$ 875,186,937	

(1) Company Exhibit 102 Sch. 3 pg 3

RATE OF RETURN

Company Proposed (1)				References
	Ratios	Cost Rate	Weighted Cost Rate	
Long-Term Debt	43.28%	5.22%	2.26%	
Short-Term Debt	2.32%	5.00%	0.12%	
Total Debt	45.60%		2.38%	
Common Equity	54.40%	11.35%	6.17%	
Total	100.00%		8.55%	

PA OCA Proposed (2)				
Long-Term Debt	47.68%	5.20%	2.5%	
Short-Term Debt	2.32%	5.00%	0.12%	
Total Debt	50.00%		2.60%	
Common Equity	50.00%	8.90%	4.5%	
Total	100.00%		7.06%	

(1) Exhibit 400 Page 5 - Rea

(2) Exhibit DJG-16

STATEMENT OF RATE BASE	(1)		FPFTY		PA OCA	References
	FTY 11/30/2025	Adjustment	12/31/2026	Adjustment		
Gas Plant In Service	\$ 4,783,387,096	\$ 436,492,629	\$ 5,219,879,725	\$ (14,507,711)	\$ 5,205,372,014	
CWIP	\$ -	\$ -	\$ -	\$ -	\$ -	
Gas Storage Underground - NC	\$ 3,794,693	\$ -	\$ 3,794,693	\$ -	\$ 3,794,693	
Depreciation Reserve	\$ (849,818,430)	\$ (77,393,668)	\$ (927,212,098)	\$ 46,038,899	\$ (881,173,199)	
Accumulated Provision Gas Lost US	\$ (163,467)	\$ -	\$ (163,467)	\$ -	\$ (163,467)	
Net Plant In Service	\$ 3,937,199,892	\$ 359,098,961	\$ 4,296,298,853	\$ 31,531,188	\$ 4,327,830,041	
Working Capital	\$ -	\$ -	\$ -			
Materials and Supplies	\$ 917,192	\$ 30,868	\$ 948,060	\$ (56,977)	\$ 891,083	Remove GDP Inf
Prepayments	\$ 5,470,802	\$ 106,749	\$ 5,577,551	\$ (262,481)	\$ 5,315,070	Remove GDP Inf
Gas Storage Underground	\$ 40,389,919	\$ 10,028,951	\$ 50,418,870	\$ -	\$ 50,418,870	OCA-9-46
Total Working Capital	\$ 46,777,913	\$ 10,166,568	\$ 56,944,481	\$ (319,457)	\$ 56,625,024	
Deferred Income Taxes						
Income Taxes - Acct. 190	\$ 36,924,536	\$ (2,766,587)	\$ 34,157,949	\$ 1	\$ 34,157,950	
Depreciation - Acct. 282	\$ (397,119,422)	\$ (12,560,751)	\$ (409,680,173)	\$ 13,116,483	\$ (396,563,690)	
Excess ADIT - Acct. 254	\$ (131,261,705)	\$ 2,485,087	\$ (128,776,618)	\$ -	\$ (128,776,619)	
Regulatory Liability Excess ADIT - Acct. 182	\$ 1,425,668	\$ (178,208)	\$ 1,247,460	\$ -	\$ 1,247,460	
Total Deferred Income Taxes	\$ (490,030,923)	\$ (13,020,459)	\$ (503,051,382)	\$ 13,116,483	\$ (489,934,899)	
Restricted Stock /LTI				\$ (719,400)	\$ (719,400)	OCA 9-9
Capitalized Profit Sharing				\$ (337,136)	\$ (337,136)	I+E RE-16
CTA				\$ (2,263,821)	\$ (2,263,821)	OCA 9-27
Capitalized Incentive				\$ (2,954,093)	\$ (2,954,093)	OCA 14-1
Total Other Adjustments				\$ (5,937,314)	\$ (6,274,450)	
Customer Deposits 13-month average	\$ (4,810,601)	\$ (2,609)	\$ (4,813,210)	\$ -	\$ (4,813,210)	
Customer Advances - Cash Deposits	\$ 2,973	\$ -	\$ 2,973	\$ -	\$ 2,973	
Total Rate Base	\$ 3,489,139,254	\$ 356,242,461	\$ 3,845,381,715	\$ 38,053,763	\$ 3,883,435,478	

(1) Exhibit 108 page 3

STATEMENT OF INCOME		(1)					
	Test Year Present Rates	Adjustments	Test Year Proposed Rates	Adjustments	Present Rates PAOCA	References	
<u>Operation Revenues</u>							
Base Rate Revenues	\$ 637,158,562	\$ 106,587,554	\$ 743,746,116				
Gas Cost Revenues	\$ 245,031,485	\$ -	\$ 245,031,485				
Rider USP	\$ 31,862,500	\$ 3,909,243	\$ 35,771,743				
Gas Procurement Charge	\$ 436,972	\$ -	\$ 436,972				
Merchant Function Charge	\$ 1,187,650	\$ -	\$ 1,187,650				
Rider CC	\$ 45,636	\$ -	\$ 45,636				
Rider EE	\$ 1,235,965		\$ 1,235,965				
Total Sales and Transportation	\$ 916,958,770	\$ 110,496,797	\$ 1,027,455,567	\$ -	\$ 916,958,770		
Off System Sales	\$ -	\$ -	\$ -		\$ -		
Late Payment Fees	\$ 1,896,259	\$ -	\$ 1,896,259	\$ -	\$ 1,896,259		
Other Operating Revenues	\$ 152,805	\$ -	\$ 152,805	\$ -	\$ 152,805		
Total Operating Revenues	\$ 919,007,834	\$ 110,496,797	\$ 1,029,504,631	\$ -	\$ 919,007,834		
		12.023%					
<u>Operating Revenue Deductions</u>							
Gas Cost Expense	\$ 245,031,485	\$ -	\$ 245,031,485	\$ -	\$ 245,031,485		
Off System Sales Expense	\$ -	\$ -	\$ -	\$ -	\$ -		
Gas Used in Co. Operations	\$ -	\$ -	\$ -	\$ -	\$ -		
O&M Expenses	\$ 222,116,320	\$ 1,487,426	\$ 223,603,746	\$ (20,223,964)	\$ 203,379,782		
Depreciation and Amortization	\$ 149,371,164	\$ -	\$ 149,371,164	\$ (46,038,863)	\$ 103,332,301		
Net Salvage Amortized	\$ 5,484,681	\$ -	\$ 5,484,681	\$ -	\$ 5,484,681		
Taxes Other Than Income	\$ 4,500,833	\$ -	\$ 4,500,833	\$ (191,398)	\$ 4,309,435		
Total O&M Revenue Deductions	\$ 626,504,483	\$ 1,487,426	\$ 627,991,909	\$ (66,454,225)	\$ 561,537,684		
Operating Income Before Income Taxes	\$ 292,503,351	\$ 109,009,371	\$ 401,512,722	\$ (44,042,572)	\$ 357,470,150		
Income Taxes	\$ 43,469,180	\$ 29,342,161	\$ 72,811,341	\$ (19,550,100)	\$ 53,261,241		
ITC	\$ (78,757)	\$ -	\$ (78,757)	\$ -	\$ (78,757)		
Operating Income	\$ 249,112,928	\$ 79,667,210	\$ 328,780,138	\$ (24,492,472)	\$ 304,287,666		
Rate Base	\$ 3,845,381,715	\$ -	\$ 3,845,381,715	\$ 38,053,763	\$ 3,883,435,478		
Rate of Return	6.4782%		8.5500%		7.06%		
			\$ 328,780,138		\$ 274,170,545		

(1) Company Exhibit 102 Sch. 3 pg 3

GAS PLANT IN SERVICE		(1)		Balance at		Balance at		PA OCA		References
		Balance at	Adjustments	11/30/2025		12/31/2026	Adjustments			
Lines 1-6	Intangible Plant	\$ 101,389,385	\$ (3,035,131)	\$ 98,354,254	\$ -	\$ 98,354,254				
Lines 7-17	Other Intangible Plant	\$ 7,614,137	\$ 514,428	\$ 8,128,565		\$ 8,218,565				
Lines 18-31	Distribution Plant	\$ 83,081,002	\$ 2,131,172	\$ 85,212,174	\$ -	\$ 85,212,174				
Lines 32-43	Other Distribution Plant	\$ 4,414,118,985	\$ 413,581,391	\$ 4,827,700,376	\$ (14,507,711)	\$ 4,813,192,665				
Lines 44-56	Other Distribution Plant	\$ 137,013,493	\$ 7,822,962	\$ 144,836,455		\$ 144,836,455				
Lines 57-65	General Plant	\$ 7,439,272	\$ (24,427)	\$ 7,414,845	\$ -	\$ 7,414,845				
Lines 66-79	Other General Plant	\$ 32,730,821	\$ 15,502,233	\$ 48,233,054		\$ 48,233,054				
Total Gas Plant In Service		\$ 4,783,387,095	\$ 436,492,628	\$ 5,219,879,723	\$ (14,507,711)	\$ 5,205,462,012				OCA 9-14, 17, 31 OCA 9-32, 33 OCA 9-28, 29, 30 OCA 9-34

(1) Exhibit 108 Shedule 1 page 6 and 13

DEPRECIATION RESERVE	(1)					
	Balance at 11/30/2025	Adjustments	Balance at 12/31/2026	Adjustments	PA OCA	References
Underground Storage	\$ 7,049,870	\$ 239,849	\$ 7,289,719	\$ -	\$ 7,289,719	
Distribution Plant	\$ 784,382,174	\$ 74,739,409	\$ 859,121,583	\$ (46,038,899)	\$ 813,082,684	
General Plant	\$ 12,741,222	\$ 1,434,585	\$ 14,175,807	\$ -	\$ 14,175,807	
Non-Depreciable Plant	\$ 235,293		\$ 235,974		\$ 235,974	
Amortizable Plant	\$ 45,409,871	\$ 979,144	\$ 46,389,015	\$ -	\$ 46,389,015	
Total Depreciation Reserve	\$ 849,583,137	\$ 77,628,961	\$ 927,212,098	\$ (46,038,899)	\$ 881,173,199	

(1) Company Exhibit 108 Schedule 3

DEFERRED INCOME TAXES	(1)					
	Balance at 11/30/2025	Adjustments	Balance at 12/31/2026	Adjustments	PA OCA	References
Account 190 - DIT						
Cap. Inventory Adj. Federal	\$ 927,911	\$ -	\$ 927,911		\$ 927,911	
Cap. Inventory Adj. - State	\$ 232,069	\$ -	\$ 232,069		\$ 232,069	
Customer Advances - Federal	\$ 317,682	\$ -	\$ 317,682		\$ 317,682	
Customer Advances - State	\$ 79,452	\$ -	\$ 79,452		\$ 79,452	
Federal Net Operating Loss	\$ 35,367,422	\$ (2,766,586)	\$ 32,600,836		\$ 32,600,836	
Total Account 190	\$ 36,924,536	\$ (2,766,586)	\$ 34,157,950	\$ -	\$ 34,157,950	
Account 282 - DIT - Depreciation						
Excess Accelerated Tax Depreciation Fed	\$ (397,119,422)	\$ (12,560,750)	\$ (409,680,172)	\$ 13,116,482	\$ (396,563,690)	
Total Account 282	\$ (397,119,422)	\$ (12,560,750)	\$ (409,680,172)	\$ 13,116,482	\$ (396,563,690)	
Account 283 - DIT Other						
Other	\$ -	\$ -	\$ -	\$ -	\$ -	
Total Account 283	\$ -	\$ -	\$ -	\$ -	\$ -	
Account 254 - Regulatory Liability Excess ADIT						
Deficient DIT - 190 NOL Inv. & Cust. Adv.	\$ 21,807,713	\$ (1,198,355)	\$ 20,609,358		\$ 20,609,358	
Excess Accelerated Tax Depr.- Fed	\$ (153,069,418)	\$ 3,683,441	\$ (149,385,977)		\$ (149,385,977)	
Total Account 254	\$ (131,261,705)	\$ (128,776,619)	\$ (128,776,619)		\$ (128,776,619)	
Account 182- Reg. Asset Deficient ADIT						
Deficient DIT - 190 Inv. & Cust. Adv.	\$ 1,425,668	\$ (178,209)	\$ 1,247,459		\$ 1,247,459	
Total Account 182	\$ 1,425,668	\$ (178,209)	\$ 1,247,459		\$ 1,247,459	
Total Accumulated Deferred Taxes	\$ (490,030,923)	\$ (13,020,459)	\$ (503,051,382)	\$ 13,116,482	\$ (489,934,900)	OCA 9-40, 41 OCA 9-38, 39, 40 OCA 9-41, 42, 43 OCA 9-45

(1) Exhibit 108 Schedule 8 page 1

OPERATING REVENUES	(1)					
	Test Year Present Rates	Adjustments	Test Year Proposed Rates	Adjustments	Present Rates PAOCA	References
Rate Schedule RSS	\$ 545,431,731	\$ 65,422,355	\$ 610,854,086			
Rate Schedule RDGSS	\$ 45,141,212	\$ -	\$ 45,141,212			
Rate Schedule SGSS	\$ 114,868,308	\$ 12,872,197	\$ 127,740,505			
Rate Schedule NSS	\$ 239,279	\$ -	\$ 239,279			
Rate Schedule LGSS	\$ 12,286,267	\$ 1,076,936	\$ 13,363,203			
Residential Distribution RDS	\$ 62,220,162	\$ 8,453,881	\$ 70,674,043			
Small Commercial Distribution SCD	\$ 36,993,449	\$ 5,124,961	\$ 42,118,410			
Small General Distribution SGDS	\$ 28,291,595	\$ 4,733,347	\$ 33,024,942			
Small Distribution SDS	\$ 37,055,677	\$ 6,510,883	\$ 43,566,560			
Large Distribution Service LDS	\$ 29,465,668	\$ 6,301,521	\$ 35,767,189			
Main Line Distribution Service MLDS	\$ 508,155	\$ -	\$ 508,155			
Main Line Distribution Service II	\$ 1,343,276	\$ -	\$ 1,343,276			
Flexible Rate / Negotiated Contract	\$ 3,113,991	\$ 644	\$ 3,114,635			
Total Base Rate Revenues	\$ 916,958,770	\$ 110,496,725	\$ 1,027,455,495		\$ 916,958,770	
Other Operating Revenue						
Forfeited Discounts	\$ 1,896,259	\$ -	\$ 1,896,259		\$ 1,896,259	
Misc. Service Revenues	\$ 107,664	\$ -	\$ 107,664		\$ 107,664	
Other Gas Revenues	\$ 45,141	\$ -	\$ 45,141		\$ 45,141	
Other	\$ -	\$ -	\$ -		\$ -	
Total Operating Revenues	\$ 919,007,834	\$ 110,496,725	\$ 1,029,504,559	\$ -	\$ 919,007,834	

(1) Company Exhibit 103 page 8 and 9

O&M EXPENSE COST ELEMENTS	(1)						PAOCA	References
	12/31/2026		12/31/2026					
	Test Year		Test Year					
	Present Rates	Adjustments	Proposed Rates	Adjustments				
Labor	\$ 38,770,674	\$ -	\$ 38,770,674	\$ (1,698,622)	\$ 37,072,052			
Incentive Compensation	\$ 2,568,808	\$ -	\$ 2,568,808	\$ (2,552,612)	\$ 16,196			
Pension	\$ -	\$ -	\$ -	\$ -	\$ -			
Pension Deferral Amortization	\$ 844,977	\$ -	\$ 844,977	\$ 0	\$ 844,977			
OPEB	\$ -	\$ -	\$ -	\$ -	\$ -			
Other Employee Benefits	\$ 8,915,459	\$ -	\$ 8,915,459	\$ (797,605)	\$ 8,117,854			
Outside Services	\$ 18,013,909	\$ -	\$ 18,013,909	\$ (1,437,457)	\$ 16,576,452			
Building Rents / Leases	\$ 734,000	\$ -	\$ 734,000	\$ -	\$ 734,000			
Other Rent and Leases	\$ 545,640	\$ -	\$ 545,640	\$ -	\$ 545,640			
Corporate Insurance	\$ 4,452,228	\$ -	\$ 4,452,228	\$ (131,774)	\$ 4,320,454			
Injury and Damages	\$ 405,057	\$ -	\$ 405,057	\$ (51,257)	\$ 353,800			
Employee Expenses	\$ 1,275,033	\$ -	\$ 1,275,033	\$ (451,550)	\$ 823,483			
Company Memberships	\$ 682,796	\$ -	\$ 682,796	\$ (258,216)	\$ 424,580			
Utilities / Company Used Gas	\$ 2,075,819	\$ -	\$ 2,075,819	\$ 28,758	\$ 2,104,577			
Advertising	\$ 391,359	\$ -	\$ 391,359	\$ 11,365	\$ 402,724			
Fleet & Other Clearing	\$ 7,518,942	\$ -	\$ 7,518,942	\$ -	\$ 7,518,942			
Materials & Supplies	\$ 6,080,827	\$ -	\$ 6,080,827	\$ (558,615)	\$ 5,522,212			
Other O&M	\$ 173,561	\$ -	\$ 173,561	\$ -	\$ 173,561			
PUC, OCA, OSBA Fees	\$ 3,299,312	\$ -	\$ 3,299,312	\$ -	\$ 3,299,312			
NCSC - Shares Services	\$ 79,191,883	\$ -	\$ 79,191,883	\$ (9,138,298)	\$ 70,053,585			
NCSC - Other	\$ -	\$ -	\$ -	\$ -	\$ -			
DEI costs - Net	\$ -	\$ -	\$ -	\$ (130,450)	\$ (130,450)	OCA-9-13		
Lobbying	\$ -	\$ -	\$ -	\$ -	\$ -			
Charitable Contributions	\$ -	\$ -	\$ -	\$ -	\$ -			
	\$ 175,940,284	\$ -	\$ 175,940,284	\$ (17,166,332)	\$ 158,773,952			
Rate Case Expenses	\$ 1,321,000	\$ -	\$ 1,321,000	\$ (182,207)	\$ 1,138,793			
Uncollectible Accounts	\$ 9,487,724	\$ 1,487,431	\$ 10,975,155	\$ (1,040,592)	\$ 9,934,563			
Uncollectible Accounts - Unbundled Gas	\$ 1,187,650	\$ -	\$ 1,187,650	\$ -	\$ 1,187,650			
COVID - 19 Amortization	\$ 708,091	\$ -	\$ 708,091	\$ -	\$ 708,091			
Rider USP	\$ 31,862,500	\$ -	\$ 31,862,500	\$ (220,000)	\$ 31,642,500			
Rider EE	\$ 1,235,965	\$ -	\$ 1,235,965	\$ -	\$ 1,235,965			
Interest on Customer Deposits	\$ 373,107	\$ -	\$ 373,107	\$ -	\$ 373,107			
Other	\$ -	\$ -	\$ -	\$ -	\$ -			
Total O&M Expenses	\$ 222,116,321	\$ 1,487,431	\$ 223,603,752	\$ (20,553,186)	\$ 203,050,565			
Additional Uncollectible Accounts					\$ (562,303)			

(1) Company Exhibit 104 Schedule 1

LABOR	(1)			
	Company Proposed	Adjustments	PA OCA	References
HTY Labor - 11/30/2024	\$ 37,521,285	\$ -	\$ 37,521,285	
HTY Labor 11/30/2024 Normalized Budget	\$ 1,191,488		\$ 1,191,488	
FTY Budget	\$ 38,712,773	\$ -	\$ 38,712,773	
Budget Adjustments FTY				
Total Labor Adjustment	\$ -	\$ -	\$ -	
Additional Headcount	\$ -	\$ -	\$ -	
Other	\$ -	\$ -	\$ -	
Total Budget Adjustments FTY	\$ -	\$ -	\$ -	
Rate Making Adjustments - FTY				
Labor Adjustment - \$931,713 *50.57%	\$ 471,184	\$ -	\$ 471,184	
Less Lobbying	\$ (12,415)		\$ (12,415)	
Total Labor Adjustment	\$ 458,769		\$ 458,769	
Budget Adjustment FPFTY				
Labor Adjustment	\$ (785,157)	\$ -	\$ (785,157)	
	\$ -	\$ -	\$ -	
Total Budget Adjustments FPFTY	\$ (785,157)	\$ -	\$ (785,157)	
Rate Making Adjustments - FPFTY				
Labor Adjustment - \$785,157 * 50.57%	\$ 397,075	\$ -	\$ 397,075	
Less Lobbying	\$ (12,787)		\$ (12,787)	
Total Labor Adjustment	\$ 384,288		\$ 384,288	
Total Labor - FPFTY	\$ 38,770,673	\$ (1,698,621)	\$ 37,072,052	OCA-9-19, 20 I&E RE-11

(1) Exhibit 104 Schedule 2 page 1
Gas RR-026 Attachment A
Vacancy Rate Ratio

4.3548%

INCENTIVE COMPENSATION	(1)			
	Company Proposed	Adjustment	PA OCA	References
HTY Balance 11/30/2024 - Normalized				
Expense	\$ 3,823,624	\$ -	\$ 3,823,624	
Capital	\$ 3,737,157		\$ 3,737,157	
Total Incentive	\$ 7,560,781		\$ 7,560,781	
Budget Adjustment FTY				
Expense	\$ 2,067,046	\$ -	\$ 2,067,046	
Capital	\$ 2,020,302		\$ 2,020,302	
Total Incentive	\$ 4,087,348		\$ 4,087,348	
Normalized FTY 11/30/2025	\$ 2,742,912		\$ 2,742,912	
Difference	\$ 1,080,712		\$ 1,080,712	
Budget Adjustment FPFTY				
Expense Adjustment	\$ 61,522	\$ -	\$ 61,522	
Capital Adjustment	\$ 60,131		\$ 60,131	
Total Budgeted Adjustment	\$ 121,653		\$ 121,653	
Ratemaking Adjustment FPFTY				
Expense Adjustment	\$ (174,105)		\$ (174,105)	
Capital Adjustment	\$ -		\$ -	
Total Ratemaking Adjustment	\$ (174,105)		\$ (174,105)	
Total Incentive Compensation FPFTY	\$ 2,568,807	\$ (1,798,165)	\$ 770,642	
Restricted Stock/LTI		\$ (754,446)	\$ (754,446)	OCA-9-9
		\$ (2,552,611)		

(1) Exhibit 104 Schedule 1 pages 2 -4
Exhibit Gas RR-026 Attachment A

PENSION / PENSION DEFERRAL AMORTIZATION	(1)				References
	Company Proposed	Adjustment	PA OCA		
2017 Pension Prepayment	\$ 8,449,772	\$ -	\$ 8,449,772		
Amortization Period	10		10		OCA 9-21
FPFTY Adjustment to Amortize	\$ 844,977	\$ -	\$ 844,977		

(1) Exhibit 104 Schedule 2 page 2

OTHER EMPLOYEE BENEFITS	(1)			References
	Company Proposed	Adjustments	PA OCA	
HTY Balance 11/30/2024	\$ 8,139,063	\$ -	\$ 8,139,063	
Profit Sharing		\$ -	\$ -	I&E RE-15
Budget Adjustment FTY	\$ 235,749	\$ -	\$ 235,749	
Subtotal	\$ 8,374,812	\$ -	\$ 8,374,812	
Profit Sharing		\$ -	\$ -	I&E RE-16
Budget Adjustment FPFTY	\$ 540,647	\$ -	\$ 540,647	
Profit Sharing		\$ (406,864)	\$ (406,864)	I&E RE-16
			\$ (390,741)	
Total Employee Benefits FPFTY	\$ 8,915,459	\$ (797,605)	\$ 8,117,854	I&E RE- 15 I&E RE-16, 17
Benefits per OCA Labor Costs		\$ 8,524,718		OCA Set 14-1
Adjustments		\$ (390,741)		

(1) Exhibit 104 Schedule 1 page 2 - 4

OUTSIDE SERVICES	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 16,852,517	\$ (1,444,261)	\$ 15,408,256		I&E RE-19
Miscellaneous Adjustment	\$ -	\$ -	\$ -		
Budgeted Adjustments FTY					
Outside Services overspend	\$ -	\$ -	\$ -		
Time Shift of work (riser and cross bore)	\$ -	\$ -	\$ -		
Meter Protection	\$ -	\$ -	\$ -		
M&R Station	\$ -	\$ -	\$ -		
GPS Work	\$ -	\$ -	\$ -		
Leak Inspection	\$ -	\$ -	\$ -		
All Other Variances	\$ -	\$ -	\$ -		
	\$ 2,286,399	\$ -	\$ 2,286,399		
Budgeted FTY Outside Services	\$ 19,138,916	\$ (1,444,261)	\$ 17,694,655		
Rate Making Adjustment FTY					
Lobbying	\$ (124,725)	\$ 3,550	\$ (121,725)		
		-2.916%			
FTY Balance 11/30/2018	\$ 19,014,191	\$ (1,441,261)	\$ 17,572,930		I&E RE-18 GAS-RR-052
Budgeted Amount FPFTY					
Adjustment	\$ (871,753)	\$ -	\$ (871,753)		
Other	\$ -	\$ -	\$ -		
Budgeted Amount FPFTY	\$ (871,753)	\$ -	\$ (871,753)		
Rate Making Amount FPFTY					
Lobbying	\$ (128,529)	\$ 3,804	\$ (124,725)		
		-3.050%			
FPFTY Balance	\$ 18,013,909	\$ (1,437,457)	\$ 16,576,452		

(1) Exhibit 104 Schedule 1 page 3-4 of 6

BUILDING RENTS / LEASES	(1)			
	Company Proposed	Adjustments	PA OCA	References
HTY Balance 11/30/2024	\$ 727,583			
Budget Adjustment FTY	\$ 39,662			
Balance	\$ 767,245	\$ -	\$ 767,245	
Rate Making Adjustment FTY	\$ (18,755)	\$ -	\$ (18,755)	
Budget Adjustment FPFTY	\$ 748,490		\$ 748,490	
Budget Adjustment	\$ (32,195)	\$ -	\$ (32,195)	
Rate Making Adjustment FPFTY	\$ 17,705	\$ -	\$ 17,705	
FPFTY Balance	\$ 734,000	\$ -	\$ 734,000	

(1) Exhibit 104 Schedule 1 pages 3-4 of 6

OTHER RENT AND LEASES	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 475,203	\$ -	\$ 475,203		I&E RE-21
Budget Adjustment FTY	\$ 71,365	\$ -	\$ 71,365		
Rate Making Adjustment FTY	\$ -	\$ -	\$ -		
Budget Adjustment FPFTY	\$ (928)	\$ -	\$ (928)		
Rate Making Adjustment FPFTY	\$ -	\$ -	\$ -		
FPFTY Balance	\$ 545,640	\$ -	\$ 545,640		OCA Set 14-2

(1) Exhibit 104 Schedule 1 pages 3-4 of 6

<u>CORPORATE INSURANCE</u>	(1)			
	Company Proposed	Adjustments	PA OCA	References
HTY Balance 11/30/2024	\$ 4,320,454	\$ (131,774) -3.05%	\$ 4,188,680	
Budget Adjustments FTY	\$ 471,340	\$ -	\$ 471,340	
Rate Making Adjustment FTY	\$ (471,340)	\$ -	\$ (471,340)	
Budget Adjustment FPFTY	\$ 612,949	\$ -	\$ 612,949	
Rate Making Adjustment FPFTY	\$ (481,175)	\$ -	\$ (481,175)	
FPFTY Balance	\$ 4,452,228	\$ (131,774)	\$ 4,320,454	

- (1) Exhibit 104 Schedule 1
Exhibit 104 Schedule 2 page 7
Exhibit 4 Schedule 2

INJURY AND DAMAGES	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 381,879	\$ (28,079)	\$ 353,800		OCA-Set 9-22
Budget Adjustment FTY	\$ (219,455)	\$ -	\$ (219,455)		
Rate Making Adjustment FTY	\$ 230,644	\$ (11,189) -2.93%	\$ 219,455		
Budget Adjustment FPFTY	\$ (256,520)	\$ -	\$ (256,520)		
Rate Making Adjustment FPFTY	\$ 268,509	\$ (11,989) -3.05%	\$ 256,520		
FPFTY Balance	\$ 405,057	\$ (51,257)	\$ 353,800		

(1) Exhibit 104 Schedule 1 pages 3-4 of 6

EMPLOYEE EXPENSES	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 1,257,246	\$ (462,912)	\$ 794,334		
Budget Adjustment FTY	\$ 210,401	\$ -	\$ 210,401		
Rate Making Adjustment FTY	\$ (192,677)	\$ 5,485	\$ (187,192)		
		2.93%			
Budget Adjustment FPFTY	\$ 198,617	\$ -	\$ 198,617		
Rate Making Adjustment FPFTY	\$ (198,554)	\$ 5,877	\$ (192,677)		
		-3.05%			
FPFTY Balance	\$ 1,275,033	\$ (451,550)	\$ 823,483		I&E RE-28/29 OCA Set 14-3

(1) Exhibit 104 Schedule 1 pages 3-4 of 6

COMPANY MEMBERSHIPS	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 668,085	\$ (260,661)	\$ 407,424		GAS-RR-032
Budget Adjustments FTY	\$ 61,826	\$ -	\$ 61,826		
Rate Making Adjustment FTY	\$ (41,430)	\$ 3,343	\$ (40,250)		
		0.0296%			
Budget Adjustments FPFTY	\$ 37,010	\$ -	\$ 37,010		
Rate Making Adjustment FPFTY	\$ (42,694)	\$ 3,445	\$ (41,430)		
		3.051%			
FPFTY Balance	\$ 682,797	\$ (258,217)	\$ 424,580		I&E RE-30

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
See Exhibit 4 Schedule 2 page 13

UTILITIES AND FUEL USED IN COMPANY OPERATIONS	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 2,573,883	\$ -	\$ 2,573,883		
Budget Adjustment FTY	\$ (17,931)	\$ -	\$ (17,931)		
Rate Making Adjustment	\$ (487,713)	\$ 13,883 2.93%	\$ (473,830)		
Budget Adjustment FPFTY	\$ 510,168	\$ -	\$ 510,168		
Rate Making Adjustment FPFTY	\$ (502,588)	\$ 14,875 -3.05%	\$ (487,713)		
FPFTY Balance	\$ 2,075,819	\$ 28,758	\$ 2,104,577		I&E RE-31

- (1) Exhibit 104 Schedule 1 pages 3-4 of 6
Exhibit 104 Schedule 2 page 10

ADVERTISING	(1)				
	Company Proposed	Adjustment	PA OCA	References	
HTY Balance 11/30/2024	\$ 505,077	\$ -	\$ 505,077	I&E RE 033	
Budget Adjustment FTY	\$ 85,275	\$ -	\$ 85,275		
Rate Making Adjustment FTY	\$ (192,762)	\$ 5,487	\$ (187,275)	2.93%	
Budget Adjustment FPFTY	\$ 192,409	\$ -	\$ 192,409		
Rate Making Adjustment FPFTY	\$ (198,641)	\$ 5,879	\$ (192,762)	-3.05%	
FPFTY Balance	\$ 391,358	\$ 11,366	\$ 402,724		

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
Exhibit 4 Schedule 8

FLEET AND OTHER CLEARING	(1)				
	Company Proposed	Adjustment	PA OCA	References	
HTY Balance 11/30/2024	\$ 8,851,664	\$ -	\$ 8,851,664	I&E RE-34	
Budget Adjustment FTY	\$ (1,103,686)	\$ -	\$ (1,103,686)		
Rate Making Adjustment FTY	\$ -	\$ -	\$ -		
Budget Adjustment FPFTY	\$ (229,036)	\$ -	\$ (229,036)		
Rate Making Adjustment FPFTY	\$ -	\$ -	\$ -		
FPFTY Balance	\$ 7,518,942	\$ -	\$ 7,518,942	OCA-Set 14- 4	

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
Check discovery

<u>MATERIALS AND SUPPLIES</u>	(1)				References
	Company Proposed	Adjustment	PA OCA		
HTY Balance 11/30/2024	\$ 7,622,402	\$ (558,615)	\$ 7,063,787		I&E RE-35
Budget Adjustment FTY	\$ (1,093,275)	\$ -	\$ (1,093,275)		
Rate Making Adjustment FTY	\$ (3,343)	\$ -	\$ (3,343)		
Budget Adjustment FPFTY	\$ (441,512)	\$ -	\$ (441,512)		
Rate Making Adjustment FPFTY	\$ (3,445)	\$ -	\$ (3,445)		
FPFTY	\$ 6,080,827	\$ (558,615)	\$ 5,522,212		OCA-Set-14-5

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
See Discovery Responses

OTHER O&M	(1)				References
	Company Proposed	Adjustment	PA OCA		
HTY Balance 11/30/2024	\$ 113,347	\$ -	\$ 113,347		I&E RE-36
Budget Adjustment FTY	\$ 448,433	\$ -	\$ 448,433		
Rate Making Adjustment FTY	\$ -	\$ -	\$ -		
Budget Adjustment FPFTY	\$ (388,219)	\$ -	\$ (388,219)		
Rate Making Adjustment FPFTY	\$ -	\$ -	\$ -		
FPFTY Balance	\$ 173,561	\$ -	\$ 173,561		OCA-Set-14-6

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
See Discovery Responses

PUC OCA OSBA FEES	(1)			
	Company Proposed	Adjustment	PA OCA	References
HTY Balance 11/30/2024				
PUC Assessment	\$ 2,931,893	\$ -	\$ 2,931,893	
OCA Assessment	\$ 303,059	\$ -	\$ 303,059	
OSBA Assessment	\$ 64,360	\$ -	\$ 64,360	
	\$ 3,299,312	\$ -	\$ 3,299,312	
Budget Adjustment FTY	\$ -	\$ -	\$ -	
Rate Making Adjustment FTY	\$ -	\$ -	\$ -	
Budget Adjustment FPFTY	\$ -	\$ -	\$ -	
Rate Making Adjustment FPFTY	\$ -	\$ -	\$ -	
FPFTY Balance	\$ 3,299,312	\$ -	\$ 3,299,312	

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
Exhibit 4 Schedule 2 Page 18

NCSC-SHARED SERVICES		(1)			
	Company	Adjustment	PA OCA	References	
	Proposed				
HTY Balance 11/30/2024	\$ 81,633,879	\$ -	\$ 81,633,879		
Budget Adjustments 11/30/2025	\$ 929,824		\$ 929,824		
Rate Making Adjustments 11/30/2025	\$ (309,385)	\$ 14,731	\$ (294,654)		
		2.93%			
FTY Balance adjusted 11/30/2025	\$ 82,254,318	\$ 14,731	\$ 82,269,049		I&E RE-38
Budget Adjustments					
Labor /Benefits/Incentive Comp	\$ -	\$ -	\$ -		
External Services	\$ -	\$ -	\$ -		
Other O&M Expense	\$ -	\$ -	\$ -		
Depreciation, Other Taxes	\$ -	\$ -	\$ -		
All Other Adjustments	\$ -	\$ -	\$ -		
Total Budget Adjustments	\$ (2,680,225)		\$ (2,680,225)		
Budget Adjustments FPFTY	\$ 79,574,093	\$ 14,731	\$ 79,588,824		
Ratemaking Adjustments					
Labor/Benefits/Incentive Comp	\$ -	\$ -	\$ -		
External Services	\$ -	\$ -	\$ -		
Other O&M Expenses	\$ -	\$ -	\$ -		
Depreciation, Other Taxes	\$ -	\$ -	\$ -		
All Other Adjustments	\$ -	\$ -	\$ -		
FPFTY Ratemaking Adjusments	\$ (382,209)	\$ 15,783	\$ (366,426)		
		3.05%			
FPFTY Balance	\$ 79,191,884	\$ (9,138,299)	\$ 70,053,585		OCA Set-14-7
Resticted Stock/LTI		\$ (4,012,229)	\$ (4,012,229)		OCA 9-9
SERP		\$ (136,102)	\$ (136,102)		OCA 9-10
Discretionary Bonuses		\$ (105,630)	\$ (105,630)		OCA 14-7
		\$ (4,253,961)			
Oher Incentive Compensation		\$ (4,884,338)			OCA-14-9 OCA-14-8

(1) Exhibit 104 Schedule 1 pages 3-4 of 6

(2) Exhibit 4 Schedule 2 page 17

RATE CASE EXPENSES	(1)				References
	Company Proposed	Adjustments	PA OCA		
Gannett Fleming	\$ 60,000				
Regulatory Finance Associates	\$ 90,000				
Atrium Economics	\$ 276,000				
Post and Schell	\$ 750,000				
Green Efficiency Group	\$ 60,000				
Legal Notices	\$ 55,000				
Travel Expenses	\$ 5,000				
Miscellaneous	\$ 25,000				
Total	\$ 1,321,000	\$ -	\$ 1,321,000		
Amortization Period	1.0		1.2		
FPFTY Total	\$ 1,321,000	\$ (182,207)	\$ 1,138,793		OCA-9-24

(1) Exhibit 104 Schedule 2 page 16

UNCOLLECTIBLES	(1)				
	Company Proposed	Adjustments	PA OCA	References	
HTY Balance 11/30/2024					
Base Rate Uncollectibles	\$ 9,459,959	\$ -	\$ 9,459,959		
Unbundled Uncollectibles	\$ 1,169,096	\$ -	\$ 1,169,096		
FTY Adjustment 11/30/2025					
Base Rate Uncollectibles (2)	\$ 26,770	\$ -	\$ 26,770		
Unbundled Uncollectibles (2)	\$ 11,865	\$ -	\$ 11,865		
FPFTY Adjustment 12/31/2026					
Base Rate Uncollectibles	\$ 995	\$ -	\$ 995		
Unbundled Uncollectibles	\$ 6,689	\$ -	\$ 6,689		
FPFTYP Proforma Balance 12/31/2026					
Base Rate Uncollectible	\$ 9,487,724		\$ 9,487,724		
Unbundled Uncollectible	\$ 1,187,650		\$ 1,187,650		
Total	\$ 10,675,374		\$ 10,675,374		
Base Rate			\$ (41,771,833)		
			0.01346130	OCA 14-10	
			\$ (562,303)		
Unbundled					

- (1) Exhibit 104 Schedule 1 page 3
(2) Exhibit 104 Schedule 2 page 17
Review Uncollectible testimony

COVID-19 AMORTIZATION				
	(1)			
	Company			
	Proposed	Adjustment	PA OCA	References
FPFTY Balance 12/31/2026	\$ 2,832,363	\$ -	\$ 2,832,363	
Amortization Period	4	0	4	
Annual Amortization	\$ 708,091	\$ -	\$ 708,091	OCA-9-23

(1) Exhibit 104 Schedule 2 page 18

RIDER USP					References
RIDER EE					
	(1) Company Proposed	Adjustment	PA OCA		
Rider USP					
HTY Balance	\$ 31,769,765				
Adjustment	\$ 75,397				
FTY Balance	\$ 31,845,162				
Adjustment	\$ 17,338				
FPFTY Balance	\$ 31,862,500	\$ (220,000)	\$ 31,642,500		OCA-Set 8-1
Rider EE					
HTY Balance	\$ 1,232,368				
Adjustment	\$ 2,925				
FTY Balance	\$ 1,235,293				
Adjustment	\$ 672				
FPFTY Balance	\$ 1,235,965		\$ 1,235,965		

(1) Company Exhibit 104 Schedule 2 page 19

DEPRECIATION / AMORTIZATION EXPENSE		(1)				
		COMPANY PROPOSED				
Account No.		Original Cost	Rate	Expense	Adjustments	PA OCA
	FPFTY Balance					
350.2-355.0	Underground Storage	\$ 8,104,684	2.5300%	\$ 205,049	\$ -	\$ 205,049
	Distribution Plant					
	Land and Land Rights (374)	\$ 14,597,875	1.4971%	\$ 218,546		
	Structures and Improvements (375)	\$ 60,955,315	2.5651%	\$ 1,563,556		
	Mains (376)	\$ 3,557,111,302	2.2953%	\$ 81,645,103	\$ (236,476)	
	Meas & Reg Equip (378-379)	\$ 198,071,623	3.2366%	\$ 6,410,749		
	Services (380)	\$ 1,012,853,468	3.2344%	\$ 32,759,583		
	Meters (381)	\$ 59,663,983	2.6405%	\$ 1,575,424		
	Meters AMR (381)	\$ 29,057,053	2.6172%	\$ 760,481		
	Meter Installations (382)	\$ 58,083,634	1.9382%	\$ 1,125,750		
	House Regulators (383)	\$ 22,247,918	2.0720%	\$ 460,972		
	House Regulator Installations (384)	\$ 3,546,998	1.2812%	\$ 45,444		
	Industry Meas & Reg Equip Other (385)	\$ 10,750,260	4.7393%	\$ 509,488		
	Other General (387)	\$ 21,150,593	4.5644%	\$ 965,399		
	Other CIS (387)	\$ -	0.0000%	\$ -		
	GPS Equip (387)	\$ -	0.0000%	\$ -		
	Total Distribution Plant	\$ 5,048,090,022		\$ 128,040,495	\$ (236,476)	\$ 127,804,019
	General Plant					
	Structures -Improvements (390)	\$ 49,821	0.0000%	\$ -		
	Office Furn & Fix (391)	\$ 7,339,407	4.9340%	\$ 362,125		
	Transportation (392)	\$ 25,617	0.0000%	\$ -		
	Tools, Shop & Garage (394)	\$ 39,447,764	3.9961%	\$ 1,576,376		
	Laboratory (395)	\$ 264,921	5.4012%	\$ 14,309		
	Power Operated Equip (396)	\$ 948,698	0.0000%	\$ -		
	Communication-Telemetry (397)	\$ 6,391,394	6.5711%	\$ 419,983		
	Misc (398)	\$ 1,180,276	6.0408%	\$ 71,298		
	Total General Plant	\$ 55,647,898		\$ 2,444,091		\$ 2,444,091
	Subtotal	\$ 5,111,842,604		\$ 130,689,635	\$ (236,475)	\$ 130,453,159
	D. Garrett Recommendation				\$ (45,802,423)	\$ 84,650,736
303.0-375.71	Amortizable Plant	\$ 104,503,946	17.8764%	\$ 18,681,565		\$ 18,681,565
	Non Depreciable Plant	\$ 3,533,173				
	Total Gas Plant	\$ 5,219,879,723		\$ 149,371,200	\$ (46,038,898)	\$ 103,332,301 (2)
	Five Year Amortization of NNS			\$ 5,484,681	\$ -	\$ 5,484,681

(1) Exhibit 105 pages 7-10

(2) Exhibit DJG-17

<u>TAXES OTHER THAN INCOME</u>	(1)				References
	Company Proposed	Adjustment	PA OCA		
FICA	\$ 2,986,116	\$ (187,573)	\$ 2,798,543	(3)	
FUTA & SUTA	\$ 97,544	\$ -	\$ 97,544		
Property Taxes	\$ 1,372,160	\$ (3,824)	\$ 1,368,336	(2)	
Capital Stock	\$ -	\$ -	\$ -		
License and Franchise	\$ -	\$ -	\$ -		
Sales and Use	\$ 37,943	\$ -	\$ 37,943		
Other	\$ 7,069	\$ -	\$ 7,069		
Total	\$ 4,500,832	\$ (191,397)	\$ 4,309,435		OCA-Set 14-11

(1) Exhibit 106 Schedule 2 page 2

(2)

(3) Recommended Labor and Incentive
Compensation times FICA Factor of
7.39520%

FEDERAL AND STATE INCOME TAX	(1)		(2)			
	Company Proposed					
	FPFTY Current Rates	Adjustments	FPFTY Proposed Rates	Adjustments	PA OCA Current Rates	References
Operating Revenues	\$ 919,007,834	\$ 110,496,797	\$ 1,029,504,631		\$ 919,007,834	
Net Gas Purchased for Resale	\$ (245,031,485)	\$ -	\$ (245,031,485)	\$ -	\$ (245,031,485)	
Operation & Maintenance Expense	\$ (222,116,320)	\$ (1,487,426)	\$ (223,603,746)	\$ 20,223,964	\$ (203,379,782)	
Depreciation and Amortization Expense	\$ (154,855,845)	\$ -	\$ (154,855,845)	\$ 46,038,863	\$ (108,816,982)	
Taxes Other Than Income	\$ (4,500,833)	\$ -	\$ (4,500,833)	\$ 191,398	\$ (4,309,435)	
Net Operating Income Before IT	\$ 292,503,351	\$ 109,009,371	\$ 401,512,722	\$ (44,042,572)	\$ 357,470,150	
Other Income and Charges	\$ -	\$ -	\$ -		\$ -	
Net Income Before IT	\$ 292,503,351	\$ 109,009,371	\$ 401,512,722	\$ (44,042,572)	\$ 357,470,150	
Statutory Adjustments						
Interest on Debt	\$ (91,366,270)	\$ -	\$ (91,366,270)	\$ 9,422,861	\$ (100,789,131)	
Employee Business Expense	\$ 330,313	\$ -	\$ 330,313	\$ -	\$ 330,313	
Employee Stock Purchase Plan	\$ 50,885	\$ -	\$ 50,885	\$ -	\$ 50,885	
Parking	\$ 21,792	\$ -	\$ 21,792	\$ -	\$ 21,792	
Total Flow Through Adjustments	\$ (90,963,280)	\$ -	\$ (90,963,280)	\$ 9,422,861	\$ (100,386,141)	
Deferred Adjustments						
Excess Tax Depreciation Over Book	\$ (35,165,499)		\$ (35,165,499)	\$ 48,400,164	\$ 13,234,665	OCA-Set 14-12
Repairs on Gas Pipeline	\$ (95,267,133)		\$ (95,267,133)		\$ (95,267,133)	OCA-Set-14-12
Sec. 263 Mixed Service Costs	\$ (1,819,238)		\$ (1,819,238)		\$ (1,819,238)	OCA Set 14-14
Loss on Retire. ACRS/MACRS Prop Basis	\$ -		\$ -			OCA-Set 9-44
CIAC	\$ -		\$ -			
Total Deferred Adjustments	\$ (132,251,870)		\$ (132,251,870)	\$ 48,400,164	\$ (83,851,706)	OCA Set 9-42
TOTAL STATUTORY ADJUSTMENTS	\$ (223,215,150)		\$ (223,215,150)	\$ 38,977,303	\$ (184,237,847)	OCA-Set 9-43 OCA-Set 9-41
PA Bonus Depr. Adj.	\$ (7,704,734)		\$ (7,704,734)	\$ 48,400,164	\$ 40,695,430	
Taxable Income	\$ 61,583,467		\$ 170,592,838	\$ 43,334,895	\$ 213,927,733	
Deductible State Income Tax	\$ (4,612,602)	\$ (8,164,802)	\$ (12,777,404)	\$ (3,245,784)	\$ (16,023,187)	
Taxable Income	\$ 64,675,600	\$ 100,844,569	\$ 165,520,168	\$ (8,311,053)	\$ 157,209,116	
Federal Income Tax @ 21%	\$ 13,581,876	\$ 21,177,360	\$ 34,759,235	\$ (1,745,321)	\$ 33,013,914	
Deferred Income Tax @21%	\$ (27,772,893)	\$ -	\$ (27,772,893)	\$ (10,917,055)	\$ (38,689,948)	
Tax Refund Amortization	\$ -	\$ -	\$ -		\$ -	
Flow Back of Excess DIT	\$ (2,498,191)	\$ -	\$ (2,498,191)	\$ -	\$ (2,498,191)	
Effect of CBIT DIT	\$ -	\$ -	\$ -	\$ -	\$ -	
Total FIT Expense	\$ (38,856,578)	\$ 21,177,360	\$ (60,033,937)	\$ (9,171,734)	\$ (69,205,671)	
Amortization of ITC	\$ (78,757)	\$ -	\$ (78,757)	\$ -	\$ (78,757)	
Net FIT Expense	\$ (38,777,821)	\$ 21,177,360	\$ (60,112,694)	\$ (9,171,734)	\$ (69,284,428)	
State Income Tax	\$ 4,612,602	\$ 8,164,802	\$ 12,777,404	\$ 3,245,784	\$ 16,023,187	
Total Income Tax Expense	\$ (43,390,422)	\$ 29,342,161	\$ (72,890,098)	\$ 19,628,857	\$ (53,261,241)	
			\$ (72,811,341)	\$ 19,628,857	\$ (53,182,484)	
Exhibit 107						
Rate Base times Cost of Debt	\$ 100,789,131					
Company Proposed	\$ (91,366,270)					
Adjustment	\$ 9,422,861					

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

Columbia Gas of Pennsylvania, Inc.

:
:
:
:
:
:
:

Docket No. R-2025-3053499

VERIFICATION

I, Dante Mugrace, hereby state that the facts above set forth in my Direct Testimony, OCA Confidential Statement 2, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 18, 2025

Signature: /s/ Dante Mugrace
Dante Mugrace

Address: 22 Brooks Avenue,
Gaithersburg, MD 20877

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2025-3053499
Columbia Gas of Pennsylvania, Inc.	)	

SURREBUTTAL TESTIMONY OF

DANTE MUGRACE

**ON BEHALF OF THE
PENNSYLVANIA
OFFICE OF CONSUMER ADVOCATE**

July 31, 2025

TABLE OF CONTENTS

	<u>PAGE</u>
I. PURPOSE OF TESTIMONY	1
II. REVENUE REQUIREMENT ISSUES	
A. Rate Base - Utility Plant in Service	5
B. Deferred Income Taxes	6
C. Material &Supplies/Prepayments	8
D. Consolidated Income Tax Adjustment	9
E. OPERATING INCOME	
1. OPERATING AND MAINTENANCE EXPENSES	
a. Labor/Vacancy Rate	10
b. Incentive Compensation	11
c. Other Employee Benefits	14
d. Outside Services	15
e. Employee Expenses	16
f. Company Memberships	16
g. Materials and Supplies	17
h. NCSC-Shared Services	18
i. Rate Case Expenses	23
j. Uncollectible Expense	24
k. Rider UPS	25
2. DEPRECIATION	25
3. TAXES OTHER THAN INCOME	26
4. INCOME TAXES	27

1 **I. PURPOSE OF SURREBUTTAL TESTIMONY**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 **A.** My name is Dante Mugrace. My business address is 22 Brooks Avenue, Gaithersburg, MD
4 20877.

5 **Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS DOCKET?**

6 **A.** Yes. I submitted Direct Testimony on June 18, 2025, which was marked as OCA Statement
7 No. 2. My qualifications and experience are attached to my Direct Testimony.

8 **Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?**

9 **A.** The purpose of my Surrebuttal Testimony is to address the Rebuttal Testimonies of
10 Company witnesses Vassalotti, Brumley, Harding, Covert, Hunter, Kempic and Leal. I am
11 also making certain adjustments to proposals in my direct testimony and a revised
12 calculation of the Company's revenue requirement that incorporates the effects of my
13 adjustments. To the extent that I do not respond to or address a particular issue or
14 argument, I defer to my direct testimony on those issues.

15 **Q. HAS THE COMPANY UPDATED ITS REVENUE REQUIREMENT PROPOSAL?**

16 **A.** Yes. In Company witness Mr. Vassalotti rebuttal testimony (Statement No. 4-R, at 5) Mr.
17 Vassalotti updated the Company's revenue requirement from the as filed request of
18 \$110,496,797 to \$110,444,676 a reduction of \$52,121. Mr. Vassalotti stated the updated
19 revenue deficiency and revenue requirement was supported by the incorporation of the
20 Company's recent sale of the Blackhawk Storage facility ("Blackhawk"). Company
21 witness Ms. Covert stated that the Company completed the sale of the Blackhawk facility
22 on June 20, 2025. (Statement No. 11-R at 4). Mr. Vassalotti stated that the Company is
23 proposing to establish a regulatory asset to defer and amortize the non-depreciable loss on
24 the sale of the Blackhawk assets of \$5,031,739 and the expenses related to the feasibility
25 study of \$389,005 for a total amount of \$5,420,743 to be amortized over a period of 5-
26 years, or \$1,084,149 per year. (Statement No. 4-R at 9).

1 **Q. WHAT DID COMPANY WITNESS MR. KEMPIC STATE REGARDING THE**
2 **SALE OF THE BLACKHAWK FACILITY?**

3 **A.** Mr. Kempic stated that on June 30, 2025 the Company closed the sale transaction on the
4 Blackhawk facility as it is no longer required in providing service to customers. (Kempic
5 Statement 1-R at 22). The Company received Commission approval for the sale on April
6 24, 2025 in Docket No. A-2025-3053161 (Kempic Statement 1-R at 22). The Company
7 undertook a feasibility study to determine if opportunities exist to repurpose Blackhawk.
8 The feasibility study concluded that additional research and cost would be necessary to
9 determine whether additional investment would be required to repurpose Blackhawk.
10 Columbia determined to pursue the sale of the Blackhawk facility rather than direct
11 additional resources into researching options to repurpose the facility. (Statement 1-R at
12 23). Mr. Kempic stated that the sale of Blackhawk will benefit customers because
13 compliance costs of about \$250,000 will not be recovered from customers and the
14 Company will avoid capital expenditures of about \$2 million for continued operations and
15 about \$5 million to \$8 million to retire the facility. (Kempic Statement 1-R at 24).

16 **Q. HOW DID THE COMPANY REFLECT THE SALE OF BLACKHAWK?**

17 **A.** Mr. Kempic stated that the Company removed the pipelines and other appurtenances and
18 equipment from the Company's rate base and made several adjustments to the exhibits. As
19 stated by Mr. Vassalotti above the revenue requirement adjustment is a decrease of
20 \$52,121. The Company has proposed to recover the loss on the sale and other associated
21 costs in rates. (Statement No. 1-R at 25). Ms. Harding adjusted the sale of the Blackhawk
22 facility by removing the accumulated deferred income tax of \$253,547 related to the assets
23 of \$253,547. This is comprised of capitalized inventory of gas of (\$33,794) and the removal
24 of the deferred tax liability for the excess book/tax depreciation of \$287,341. (Statement
25 No. 10-R at 6). Company witness Mr. Leal stated that the O&M Expenses associated with
26 the sale of the Blackhawk facilities will be reduced by \$225,593 which are related to labor,
27 materials, outside services and other O&M. (Statement No. 18-R at 16-17).

1 **Q. DOES YOUR SURREBUTTAL TESTIMONY RECOMMENDATIONS INCLUDE**
2 **ANY ADJUSTMENTS TO MR. VASSALOTTI'S UPDATED REVENUE**
3 **REQUIREMENT ADJUSTMENT OF THE \$52,121 REDUTION?**

4 **A.** No. The revenue requirement adjustments addressed above by the Company witnesses
5 related to rate base adjustments and O&M expense adjustments calculate to an overall
6 reduction in revenue requirement of \$51,121. This adjustment is de minimis and will not
7 likely have any substantial impact or effect on my adjustments contained in my surrebuttal
8 testimony.

9 **Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S**
10 **POSITION ON CREATING A REGULATORY ASSET TO RECOVER THE**
11 **COSTS RELATED TO THE SALE OF THE BLACKHAWK FACILITY?**

12 **A.** Given that the Commission has approved the sale of the Blackhawk facility, I am accepting
13 the Company's proposal to establish a regulatory asset (Blackhawk Regulatory Asset) to
14 defer and amortize the non-depreciable loss on the sale of \$5,031,739 and the expenses
15 related to the feasibility study of \$389,005 for a total amount of \$5,420,743 to be amortized
16 over a five-year period, or \$1,084,149 per year.

17 **Q. DOES YOUR SURREBUTTAL TESTIMONY CORRECT THE ERRORS AND**
18 **ADJUSTMENTS IN YOUR DIRECT TESTIMONY AS TESTIFIED TO BY THE**
19 **COMPANY'S WITNESSES?**

20 **A.** Yes. My surrebuttal testimony incorporates the corrections to errors and adjustments that I
21 had in my direct testimony.

22 **Q. WITH YOUR ADJUSTMENTS TO YOUR DIRECT TESTIMONY, WHAT IS**
23 **YOUR REVISED COMPANY REVENUE REQUIREMENT?**

24 **A.** With my revised adjustments, I have calculated a revenue requirement decrease of
25 \$36,316,933 or -3.96% over current rates of \$919,007,834. (See Revised Exhibits -DM-
26 SR attached). This includes OCA Witness Mr. Garrett's overall rate of return of 7.06%
27 which includes a common equity component of 8.90%.

1 **Q. WHAT REVENUE DEFICIENCIES OR ADJUSTMENTS ARE YOU**
2 **RECOMMENDING?**

3 **A.** Based upon the use of the Company's proposed fully projected future test year ending
4 December 31, 2026, I have the following Surrebuttal recommendations:

- 5 • My recommended Rate Base balance is \$3,861,622,942 which is \$16,241,227 higher
6 than the Company's proposed Rate Base balance of \$3,845,381,715.
- 7 • My overall Rate of Return is based upon OCA witness Mr. Garrett's recommendation
8 of 7.06%, which includes a Common Equity component of 8.90%. This incorporates
9 a Long-Term Debt ratio of 47.68%, a Short-Term Debt ratio of 2.32% and a Common
10 Equity ratio of 50%.
- 11 • My recommended Rate of Return on Rate Base is \$272,630,580, which is \$56,149,557
12 lower than the Company's Rate of Return on Rate Base of \$328,780,137.
- 13 • My recommended Operating Revenue at Present Rates is computed at \$919,077,834
14 which is the same as Company's Present Rate Revenue of \$919,077,833.
- 15 • My recommended total for Operating Expenses is \$565,003,970, which is \$62,987,939
16 lower than the Company's proposed Operating Expenses of \$627,991,908.
- 17 • My recommended Income Tax expense is \$55,267,855, which is \$17,543,486 lower
18 than the Company's proposed Income Taxes of \$72,811,341. I have accepted the
19 Company's Proposed Investment Tax Credit of (\$78,757).
- 20 • Overall, I recommend a revenue requirement decrease of \$36,316,933 which is
21 \$146,813,730 lower than the Company's proposed revenue requirement increase of
22 \$110,496,797.

1 **II. REVENUE REQUIREMENT ISSUES**

2 **A. Rate Base – Utility Plant in Service**

3 **Q. WHAT HAS THE COMPANY STATED REGARDING YOUR DISALLOWANCE**
4 **OF INFLATION ADJUSTMENTS TO CALCULATED THE UTILITY PLANT IN**
5 **SERVICE BALANCE?**

6 **A.** Company witness Mr. Brumley stated that he did not agree with my adjustments to the
7 Company's projected capital expenditures for 2025 and 2026 by reducing the costs related
8 to inflation adjustments of 4% in 2025 and 5% in 2026. (Brumley Statement No. 7-R at 2-
9 3). Mr. Brumley stated the Company has seen an increased average per unit costs of main
10 replacement over the years. Mr. Brumley states that Columbia has seen an average increase
11 of 7% over the last five years. (Statement No. 7-R at 3). Mr. Brumley stated that the
12 increase in projections for overall unit costs of 4% and 5% for years 2025 and 2026 are
13 reasonable and appropriate. (Statement No. 7-R at 3). Mr. Brumley then stated that the
14 Company has historically spent its capital expenditure replacement budget and if actual
15 units costs are less than budgeted the Company identifies additional replacement work to
16 spend the budget. (Statement No. 7-R at 3-4). Mr. Brumley stated that each year the
17 Company files standard data request GAS-RR-015 as part of its initial rate case filing
18 which compares replacement budgeted capital expenditures. The Company has spent its
19 capital expenditures replacement budget above what it had projected to spend in the last
20 three years. (Statement No. 7-R at 4-5).

21 **Q. WHAT DID COMPANY WITNESS MR. VASSALOTTI STATE REGARDING**
22 **YOUR DISALLOWANCE RELATED TO INFLATION?**

23 **A.** Mr. Vassalotti stated that he did not agree with my adjustments to remove inflation. He
24 stated that Inflation/Deflation is a well-known economic variable with wide-ranging
25 impacts. (Statement No. 4-R at 11-12).

26 **Q. WHAT IS YOUR RESPONSE?**

27 **A.** As I stated in my direct testimony, inflationary adjustments are not known and measurable
28 and they do not accurately provide the true costs of adjusting costs. Inflationary related

1 costs are typically blanket increases that are applied to all costs. Costs should be predicated
2 upon known and measurable concepts. These types of inflation-related adjustments do not
3 provide a good index or pattern of increased costs over time. While such types of
4 inflationary increases are useful to develop economic data, they should not be used to
5 develop and set rates for utility service under a ratemaking methodology. Rates once set
6 are collected until they change in another rate case and thus have to be set as just and
7 reasonable rates. The Company has not provided any additional information or evidence
8 showing that these cost increases will be realized or be present in its FPFTY period. If
9 inflation costs were utilized, and if those costs did not materialize when rates are set by the
10 Commission, the Company will recover costs greater than its cost of service and over-
11 recover costs which ratepayers will not be able to get back. I continue to recommend the
12 disallowance of the 4% and 5% of inflationary costs in 2025 and 2026 related to the
13 Company's capital expenditure replacements. Further, Mr. Vassalotti's argument that
14 disallowance of these inflation costs would diminish a utility's ability to meet its cost of
15 service requirement and earn its allowed rate of return is without merit. The Company has
16 the opportunity to recovery its known and measurable costs and earn its rate of return; it is
17 not a guarantee of 100% recovery. Inflation / Deflation costs are not the sort of adjustments
18 that should be used to set rates for utility services. Mr. Vassalotti is correct to state that
19 Inflation/Deflation costs are used for economic data. However, they should not be used for
20 ratemaking purposes to set the revenue requirement recovery from ratepayers. My
21 adjustment is shown on my Exhibit DM-SR-5. This adjustment reduces the revenue
22 requirement by about \$1.42 million.

23 **B. Deferred Income Taxes**

24 **Q. WHAT DID MS. HARDING STATE REGARDING YOUR ADJUSTMENTS TO**
25 **THE BOOK TO TAX ADJUSTMENTS AND TAX RATES USED FOR THE**
26 **COMPUTATION OF THE PROPOSED ACCUMULATED DEFERRED INCOME**
27 **TAX ADJUSTMENTS?**

28 **A.** Ms. Harding stated that my proposed adjustments to the Deferred Income Taxes
29 understated income tax expense resulting in understating the revenue requirement.
30 (Harding Statement No. 10-R at 2). Ms. Harding stated that my adjustment included errors

1 in the book depreciation calculation of \$48,400,164, representing Mains Depreciation
2 adjustment of \$236,476, and Mr. Garrett's adjustment to depreciation of \$45,802,423,
3 along with an unexplained adjustment of \$2,834,217. Ms. Harding stated that the decrease
4 in book depreciation should increase the deduction for excess tax depreciation over book
5 and not decrease it. (Statement No. 10-R at 2). Ms. Harding stated that the balance of my
6 recommended depreciation expense should be reduced by \$4,629,152 related to the
7 decrease in tax repairs, mixed service costs and tax depreciation attributable to the
8 reduction in capital expenditures. (Statement No. 10-R at 2). This results in a net book/tax
9 adjustment of \$41,409,747. Ms. Harding stated that this \$41,409,747 balance should be
10 used to calculate the Federal Accumulated Deferred Income Tax (ADIT) by the Federal
11 tax rate of 21% instead of my combined tax rate of 28.49% rate. Ms. Harding stated that
12 Pennsylvania is a flow-through state and only the Federal ADIT is normalized and included
13 in Rate Base since the current period tax deductions flow through as a benefit in current
14 state tax expense. (Statement No. 10-R at 3). Ms. Harding calculated an ADIT adjustment
15 of (\$41,409,747 times 21%) of \$8,696,047. (Covert Exhibit JH-1R). This reduces the
16 Company's revenue requirement by about \$916,650.

17 **Q. DOES THE COMPANY AGREE WITH YOUR ADJUSTMENTS RELATED TO**
18 **THE ADJUSTMENT TO DEPRECIATION EXPENSES, WHICH CALCULATES**
19 **THE ACCUMULATED DEFERRED INCOME TAX ADJUSTMENT?**

20 **A.** No. Ms. Harding does not agree with my adjustment to the Accumulated Deferred Income
21 Taxes or the adjustments thereof. Ms. Harding stated that her surrebuttal addresses my
22 formula errors which she has corrected.

23 **Q. WHAT IS YOUR RESPONSE?**

24 **A.** I reviewed my exhibits and the calculations that are reflected in Ms. Harding's Schedule
25 JH-1R. I am accepting Ms. Harding's adjustment of the Depreciation Expense calculation
26 to the \$41,409,747 balance, which reflects the decrease in tax repairs of \$4,629,116 related
27 to mixed service costs and reduction in capital expenditures. Although Ms. Harding did
28 not identify how the calculation of the reduction of \$4,629,152 was derived in her direct
29 testimony, I am accepting this balance for purposes of calculating the Company's Deferred
30 Income Tax balance. With respect to Ms. Harding's discussion of the unexplained

1 adjustment of \$2,834,217, I note that in response to OCA-Set 9-42, the Company stated
2 that this adjustment was part of an update related to Excess Tax Depreciation over Book
3 Depreciation of \$32,331,282, representing the state flow through net of federal benefits.
4 However, the Company utilized the balance of \$35,165,499 to calculate the excess tax
5 depreciation over book. I am accepting this calculation for purposes of adjusting the excess
6 tax depreciation over book. My updated ADIT balance is calculated at \$8,696,054 as
7 shown on my Exhibit DM-SR-7.¹

8 **C. Material & Supplies/Prepayments**

9 **Q. WHAT HAS COMPANY WITNESS MS. COVERT STATED REGARDING YOUR**
10 **DISALLOWANCE OF INFLATION ADJUSTMENTS FOR MATERIALS AND**
11 **SUPPLIES AND PREPAYMENTS?**

12 **A.** Ms. Covert stated that I incorrectly calculated my adjustment to remove inflation from
13 Materials and Supplies and Prepayments by removing only the 2025 GDP deflator of
14 2.93% and ignoring the 2026 GDP Deflator of 3.05%. (Statement No. 11-R at 2).

15 **Q. WHAT IS YOUR RESPONSE?**

16 **A.** I began with the Company's 2025 13-month average balance of its Materials and Supplies
17 of \$917,192. Included in that balance is an inflation adjustment of 2.93% (Statement No.
18 11-R at 2). I disallowed this inflation adjustment and calculated a non-inflated balance of
19 \$891,083. There was no need to include the 2026 inflation adjustment of 3.05% because
20 my adjustment sets the Materials and Supplies at the 2025 level at actual costs with no
21 further adjustment needed. The same holds true for the Company's Prepayments. The
22 Company reflected a 2025 13-month average balance of \$5,470,802. Included in that
23 balance is an inflation adjustment of 2.93% (Statement No. 11-R at 2). I disallowed this
24 inflation adjustment and calculated a non-inflated balance of \$5,315,070. There was no
25 need to include the 2026 inflation adjustment of 3.05% because my adjustment sets the
26 Prepayments at the 2025 level at actual costs with no further adjustment needed. My

¹ Any differences due to rounding issues.

1 adjustment is shown on my Exhibit DM-SR-3. This reduces the revenue requirement by
2 about \$31,280.

3 **D. Consolidated Tax Adjustment (CTA)**

4 **Q. WHAT HAS MS. HARDING STATED REGARDING YOUR CONSOLIDATED**
5 **TAX ADJUSTMENT?**

6 **A.** Ms. Harding did not agree with my CTA adjustment of \$2,263,821. She stated that the
7 passage of Act 40, 66 Pa. C.S. § 1301.1 which became effective August 10, 2016,
8 eliminated the CTA in ratemaking. Ms. Harding stated that the section addressed stated
9 that if an expense or investment is allowed to be included in a public utility's rates for
10 ratemaking purposes, the related tax deductions and credits shall also be included in the
11 computation of current deferred income tax expense to reduce rates. (Statement No. 10-R
12 at 4). Ms. Harding claims I failed to recognize that the Company's FPFTY Operating and
13 Maintenance expenses of \$223.6 million exceeds 50% of the computed differential of
14 \$2.26 million. According to Ms. Harding, Columbia has demonstrated that it will be using
15 the other 50% for general corporate purposes. (Statement No. 10-R at 5).

16 **Q. WHAT IS YOUR RESPONSE?**

17 **A.** I believe that the Company has not supported the 50% differential use to be used for general
18 corporate purposes. The Company has not specifically identified or specifically
19 demonstrated how the differential is to be used. When ratepayers are already supporting
20 the Company's infrastructure projects and reliability investments, and general corporate
21 purposes through rates, more information and support is needed to show that the additional
22 revenues now being provided by ratepayers are actually being used for general corporate
23 purposes and not simply going to shareholders in the form of incentive compensation or
24 restricted stock payments. The Company should provide evidence of actual applications
25 of its differential related to general corporate purposes in a manner that reduces ratepayer
26 obligations. My recommendation is shown on my Exhibit DM-SR-3. My adjustment
27 reduces the revenue requirement by about \$2.359 million.

E. OPERATING INCOME

1. Operating and Maintenance Expenses

a. Labor and Vacancy Rate

Q. WHAT DID COMPANY WITNESS MR. LEAL STATE WITH RESPECT TO YOUR ADJUSTMENTS TO A LABOR VACANCY RATE?

A. Mr. Leal did not agree with my inclusion of a vacancy rate resulting in an adjustment of \$1,698,621. He stated that my vacancy rate adjustment is based upon an incorrect assumption that the Company's Labor O&M expenses include unfilled positions. (Leal Statement No. 18-R at 5). Mr. Leal argues that Columbia's FPFTY Labor projection is based solely on actual filled positions as the end of the HTY and therefore, already excludes vacancies. (Statement No. 18-R at 5). Mr. Leal stated that Columbia used a headcount of 715 filled positions as of the end of the HTY. This methodology in place since Columbia's 2022 rate case excludes any vacant positions and more accurately reflects labor costs expectations during the FPFTY. (Statement No. 18-R at 5). Mr. Leal stated that my adjustment is duplicative in that my calculation assumed that the Company's labor budget includes all authorized positions both filled and vacant while Columbia's FPFTY labor projections include only filled positions. Mr. Leal stated that my adjustment removes costs that were not reflected in the revenue requirement requested by the Company. (Statement No. 18-R at 6).

Q. WHAT IS YOUR RESPONSE?

A. In all organizations, there will be a level of vacancies that will exist at any given point in time. This is due to employees retiring, leaving the company, getting fired, being laid off, or the Company's decision to scale back total employee count. The Company cannot with certainty know the actual employee count expected to be actually filled. The Company's prior vacancy rate ratios show a number of vacancies were present (I&E RE-11 Attachment B). The level of employees is typically determined based upon the number of employees needed to perform the work assignments, the level of productivity needed to be achieved, the areas in which staff appears to be over or underworked and the replacement of employees who are under-performing. By not incorporating a vacancy rate ratio to adjust

1 employee counts in the forecasted test year, there could be a situation where the Company
2 could over-earn in the event the Company's forecasted employee head count does not come
3 to fruition. Given this scenario, I am continuing to recommend a vacancy rate ratio
4 resulting in an adjustment of \$1,698,606. This is shown on my Exhibit DM-SR-10. My
5 adjustment reduces the revenue requirement (including the flow through of taxes) by about
6 \$2.359 million.

7 **b. Incentive Compensation**

8 **Q. WHAT DID COMPANY WITNESS MS. HUNTER STATE WITH RESPECT TO**
9 **YOUR REMOVAL OF A PORTION OF INCENTIVE COMPENSATION?**

10 **A.** Ms. Hunter stated that she did not agree with my disallowance of 70% of Short-Term
11 Incentive (STI) costs or \$1,798,165 related to financial performance based upon the most
12 current 2025 performance metrics. (Hunter Statement No. 20-R at 6). Ms. Hunter stated
13 that cash-based incentive awards, including STI, are a common element of compensation
14 in major utilities and similar organizations nationwide and should be recoverable for
15 ratemaking purposes. Ms. Hunter claims that these incentives motivate employees by
16 setting achievable goals that align rewards with delivering safe, reliable, efficient and cost-
17 effective service. Ms. Hunter further argues that both financial and non-financial
18 performance metrics are necessary to attract, retain and motivate employees who ensure
19 safe and reliable service. (Statement No. 20-R at 6-7). Ms. Hunter stated that retaining and
20 attracting talented individuals is critical to maintaining high quality service, efficiency, and
21 safety, and therefore, offering STI rewards is an appropriate cost of providing reliable
22 service to Columbia's customers. According to Ms. Hunter, if the Company did not
23 provide STI rewards, it would be at high risk of losing talent to competitors. (Statement
24 No. 20-R at 7). Ms. Hunter stated that failure to retain and attract experienced, skilled
25 employees can adversely affect Columbia's ability to continue to provide safe and reliable
26 service for its customers. (Statement No. 20-R at 7). Ms. Hunter stated that she was advised
27 that the Commission has allowed full recovery of incentive compensation amounts even
28 where financial performance is a trigger to payment of the rewards. (Statement No. 20-R
29 at 7-8).

1 **Q. WHAT DID MS. HUNTER STATE REGARDING THE REMOVAL OF**
2 **RESTRICTED STOCK?**

3 **A.** Ms. Hunter stated that she did not agree with my disallowance of the Restricted Stock of
4 \$754,446. Ms. Hunter stated that Restricted Stock or Labor Incentive Compensation (LTI)
5 is a standard compensation component for management nationwide, including utilities, and
6 should be recoverable. (Statement No. 20-R at 9). According to Ms. Hunter, LTI motivates
7 employees by setting achievable goals aligned with safe, reliable, efficient and cost-
8 effective service to customers and rewards achievement of these goals. Ms. Hunter argues
9 that both financial and non-financial metrics are integral to attracting and retaining
10 leadership essential to customer service. (Statement No. 20-R at 9). Ms. Hunter stated that
11 the Company's LTI goals should be recovered because they encompass operational
12 excellence, safety, employee engagement and environmental measures. Disallowing
13 recovery sends the wrong message by devaluing cost effectiveness. (Statement No. 20-R
14 at 9). Ms. Hunter stated that LTI is designed to attract and retain key talent over the long
15 term and is essential for setting the tone and direction of the Company. According to Ms.
16 Hunter, offering LTI is an appropriate cost of providing reliable service to the Company's
17 customers and if the Company did not provide LTI it would be at risk of losing talent to
18 competitors, which would create a loss of valuable skills and institutional knowledge. Ms.
19 Hunter argues that this would have a significant financial impact associated with turnover,
20 including recruiting costs, relocation costs and training costs. (Statement No. 20-R at 10).

21 **Q. WHAT IS YOUR RESPONSE?**

22 **A.** While I understand the importance of providing incentive compensation to employees, I
23 do not believe that incentive compensation related to financial performance should be
24 recoverable from ratepayers. I believe that incentive compensation should only be
25 recovered from ratepayers if it provides a specific benefit to ratepayers, but not if it benefits
26 the Company in the form of increasing net operating earnings per share. Further, Ms.
27 Hunter stated that incentive compensation gives managers the power to reward and retain
28 its top executives, which would be difficult to accomplish without the element of incentive
29 compensation. Ms. Hunter stated that in order to retain key leaders and attract new talented
30 individuals, offering stock-based programs is an appropriate cost of providing reliable

1 service to Columbia's customers, and absent that, it would have a significant financial
2 impact in the form of turnover costs, recruiting costs, relocation costs and training costs.
3 Part of the Company's argument is that in order to provide safe and reliable service to its
4 customers it has to incent employees. This appears to be an all or nothing approach to
5 compensation in that without appropriate incentive compensation, employees would not be
6 able to perform their duties. The Company has the right and the opportunity to provide its
7 employees with market-based and comparable compensation as other companies offer.
8 While the Company assumes that such compensation may be at a fair and reasonable level
9 to include in rates, there should be no assumption that all of these costs should be recovered.
10 The Company has the opportunity to recover these costs for ratemaking purposes only if
11 they are prudent and reasonable and to the benefit of ratepayers. It is not the responsibility
12 of ratepayers to be required to recover costs related to financial performance (shareholder
13 benefit) or to reward employees with stock awards, to retain and attract employees when it
14 is clearly the responsibility of the Company to share in the burden of absorbing these costs.
15 The Company should not have unfettered access to ratepayers' money when these types of
16 incentive costs do not benefit ratepayers. I am not arguing for the elimination of these
17 incentive type costs. However, costs related to financial metrics and financial performance
18 should be a risk that the Company is taking.

19 **Q. HAVE THE COMPANY'S REBUTTAL WITNESSES CHANGED YOUR MIND**
20 **WITH RESPECT TO INCENTIVE COMPENSATION?**

21 **A.** No. My recommendation is the same as in my direct testimony. I note that 70% of the
22 Company's total incentive compensation is related to financial performance (adjusted
23 earnings per share) (GAS-RR-027 Attachment B). I am recommending that only \$770,642,
24 a portion of the Company's \$2,568,807 incentive compensation, be included in rates. I
25 believe this portion is related to Customer Care, Safety, and Satisfaction. My
26 recommendation is shown on my Exhibit DM-SR-11. With respect to the Company's
27 Restricted Stock/LTI costs of \$754,446, I am still of the opinion that these types of
28 incentive related costs should be borne by the Company if it truly believes that it provides
29 ratepayer benefits in the area of customer service, satisfaction, safety and reliability to

1 ratepayers. I do not see any customer-oriented benefits inuring to ratepayers by requiring
2 ratepayers to pay for restricted stock paid out to employees.

3 **c. Other Employee Benefits**

4 **Q. WHAT HAS THE COMPANY STATED IN REGARD TO YOUR EMPLOYEE**
5 **BENEFITS ADJUSTMENT?**

6 **A.** Company witness Ms. Hunter did not agree with my disallowance of profit sharing of
7 \$406,864. She stated that profit sharing is an important element of the Company's
8 retirement savings plan (401K) and as such is an important part of overall retirement
9 funding earned by Columbia employees. Ms. Hunter stated that profit Sharing supplements
10 employee contributions to their retirement accounts. According to Ms. Hunter, absent
11 these contributions, the Company would have to make other adjustments to its
12 compensation package, such as an increase to base pay, to remain competitive in the market
13 for quality employees. (Statement No. 20-R at 11).

14 **Q. WHAT IS YOUR RECOMMENDATION?**

15 **A.** After review, I am accepting Ms. Hunter's argument as to profit sharing costs of \$406,864.
16 Given that more traditional elements of retirement savings including defined benefits plans
17 are no longer available to new hires, I am recommending recovery of these costs in the
18 FPFTY period. My recommendation is shown on my Exhibit DM-SR-13.

19 **Q. WHAT DID MR. LEAL STATE REGARDING YOUR ADJUSTMENT OF \$390,741**
20 **RELATED TO YOUR REDUCTION OF OTHER EMPLOYEE BENEFITS?**

21 **A.** Mr. Leal did not agree with my adjustment reduction of \$390,741 ties to my O&M labor
22 adjustment. Mr. Leal stated that my adjustment was flawed in relation to my Labor
23 adjustment to my vacancy rate adjustment. (Statement No. 18-R at 6 and 7). Mr. Leal
24 stated that my adjustment is mechanically dependent on my Labor O&M Expense which
25 he stated is a mischaracterization of how the Company determined its labor budget. He
26 stated that the Company already excludes vacancies and applying an additional vacancy
27 rate artificially understates the labor base and disregards the cost calculation provided by
28 the Company's actuary. (Statement No. 18-R at 7).

1 **Q. WHAT IS YOUR RESPONSE?**

2 **A.** As I previously stated under my Labor vacancy rate ratio adjustment, my adjustment to the
3 Company's Employee Benefits are correlated to my recommended vacancy rate ratio. My
4 arguments in support of my adjustment to the Company's Employee Benefits reflect this
5 vacancy rate ratio. My adjustment reduces the revenue requirement by about \$543,000.

6 **d. Outside Services**

7 **Q. WHAT HAS THE COMPANY STATED IN REGARD TO YOUR ADJUSTMENT**
8 **TO OUTSIDE SERVICES?**

9 **A.** Company witness Mr. Leal did not agree with my adjustment to the Company's Outside
10 Services adjustment of \$1,444,261. Mr. Leal stated that my approach of using historical
11 data fails to account for the Company's forward-looking operational plans and
12 departmental cost allocations supporting the Company's Outside Service forecast.
13 (Statement No. 18-R at 10). Mr. Leal claims that this adjustment does not recognize that
14 Outside Services spending is inherently variable due to timing, scope and the deferral of
15 certain work activities that are not indicative of a permanent structural decline in costs.
16 (Statement No. 18-R at 11).

17 **Q. WHAT IS YOUR RESPONSE?**

18 **A.** I continue to recommend the use of a three-year average to set Outside Services. The mere
19 fact that this variance has occurred in the past was due to deferral of certain work activities
20 does not change my recommendation. Changes in timing and scope of services does not
21 negate the fact these occurrences may occur going forward. The Company cannot predict
22 with certainty that the Company's forward-looking costs will not vary as in the past.
23 Variations exist as a normal course of business. As I indicated in my direct testimony,
24 these Outside Services costs varied from a low of 4.52% to a high of 31.36%. These
25 variances existed for a reason as the Company has changed its scope and scale of work
26 activity, which is a part of the cost of doing business. My adjustment is shown on my
27 Exhibit DM-SR-14. My adjustment reduces the revenue requirement by about \$2 million.

1 **e. Employee Expenses**

2 **Q. WHAT HAS COMPANY WITNESS MR. LEAL STATED WITH REGARD TO**
3 **YOUR ADJUSTMENT TO EMPLOYEE EXPENSES?**

4 **A.** Mr. Leal stated that the Company identified a categorization error. Mr. Leal stated that
5 \$417,305 of budgeted costs related to clothing allowance was inadvertently included under
6 Employee Expenses. (Statement No. 18-R at 17).

7 **Q. WHAT HAS COMPANY WITNESS VASSALOTTI STATE REGARDING YOUR**
8 **ADJUSTMENT TO THIS EXPENSE ACCOUNT?**

9 **A.** Mr. Vassalotti reiterated what Mr. Leal stated regarding the correction of the Company's
10 Employees Expenses: that gifts and entertainment expenses should be removed from the
11 revenue requirement. (Statement No. 4-R at 17). However, he stated that the recoverable
12 amounts included in the Company's updated Rebuttal revenue requirement claim for
13 Employee Expenses are reasonable and prudent because they support the provision of safe
14 and reliable service. (Statement No. 4-R at 18).

15 **Q. WHAT IS YOUR RESPONSE?**

16 **A.** I am accepting Mr. Leal's categorization error related to clothing allowance. The
17 difference between the Company's error of \$417,305 and the remaining costs of \$438,829
18 or \$21,524 should be disallowed which are costs related to Employee Expenses which I
19 believe are related to non-customer oriented costs. My adjusted disallowance balance is
20 \$45,607 (\$24,083 related to 50% allowed Meals / Entertainment and \$21,524 related to
21 Employee Expenses). My argument to disallow these costs are the same as in my direct
22 testimony. My adjusted balance is shown on my Exhibit DM-SR-19. My adjustment
23 reduces the revenue requirement by about \$47,560.

24 **f. Company Memberships**

25 **Q. WHAT HAS MR. VASSALOTTI STATED WITH REGARD TO YOUR**
26 **ADJUSTMENTS TO COMPANY MEMBERSHIPS?**

27 **A.** Mr. Vassalotti stated that he did not agree with my disallowance of costs related to
28 Company Memberships. He stated that these costs were incorrectly identified as the

1 Company does not seek recovery for any dues and memberships paid to industry
2 associations and Chambers of Commerce as well as expenses paid to fraternal, social or
3 sports clubs or organizations. (Statement No. 4-R at 19). Mr. Vassalotti stated that the
4 costs include membership fees to national and state utility industry associations or paid to
5 state and local Chambers of Commerce. (Statement No. 4-R at 20-21).

6 **Q. WHAT IS YOUR RESPONSE?**

7 **A.** My argument as stated in my direct testimony has not changed. These costs do not comport
8 to costs associated with Company Memberships, but rather to organizations in the form of
9 membership fees, such as and including Chamber of Commerce dues. 66 Pa. C.S. Section
10 1316.1, identified by Mr. Vassalotti, clearly depicts these very same costs shown on his
11 testimony page 20. As such, ratepayers cannot be charged for costs associated with these
12 types of expenses. Organizations which provide economic benefit and development to
13 areas where the Company services and policy analysis on regulatory issues provide no
14 demonstrated benefits to ratepayers. The notion of such is too far removed from utility
15 service to justify the inclusion in the revenue requirement, as there is no direct connection
16 to providing customers with adequate service, customer service and safety or reliability.
17 Therefore, these costs cannot be charged to ratepayers. My recommendation is shown on
18 my Exhibit DM-SR-20. My adjustment reduces the revenue requirement by about
19 \$353,000.

20 **g. Materials and Supplies**

21 **Q. WHAT DID MR. VASSALOTTI STATE WITH REGARD TO YOUR MATERIALS**
22 **AND SUPPLIES ADJUSTMENT?**

23 **A.** Mr. Vassalotti did not agree with my adjustment to reduce the Company's Materials and
24 Supplies by \$558,615 (Statement No. 4-R at 22). Mr. Vassalotti stated that the variance
25 is related to an accounting change that occurred in 2024, and such a change in the O&M
26 Expense resulted in a movement of expenses from Outside Services to Material and
27 Supplies. The Company is currently searching for the best method to correct the
28 inadvertent O&M Expense category for the vendor change. (Statement No. 4-R at 22).

1 **Q. WHAT IS YOUR RESPONSE?**

2 **A.** I continue to recommend normalizing these costs over a three-year period. But for the
3 accounting change occurring in 2024 and the inadvertent change in the O&M Expense
4 related to a vendor adjustment, the Company has not provided any further information. As
5 indicated by Mr. Vassalotti, the Company is currently researching the best method to
6 correct the inadvertent O&M Expense change related to a vendor adjustment. Until such
7 time as the Company's alters or changes its method, I am continuing to recommend the
8 three-year normalization adjustment of \$558,615. My recommendation is shown on my
9 Exhibit DM-SR-24. My adjustment reduces the revenue requirement by about \$776,000.

10 **h. NCSC-Shared Services**

11 **Q. WHAT DID COMPANY WITNESS MS. HUNTER STATE WITH REGARD TO**
12 **YOUR ADJUSTMENT RELATED TO ITS NCSC-SHARED SERVICES –**
13 **SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN (SERP) EXPENSE AND**
14 **DISCRETIONARY BONUSES?**

15 **A.** Ms. Hunter stated that she does not agree with my removal of the Company's SERP costs
16 of \$136,102, and Discretionary Bonuses of \$105,630.

17 **Q. PLEASE EXPLAIN MS. HUNTER'S CLAIM OF SERP COSTS TO BE INCLUDED**
18 **IN THE COMPANY'S COMPENSATION COSTS?**

19 **A.** Ms. Hunter stated that SERP is part of the compensation and benefits that is provided to
20 employees. Ms. Hunter further stated that the Company's compensation and benefits taken
21 as a whole and including SERP provides the means to competitively compensate
22 employees in order to attract and retain quality employees responsible for the safe, reliable
23 and cost effective service to Columbia.

24 **Q. WHAT IS YOUR RESPONSE TO MS. HUNTER'S INCLUSION OF SERP?**

25 **A.** It is still my opinion that SERP costs should not be included in rates. As I stated in my
26 direct testimony there are no discernable benefits accruing to ratepayers because these
27 types of costs accrue to the Company by retaining employees and are used as rewards for
28 the sole benefit of employees. Under a SERP, the Company retains the benefit in the event

1 an employee dies, leaves or quits the Company. The Company has access to the dollars in
2 the SERP and gets the cash value of the plan. I do not see a nexus between the recovery
3 of SERP costs from ratepayers and ratepayer benefits. The Company should bear the
4 burden and the responsibility to fund these costs.

5 **Q. WHAT HAS MS. HUNTER STATED REGARDING THE INCLUSION OF**
6 **DISCRETIONARY BONUSES?**

7 **A.** Ms. Hunter stated that these are modest targeted awards recognizing exceptional
8 contributions by employees that directly impact the Company's ability to provide safe,
9 reliable and cost-effective service. The average award is \$2,548 and is typically used to
10 recognize performance for activities such as going above and beyond to serve customers
11 and safety actions following work zone intrusions. Using discretionary bonuses to
12 recognize employee's efforts avoids the need for ongoing fixed or incentive compensation
13 costs. (Statement No. 20-R at 12).

14 **Q. WHAT IS YOUR RESPONSE?**

15 **A.** After review I am accepting Ms. Hunter's explanation of discretionary bonuses. Given
16 that these bonuses are geared toward customer services and safety initiatives, I am
17 accepting the balance of these bonuses of \$105,630. This is shown on my Exhibit DM-
18 SR-27.

19 **Q. WHAT HAS MS. HUNTER STATED WITH RESPECT TO YOUR**
20 **DISALLOWANCE OF COSTS RELATED TO DIVERSTIY, EQUITY, AND**
21 **INCLUSION (DEI)?**

22 **A.** Ms. Hunter stated that she did not agree with disallowing DEI costs of \$130,450. She
23 stated that my description of DEI programs does not accurately reflect the Company's
24 purpose for this team. (Statement No. 20-R at 13). She stated that programs that strive to
25 include the voices of all employees are necessary to attract and retain the Company's talent
26 as these programs cultivate a connected, collaborative and innovative workforce where
27 every employee has the opportunity to learn, grow and succeed in support of provide safe,
28 reliable and cost-effective service to customers. (Statement No. 20-R at 13). The balance
29 of \$130,450 represents labor and benefits of three employees who worked in the DEI team,

1 now known as Workplace Connections. (1) talent engagement; 2) communities and
2 partnerships; 3) people experience and; 4) insights and impact).

3 **Q. WHAT IS YOUR RESPONSE?**

4 **A.** I continue to recommend disallowance of these costs. The Company has provided no
5 evidence on whether these costs actually produce benefits to ratepayers, nor has the
6 Company evaluated metrics to demonstrate ratepayer value. While Ms. Hunter stated that
7 these costs benefit ratepayers, these appear to be costs to benefit the Company such as
8 corporate branding, imaging and touting Company stewardships.

9 **Q. WHAT HAS MS. HUNTER STATED REGARDING YOUR DISALLOWANCE OF**
10 **RESTRICTED STOCK/LTI?**

11 **A.** Ms. Hunter stated she did not agree with my recommended adjustment to disallow all of
12 the Restricted Stock of \$4,012,229. As discussed above, in my Incentive Compensation
13 section, Ms. Hunter stated that LTI is a standard compensation component for management
14 nationwide, including utilities, and should be recoverable. (Statement No. 20-R at 9). Ms.
15 Hunter stated that LTI motivates employees by setting achievable goals aligned with safe,
16 reliable, efficient and cost-effective service to customers and rewards achievements of
17 these goals. Both financial and non-financial metrics are integral to attract and retain
18 leadership essential to customer service. Ms. Hunter stated that disallowing these costs
19 sends the wrong message by devaluing cost-effectiveness. (Statement No. 20-R at 9).

20 **Q. WHAT IS YOUR RESPONSE?**

21 **A.** As I stated previously in my Surrebuttal Testimony, I do not believe that ratepayers should
22 pay for Restricted Stock Compensation / LTI that I believe are related to higher level
23 Corporate executives and officers. Ms. Hunter's argument that without stock awards, the
24 Company would be at a high risk of losing talent to competitors, and the potential departure
25 of Company leadership would create a loss of valuable skills and have a significant
26 financial impact is not supported. (Statement No. 20-R at 10). The Company has not
27 shown that without these stock awards it would deteriorate the Company's ability to
28 provide safe and reliable service to its customers. The Company's employees were hired
29 to do just that, provide safe and reliable service to customers without the need for an

1 incentive to do so. I believe that Company shareholders should fund these executive level
2 incentive-based programs and not ratepayers.

3 Further, the Restricted Stock / LTI awards are not broken down by categories. Therefore,
4 there is no way to discern whether the Restricted Stock / LTI costs actually benefit
5 ratepayers.

6 **Q. WHAT HAS MS. HUNTER STATED REGARDING YOUR DISALLOWANCE OF**
7 **OTHER INCENTIVE COMPENSATION?**

8 **A.** As previously indicated Ms. Hunter stated that she did not agree with my disallowance of
9 70% of STI costs or \$4,884,338 related to financial performance based upon the most
10 current 2025 performance metrics. (Hunter Statement No. 20-R at 6). Ms. Hunter stated
11 that cash-based incentive awards are a common element of compensation in major utilities
12 and similar organizations nationwide and should be recoverable for ratemaking purposes.
13 These incentives motivate employees by setting achievable goals that align rewards with
14 delivering safe, reliable, efficient and cost-effective service. Both financial and non-
15 financial performance metrics are necessary to attract, retain and motivate employees who
16 ensure safe and reliable service. (Statement No. 20-R at 6-7). Ms. Hunter stated that
17 retaining and attracting talented individuals is critical to maintaining high quality service,
18 efficiency, and safety. Ms. Hunter stated that failure to retain and attract experienced,
19 skilled employees can adversely affect Columbia's ability to continue to provide safe and
20 reliable service for its customers. (Statement No. 20-R at 7). Ms. Hunter stated that she
21 was advised that the Commission has allowed full recovery of incentive compensation
22 amounts even where financial performance is a trigger to payment of the rewards.
23 (Statement No. 20-R at 7-8).

24 **Q. WHAT IS YOUR RESPONSE?**

25 **A.** As I stated previously in my surrebuttal testimony, while I understand the importance of
26 providing incentive compensation to employees, I do not believe that incentive
27 compensation related to financial performance should be recoverable from ratepayers. I
28 believe that incentive compensation should only be recovered from ratepayers if it provides
29 a specific benefit to ratepayers, but not if it benefits the Company in the form of increasing

1 net operating earnings per share. Further, Ms. Hunter stated that incentive compensation
2 gives managers the power to reward and retain its top executives, which would be difficult
3 to accomplish without the element of incentive compensation. Ms. Hunter stated that, in
4 order to retain key leaders and attract new talented individuals, offering stock-based
5 programs is an appropriate cost of providing reliable service to Columbia's customers, and
6 absent that, it would have a significant financial impact in the form of turnover costs,
7 recruiting costs, relocation costs and training costs. Part of the Company's argument is
8 that in order to provide safe and reliable service to its customers it has to incent employees.
9 This appears to be an all or nothing approach to compensation in that without appropriate
10 incentive compensation, employees would not be able to perform their duties. The
11 Company has the right and the opportunity to provide its employees with market-based and
12 comparable compensation as other companies offer. While the Company assumes that
13 such compensation may be at a fair and reasonable level to include in rates, there should
14 be no assumption that all of these costs should be recovered. The Company has the
15 opportunity to recover these costs for ratemaking purposes only if they are prudent and
16 reasonable and to the benefit of ratepayers. It is not the responsibility of ratepayers to be
17 required to recover costs related to financial performance (shareholder benefit) or to reward
18 employees with stock awards, to retain and attract employees when it is clearly the
19 responsibility of the Company to share in the burden of absorbing these costs. The
20 Company should not have unfettered access to ratepayers' money when these types of
21 incentive costs do not benefit ratepayers. I am not arguing for the elimination of these
22 incentive type costs. However, the costs related to financial metrics and financial
23 performance should be the risk that the Company bears.

24 **Q. WHAT HAS MR. VASSALOTTI STATED REGARDING YOUR ADJUSTMENT**
25 **RELATED TO NCSC COSTS ALLOCATED TO THE COMPANY REGARDING**
26 **THE STI O&M EXPENSES?**

27 **A.** Mr. Vassalotti stated that my adjustment to remove \$6,977,626 of STI allocated costs in
28 the FTY 2024 is not reflected in the FPFTY expense. (Statement No. 4-R at 30-31). He
29 stated that the FPFTY 2026 budget reflects the 2026 calendar year performance expense at
30 target. (Statement No. 4-R at 31). Mr. Vassalotti stated that the correct amount for the

1 FPPTY NCSC allocated STI O&M Expense budget is \$5,029,637. (Statement No. 4-R at
2 31). The disallowance, using the 70% related to financial performance, results in an
3 adjustment of \$3,520,746. Mr. Vassalotti stated that this is inconsistent with what I
4 adjusted with respect to the Company's directly incurred STI O&M Expense for the
5 FPPTY O&M Expense. (Statement No. 4-R at 31).

6 **Q. WHAT IS YOUR RESPONSE?**

7 **A.** After review of my response to OCA 6-001 and Mr. Vassalotti's testimony, and in order to
8 be consistent with my adjustments related to the Company's directly incurred STI O&M
9 Expense shown on Company's response to OCA-Set 9-1, I am adjusting my disallowance
10 to the Company's NCSC Allocated STI O&M Expense to \$5,029,637 with a 70%
11 disallowance related to financial achievement resulting in a decrease of \$3,520,746. This
12 is shown on my Exhibit DM-SR-27. My adjustments for all of the related incentive
13 compensation costs reduces the revenue requirement by about \$10.651 million.

14 **i. Rate Case Expenses**

15 **Q. WHAT HAS COMPANY WITNESS MR. VASSALOTTI STATED REGARDING**
16 **TO YOUR ADJUSTMENT TO RATE CASE EXPENSES?**

17 **A.** Mr. Vassalotti stated that he did not agree with my normalization adjustment to recover
18 rate case expenses over a period of 1.16 years. He stated that the Company's used a 12-
19 month period because the Company anticipates a need to file annual rate cases for the
20 foreseeable future. (Statement No. 4-R at 14). Mr. Vassalotti stated that the Company has
21 filed 8 rate cases during the last 10 years and anticipates a need to file annual rate cases.
22 (Statement No. 4-R at 14).

23 **Q. WHAT IS YOUR RESPONSE?**

24 **A.** I reviewed the Company's past rate case proceedings since 2018. The Company has filed
25 6 rate case proceedings during that time period. This is equal to 1 rate case every 14
26 months. I believe that more recent rate case filings should be the basis to set the
27 normalization period going forward and not to go back 10 years regarding the settlement
28 of rate case expense recovery. Therefore, I am recommending that Rate Case Expenses

1 be normalized over 14 months. This reduces the Company's Rate Case Expense from
2 \$1,321,000 to \$1,138,793, a reduction of \$182,207. My recommendation is shown on my
3 Exhibit DM-SR-28. The Commission typically normalizes rate case expenses for
4 ratemaking purposes based upon the history of past rate filings which typically acts as a
5 guide to rate case frequency. My adjustment reduces the revenue requirement by about
6 \$253,000.

7 **j. Uncollectible Expense**

8 **Q. WHAT HAS MR. VASSALOTTI STATED WITH REGARD TO YOUR LEVEL OF**
9 **UNCOLLECTIBLE EXPENSE?**

10 **A.** Mr. Vassalotti stated that I made various adjustments to the Company's Uncollectible
11 Expenses to corrected/revised my errors in calculating the Uncollectible Expenses
12 (Statement No. 4-R at 23). Mr. Vassalotti did not agree with my adjustments to the
13 Company's Uncollectible Accounts Expense (base rates) because he stated that I
14 improperly removed the gross-up for uncollectible account expense in the calculation of
15 the revenue reduction (surplus) shown on Company Exhibit JV-8R. (Statement No. 4-R at
16 25).

17 **Q. WHAT IS YOUR RESPONSE?**

18 **A.** I updated my level of Uncollectible Expenses since I updated my recommended revenue
19 requirement adjustment. Upon review, I corrected my adjustment and do not include the
20 Uncollectible Expense adjustment in my overall O&M Expense balance. Given that the
21 revenue gross-up factor includes a factor to account for uncollectible expense, (as well as
22 all expenses), as stated by Mr. Vassalotti, in which I am accepting, I am not including my
23 Uncollectible Expense adjustment in my overall O&M Expense balance. The totality of
24 my O&M Expenses are being grossed-up (include uncollectible expenses) as shown on my
25 Exhibit DM-SR-1 by the revenue conversion factor of 1.38698. My Uncollectible Expense
26 is now calculated at (\$488,873) by the use of my overall revenue requirement decrease of
27 \$36,316,933 times the uncollectible account factor of 0.01346130 or (\$488,873). This
28 adjustment is shown and incorporated in my revenue deficiency of \$26,184,186 and

1 multiplied by the revenue conversion factor to produce the overall revenue requirement
2 decrease of \$36,316,933 and is shown on my Exhibit DM-SR-29 and DM-SR-9.

3 **k. Rider Universal Service Plan (USP)**

4 **Q. WHAT DID MR. VASSALOTTI STATE REGARDING YOUR ADJUSTMENT TO**
5 **THE COMPANY'S RIDER USP?**

6 **A.** Mr. Vassalotti stated that he did not agree with my adjustment to disallow \$220,000 related
7 to the recovery of Rider USP associated with the Company's EAT Administrative O&M
8 expenses based upon OCA Witness Mr. Colton's recommendation. (Statement No. 4-R at
9 27). He stated that the Rider USP is a fully reconcilable mechanism to Rider USP revenue.
10 Therefore, there is no impact on the revenue deficiency because the expenses offsets
11 revenue. He stated that my removal of the \$220,000 results in an error of matching
12 expenses to revenues. (Statement No. 4-R at 28). Mr. Vassalotti stated that my adjustment
13 is contradictory to OCA Witness Mr. Colton's recommendation that the cost recovery of
14 these expenses should remain in base rates. (Statement No. 4-R at 28). Mr. Vassalotti
15 stated that the Company rejects my adjustment, unless the Commission agrees with the
16 Company to move recovery of the Rider USP EAT costs from base rates to Rider USP.
17 (Statement No. 4-R at 28).

18 **Q. WHAT IS YOUR RESPONSE?**

19 **A.** As further discussed in Mr. Colton's testimony, I am continuing to include the removal of
20 the \$220,000 in the Rider USP. (OCA Colton Surrebuttal Statement 5-SR at 22). This is
21 shown on my Exhibit DM-SR-31. My adjustment reduces the revenue requirement by
22 about \$306,000.

23
24 **3. DEPRECIATION AND AMORTIZATION EXPENSE**

25 **Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE**
26 **COMPANY'S DEPRECIATION AND AMORTIZATION EXPENSE?**

27 **A.** Based upon OCA witness Mr. Garrett's recommendation, I am continuing to include the
28 Depreciation Expense balance adjustment of \$45,802,423. This \$45,802,423 needs to be

1 grossed up to account for federal and state taxes. This is shown on my Exhibit DM-SR-32.
2 My adjustment reduces the revenue requirement by \$63.615 million.

3
4 **4. TAXES OTHER THAN INCOME**

5 **Q. WHAT CHANGES DO YOU HAVE WITH RESPECT TO TAXES OTHER THAN**
6 **INCOME TAXES?**

7 **A.** My adjustments to the Company's Taxes other than Income Taxes reflect the flow through
8 adjustments related to my adjustments to Labor and Incentive Compensation. To the extent
9 that I made such changes, these adjustments will flow through the Taxes other than Income
10 Taxes schedules. This is shown on my Exhibit DM-SR-33. My adjustment reduces the
11 revenue requirement by about \$266,000.

12
13 **5. INCOME TAXES**

14 **Q. WHAT DID MS. HARDING STATE REGARDING YOUR ADJUSTMENT TO**
15 **THE COMPANY'S INCOME TAXES?**

16 **A.** Ms. Harding stated that my adjustments to the Company's Income Taxes related to the
17 excess tax depreciation over book for the decrease in book depreciation resulted in
18 understating the revenue requirement. (Statement No. 10-R at 2). Ms. Harding stated that
19 the book depreciation adjustment of \$45,802,423 as recommended by OCA Witness Mr.
20 Garrett should be adjusted by \$4,629,152 to offset the balance due to the Company's
21 decrease in tax repairs, mixed service cost and tax depreciation attributable to the reduction
22 of capital expenditures. (Statement No. 10-R at 2). Mr. Harding stated that I had several
23 formula errors in the computation of income tax expense. (Statement No. 10-R at 4).

24 **Q. WHAT IS YOUR RESPONSE?**

25 **A.** I reviewed Ms. Harding's adjustments to my income tax expense balance and have
26 accepted her adjustments. My surrebuttal testimony reflects these adjustments and the flow

1 though changes with respect to my surrebuttal revenue requirement recommendation. This
2 is shown on my Exhibit DM-SR-34.

3 **Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?**

4 **A.** Yes, it does.

REVENUE REQUIREMENT SUMMARY		(1)		
	Company Proposed	Adjustments	PAOCA	References
Rate Base	\$ 3,845,381,715	\$ 16,241,227	\$ 3,861,622,942	
Rate of Return	8.55%		7.06%	
Operating Income	\$ 328,780,137	\$ (56,149,557)	\$ 272,630,580	
Operating Income at Present Rates	\$ 249,112,928	\$ 49,701,838	\$ 298,814,766	
Revenue Deficiency	\$ 79,667,209	\$ (105,851,395)	\$ (26,184,186)	
Revenue Conversion Factor	1.38697964		1.38697964	
Gross Revenue Requirement	\$ 110,496,797	\$ (146,813,730)	\$ (36,316,933)	
Current Rates	\$ 916,958,770		\$ 916,958,770	
% Increase	12.05%		-3.96%	
Proposed Rates	\$ 1,027,455,567	\$ (146,813,730)	\$ 880,641,837	

(1) Company Exhibit 102 Sch. 3 pg 3

RATE OF RETURN

Company Proposed (1)				
	Ratios	Cost Rate	Weighted Cost Rate	References
Long-Term Debt	43.28%	5.22%	2.26%	
Short-Term Debt	2.32%	5.00%	0.12%	
Total Debt	45.60%		2.38%	
Common Equity	54.40%	11.35%	6.17%	
Total	100.00%		8.55%	
PA OCA Proposed (2)				
Long-Term Debt	47.68%	5.20%	2.5%	
Short-Term Debt	2.32%	5.00%	0.12%	
Total Debt	50.00%		2.60%	
Common Equity	50.00%	8.90%	4.5%	
Total	100.00%		7.06%	

(1) Exhibit 400 Page 5 - Rea

(2) Exhibit DJG-16

STATEMENT OF RATE BASE	(1)		FPFTY		PA OCA		References
	FTY 11/30/2025	Adjustment	12/31/2026	Adjustment			
Gas Plant In Service	\$ 4,783,387,096	\$ 436,492,629	\$ 5,219,879,725	\$ (14,507,711)	\$ 5,205,372,014		
CWIP	\$ -	\$ -	\$ -	\$ -	\$ -		
Gas Storage Underground - NC	\$ 3,794,693	\$ -	\$ 3,794,693	\$ -	\$ 3,794,693		
Depreciation Reserve	\$ (849,818,430)	\$ (77,393,668)	\$ (927,212,098)	\$ 46,038,899	\$ (881,173,199)		
Accumulated Provision Gas Lost US	\$ (163,467)	\$ -	\$ (163,467)	\$ -	\$ (163,467)		
Net Plant In Service	\$ 3,937,199,892	\$ 359,098,961	\$ 4,296,298,853	\$ 31,531,188	\$ 4,327,830,041		
Working Capital	\$ -	\$ -	\$ -				
Materials and Supplies	\$ 917,192	\$ 30,868	\$ 948,060	\$ (56,977)	\$ 891,083		Remove GDP Inf
Prepayments	\$ 5,470,802	\$ 106,749	\$ 5,577,551	\$ (262,481)	\$ 5,315,070		Remove GDP Inf
Gas Storage Underground	\$ 40,389,919	\$ 10,028,951	\$ 50,418,870	\$ -	\$ 50,418,870		OCA-9-46
Total Working Capital	\$ 46,777,913	\$ 10,166,568	\$ 56,944,481	\$ (319,457)	\$ 56,625,024		
Deferred Income Taxes							
Income Taxes - Acct. 190	\$ 36,924,536	\$ (2,766,587)	\$ 34,157,949	\$ 1	\$ 34,157,950		
Depreciation - Acct. 282	\$ (397,119,422)	\$ (12,560,751)	\$ (409,680,173)	\$ (8,696,053)	\$ (418,376,226)		
Excess ADIT - Acct. 254	\$ (131,261,705)	\$ 2,485,087	\$ (128,776,618)	\$ -	\$ (128,776,619)		
Regulatory Liability Excess ADIT - Acct. 182	\$ 1,425,668	\$ (178,208)	\$ 1,247,460	\$ -	\$ 1,247,460		
Total Deferred Income Taxes	\$ (490,030,923)	\$ (13,020,459)	\$ (503,051,382)	\$ (8,696,053)	\$ (511,747,435)		
Restricted Stock /LTI				\$ (719,400)	\$ (719,400)		OCA 9-9
Capitalized Profit Sharing				\$ (337,136)	\$ (337,136)		I+E RE-16
CTA				\$ (2,263,821)	\$ (2,263,821)		OCA 9-27
Capitalized Incentive				\$ (2,954,093)	\$ (2,954,093)		OCA 14-1
Total Other Adjustments				\$ (5,937,314)	\$ (6,274,450)		
Customer Deposits 13-month average	\$ (4,810,601)	\$ (2,609)	\$ (4,813,210)	\$ -	\$ (4,813,210)		
Customer Advances - Cash Deposits	\$ 2,973	\$ -	\$ 2,973	\$ -	\$ 2,973		
Total Rate Base	\$ 3,489,139,254	\$ 356,242,461	\$ 3,845,381,715	\$ 16,241,227	\$ 3,861,622,942		

(1) Exhibit 108 page 3

STATEMENT OF INCOME		(1)					
	Test Year Present Rates	Adjustments	Test Year Proposed Rates	Adjustments	Present Rates PAOCA	References	
<u>Operation Revenues</u>							
Base Rate Revenues	\$ 637,158,562	\$ 106,587,554	\$ 743,746,116				
Gas Cost Revenues	\$ 245,031,485	\$ -	\$ 245,031,485				
Rider USP	\$ 31,862,500	\$ 3,909,243	\$ 35,771,743				
Gas Procurement Charge	\$ 436,972	\$ -	\$ 436,972				
Merchant Function Charge	\$ 1,187,650	\$ -	\$ 1,187,650				
Rider CC	\$ 45,636	\$ -	\$ 45,636				
Rider EE	\$ 1,235,965		\$ 1,235,965				
Total Sales and Transportation	\$ 916,958,770	\$ 110,496,797	\$ 1,027,455,567	\$ -	\$ 916,958,770		
Off System Sales	\$ -	\$ -	\$ -		\$ -		
Late Payment Fees	\$ 1,896,259	\$ -	\$ 1,896,259	\$ -	\$ 1,896,259		
Other Operating Revenues	\$ 152,805	\$ -	\$ 152,805	\$ -	\$ 152,805		
Total Operating Revenues	\$ 919,007,834	\$ 110,496,797	\$ 1,029,504,631	\$ -	\$ 919,007,834		
12.023%							
<u>Operating Revenue Deductions</u>							
Gas Cost Expense	\$ 245,031,485	\$ -	\$ 245,031,485	\$ -	\$ 245,031,485		
Off System Sales Expense	\$ -	\$ -	\$ -	\$ -	\$ -		
Gas Used in Co. Operations	\$ -	\$ -	\$ -	\$ -	\$ -		
O&M Expenses	\$ 222,116,320	\$ 1,487,426	\$ 223,603,746	\$ (16,757,679)	\$ 206,846,067		
Depreciation and Amortization	\$ 149,371,164	\$ -	\$ 149,371,164	\$ (46,038,863)	\$ 103,332,301		
Net Salvage Amortized	\$ 5,484,681	\$ -	\$ 5,484,681	\$ -	\$ 5,484,681		
Taxes Other Than Income	\$ 4,500,833	\$ -	\$ 4,500,833	\$ (191,398)	\$ 4,309,435		
Total O&M Revenue Deductions	\$ 626,504,483	\$ 1,487,426	\$ 627,991,909	\$ (62,987,939)	\$ 565,003,970		
Operating Income Before Income Taxes	\$ 292,503,351	\$ 109,009,371	\$ 401,512,722	\$ (47,508,858)	\$ 354,003,864		
Income Taxes	\$ 43,469,180	\$ 29,342,161	\$ 72,811,341	\$ (17,543,486)	\$ 55,267,855		
ITC	\$ (78,757)	\$ -	\$ (78,757)	\$ -	\$ (78,757)		
Operating Income	\$ 249,112,928	\$ 79,667,210	\$ 328,780,138	\$ (29,965,372)	\$ 298,814,766		
Rate Base	\$ 3,845,381,715	\$ -	\$ 3,845,381,715	\$ 16,241,227	\$ 3,861,622,942		
Rate of Return	6.4782%		8.5500%		7.06%		
			\$ 328,780,138		\$ 272,630,580		

(1) Company Exhibit 102 Sch. 3 pg 3

GAS PLANT IN SERVICE		(1)		(1)					
		Balance at	Adjustments	Balance at	Adjustments	PA OCA	References		
		11/30/2025		12/31/2026					
Lines 1-6	Intangible Plant	\$ 101,389,385	\$ (3,035,131)	\$ 98,354,254	\$ -	\$ 98,354,254			
Lines 7-17	Other Intangible Plant	\$ 7,614,137	\$ 514,428	\$ 8,128,565		\$ 8,218,565			
Lines 18-31	Distribution Plant	\$ 83,081,002	\$ 2,131,172	\$ 85,212,174	\$ -	\$ 85,212,174			
Lines 32-43	Other Distribution Plant	\$ 4,414,118,985	\$ 413,581,391	\$ 4,827,700,376	\$ (14,507,711)	\$ 4,813,192,665			
Lines 44-56	Other Distribution Plant	\$ 137,013,493	\$ 7,822,962	\$ 144,836,455		\$ 144,836,455			
Lines 57-65	General Plant	\$ 7,439,272	\$ (24,427)	\$ 7,414,845	\$ -	\$ 7,414,845			
Lines 66-79	Other General Plant	\$ 32,730,821	\$ 15,502,233	\$ 48,233,054		\$ 48,233,054			
Total Gas Plant In Service		\$ 4,783,387,095	\$ 436,492,628	\$ 5,219,879,723	\$ (14,507,711)	\$ 5,205,462,012			

OCA 9-14, 17, 31
OCA 9-32, 33
OCA 9-28, 29, 30
OCA 9-34

(1) Exhibit 108 Shedule 1 page 6 and 13

DEPRECIATION RESERVE	(1)					
	Balance at 11/30/2025	Adjustments	Balance at 12/31/2026	Adjustments	PA OCA	References
Underground Storage	\$ 7,049,870	\$ 239,849	\$ 7,289,719	\$ -	\$ 7,289,719	
Distribution Plant	\$ 784,382,174	\$ 74,739,409	\$ 859,121,583	\$ (46,038,899)	\$ 813,082,684	
General Plant	\$ 12,741,222	\$ 1,434,585	\$ 14,175,807	\$ -	\$ 14,175,807	
Non-Depreciable Plant	\$ 235,293		\$ 235,974		\$ 235,974	
Amortizable Plant	\$ 45,409,871	\$ 979,144	\$ 46,389,015	\$ -	\$ 46,389,015	
Total Depreciation Reserve	\$ 849,583,137	\$ 77,628,961	\$ 927,212,098	\$ (46,038,899)	\$ 881,173,199	

(1) Company Exhibit 108 Schedule 3
Tax Repairs / Mixed Services

\$ 4,629,116

DEFERRED INCOME TAXES	(1)					
	Balance at 11/30/2025	Adjustments	Balance at 12/31/2026	Adjustments	PA OCA	References
Account 190 - DIT						
Cap. Inventory Adj. Federal	\$ 927,911	\$ -	\$ 927,911		\$ 927,911	
Cap. Inventory Adj. - State	\$ 232,069	\$ -	\$ 232,069		\$ 232,069	
Customer Advances - Federal	\$ 317,682	\$ -	\$ 317,682		\$ 317,682	
Customer Advances - State	\$ 79,452	\$ -	\$ 79,452		\$ 79,452	
Federal Net Operating Loss	\$ 35,367,422	\$ (2,766,586)	\$ 32,600,836		\$ 32,600,836	
Total Account 190	\$ 36,924,536	\$ (2,766,586)	\$ 34,157,950	\$ -	\$ 34,157,950	
Account 282 - DIT - Depreciation						
Excess Accelerated Tax Depreciation Fed	\$ (397,119,422)	\$ (12,560,750)	\$ (409,680,172)	\$ 8,696,054	\$ (418,376,226)	
Total Account 282	\$ (397,119,422)	\$ (12,560,750)	\$ (409,680,172)	\$ 8,696,054	\$ (418,376,226)	
Account 283 - DIT Other						
Other	\$ -	\$ -	\$ -	\$ -	\$ -	
Total Account 283	\$ -	\$ -	\$ -	\$ -	\$ -	
Account 254 - Regulatory Liability Excess ADIT						
Deficient DIT - 190 NOL Inv. & Cust. Adv.	\$ 21,807,713	\$ (1,198,355)	\$ 20,609,358		\$ 20,609,358	
Excess Accelerated Tax Depre.- Fed	\$ (153,069,418)	\$ 3,683,441	\$ (149,385,977)		\$ (149,385,977)	
Total Account 254	\$ (131,261,705)	\$ (128,776,619)	\$ (128,776,619)		\$ (128,776,619)	
Account 182- Reg. Asset Deficient ADIT						
Deficient DIT - 190 Inv. & Cust. Adv.	\$ 1,425,668	\$ (178,209)	\$ 1,247,459		\$ 1,247,459	
Total Account 182	\$ 1,425,668	\$ (178,209)	\$ 1,247,459		\$ 1,247,459	
Total Accumulated Deferred Taxes	\$ (490,030,923)	\$ (13,020,459)	\$ (503,051,382)	\$ (8,696,054)	\$ (511,747,436)	OCA 9-40, 41 OCA 9-38, 39, 40 OCA 9-41, 42, 43 OCA 9-45

(1) Exhibit 108 Schedule 8 page 1

OPERATING REVENUES	(1)					
	Test Year Present Rates	Adjustments	Test Year Proposed Rates	Adjustments	Present Rates PAOCA	References
Rate Schedule RSS	\$ 545,431,731	\$ 65,422,355	\$ 610,854,086			
Rate Schedule RDGSS	\$ 45,141,212	\$ -	\$ 45,141,212			
Rate Schedule SGSS	\$ 114,868,308	\$ 12,872,197	\$ 127,740,505			
Rate Schedule NSS	\$ 239,279	\$ -	\$ 239,279			
Rate Schedule LGSS	\$ 12,286,267	\$ 1,076,936	\$ 13,363,203			
Residential Distribution RDS	\$ 62,220,162	\$ 8,453,881	\$ 70,674,043			
Small Commercial Distribution SCD	\$ 36,993,449	\$ 5,124,961	\$ 42,118,410			
Small General Distribution SGDS	\$ 28,291,595	\$ 4,733,347	\$ 33,024,942			
Small Distribution SDS	\$ 37,055,677	\$ 6,510,883	\$ 43,566,560			
Large Distribution Service LDS	\$ 29,465,668	\$ 6,301,521	\$ 35,767,189			
Main Line Distribution Service MLDS	\$ 508,155	\$ -	\$ 508,155			
Main Line Distribution Service II	\$ 1,343,276	\$ -	\$ 1,343,276			
Flexible Rate / Negotiated Contract	\$ 3,113,991	\$ 644	\$ 3,114,635			
Total Base Rate Revenues	\$ 916,958,770	\$ 110,496,725	\$ 1,027,455,495		\$ 916,958,770	
Other Operating Revenue						
Forfeited Discounts	\$ 1,896,259	\$ -	\$ 1,896,259		\$ 1,896,259	
Misc. Service Revenues	\$ 107,664	\$ -	\$ 107,664		\$ 107,664	
Other Gas Revenues	\$ 45,141	\$ -	\$ 45,141		\$ 45,141	
Other	\$ -	\$ -	\$ -		\$ -	
Total Operating Revenues	\$ 919,007,834	\$ 110,496,725	\$ 1,029,504,559	\$ -	\$ 919,007,834	

(1) Company Exhibit 103 page 8 and 9

O&M EXPENSE COST ELEMENTS	(1)						PAOCA	References
	12/31/2026		12/31/2026					
	Test Year		Test Year					
	Present Rates	Adjustments	Proposed Rates	Adjustments				
Labor	\$ 38,770,674	\$ -	\$ 38,770,674	\$ (1,698,622)	\$ 37,072,052			
Incentive Compensation	\$ 2,568,808	\$ -	\$ 2,568,808	\$ (2,552,612)	\$ 16,196			
Pension	\$ -	\$ -	\$ -	\$ -	\$ -			
Pension Deferral Amortization	\$ 844,977	\$ -	\$ 844,977	\$ 0	\$ 844,977			
OPEB	\$ -	\$ -	\$ -	\$ -	\$ -			
Other Employee Benefits	\$ 8,915,459	\$ -	\$ 8,915,459	\$ (390,741)	\$ 8,524,718			
Outside Services	\$ 18,013,909	\$ -	\$ 18,013,909	\$ (1,436,907)	\$ 16,577,002			
Building Rents / Leases	\$ 734,000	\$ -	\$ 734,000	\$ -	\$ 734,000			
Other Rent and Leases	\$ 545,640	\$ -	\$ 545,640	\$ -	\$ 545,640			
Corporate Insurance	\$ 4,452,228	\$ -	\$ 4,452,228	\$ (131,774)	\$ 4,320,454			
Injury and Damages	\$ 405,057	\$ -	\$ 405,057	\$ (51,257)	\$ 353,800			
Employee Expenses	\$ 1,275,033	\$ -	\$ 1,275,033	\$ (34,245)	\$ 1,240,788			
Company Memberships	\$ 682,796	\$ -	\$ 682,796	\$ (253,872)	\$ 428,924			
Utilities / Company Used Gas	\$ 2,075,819	\$ -	\$ 2,075,819	\$ 28,758	\$ 2,104,577			
Advertising	\$ 391,359	\$ -	\$ 391,359	\$ 11,365	\$ 402,724			
Fleet & Other Clearing	\$ 7,518,942	\$ -	\$ 7,518,942	\$ -	\$ 7,518,942			
Materials & Supplies	\$ 6,080,827	\$ -	\$ 6,080,827	\$ (558,615)	\$ 5,522,212			
Other O&M	\$ 173,561	\$ -	\$ 173,561	\$ -	\$ 173,561			
PUC, OCA, OSBA Fees	\$ 3,299,312	\$ -	\$ 3,299,312	\$ -	\$ 3,299,312			
NCSC - Shares Services	\$ 79,191,883	\$ -	\$ 79,191,883	\$ (7,669,076)	\$ 71,522,807			
NCSC - Other	\$ -	\$ -	\$ -	\$ -	\$ -			
DEI costs - Net	\$ -	\$ -	\$ -	\$ (130,450)	\$ (130,450)	OCA-9-13		
Lobbying	\$ -	\$ -	\$ -	\$ -	\$ -			
Charitable Contributions	\$ -	\$ -	\$ -	\$ -	\$ -			
	\$ 175,940,284	\$ -	\$ 175,940,284	\$ (14,868,047)	\$ 161,072,237			
Rate Case Expenses	\$ 1,321,000	\$ -	\$ 1,321,000	\$ (182,207)	\$ 1,138,793			
Uncollectible Accounts	\$ 9,487,724	\$ 1,487,431	\$ 10,975,155	\$ (1,487,431)	\$ 9,487,724			
Uncollectible Accounts - Unbundled Gas	\$ 1,187,650	\$ -	\$ 1,187,650	\$ -	\$ 1,187,650			
COVID - 19 Amortization	\$ 708,091	\$ -	\$ 708,091		\$ 708,091			
Rider USP	\$ 31,862,500	\$ -	\$ 31,862,500	\$ (220,000)	\$ 31,642,500			
Rider EE	\$ 1,235,965	\$ -	\$ 1,235,965		\$ 1,235,965			
Interest on Customer Deposits	\$ 373,107	\$ -	\$ 373,107	\$ -	\$ 373,107			
Other	\$ -	\$ -	\$ -	\$ -	\$ -			
Total O&M Expenses	\$ 222,116,321	\$ 1,487,431	\$ 223,603,752	\$ (16,757,684)	\$ 206,846,067			
Additional Uncollectible Accounts					\$ (488,873)			

(1) Company Exhibit 104 Schedule 1

LABOR	(1)			
	Company Proposed	Adjustments	PA OCA	References
HTY Labor - 11/30/2024	\$ 37,521,285	\$ -	\$ 37,521,285	
HTY Labor 11/30/2024 Normalized Budget	\$ 1,191,488		\$ 1,191,488	
FTY Budget	\$ 38,712,773	\$ -	\$ 38,712,773	
Budget Adjustments FTY				
Total Labor Adjustment	\$ -	\$ -	\$ -	
Additional Headcount	\$ -	\$ -	\$ -	
Other	\$ -	\$ -	\$ -	
Total Budget Adjustments FTY	\$ -	\$ -	\$ -	
Rate Making Adjustments - FTY				
Labor Adjustment - \$931,713 *50.57%	\$ 471,184	\$ -	\$ 471,184	
Less Lobbying	\$ (12,415)		\$ (12,415)	
Total Labor Adjustment	\$ 458,769		\$ 458,769	
Budget Adjustment FPFTY				
Labor Adjustment	\$ (785,157)	\$ -	\$ (785,157)	
	\$ -	\$ -	\$ -	
Total Budget Adjustments FPFTY	\$ (785,157)	\$ -	\$ (785,157)	
Rate Making Adjustments - FPFTY				
Labor Adjustment - \$785,157 * 50.57%	\$ 397,075	\$ -	\$ 397,075	
Less Lobbying	\$ (12,787)		\$ (12,787)	
Total Labor Adjustment	\$ 384,288		\$ 384,288	
Total Labor - FPFTY	\$ 38,770,673	\$ (1,698,621)	\$ 37,072,052	

OCA-9-19, 20
I&E RE-11
Attachment B

- (1) Exhibit 104 Schedule 2 page 1
Gas RR-026 Attachment A
Vacancy Rate Ratio

4.3812%

INCENTIVE COMPENSATION	(1)				
	Company Proposed	Adjustment	PA OCA	References	
HTY Balance 11/30/2024 - Normalized					
Expense	\$ 3,823,624	\$ -	\$ 3,823,624		
Capital	\$ 3,737,157		\$ 3,737,157		
Total Incentive	\$ 7,560,781		\$ 7,560,781		
Budget Adjustment FTY					
Expense	\$ 2,067,046	\$ -	\$ 2,067,046		
Capital	\$ 2,020,302		\$ 2,020,302		
Total Incentive	\$ 4,087,348		\$ 4,087,348		
Normalized FTY 11/30/2025	\$ 2,742,912		\$ 2,742,912		
Difference	\$ 1,080,712		\$ 1,080,712		
Budget Adjustment FPFTY					
Expense Adjustment	\$ 61,522	\$ -	\$ 61,522		
Capital Adjustment	\$ 60,131		\$ 60,131		
Total Budgeted Adjustment	\$ 121,653		\$ 121,653		
Ratemaking Adjustment FPFTY					
Expense Adjustment	\$ (174,105)		\$ (174,105)		
Capital Adjustment	\$ -		\$ -		
Total Ratemaking Adjustment	\$ (174,105)		\$ (174,105)		
Total Incentive Compensation FPFTY	\$ 2,568,807	\$ (1,798,165)	\$ 770,642		
Restricted Stock/LTI		\$ (754,446)	\$ (754,446)	OCA-9-9	
		\$ (2,552,611)			

(1) Exhibit 104 Schedule 1 pages 2 -4
Exhibit Gas RR-026 Attachment A

PENSION / PENSION DEFERRAL AMORTIZATION	(1)				References
	Company Proposed	Adjustment	PA OCA		
2017 Pension Prepayment	\$ 8,449,772	\$ -	\$ 8,449,772		
Amortization Period	10		10		OCA 9-21
FPFTY Adjustment to Amortize	\$ 844,977	\$ -	\$ 844,977		

(1) Exhibit 104 Schedule 2 page 2

OTHER EMPLOYEE BENEFITS	(1)			PA OCA	References
	Company Proposed	Adjustments			
HTY Balance 11/30/2024	\$ 8,139,063	\$ -	\$ 8,139,063		
Profit Sharing		\$ -	\$ -		I&E RE-15
Budget Adjustment FTY	\$ 235,749	\$ -	\$ 235,749		
Subtotal	\$ 8,374,812	\$ -	\$ 8,374,812		
Profit Sharing		\$ -	\$ -		I&E RE-16
Budget Adjustment FPFTY	\$ 540,647	\$ -	\$ 540,647		
Profit Sharing		\$ -	\$ -		I&E RE-16
			\$ (390,741)		
Total Employee Benefits FPFTY	\$ 8,915,459	\$ (390,741)	\$ 8,524,718		I&E RE- 15 I&E RE-16, 17 OCA Set 14-1
Benefits per OCA Labor Costs		\$ 8,524,718			
Adjustments		\$ (390,741)			

(1) Exhibit 104 Schedule 1 page 2 - 4

OUTSIDE SERVICES	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 16,852,517	\$ (1,444,261)	\$ 15,408,256		I&E RE-19
Miscellaneous Adjustment	\$ -	\$ -	\$ -		
Budgeted Adjustments FTY					
Outside Services overspend	\$ -	\$ -	\$ -		
Time Shift of work (riser and cross bore)	\$ -	\$ -	\$ -		
Meter Protection	\$ -	\$ -	\$ -		
M&R Station	\$ -	\$ -	\$ -		
GPS Work	\$ -	\$ -	\$ -		
Leak Inspection	\$ -	\$ -	\$ -		
All Other Variances	\$ -	\$ -	\$ -		
	\$ 2,286,399	\$ -	\$ 2,286,399		
Budgeted FTY Outside Services	\$ 19,138,916	\$ (1,444,261)	\$ 17,694,655		
Rate Making Adjustment FTY					
Lobbying	\$ (124,725)	\$ 3,550	\$ (121,175)		
		-2.930%			
FTY Balance 11/30/2018	\$ 19,014,191	\$ (1,440,711)	\$ 17,573,480		I&E RE-18 GAS-RR-052
Budgeted Amount FPFTY					
Adjustment	\$ (871,753)	\$ -	\$ (871,753)		
Other	\$ -	\$ -	\$ -		
Budgeted Amount FPFTY	\$ (871,753)	\$ -	\$ (871,753)		
Rate Making Amount FPFTY					
Lobbying	\$ (128,529)	\$ 3,804	\$ (124,725)		
		-3.050%			
FPFTY Balance	\$ 18,013,909	\$ (1,436,907)	\$ 16,577,002		

(1) Exhibit 104 Schedule 1 page 3-4 of 6

BUILDING RENTS / LEASES	(1)			
	Company Proposed	Adjustments	PA OCA	References
HTY Balance 11/30/2024	\$ 727,583			
Budget Adjustment FTY	\$ 39,662			
Balance	\$ 767,245	\$ -	\$ 767,245	
Rate Making Adjustment FTY	\$ (18,755)	\$ -	\$ (18,755)	
Budget Adjustment FPFTY	\$ 748,490		\$ 748,490	
Budget Adjustment	\$ (32,195)	\$ -	\$ (32,195)	
Rate Making Adjustment FPFTY	\$ 17,705	\$ -	\$ 17,705	
FPFTY Balance	\$ 734,000	\$ -	\$ 734,000	

(1) Exhibit 104 Schedule 1 pages 3-4 of 6

OTHER RENT AND LEASES	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 475,203	\$ -	\$ 475,203		I&E RE-21
Budget Adjustment FTY	\$ 71,365	\$ -	\$ 71,365		
Rate Making Adjustment FTY	\$ -	\$ -	\$ -		
Budget Adjustment FPFTY	\$ (928)	\$ -	\$ (928)		
Rate Making Adjustment FPFTY	\$ -	\$ -	\$ -		
FPFTY Balance	\$ 545,640	\$ -	\$ 545,640		OCA Set 14-2

(1) Exhibit 104 Schedule 1 pages 3-4 of 6

<u>CORPORATE INSURANCE</u>	(1)			
	Company Proposed	Adjustments	PA OCA	References
HTY Balance 11/30/2024	\$ 4,320,454	\$ (131,774) -3.05%	\$ 4,188,680	
Budget Adjustments FTY	\$ 471,340	\$ -	\$ 471,340	
Rate Making Adjustment FTY	\$ (471,340)	\$ -	\$ (471,340)	
Budget Adjustment FPFTY	\$ 612,949	\$ -	\$ 612,949	
Rate Making Adjustment FPFTY	\$ (481,175)	\$ -	\$ (481,175)	
FPFTY Balance	\$ 4,452,228	\$ (131,774)	\$ 4,320,454	

- (1) Exhibit 104 Schedule 1
Exhibit 104 Schedule 2 page 7
Exhibit 4 Schedule 2

INJURY AND DAMAGES	(1)			
	Company Proposed	Adjustments	PA OCA	References
HTY Balance 11/30/2024	\$ 381,879	\$ (28,079)	\$ 353,800	OCA-Set 9-22
Budget Adjustment FTY	\$ (219,455)	\$ -	\$ (219,455)	
Rate Making Adjustment FTY	\$ 230,644	\$ (11,189) -2.93%	\$ 219,455	
Budget Adjustment FPFTY	\$ (256,520)	\$ -	\$ (256,520)	
Rate Making Adjustment FPFTY	\$ 268,509	\$ (11,989) -3.05%	\$ 256,520	
FPFTY Balance	\$ 405,057	\$ (51,257)	\$ 353,800	

(1) Exhibit 104 Schedule 1 pages 3-4 of 6

EMPLOYEE EXPENSES	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 1,257,246	\$ (45,607)	\$ 1,211,639		
Budget Adjustment FTY	\$ 210,401	\$ -	\$ 210,401		
Rate Making Adjustment FTY	\$ (192,677)	\$ 5,485 2.93%	\$ (187,192)		
Budget Adjustment FPFTY	\$ 198,617	\$ -	\$ 198,617		
Rate Making Adjustment FPFTY	\$ (198,554)	\$ 5,877 -3.05%	\$ (192,677)		
FPFTY Balance	\$ 1,275,033	\$ (34,245)	\$ 1,240,788		I&E RE-28/29 OCA Set 14-3

(1) Exhibit 104 Schedule 1 pages 3-4 of 6

COMPANY MEMBERSHIPS	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 668,085	\$ (260,661)	\$ 407,424		GAS-RR-032
Budget Adjustments FTY	\$ 61,826	\$ -	\$ 61,826		
Rate Making Adjustment FTY	\$ (41,430)	\$ 3,343	\$ (38,087)		
		0.0296%			
Budget Adjustments FPFTY	\$ 37,010	\$ -	\$ 37,010		
Rate Making Adjustment FPFTY	\$ (42,694)	\$ 3,445	\$ (39,249)		
		3.051%			
FPFTY Balance	\$ 682,797	\$ (253,873)	\$ 428,924		I&E RE-30

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
See Exhibit 4 Schedule 2 page 13

UTILITIES AND FUEL USED IN COMPANY OPERATIONS	(1)				References
	Company Proposed	Adjustments	PA OCA		
HTY Balance 11/30/2024	\$ 2,573,883	\$ -	\$ 2,573,883		
Budget Adjustment FTY	\$ (17,931)	\$ -	\$ (17,931)		
Rate Making Adjustment	\$ (487,713)	\$ 13,883 2.93%	\$ (473,830)		
Budget Adjustment FPFTY	\$ 510,168	\$ -	\$ 510,168		
Rate Making Adjustment FPFTY	\$ (502,588)	\$ 14,875 -3.05%	\$ (487,713)		
FPFTY Balance	\$ 2,075,819	\$ 28,758	\$ 2,104,577		I&E RE-31

- (1) Exhibit 104 Schedule 1 pages 3-4 of 6
Exhibit 104 Schedule 2 page 10

ADVERTISING	(1)				
	Company Proposed	Adjustment	PA OCA	References	
HTY Balance 11/30/2024	\$ 505,077	\$ -	\$ 505,077	I&E RE 033	
Budget Adjustment FTY	\$ 85,275	\$ -	\$ 85,275		
Rate Making Adjustment FTY	\$ (192,762)	\$ 5,487	\$ (187,275)		
		2.93%			
Budget Adjustment FPFTY	\$ 192,409	\$ -	\$ 192,409		
Rate Making Adjustment FPFTY	\$ (198,641)	\$ 5,879	\$ (192,762)		
		-3.05%			
FPFTY Balance	\$ 391,358	\$ 11,366	\$ 402,724		

- (1) Exhibit 104 Schedule 1 pages 3-4 of 6
Exhibit 4 Schedule 8

FLEET AND OTHER CLEARING	(1)				
	Company Proposed	Adjustment	PA OCA	References	
HTY Balance 11/30/2024	\$ 8,851,664	\$ -	\$ 8,851,664	I&E RE-34	
Budget Adjustment FTY	\$ (1,103,686)	\$ -	\$ (1,103,686)		
Rate Making Adjustment FTY	\$ -	\$ -	\$ -		
Budget Adjustment FPFTY	\$ (229,036)	\$ -	\$ (229,036)		
Rate Making Adjustment FPFTY	\$ -	\$ -	\$ -		
FPFTY Balance	\$ 7,518,942	\$ -	\$ 7,518,942	OCA-Set 14- 4	

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
Check discovery

<u>MATERIALS AND SUPPLIES</u>	(1)				References
	Company Proposed	Adjustment	PA OCA		
HTY Balance 11/30/2024	\$ 7,622,402	\$ (558,615)	\$ 7,063,787		I&E RE-35
Budget Adjustment FTY	\$ (1,093,275)	\$ -	\$ (1,093,275)		
Rate Making Adjustment FTY	\$ (3,343)	\$ -	\$ (3,343)		
Budget Adjustment FPFTY	\$ (441,512)	\$ -	\$ (441,512)		
Rate Making Adjustment FPFTY	\$ (3,445)	\$ -	\$ (3,445)		
FPFTY	\$ 6,080,827	\$ (558,615)	\$ 5,522,212		OCA-Set-14-5

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
See Discovery Responses

OTHER O&M	(1)		PA OCA	References
	Company Proposed	Adjustment		
HTY Balance 11/30/2024	\$ 113,347	\$ -	\$ 113,347	I&E RE-36
Budget Adjustment FTY	\$ 448,433	\$ -	\$ 448,433	
Rate Making Adjustment FTY	\$ -	\$ -	\$ -	
Budget Adjustment FPFTY	\$ (388,219)	\$ -	\$ (388,219)	
Rate Making Adjustment FPFTY	\$ -	\$ -	\$ -	
FPFTY Balance	\$ 173,561	\$ -	\$ 173,561	OCA-Set-14-6

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
See Discovery Responses

PUC OCA OSBA FEES	(1)			
	Company Proposed	Adjustment	PA OCA	References
HTY Balance 11/30/2024				
PUC Assessment	\$ 2,931,893	\$ -	\$ 2,931,893	
OCA Assessment	\$ 303,059	\$ -	\$ 303,059	
OSBA Assessment	\$ 64,360	\$ -	\$ 64,360	
	\$ 3,299,312	\$ -	\$ 3,299,312	
Budget Adjustment FTY	\$ -	\$ -	\$ -	
Rate Making Adjustment FTY	\$ -	\$ -	\$ -	
Budget Adjustment FPFTY	\$ -	\$ -	\$ -	
Rate Making Adjustment FPFTY	\$ -	\$ -	\$ -	
FPFTY Balance	\$ 3,299,312	\$ -	\$ 3,299,312	

(1) Exhibit 104 Schedule 1 pages 3-4 of 6
Exhibit 4 Schedule 2 Page 18

NCSC-SHARED SERVICES		(1)			
	Company	Adjustment	PA OCA	References	
	Proposed				
HTY Balance 11/30/2024	\$ 81,633,879	\$ -	\$ 81,633,879		
Budget Adjustments 11/30/2025	\$ 929,824		\$ 929,824		
Rate Making Adjustments 11/30/2025	\$ (309,385)	\$ 14,731	\$ (294,654)		
		2.93%			
FTY Balance adjusted 11/30/2025	\$ 82,254,318	\$ 14,731	\$ 82,269,049		I&E RE-38
Budget Adjustments					
Labor /Benefits/Incentive Comp	\$ -	\$ -	\$ -		
External Services	\$ -	\$ -	\$ -		
Other O&M Expense	\$ -	\$ -	\$ -		
Depreciation, Other Taxes	\$ -	\$ -	\$ -		
All Other Adjustments	\$ -	\$ -	\$ -		
Total Budget Adjustments	\$ (2,680,225)		\$ (2,680,225)		
Budget Adjustments FPFTY	\$ 79,574,093	\$ 14,731	\$ 79,588,824		
Ratemaking Adjustments					
Labor/Benefits/Incentive Comp	\$ -	\$ -	\$ -		
External Services	\$ -	\$ -	\$ -		
Other O&M Expenses	\$ -	\$ -	\$ -		
Depreciation, Other Taxes	\$ -	\$ -	\$ -		
All Other Adjustments	\$ -	\$ -	\$ -		
FPFTY Ratemaking Adjusments	\$ (382,209)	\$ 15,783	\$ (366,426)		
		3.05%			
FPFTY Balance	\$ 79,191,884	\$ (7,669,077)	\$ 71,522,807		OCA Set-14-7
Resticted Stock/LTI		\$ (4,012,229)	\$ (4,012,229)		OCA 9-9
SERP		\$ (136,102)	\$ (136,102)		OCA 9-10
Discretionary Bonuses		\$ -	\$ -		OCA 14-7
		\$ (4,148,331)			
Oher Incentive Compensation		\$ (3,520,746)			OCA-14-9 OCA-14-8

- (1) Exhibit 104 Schedule 1 pages 3-4 of 6
(2) Exhibit 4 Schedule 2 page 17

RATE CASE EXPENSES	(1)				References
	Company Proposed	Adjustments	PA OCA		
Gannett Fleming	\$ 60,000				
Regulatory Finance Associates	\$ 90,000				
Atrium Economics	\$ 276,000				
Post and Schell	\$ 750,000				
Green Efficiency Group	\$ 60,000				
Legal Notices	\$ 55,000				
Travel Expenses	\$ 5,000				
Miscellaneous	\$ 25,000				
Total	\$ 1,321,000	\$ -	\$ 1,321,000		
Amortization Period	1.0		1.2		
FPFTY Total	\$ 1,321,000	\$ (182,207)	\$ 1,138,793		OCA-9-24

(1) Exhibit 104 Schedule 2 page 16

UNCOLLECTIBLES	(1)				
	Company Proposed	Adjustments	PA OCA	References	
HTY Balance 11/30/2024					
Base Rate Uncollectibles	\$ 9,459,959	\$ -	\$ 9,459,959		
Unbundled Uncollectibles	\$ 1,169,096	\$ -	\$ 1,169,096		
FTY Adjustment 11/30/2025					
Base Rate Uncollectibles (2)	\$ 26,770	\$ -	\$ 26,770		
Unbundled Uncollectibles (2)	\$ 11,865	\$ -	\$ 11,865		
FPFTY Adjustment 12/31/2026					
Base Rate Uncollectibles	\$ 995	\$ -	\$ 995		
Unbundled Uncollectibles	\$ 6,689	\$ -	\$ 6,689		
FPFTYP Proforma Balance 12/31/2026					
Base Rate Uncollectible	\$ 9,487,724		\$ 9,487,724		
Unbundled Uncollectible	\$ 1,187,650		\$ 1,187,650		
Total	\$ 10,675,374		\$ 10,675,374		
Base Rate			\$ (36,316,933)		
			0.01346130	OCA 14-10	
			\$ (488,873)		
Unbundled					

- (1) Exhibit 104 Schedule 1 page 3
(2) Exhibit 104 Schedule 2 page 17
Review Uncollectible testimony

COVID-19 AMORTIZATION				
	(1)			
	Company			
	Proposed	Adjustment	PA OCA	References
FPFTY Balance 12/31/2026	\$ 2,832,363	\$ -	\$ 2,832,363	
Amortization Period	4	0	4	
Annual Amortization	\$ 708,091	\$ -	\$ 708,091	OCA-9-23

(1) Exhibit 104 Schedule 2 page 18

RIDER USP					References
RIDER EE					
	(1) Company Proposed	Adjustment	PA OCA		
Rider USP					
HTY Balance	\$ 31,769,765				
Adjustment	\$ 75,397				
FTY Balance	\$ 31,845,162				
Adjustment	\$ 17,338				
FPFTY Balance	\$ 31,862,500	\$ (220,000)	\$ 31,642,500		OCA-Set 8-1
Rider EE					
HTY Balance	\$ 1,232,368				
Adjustment	\$ 2,925				
FTY Balance	\$ 1,235,293				
Adjustment	\$ 672				
FPFTY Balance	\$ 1,235,965		\$ 1,235,965		

(1) Company Exhibit 104 Schedule 2 page 19

DEPRECIATION / AMORTIZATION EXPENSE		(1)					
		COMPANY PROPOSED					
Account No.		Original Cost	Rate	Expense	Adjustments	PA OCA	References
	FPFTY Balance						
350.2-355.0	Underground Storage	\$ 8,104,684	2.5300%	\$ 205,049	\$ -	\$ 205,049	
	Distribution Plant						
	Land and Land Rights (374)	\$ 14,597,875	1.4971%	\$ 218,546			
	Structures and Improvements (375)	\$ 60,955,315	2.5651%	\$ 1,563,556			
	Mains (376)	\$ 3,557,111,302	2.2953%	\$ 81,645,103	\$ (236,476)		
	Meas & Reg Equip (378-379)	\$ 198,071,623	3.2366%	\$ 6,410,749			
	Services (380)	\$ 1,012,853,468	3.2344%	\$ 32,759,583			
	Meters (381)	\$ 59,663,983	2.6405%	\$ 1,575,424			
	Meters AMR (381)	\$ 29,057,053	2.6172%	\$ 760,481			
	Meter Installations (382)	\$ 58,083,634	1.9382%	\$ 1,125,750			
	House Regulators (383)	\$ 22,247,918	2.0720%	\$ 460,972			
	House Regulator Installations (384)	\$ 3,546,998	1.2812%	\$ 45,444			
	Industry Meas & Reg Equip Other (385)	\$ 10,750,260	4.7393%	\$ 509,488			
	Other General (387)	\$ 21,150,593	4.5644%	\$ 965,399			
	Other CIS (387)	\$ -	0.0000%	\$ -			
	GPS Equip (387)	\$ -	0.0000%	\$ -			
	Total Distribution Plant	\$ 5,048,090,022		\$ 128,040,495	\$ (236,476)	\$ 127,804,019	
	General Plant						
	Structures -Improvements (390)	\$ 49,821	0.0000%	\$ -			
	Office Furn & Fix (391)	\$ 7,339,407	4.9340%	\$ 362,125			
	Transportation (392)	\$ 25,617	0.0000%	\$ -			
	Tools, Shop & Garage (394)	\$ 39,447,764	3.9961%	\$ 1,576,376			
	Laboratory (395)	\$ 264,921	5.4012%	\$ 14,309			
	Power Operated Equip (396)	\$ 948,698	0.0000%	\$ -			
	Communication-Telemetry (397)	\$ 6,391,394	6.5711%	\$ 419,983			
	Misc (398)	\$ 1,180,276	6.0408%	\$ 71,298			
	Total General Plant	\$ 55,647,898		\$ 2,444,091		\$ 2,444,091	
	Subtotal	\$ 5,111,842,604		\$ 130,689,635	\$ (236,475)	\$ 130,453,159	
	D. Garrett Recommendation				\$ (45,802,423)	\$ 84,650,736	
303.0-375.71	Amortizable Plant	\$ 104,503,946	17.8764%	\$ 18,681,565		\$ 18,681,565	
	Non Depreciable Plant	\$ 3,533,173					
	Total Gas Plant	\$ 5,219,879,723		\$ 149,371,200	\$ (46,038,898)	\$ 103,332,301	(2)
	Five Year Amortization of NNS			\$ 5,484,681	\$ -	\$ 5,484,681	

(1) Exhibit 105 pages 7-10

(2) Exhibit DJG-17

<u>TAXES OTHER THAN INCOME</u>	(1)				References
	Company Proposed	Adjustment	PA OCA		
FICA	\$ 2,986,116	\$ (187,573)	\$ 2,798,543	(3)	
FUTA & SUTA	\$ 97,544	\$ -	\$ 97,544		
Property Taxes	\$ 1,372,160	\$ (3,824)	\$ 1,368,336	(2)	
Capital Stock	\$ -	\$ -	\$ -		
License and Franchise	\$ -	\$ -	\$ -		
Sales and Use	\$ 37,943	\$ -	\$ 37,943		
Other	\$ 7,069	\$ -	\$ 7,069		
Total	\$ 4,500,832	\$ (191,397)	\$ 4,309,435		OCA-Set 14-11

(1) Exhibit 106 Schedule 2 page 2

(2)

(3) Recommended Labor and Incentive
Compensation times FICA Factor of
7.39520%

FEDERAL AND STATE INCOME TAX	(1)		(2)				References
	Company Proposed						
	FPFTY Current Rates	Adjustments	FPFTY Proposed Rates	Adjustments	PA OCA Current Rates		
Operating Revenues	\$ 919,007,834	\$ 110,496,797	\$ 1,029,504,631		\$ 919,007,834		
Net Gas Purchased for Resale	\$ (245,031,485)	\$ -	\$ (245,031,485)	\$ -	\$ (245,031,485)		
Operation & Maintenance Expense	\$ (222,116,320)	\$ (1,487,426)	\$ (223,603,746)	\$ 16,757,679	\$ (206,846,067)		
Depreciation and Amortization Expense	\$ (154,855,845)	\$ -	\$ (154,855,845)	\$ 46,038,863	\$ (108,816,982)		
Taxes Other Than Income	\$ (4,500,833)	\$ -	\$ (4,500,833)	\$ 191,398	\$ (4,309,435)		
Net Operating Income Before IT	\$ 292,503,351	\$ 109,009,371	\$ 401,512,722	\$ (47,508,858)	\$ 354,003,864		
Other Income and Charges	\$ -	\$ -	\$ -		\$ -		
Net Income Before IT	\$ 292,503,351	\$ 109,009,371	\$ 401,512,722	\$ (47,508,858)	\$ 354,003,864		
<u>Statutory Adjustments</u>							
Interest on Debt	\$ (91,366,270)	\$ -	\$ (91,366,270)	\$ 8,856,747	\$ (100,223,017)		
Employee Business Expense	\$ 330,313	\$ -	\$ 330,313	\$ -	\$ 330,313		
Employee Stock Purchase Plan	\$ 50,885	\$ -	\$ 50,885	\$ -	\$ 50,885		
Parking	\$ 21,792	\$ -	\$ 21,792	\$ -	\$ 21,792		
Total Flow Through Adjustments	\$ (90,963,280)	\$ -	\$ (90,963,280)	\$ 8,856,747	\$ (99,820,027)		
<u>Deferred Adjustments</u>							
Excess Tax Depreciation Over Book	\$ (35,165,499)		\$ (35,165,499)	\$ (41,409,747)	\$ (76,575,246)	OCA-Set 14-12	
Repairs on Gas Pipeline	\$ (95,267,133)		\$ (95,267,133)		\$ (95,267,133)	OCA-Set-14-12	
Sec. 263 Mixed Service Costs	\$ (1,819,238)		\$ (1,819,238)		\$ (1,819,238)	OCA Set 14-14	
Loss on Retire. ACRS/MACRS Prop Basis	\$ -		\$ -			OCA-Set 9-44	
CIAC	\$ -		\$ -				
Total Deferred Adjustments	\$ (132,251,870)		\$ (132,251,870)	\$ (41,409,747)	\$ (173,661,617)	OCA Set 9-42	
TOTAL STATUTORY ADJUSTMENTS	\$ (223,215,150)		\$ (223,215,150)	\$ (50,266,494)	\$ (273,481,644)	OCA-Set 9-43 OCA-Set 9-41	
PA Bonus Depr. Adj.	\$ (7,704,734)		\$ (7,704,734)	\$ -	\$ (7,704,734)		
Taxable Income	\$ 61,583,467		\$ 170,592,838	\$ (97,775,351)	\$ 72,817,487		
Deductible State Income Tax	\$ (4,612,602)	\$ (8,164,802)	\$ (12,777,404)	\$ 7,323,374	\$ (5,454,030)		
Taxable Income	\$ 64,675,600	\$ 100,844,569	\$ 165,520,168	\$ (90,451,978)	\$ 75,068,191		
Federal Income Tax @ 21%	\$ 13,581,876	\$ 21,177,360	\$ 34,759,235	\$ (18,994,915)	\$ 15,764,320		
Deferred Income Tax @21%	\$ (27,772,893)	\$ -	\$ (27,772,893)	\$ (8,696,047)	\$ (36,468,940)		
Tax Refund Amortization	\$ -	\$ -	\$ -	\$ -	\$ -		
Flow Back of Excess DIT	\$ (2,498,191)	\$ -	\$ (2,498,191)	\$ -	\$ (2,498,191)		
Effect of CBIT DIT	\$ -	\$ -	\$ -	\$ -	\$ -		
Total FIT Expense	\$ (38,856,578)	\$ 21,177,360	\$ (60,033,937)	\$ 10,298,868	\$ (49,735,069)		
Amortization of ITC	\$ (78,757)	\$ -	\$ (78,757)	\$ -	\$ (78,757)		
Net FIT Expense	\$ (38,777,821)	\$ 21,177,360	\$ (60,112,694)	\$ 10,298,868	\$ (49,813,826)		
State Income Tax	\$ 4,612,602	\$ 8,164,802	\$ 12,777,404	\$ (7,323,374)	\$ 5,454,030		
Total Income Tax Expense	\$ (43,390,422)	\$ 29,342,161	\$ (72,890,098)	\$ 17,622,242	\$ (55,267,855)		
			\$ (72,811,341)	\$ 17,622,242	\$ (55,189,098)		
Exhibit 107							
Rate Base times Cost of Debt	\$ 100,223,017						
Company Proposed	\$ (91,366,270)						
Adjustment	\$ 8,856,747						

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

Columbia Gas of Pennsylvania, Inc.

:
:
:
:
:
:
:

Docket No. R-2025-3053499

VERIFICATION

I, Dante Mugrace, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 2SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: July 31, 2025

Signature: /s/ Dante Mugrace
Dante Mugrace

Address: 22 Brooks Avenue,
Gaithersburg, MD 20877

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**Pennsylvania Public Utility Commission :
v. : Docket No. R-2025-3053499
Columbia Gas of Pennsylvania :**

DIRECT TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

June 18, 2025

TABLE OF CONTENTS

I.	INTRODUCTION	1
II.	EXECUTIVE SUMMARY	2
A.	Rate of Return Summary	2
B.	Depreciation Summary	4

Part One: Rate of Return

III.	REGULATORY STANDARDS	7
IV.	GENERAL CONCEPTS AND METHODOLOGY	10
V.	RISK AND RETURN CONCEPTS	13
VI.	DISCOUNTED CASH FLOW ANALYSIS	20
A.	Stock Price	20
B.	Dividend.....	22
C.	Growth Rate.....	23
D.	Response to Mr. Rea's DCF Model.....	27
VII.	CAPITAL ASSET PRICING MODEL ANALYSIS	28
A.	The Risk-Free Rate	29
B.	The Beta Coefficient.....	30
C.	The Equity Risk Premium.....	31
D.	Response to Mr. Rea's CAPM Analysis and Other Issues	38
1.	Beta 39	
2.	Equity Risk Premium.....	40
3.	Size Effect.....	41
4.	Other Risk Premium Analysis	44
VIII.	CAPITAL STRUCTURE	45
A.	Proxy and Industry Debt Ratios.....	50
B.	The Hamada Model: Capital Structure's Effect on ROE.....	53
IX.	MANAGEMENT PERFORMANCE PREMIUM	56
X.	RATE OF RETURN CONCLUSION	57

Part Two: Depreciation

XI.	REGULATORY STANDARDS	59
A.	Depreciation System	60
B.	Average Life vs Equal Life Method	61
XII.	SERVICE LIFE ANALYSIS.....	66

LIST OF EXHIBITS

Part One: Rate of Return

Exhibit DJG-1	Curriculum Vitae
Exhibit DJG-2	Proxy Group Summary
Exhibit DJG-3	DCF – Stock and Index Prices
Exhibit DJG-4	DCF – Dividend Yields
Exhibit DJG-5	DCF – Terminal Growth Determinants
Exhibit DJG-6	DCF – Final Results
Exhibit DJG-7	CAPM – Risk-Free Rate Estimate
Exhibit DJG-8	CAPM – Beta Coefficients
Exhibit DJG-9	CAPM – Implied ERP Estimate
Exhibit DJG-10	CAPM – Equity Risk Premium Results
Exhibit DJG-11	CAPM – Final Results
Exhibit DJG-12	Cost of Equity Summary
Exhibit DJG-13	Proxy Group Debt Ratios
Exhibit DJG-14	Competitive Industry Debt Ratios
Exhibit DJG-15	Hamda Model Results
Exhibit DJG-16	Final Rate of Return Recommendation

Part Two: Depreciation

Exhibit DJG-17	Summary Rate and Accrual Adjustment
Exhibit DJG-18	Detailed Rate Comparison – 2024
Exhibit DJG-19	Depreciation Rate Development – 2024
Exhibit DJG-20	Detailed Rate Comparison – 2025
Exhibit DJG-21	Depreciation Rate Development – 2025
Exhibit DJG-22	Detailed Rate Comparison – 2026
Exhibit DJG-23	Depreciation Rate Development – 2026
Exhibit DJG-24	Remaining Life Development

APPENDICES

Appendix A:	Discounted Cash Flow Model Theory
Appendix B:	Capital Asset Pricing Model Theory
Appendix C:	The Depreciation System
Appendix D:	Iowa Curves
Appendix E:	Actuarial Analysis

1 **I. INTRODUCTION**

2 **Q. State your name and occupation.**

3 A. My name is David J. Garrett. I am a consultant specializing in public utility regulation. I
4 am the managing member of Resolve Utility Consulting PLLC.

5 **Q. Summarize your educational background and professional experience.**

6 A. I received a B.B.A. with a major in Finance, an M.B.A., and a Juris Doctor from the
7 University of Oklahoma. I worked in private legal practice for several years before
8 accepting a position as assistant general counsel at the Oklahoma Corporation Commission
9 in 2011. At the commission, I worked in the Office of General Counsel in regulatory
10 proceedings. In 2012, I began working for the Public Utility Division as a regulatory
11 analyst providing testimony in regulatory proceedings. After leaving the commission, I
12 formed Resolve Utility Consulting PLLC, where I have represented various consumer
13 groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of
14 capital and depreciation. I am a Certified Depreciation Professional with the Society of
15 Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society
16 of Utility and Regulatory Financial Analysts. A more complete description of my
17 qualifications and regulatory experience is included in my curriculum vitae.¹

18 **Q. On whose behalf are you testifying in this proceeding?**

19 A. I am testifying on behalf of the Pennsylvania Office of Consumer Advocate (“OCA”).

¹ Exhibit DJG-1.

1 **Q. Describe the purpose and scope of your testimony in this proceeding.**

2 A. My testimony addresses Columbia Gas of Pennsylvania's ("Columbia" or the "Company")
3 proposed rate of return in response to the direct testimony of Company witness Vincent
4 Rea. I also address Columbia's depreciation study and proposed depreciation rates in
5 response to the direct testimony of Company witness John Spanos.

6 **Q. Please describe the organization of your testimony.**

7 A. In the executive summary below, I provide an overview of the cost of capital issues, my
8 recommendations, and my response to the Company's testimony on these issues. In the
9 sections that follow, I discuss the legal standards governing the awarded return issue as
10 well as the general concepts involved in estimating the cost of equity. I discuss the concepts
11 of risk and return. I provide detailed analysis of the Discounted Cash Flow ("DCF") Model,
12 the Capital Asset Pricing Model ("CAPM"), including my results for these models and my
13 responses to Mr. Rea's results. I also address capital structure, which is a key component
14 to the cost of capital. In the executive summary. In addition, I discuss my recommendation
15 to reject the Company's proposed depreciation rates, which are based on a methodology
16 that effectively results in accelerated depreciation at the expense of customers.

17 **II. EXECUTIVE SUMMARY**

18 **A. Rate of Return Summary**

19 **Q. Please summarize your rate of return recommendation to the Commission.**

20 A. The key points of my testimony are as follows:

- 21 • The Commission should reject the Company's proposed return on equity ("ROE")
22 of 11.35% as excessive and unsupported. An objective cost of equity analysis

1 shows that the Company's market-determined cost of equity is notably lower than
2 the Company's proposed ROE.

- 3 • The Company's proposed ROE of 11.35% includes a 0.25% upward adjustment for
4 management performance. The Commission should reject the argument that
5 management performance should have an increasing effect on the Company's
6 authorized ROE. Managerial performance is a type of company-specific risk factor
7 that investors do not expect an additional return for, and thus it has no material
8 impact on the cost of equity estimate. OCA Witness Colton and Alexander also
9 address problems with the Company's management performance arguments. The
10 Company's decision to propose a management performance premium increases the
11 revenue requirement by \$6.9 million.

- 12 • Based on the results of my financial modeling using the DCF and CAPM models,
13 I recommend that the Commission authorize an ROE of 8.9% for the Company.

- 14 • I propose the Commission impute a capital structure for ratemaking purposes that
15 consists of 50% total debt and 50% equity.² Due to the discrepancy between
16 Columbia's capital structure and the proxy group's capital structure, this
17 adjustment is necessary to account for the fact that Columbia has less financial risk
18 than the proxy group.

- 19 • My proposed adjustments to the Company's ROE and capital structure result in an
20 overall weighted rate of return of 7.06%. Adopting my recommended adjustments

² The specific capital structure I propose consists of 47.68% long-term debt, 2.32% short-term debt, and 50% common equity. Throughout my testimony, the reference to my proposed debt ratio of 50% refers to total debt.

1 to ROE and capital structure would result in a revenue requirement reduction of
2 \$54.6 million.³ More importantly, it would result in a fair rate of return that
3 balances the interests of consumers and shareholders in contrast to the Company's
4 excessive rate or return proposal.⁴

5 **B. Depreciation Summary**

6 **Q. Please summarize the Company's proposed depreciation rates.**

7 A. Columbia's proposed depreciation rates amount to a total annual depreciation accrual of
8 \$121 million based on plant balances at December 31, 2026.⁵ The Company's proposed
9 depreciation rates are based on the depreciation study sponsored by Mr. Spanos, which is
10 based on plant balances as of December 31, 2024 (the "2024 Study"), December 31, 2025
11 (the "2025 Study"), and December 31, 2026 (the "2026 Study"). Mr. Spanos applied the
12 equal life group ("ELG") method to calculate his proposed remaining lives for the
13 Company's depreciable plant.

14 **Q. Please summarize your adjustments to the Company's proposed depreciation rates.**

15 A. I recommend that the Commission authorize depreciation rates for the Company's assets
16 that are calculated using the average life group ("ALG") method. The key points of my
17 testimony are as follows:

- 18 • The Commission should reject the Company's use of the ELG method, which
19 effectively results in an accelerated form of cost recovery from consumers. The

³ See OCA St. 1, Direct Testimony of Dante Mugrace, p. 3.

⁴ Exhibit DJG-16.

⁵ Exhibit DJG-17.

Company’s use of the ELG method, rather than the widely applied ALG method, increases the annual depreciation accrual charged to customers by \$37 million in the 2024 Study, by \$39 million in the 2025 Study, and by \$44 million in the 2026 Study. In other words, even if there are no adjustments to the net salvage rates, service life, or other depreciation parameters for any accounts in the depreciation study, using the majority-view ALG method alone will result in significantly fairer rates for customers.

- The results of my application of the ALG method to the Company’s depreciation studies are summarized in the table below.⁶

**Figure 1:
Summary Depreciation Accrual Adjustment – 2024 Study**

Plant Function	Columbia Accrual	OCA Accrual	OCA Adjustment
UG Storage	850,896	835,280	(15,616)
Distribution	109,087,106	69,668,279	(39,418,827)
General	1,312,807	1,313,365	558
TOTAL	\$ 111,250,809	\$ 71,816,924	\$ (39,433,885)

⁶ Exhibit DJG-17; *see also* Exhibits DJG-18 through DJG-23 for detailed depreciation rate calculations and comparisons for the 2024 Study, 2025 Study, and 2026 Study.

Figure 2:
Summary Depreciation Accrual Adjustment – 2025 Study

Plant Function	Columbia Accrual	OCA Accrual	OCA Adjustment
UG Storage	180,222	180,756	534
Distribution	118,128,719	75,559,095	(42,569,624)
General	1,721,226	1,720,074	(1,152)
TOTAL	\$ 120,030,167	\$ 77,459,925	\$ (42,570,242)

Figure 3:
Summary Depreciation Accrual Adjustment – 2026 Study

Plant Function	Columbia Accrual	OCA Accrual	OCA Adjustment
UG Storage	205,013	203,741	(1,272)
Distribution	128,040,495	82,237,903	(45,802,592)
General	2,444,091	2,445,532	1,441
TOTAL	\$ 130,689,599	\$ 84,887,176	\$ (45,802,423)

The evidence supporting my recommendations are discussed in more detail in my testimony.

1 **PART ONE: RATE OF RETURN**

2 **III. REGULATORY STANDARDS**

3 **Q. Discuss the legal standards governing the awarded rate of return on capital**
4 **investments for regulated utilities.**

5 A. In *Wilcox v. Consolidated Gas Co. of New York*,⁷ the Supreme Court first addressed the
6 meaning of a fair rate of return for public utilities. The Court found that “the amount of
7 risk in the business is a most important factor” in determining the appropriate allowed rate
8 of return.⁸ Later, in two landmark cases, the Court set forth the standards by which utilities
9 are allowed to earn a return on capital investments. In *Bluefield Water Works &*
10 *Improvement Co. v. Public Service Commission of West Virginia*,⁹ the Court held:

11 A public utility is entitled to such rates as will permit it to earn a return on
12 the value of the property which it employs for the convenience of the
13 public . . . but it has no constitutional right to profits such as are realized or
14 anticipated in highly profitable enterprises or speculative ventures. The
15 return should be reasonably sufficient to assure confidence in the financial
16 soundness of the utility and should be adequate, under efficient and
17 economical management, to maintain and support its credit and enable it to
18 raise the money necessary for the proper discharge of its public duties.¹⁰

19 In *Federal Power Commission v. Hope Natural Gas Company*,¹¹ the Court expanded on
20 the guidelines set forth in *Bluefield* and stated:

⁷ *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19 (1909).

⁸ *Id.* at 48.

⁹ *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923).

¹⁰ *Id.* at 692-93.

¹¹ *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

1 From the investor or company point of view it is important that there be
2 enough revenue not only for operating expenses but also for the capital costs
3 of the business. These include service on the debt and dividends on the
4 stock. By that standard the return to the equity owner should be
5 commensurate with returns on investments in other enterprises having
6 corresponding risks. That return, moreover, should be sufficient to assure
7 confidence in the financial integrity of the enterprise, so as to maintain its
8 credit and to attract capital.¹²

9 The cost of capital models I have employed in this case are in accordance with the
10 foregoing legal standards.

11 **Q. Should the awarded rate of return be based on the Company's actual cost of capital?**

12 A. Yes. The *Hope* Court makes it clear that the allowed return should be based on the actual
13 cost of capital. Moreover, the awarded return must also be fair, just, and reasonable under
14 the circumstances of each case. Under the rate base rate of return model, a utility should
15 be allowed to recover all its reasonable expenses, its capital investments through
16 depreciation, and a return on its capital investments sufficient to satisfy the required return
17 of its investors. The "required return" from the investors' perspective is synonymous with
18 the "cost of capital" from the utility's perspective. Scholars agree that the allowed rate of
19 return should be based on the actual cost of capital:

20 Since by definition the cost of capital of a regulated firm represents
21 precisely the expected return that investors could anticipate from other
22 investments while bearing no more or less risk, and since investors will not
23 provide capital unless the investment is expected to yield its opportunity
24 cost of capital, the correspondence of the definition of the cost of capital
25 with the court's definition of legally required earnings appears clear.¹³

¹² *Id.* at 603 (emphasis added).

¹³ A. Lawrence Kolbe, James A. Read, Jr. & George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, p. 21 (The MIT Press 1984).

1 The models I have employed in this case closely estimate the Company's market-based
2 cost of equity. If the Commission sets the awarded return based on my lower, and more
3 reasonable, rate of return, it will comply with the U.S. Supreme Court's standards, allow
4 the Company to maintain its financial integrity, and satisfy the claims of its investors. On
5 the other hand, if the Commission sets the allowed rate of return *higher* than the true cost
6 of capital, it arguably results in an inappropriate transfer of wealth from ratepayers to
7 shareholders.

8 **Q. What does this standard mean for determining the awarded return and the cost of**
9 **capital?**

10 A. It is important to understand that the *awarded* return and the *cost* of capital are different
11 but related concepts. The two concepts are related in that the legal and technical standards
12 encompassing this issue require that the awarded return reflects the true cost of capital. On
13 the other hand, the two concepts are different in that the legal standards do not mandate
14 that awarded returns exactly match the cost of capital. Awarded returns are set through the
15 regulatory process and may be influenced by factors other than objective market drivers.
16 The cost of capital, on the other hand, should be evaluated objectively and be closely tied
17 to economic realities. In other words, the cost of capital is driven by stock prices,
18 dividends, growth rates, and — most importantly — it is driven by risk. The cost of capital
19 can be estimated by financial models used by firms, investors, and academics around the
20 world for decades. The problem is, with respect to regulated utilities, there has been a trend
21 in which awarded returns fail to closely track with actual market-based cost of capital as
22 further discussed below. To the extent this occurs, the results are detrimental to ratepayers
23 and the state's economy.

1 **Q. Describe the economic impact that occurs when the awarded return strays too far**
2 **from the U.S. Supreme Court's cost of equity standard.**

3 A. When the awarded ROE is set far above the *cost* of equity, it runs the risk of violating the
4 U.S. Supreme Court's standards that the awarded return should be *based on the cost of*
5 *capital*. If the Commission were to adopt the Company's position in this case, it would be
6 permitting an excess transfer of wealth from customers to Company shareholders.
7 Moreover, establishing an awarded return that far exceeds the true cost of capital
8 effectively prevents the awarded returns from changing along with economic conditions.
9 This is especially true given the fact that regulators tend to be influenced by the awarded
10 returns in other jurisdictions, regardless of the various unknown factors influencing those
11 awarded returns. This is yet another reason why it is crucial for regulators to focus on the
12 target utility's actual *cost* of equity, rather than awarded returns from other jurisdictions.
13 Awarded returns may be influenced by settlements and other political factors not based on
14 true market conditions. In contrast, the market-based cost of equity as estimated through
15 objective models is not influenced by these factors but is instead driven by market-based
16 factors. If regulators rely too heavily on the awarded returns from other jurisdictions, it
17 can create a cycle over time that bears little relation to the market-based cost of equity.

18 **IV. GENERAL CONCEPTS AND METHODOLOGY**

19 **Q. Discuss your approach to estimating the cost of equity in this case.**

20 A. While a competitive firm must estimate its own cost of capital to assess the profitability of
21 competing capital projects, regulators determine a utility's cost of capital to establish a fair
22 rate of return. The legal standards set forth above do not include specific guidelines
23 regarding the models that must be used to estimate the cost of equity. Over the years,

1 however, regulatory commissions have consistently relied on several models. The models
2 I have employed in this case have been the two most widely used and accepted in regulatory
3 proceedings for many years. These models are the DCF Model and the CAPM. The
4 specific inputs and calculations for these models are described in more detail below.

5 **Q. Please explain why multiple models are used to estimate the cost of equity.**

6 A. The models used to estimate the cost of equity attempt to measure the return on equity
7 required by investors by estimating several different inputs. It is preferable to use multiple
8 models because the results of any one model may contain a degree of imprecision,
9 especially depending on the reliability of the inputs used at the time of conducting the
10 model. By using multiple models, the analyst can compare the results of the models and
11 look for outlying results and inconsistencies. Likewise, if multiple models produce a
12 similar result, it may indicate a narrower range for the cost of equity estimate.

13 **Q. Please discuss the benefits of choosing a proxy group of companies in conducting cost**
14 **of capital analyses.**

15 A. The cost of equity models in this case can be used to estimate the cost of capital of any
16 individual, publicly-traded company. There are advantages, however, to conducting cost
17 of capital analyses on a “proxy group” of companies that are comparable to the target
18 company. First, it is better to assess the financial soundness of a utility by comparing it to
19 a group of other financially sound utilities. Second, using a proxy group provides more
20 reliability and confidence in the overall results because there is a larger sample size.
21 Finally, the use of a proxy group is often a pure necessity when the target company is a
22 subsidiary that is not publicly traded. This is because the financial models used to estimate

1 the cost of equity require information from publicly-traded firms, such as stock prices and
2 dividends.

3 **Q. Describe the proxy group you selected in this case.**

4 A. In this case, I chose to use the same utility proxy group consisting of six gas companies
5 that Mr. Rea used for his analyses, which he refers to as the “Gas LDC Group.”¹⁴ Mr. Rea
6 also conducted cost of equity analyses on a “Combination Utility Group” and a “Non-
7 Regulated Utility Group.”¹⁵ In my opinion, it is not necessary to perform cost of equity
8 analyses on a proxy group beyond the Gas LDC Group. In my experience, most rate of
9 return experts in utility rate proceedings do not take this approach. Moreover, the cost of
10 equity analysis Mr. Rea performed on the Non-Regulated Group is completely
11 unnecessary, as discussed more below.

12 **Q. Do the results of any cost of equity models conducted by Mr. Rea on a group of non-**
13 **utility companies indicate an accurate cost of equity estimate for Columbia?**

14 A. No. First, the same types of unreasonable assumptions and inputs employed by Mr. Rea
15 on the Gas LDC Group (as discussed later in my testimony) also apply to his non-utility
16 group modeling. For that reason alone, the results of the non-utility modeling should be
17 rejected. Moreover, this model adds no marginal value to the process of developing a
18 reasonable estimate for Columbia’s cost of equity. The companies included in Mr. Rea’s
19 non-utility group are undoubtedly less comparable than those included in the Gas LDC
20 Group. For these reasons, the Commission should reject the results of the non-utility
21 modeling as providing a meaningful indication of Columbia’s cost of equity in this case.

¹⁴ See Columbia Statement No. 8, Direct Testimony of Vincent V. Rea, p. 5, lines 3-14.

¹⁵ See *id.*

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A. As discussed above, risk is the most important factor for the Commission to consider when determining the allowed return. There is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand. There are two primary types of risk: firm-specific risk and market risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees.

A. Firm-specific risk affects individual companies, rather than the entire market. For example, a competitive firm might overestimate customer demand for a new product, resulting in reduced sales revenue. This is an example of a firm-specific risk called “project risk.”¹⁶ There are several other types of firm-specific risks, including: (1) “financial risk” — the risk that equity investors of leveraged firms face as residual claimants on earnings; (2) “default risk” — the risk that a firm will default on its debt securities; and (3) “business risk” — which encompasses all other operating and managerial factors that may result in investors realizing less than their expected return in that particular company.

While firm-specific risk affects individual companies, market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate

13

1 risk, inflation risk, and the risk of major socio-economic events. When there are changes
2 in these risk factors, they affect all firms in the market to some extent.¹⁷

3 Analysis of the U.S. market in 2001 provides a good example for contrasting firm-
4 specific risk and market risk. During that year, Enron Corp.'s stock fell from \$80 per share
5 and the company filed for bankruptcy at the end of the year. If an investor's portfolio had
6 held only Enron stock at the beginning of 2001, this irrational investor would have lost the
7 entire investment by the end of the year due to assuming the full exposure of Enron's firm-
8 specific risk (in that case, imprudent management). On the other hand, a rational,
9 diversified investor who invested the same amount of capital in a portfolio holding every
10 stock in the S&P 500 would have had a much different result that year. The rational
11 investor would have been relatively unaffected by the fall of Enron because her portfolio
12 included 499 other stocks. Each of those stocks, however, would have been affected by
13 various *market* risk factors that occurred that year, including the terrorist attacks on
14 September 11th, which affected all stocks in the market. Thus, the rational investor would
15 have incurred a relatively minor loss due to market risk factors, while the irrational investor
16 would have lost everything due to firm-specific risk factors.

17 **Q. Can investors minimize firm-specific risk through portfolio diversification?**

18 A. Yes. A fundamental concept in finance is that firm-specific risk can be minimized through
19 diversification.¹⁸ If someone irrationally invested all their funds in one firm (such as
20 Enron), they would be exposed to all the firm-specific risk *and* the market risk inherent in

¹⁷ See Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments*, p. 149 (9th ed., McGraw-Hill/Irwin 2013).

¹⁸ See John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, pp. 179-80 (3rd ed., South Western Cengage Learning 2010).

1 that single firm. Rational investors, however, are risk-averse and seek to eliminate risk
2 they can control. Investors can essentially eliminate firm-specific risk by adding more
3 stocks to their portfolio through a process called “diversification.”

4 There are two reasons why diversification eliminates firm-specific risk. First, each
5 stock in a diversified portfolio represents a much smaller percentage of the overall portfolio
6 than it would in a portfolio of just one or a few stocks. Thus, any firm-specific action that
7 changes the stock price of one stock in the diversified portfolio will have only a small
8 impact on the entire portfolio.¹⁹

9 The second reason why diversification eliminates firm-specific risk is that the
10 effects of firm-specific actions on stock prices can be either positive or negative for each
11 stock. Thus, in large, diversified portfolios, the net effect of these positive and negative
12 firm-specific risk factors will be essentially zero and will not affect the value of the overall
13 portfolio.²⁰ Firm-specific risk is also called “diversifiable risk” because it can be easily
14 eliminated through diversification.

15 **Q. Do investors expect an additional return for assuming firm-specific risks?**

16 A. No. Because investors eliminate firm-specific risk through diversification, they know they
17 cannot expect a higher return for assuming the firm-specific risk in any one company.
18 Thus, the risks associated with an individual firm’s operations are not rewarded by the
19 market. In fact, firm-specific risk is also called “unrewarded” risk for this reason. Market
20 risk, on the other hand, cannot be eliminated through diversification. Because market risk

¹⁹ See Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, p. 64 (3rd ed., John Wiley & Sons, Inc. 2012).

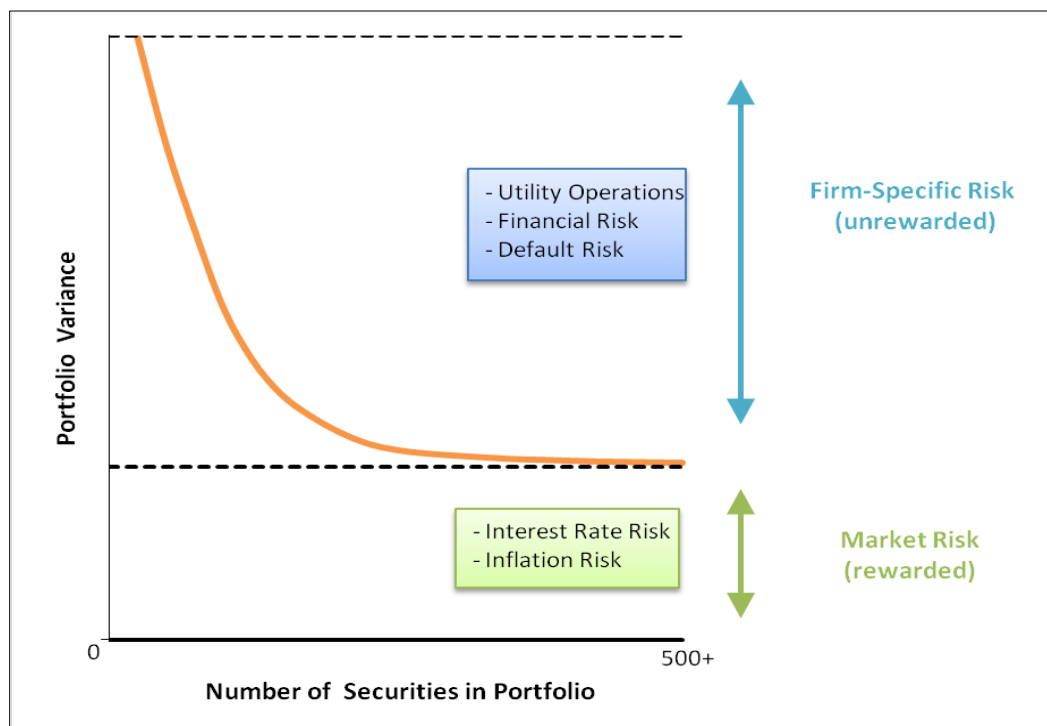
²⁰ *Id.*

cannot be eliminated through diversification, investors expect a return for assuming this type of risk. Market risk is also called “systematic risk.” Scholars recognize the fact that market risk, or “systematic risk,” is the only type of risk for which investors expect a return for bearing:

If investors can cheaply eliminate some risks through diversification, then we should not expect a security to earn higher returns for risks that can be eliminated through diversification. Investors can expect compensation *only* for bearing systematic risk (i.e., risk that cannot be diversified away).²¹

These important concepts are illustrated in the figure below. Some form of this figure is found in many financial textbooks.

**Figure 4:
Effects of Portfolio Diversification**



²¹ See John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 180 (3rd ed., South Western Cengage Learning 2010).

1 This figure shows that as stocks are added to a portfolio, the amount of firm-specific risk
2 is reduced until it is essentially eliminated. No matter how many stocks are added,
3 however, there remains a certain level of fixed market risk. The level of market risk will
4 vary from firm to firm. Market risk is the only type of risk that is rewarded by the market
5 and is thus the primary type of risk the Commission should consider when determining the
6 allowed return for the utilities it regulates.

7 **Q. Describe how market risk is measured.**

8 A. Investors who want to eliminate firm-specific risk must hold a fully diversified portfolio.
9 To determine the amount of risk that a single stock adds to the overall market portfolio,
10 investors measure the covariance between a single stock and the market portfolio. The
11 result of this calculation is called “beta.”²² Beta represents the sensitivity of a given
12 security to the market as a whole. The market portfolio of all stocks has a beta equal to
13 one. Stocks with betas greater than one are relatively more sensitive to market risk than
14 the average stock. For example, if the market increases (decreases) by 1.0%, a stock with
15 a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas
16 of less than one are less sensitive to market risk, such that if the market increases
17 (decreases) by 1.0%, a stock with a beta of 0.5 will, on average, only increase (decrease)
18 by 0.5%. Thus, stocks with low betas are relatively insulated from market conditions. The
19 beta term is used in the CAPM to estimate the cost of equity, which is discussed in more
20 detail later.²³

²² *Id.* at 180-81.

²³ Though it will be discussed in more detail later, Exhibit DJG-9 shows that the average beta of the proxy group was less than 1.0. This confirms the well-known concept that utilities are relatively low-risk firms.

1 **Q. Are public utilities characterized as defensive firms that have low betas, low market**
2 **risk, and are relatively insulated from overall market conditions?**

3 A. Yes. Although market risk affects all firms in the market, it affects different firms to
4 varying degrees. Firms with high betas are affected more than firms with low betas, which
5 is why firms with high betas are riskier. Stocks with betas greater than one are generally
6 known as “cyclical stocks.” Firms in cyclical industries are sensitive to recurring patterns
7 of recession and recovery known as the “business cycle.”²⁴ Thus, cyclical firms are
8 exposed to a greater level of market risk. Securities with betas less than one, on the other
9 hand, are known as “defensive stocks.” Companies in defensive industries, such as public
10 utility companies, “will have low betas and performance that is comparatively unaffected
11 by overall market conditions.”²⁵ In fact, financial textbooks often use utility companies as
12 prime examples of low-risk, defensive firms. The figure below compares the betas of
13 several industries and illustrates that the utility industry is one of the least risky industries
14 in the U.S. market.²⁶

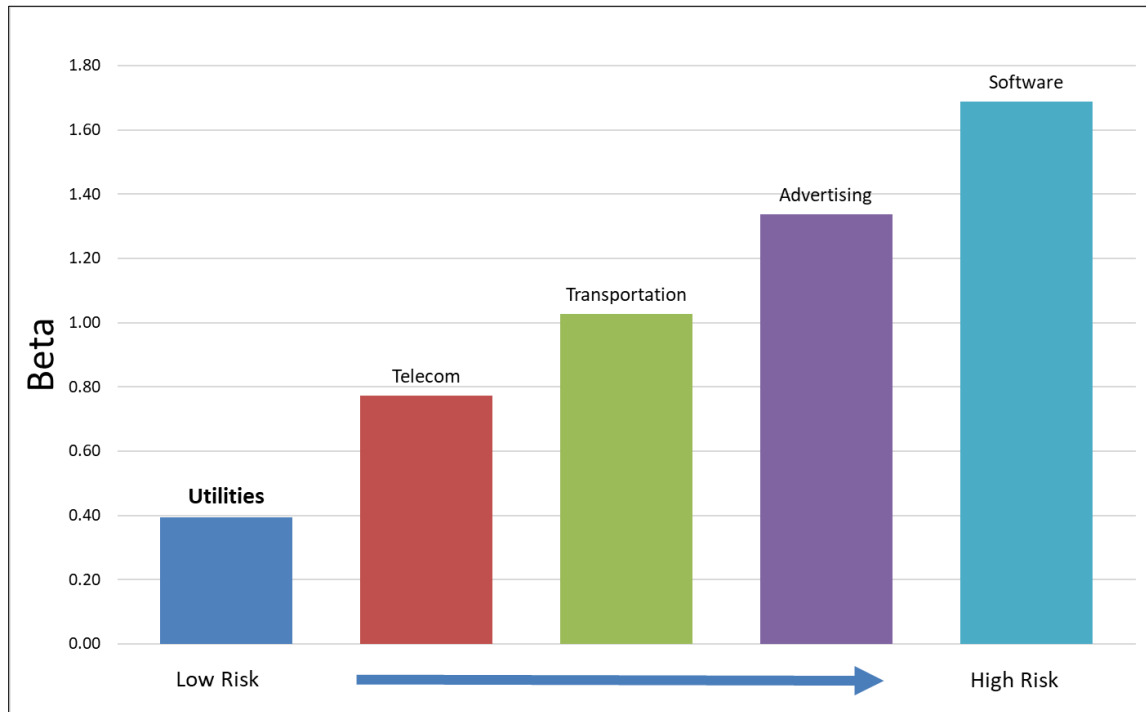
²⁴ See Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments*, p. 382 (9th ed., McGraw-Hill/Irwin 2013).

²⁵ *Id.* at 383.

²⁶ See Betas by Sector (US) available at <http://pages.stern.nyu.edu/~adamodar/> (2018). (After clicking the link, click “Data” then “Current Data” then “Risk / Discount Rate” from the drop down menu, then “Total Beta by Industry Sector”). The exact beta calculations are not as important as illustrating the well-known fact that utilities are very low-risk companies. The fact that the utility industry is one of the lowest risk industries in the country should not change from year to year.

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**Figure 5:
Beta by Industry**



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The fact that utilities are defensive firms that are exposed to little market risk is beneficial to society. When the business cycle enters a recession, consumers can be assured that their utility companies will be able to maintain normal business operations and provide safe and reliable service under efficient management. Likewise, utility investors can be confident that utility stock prices will not widely fluctuate. So, while it is recognized and accepted that utilities are defensive firms that experience little market risk and are relatively insulated from market conditions, this fact should also be appropriately reflected in the Company's awarded return.

VI. DISCOUNTED CASH FLOW ANALYSIS

Q. Describe the DCF Model.

A. The DCF Model is based on a fundamental financial model called the “dividend discount model,” which maintains that the value of a security is equal to the present value of the future cash flows it generates.²⁷ Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. These versions, along with other formulas and theories related to the DCF Model, are discussed in more detail in Appendix A.

Q. Describe the inputs to the DCF Model.

A. There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate. The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated. I discuss each of these inputs separately below.

A. Stock Price

Q. How did you determine the stock price input of the DCF Model?

A. For the stock price (P_0), I used a 30-day average of stock prices for each company in the proxy group.²⁸ Analysts sometimes rely on average stock prices for longer periods (*e.g.*, 60, 90, or 180 days). According to the efficient market hypothesis, however, markets reflect all relevant information available at a particular time, and prices adjust

²⁷ Present value (PV) is the current value of a future sum of money or stream of cash flows given a specified rate of return. Present value takes the future value and applies a discount rate or the interest rate that could be earned if invested.

²⁸ Exhibit DJG-3.

1 instantaneously to the arrival of new information.²⁹ Past stock prices, in essence, reflect
2 outdated information. The DCF Model used in utility rate cases is a derivation of the
3 dividend discount model, which is used to determine the current value of an asset. Thus,
4 according to the dividend discount model and the efficient market hypothesis, the value for
5 the “P₀” term in the DCF Model should technically be the current stock price, rather than
6 an average.

7 **Q. Why did you use a 30-day average for the current stock price input?**

8 A. Using a short-term average of stock prices for the current stock price input adheres to
9 market efficiency principles while avoiding any irregularities that may arise from using a
10 single current stock price. In the context of a utility rate proceeding, there is a significant
11 length of time between when an application is filed and when testimony is due. Choosing
12 a current stock price for one particular day could raise a separate issue concerning which
13 day was chosen to be used in the analysis. In addition, a single stock price on a particular
14 day may be unusually high or low. It is arguably ill-advised to use a single stock price in
15 a model that is ultimately used to set rates for several years, especially if a stock is
16 experiencing some volatility. Thus, it is preferable to use a short-term average of stock
17 prices, which represents a good balance between adhering to well-established principles of
18 market efficiency while avoiding any unnecessary contentions that may arise from using a

²⁹ See Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Vol. 25, No. 2 The Journal of Finance, p. 383 (1970); see also John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 357 (3rd ed., South Western Cengage Learning 2010). The efficient market hypothesis was formally presented by Eugene Fama in 1970 and is a cornerstone of modern financial theory and practice.

1 single stock price on a given day. The stock prices I used in my DCF analysis are based
2 on 30-day averages of adjusted closing stock prices for each company in the proxy group.³⁰

3 **B. Dividend**

4 **Q. Describe how you determined the dividend input of the DCF Model.**

5 A. The dividend term in the DCF Model represents dividends per share (d_0). I used forward-
6 looking annualized dividends published by Yahoo! Finance for the dividend input to my
7 constant growth DCF Model.³¹ Dividing these dividends by the stock prices for each proxy
8 company results in the dividend yield for each company.³²

9 **Q. Are the stock price and dividend inputs for each proxy company a significant issue in**
10 **this case?**

11 A. No. Although my stock price and dividend inputs are more recent than those used by Mr.
12 Rea, there is not a statistically significant difference between them because utility stock
13 prices and dividends are generally quite stable. This is another reason that cost of capital
14 models such as the CAPM and the DCF Model are well-suited to be conducted on utilities.
15 The differences between my DCF Model and Mr. Rea's DCF Model are primarily driven
16 by differences in our growth rate estimates, which are further discussed below.

³⁰ Exhibit DJG-3. Adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices. The adjusted price provides an accurate representation of the firm's equity value beyond the mere market price because it accounts for stock splits and dividends.

³¹ Exhibit DJG-4.

³² *Id.*

1 **C. Growth Rate**

2 **Q. Please Summarize the growth rate input in the DCF Model.**

3 A. The most critical input in the DCF Model is the growth rate. Unlike the stock price and
4 dividend inputs, the growth rate input (g) must be estimated. As a result, the growth rate
5 is often the most contentious issue related to DCF model inputs in utility rate cases. The
6 DCF model used in this case is based on the sustainable growth valuation model. Under
7 this model, a stock is valued by the present value of its future cash flows in the form of
8 dividends. Before future cash flows are discounted by the cost of equity, however, they
9 must be “grown” into the future by a sustainable growth rate. As stated above, one of the
10 inherent assumptions of this model is that these cash flows in the form of dividends grow
11 at a sustainable rate forever. For young, high-growth firms, estimating the growth rate to
12 be used in the model can be especially difficult, and may require the use of multi-stage
13 growth models. For mature, low-growth firms such as utilities, however, estimating the
14 sustainable growth rate is more transparent. The growth term of the DCF Model is one of
15 the most important, yet least understood, aspects of cost of equity estimations in utility
16 regulatory proceedings. I provide a more detailed explanation on the various determinants
17 of growth below.

18 **Q. Describe the various determinants of growth that can be considered for the growth**
19 **rate input in the DCF Model.**

20 A. Although the DCF Model directly considers the growth of dividends, there are a variety of
21 growth determinants that should be considered when estimating growth rates. It should be
22 noted that these various growth determinants are used primarily to determine the short-
23 term growth rates in multi-stage DCF models. For utility companies, it is necessary to

1 focus primarily on a long-term growth rate in dividends. This is also known as a
2 “sustainable” growth rate, since this is the growth rate assumed for the company’s
3 dividends in perpetuity. That is not to say that these growth determinants cannot be
4 considered when estimating sustainable growth; however, as discussed below, sustainable
5 growth must be constrained much more than short-term growth, especially for young firms
6 with high growth opportunities. Additionally, I briefly discuss these growth determinants
7 here because it may reveal some of the sources of confusion in this area.

8 (1) Historical Growth

9 Looking at a firm’s actual historical experience may theoretically provide a good
10 starting point for estimating short-term growth. However, past growth is not always a good
11 indicator of future growth. Some metrics that might be considered here are a historical
12 growth in revenues, operating income, and net income. Since dividends are paid from
13 earnings, estimating historical earnings growth may provide an indication of future
14 earnings and dividend growth.

15 (2) Analyst Growth Rates

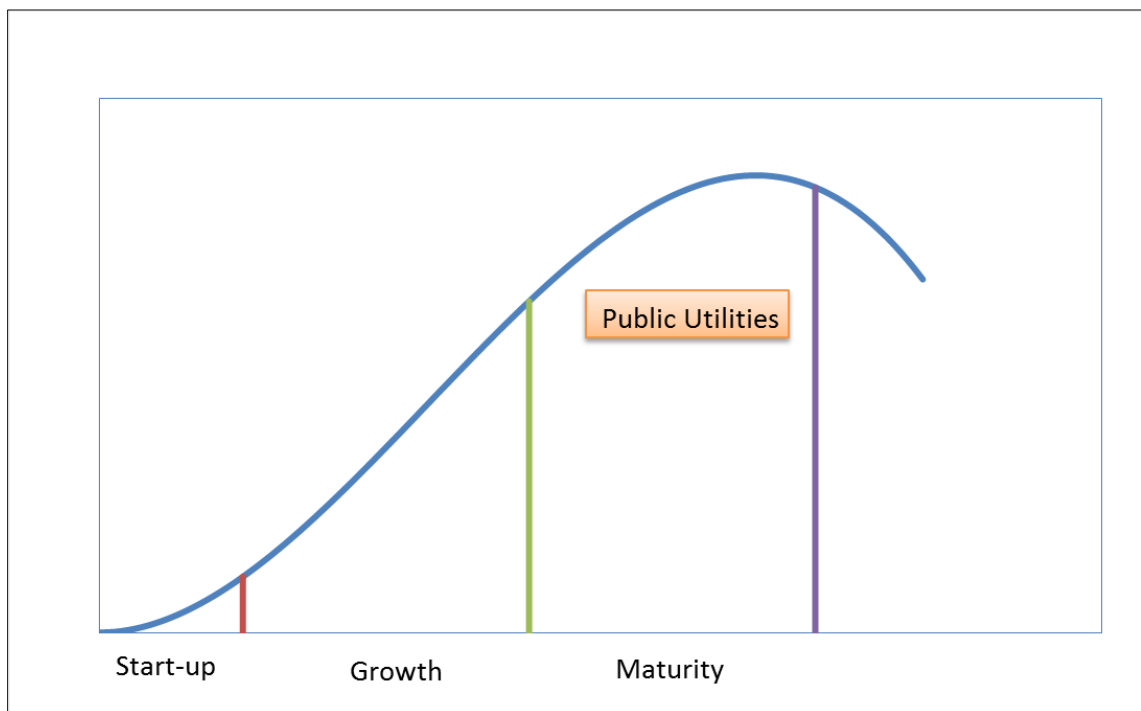
16 Analyst growth rates refer to short-term projections of earnings growth published
17 by institutional research analysts such as Value Line and Bloomberg. Analyst growth rates,
18 including the limitations with using them in the DCF Model to estimate utility cost of
19 equity, are discussed in more detail below.

20 (3) Sustainable Growth Rates

21 In order to make the DCF Model a viable, practical model, an infinite stream of
22 future cash flows must be estimated and then discounted back to the present. Otherwise,
23 each annual cash flow would have to be estimated separately. Some analysts use “multi-

stage” DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being sustainable. However, it is not necessary to use multi-stage DCF Models to analyze the cost of equity of regulated utility companies. This is because regulated utilities are already in their “sustainable,” low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical service territories and limited primarily by ratepayer and load growth within those territories. The Figure below illustrates the well-known business/industry life-cycle pattern.

**Figure 6:
Industry Life Cycle**



In an industry’s early stages, there are ample opportunities for growth and profitable reinvestment. In the maturity stage however, growth opportunities diminish, and firms choose to pay out a larger portion of their earnings in the form of dividends instead of

reinvesting them in operations to pursue further growth opportunities. Once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one sustainable growth rate.

Q. Is the aggregate growth rate of the economy typically a limiting factor for the terminal growth rate in the DCF Model?

A. Yes. A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates.³³ Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Damodaran: “[i]f a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value.”³⁴

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is less than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding into new and developing markets, utility operating companies with defined service territories cannot do any of these things to grow. Gross Domestic Product (“GDP”) is one of the most widely used measures of economic production and is used to measure aggregate economic growth.

³³ See Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

³⁴ Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 306 (3rd ed., John Wiley & Sons, Inc. 2012).

1 According to the Congressional Budget Office's Budget Outlook, the long-term forecast
2 for nominal U.S. GDP growth is 3.7%.³⁵ For mature companies in mature industries, such
3 as utility companies, the terminal growth rate should not exceed nominal GDP growth.

4 **Q. Did you also consider a variation of the DCF Model that incorporates analysts'**
5 **growth rate projections?**

6 A. Yes. In this case, I present the results of analyst growth variation of my DCF Model
7 because it is commonly presented in rate proceedings and considered by regulators when
8 assessing a utility's authorized ROE.

9 **Q. Please describe the results of your DCF Models?**

10 A. For my DCF Models, I considered two variations: one using analysts' growth rates and
11 one using the maximum sustainable growth rate. The results of these models are 7.5% and
12 7.3%, respectively.

13 **D. Response to Mr. Rea's DCF Model**

14 **Q. Please summarize the results of Mr. Rea's DCF analyses.**

15 A. Mr. Rea's DCF Model conducted on the Gas LDC Group produced a result of 10.97%.³⁶

16 **Q. Does the result of Mr. Rea's DCF Model indicate a reasonable cost of equity estimate**
17 **for Columbia?**

18 A. No. Whether the sustainable GDP growth rate or projected dividend growth rates
19 published by Value Line are considered, the highest DCF result I obtained was 7.5%. The
20 primary reason Mr. Rea's DCF results are overstated is his use of unsustainably high
21 growth rates for some proxy companies. Mr. Rea also eliminated several results of the

³⁵ Congressional Budget Office Long-Term Budget Outlook, <https://www.cbo.gov/publication/59014>.

³⁶ Columbia Statement No. 8, Direct Testimony of Vincent V. Rea, p. 8, Table VVR-1.

1 proxy companies from his analysis because he considered them to be too low. Specifically,
2 he removed any individual DCF estimate below 7.0%. However, he did not remove any
3 of his higher DCF estimates for the proxy companies, which are as high as 13.4%.³⁷ In
4 addition, the perpetual growth rates he used for some proxy companies are unrealistically
5 high and are not sustainable. For example, Mr. Rea assumes an annual long-term growth
6 rate of 10% for Southwest Gas. This means Mr. Rea is suggesting the company's earnings
7 will grow by 10% each year, every year, in perpetuity. This 10% growth estimate is from
8 Value Line. However, Value Line is representing this to be a short-term annual growth
9 rate over the next few years. It is Mr. Rea who is suggesting that this annual earnings
10 growth rate can be achieved each year in perpetuity. As a result, the cost of equity results
11 indicated by Mr. Rea's DCF Model are unreasonably high in my opinion.

12 VII. CAPITAL ASSET PRICING MODEL ANALYSIS

13 **Q. Please describe the CAPM.**

14 A. The CAPM is a market-based model founded on the principle that investors expect higher
15 returns for incurring additional risk.³⁸ The CAPM estimates this expected return. The
16 various assumptions, theories, and equations involved in the CAPM are discussed further
17 in Appendix B. Using the CAPM to estimate the cost of equity of a regulated utility is
18 consistent with the legal standards governing the fair rate of return. The U.S. Supreme

³⁷ Columbia Statement No. 8, Direct Testimony of Vincent V. Rea, Exhibit VVR-7.

³⁸ William F. Sharpe, *A Simplified Model for Portfolio Analysis*, pp. 277-93 (Management Science IX 1963); see also John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 208 (3rd ed., South-Western Cengage Learning 2010).

1 Court has recognized that “the amount of *risk* in the business is a most important factor”
2 in determining the allowed rate of return,³⁹ and that “the return to the equity owner should
3 be commensurate with returns on investments in other enterprises having corresponding
4 *risks*.”⁴⁰ The CAPM is a useful model because it directly considers the amount of risk
5 inherent in a business and directly measures the most important component of a fair rate of
6 return analysis: Risk.

7 **Q. Describe the inputs for the CAPM.**

8 A. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the
9 risk-free rate; (2) the beta coefficient; and (3) the equity risk premium. Each input is
10 discussed separately below.

11 **A. The Risk-Free Rate**

12 **Q. Please explain the risk-free rate.**

13 A. The first term in the CAPM is the risk-free rate (R_F). The risk-free rate is simply the level
14 of return investors can achieve without assuming any risk. The risk-free rate represents the
15 bare minimum return that any investor would require on a risky asset. Even though no
16 investment is technically devoid of risk, investors often use U.S. Treasury securities to
17 represent the risk-free rate because they accept that those securities essentially contain no
18 default risk. The Treasury issues securities with different maturities, including short-term
19 Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

³⁹ *Wilcox*, 212 U.S. at 48 (emphasis added).

⁴⁰ *Hope Natural Gas Co.*, 320 U.S. at 603 (emphasis added).

1 **Q. Is it preferable to use the yield on long-term Treasury bonds for the risk-free rate in**
2 **the CAPM?**

3 A. Yes. In valuing an asset, investors estimate cash flows over long periods of time. Common
4 stock is viewed as a long-term investment, and the cash flows from dividends are assumed
5 to last indefinitely. As a result, short-term Treasury bill yields are rarely used in the CAPM
6 to represent the risk-free rate. Short-term rates are subject to greater volatility and thus can
7 lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to
8 represent the risk-free rate in the CAPM. I considered a 30-day average of daily Treasury
9 yield curve rates on 30-year Treasury bonds in my risk-free rate estimate, which resulted
10 in a risk-free rate of 4.89%.⁴¹

11 **B. The Beta Coefficient**

12 **Q. How is the beta coefficient used in this model?**

13 A. As discussed above, beta represents the sensitivity of a given security to movements in the
14 overall market. The CAPM states that in efficient capital markets, the expected risk
15 premium on each investment is proportional to its beta. Recall that a security with a beta
16 greater than 1.0 is riskier than the market portfolio. Conversely, a security with a beta less
17 than one is less risky than the market portfolio. An index such as the S&P 500 Index is
18 used as a proxy for the market portfolio. The historical betas for publicly traded firms are
19 published by various institutional analysts. Beta may also be calculated through a linear
20 regression analysis, which provides additional statistical information about the relationship
21 between a single stock and the market portfolio. The market portfolio of all stocks has a

⁴¹ Exhibit DJG-7.

1 beta equal to one. Stocks with betas greater than one are relatively more sensitive to market
2 risk than the average stock. In contrast, stocks with betas of less than one are less sensitive
3 to market risk.

4 **Q. Describe the source for the betas you used in your CAPM analysis.**

5 A. I used betas recently published by Value Line Investment Survey. The beta for each proxy
6 company is less than 1.0, and the average beta for the total proxy group is only 0.83.⁴²
7 Thus, we have an objective measure to prove the well-known concept that utility stocks
8 are less risky than the average stock in the market. While there is evidence suggesting that
9 betas published by sources such as Value Line may actually overestimate the risk of
10 utilities (and thus overestimate the CAPM), I used the betas published by Value Line in the
11 interest of reasonableness.⁴³

12 **C. The Equity Risk Premium**

13 **Q. Describe the equity risk premium.**

14 A. The final term of the CAPM is the equity risk premium (“ERP”), which is the required
15 return on the market portfolio less the risk-free rate ($R_M - R_F$). In other words, the ERP is
16 the level of return investors expect above the risk-free rate in exchange for investing in
17 risky securities. Many experts agree that “the single most important variable for making
18 investment decisions is the equity risk premium.”⁴⁴ Likewise, the ERP is arguably the
19 single most important factor in estimating the cost of capital in this matter. There are three

⁴² Exhibit DJG-8.

⁴³ See Appendix B for a more detailed discussion of raw beta calculations and adjustments.

⁴⁴ Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, p. 4 (Princeton University Press 2002).

basic methods that can be used to estimate the ERP: (1) calculating a historical average; (2) taking a survey of experts; and (3) calculating the implied ERP. I will discuss each method in turn, noting advantages and disadvantages of these methods.

1. Historical Average

Q. Describe the historical equity risk premium.

A. The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period of time. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because it is easy to obtain. However, there are disadvantages to relying on the historical ERP.

Q. What are the limitations of relying solely on a historical average to estimate the current or forward-looking ERP?

A. Some investors may rely on the historic ERP because it is convenient and easy to calculate. But what matters in the CAPM model is the current and forward-looking risk premium.⁴⁵ Some investors may think that a historic ERP provides some indication of what the prospective risk premium is; however, there is empirical evidence to suggest the prospective, forward-looking ERP is actually *lower* than the historical ERP. In a landmark publication on risk premiums around the world, *Triumph of the Optimists*, the authors suggest through extensive empirical research that the prospective ERP is lower than the historical ERP.⁴⁶ This is due in large part to what is known as “survivorship bias” or

⁴⁵ John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 330 (3rd ed., South-Western Cengage Learning 2010).

⁴⁶ Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, p. 34 (Princeton University Press 2002).

1 “success bias” — a tendency for failed companies to be excluded from historical indices.⁴⁷

2 From their extensive analysis, the authors make the following conclusion regarding the
3 prospective ERP:

4 The result is a forward-looking, geometric mean risk premium for the
5 United States . . . of around 2½ to 4 percent and an arithmetic mean risk
6 premium . . . that falls within a range from a little below 4 to a little above
7 5 percent.⁴⁸

8 Indeed, these results are lower than many reported historical risk premiums. Other noted
9 experts agree:

10 The historical risk premium obtained by looking at U.S. data is biased
11 upwards because of survivor bias. . . The true premium, it is argued, is
12 much lower. This view is backed up by a study of large equity markets over
13 the twentieth century (*Triumph of the Optimists*), which concluded that the
14 historical risk premium is closer to 4%.⁴⁹

15 Regardless of the variations in historic ERP estimates, many leading scholars and
16 practitioners agree that simply relying on a historic ERP to estimate the risk premium going
17 forward is not ideal. Fortunately, “a naïve reliance on long-run historical averages is not
18 the only approach for estimating the expected risk premium.”⁵⁰

19 **Q. Did you rely on the historical ERP as part of your CAPM analysis in this case?**

20 A. No. Due to the limitations of this approach, I primarily relied on the ERP reported in expert
21 surveys and the implied ERP method discussed below.

⁴⁷ *Id.* at 194.

⁴⁸ *Id.*

⁴⁹ Aswath Damodaran, *Equity Risk Premiums: Determinants, Estimation and Implications – The 2015 Edition*, p. 17 (New York University 2015).

⁵⁰ John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 330 (3rd ed., South Western Cengage Learning 2010).

2. Expert Surveys

Q. Describe the expert survey approach to estimating the ERP.

A. As its name implies, the expert survey approach to estimating the ERP involves conducting a survey of experts including professors, analysts, chief financial officers, and other executives around the country and asking them what they think the ERP is. The IESE Business School conducts such a survey each year. Its 2025 expert survey reported an average ERP of 5.5%.⁵¹

3. Implied Equity Risk Premium

Q. Describe the implied equity risk premium approach.

A. The third method of estimating the ERP is arguably the best. The implied ERP relies on the stable growth model proposed by Gordon, often called the “Gordon Growth Model,” which is a basic stock valuation model that has been widely used in finance for many years.⁵² This model is a mathematical derivation of the DCF Model. In fact, the underlying concept in both models is the same: The current value of an asset is equal to the present value of its future cash flows. Instead of using this model to determine the discount rate of one company, we can use it to determine the discount rate for the entire market by substituting the inputs of the model. Specifically, instead of using the current stock price (P_0), we will use the current value of the S&P 500 (V_{500}). Instead of using the dividends of a single firm, we will consider the dividends paid by the entire market. Additionally,

⁵¹ Pablo Fernandez, et al., *Survey: Market Risk Premium and Risk-Free Rate used for 54 countries in 2025* (IESE Business School 2024), copy available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=5260463
IESE Business School is the graduate business school of the University of Navarra.

⁵² Myron J. Gordon and Eli Shapiro, *Capital Equipment Analysis: The Required Rate of Profit* 102-10 (Management Science Vol. 3, No. 1 Oct. 1956).

we should consider potential dividends. In other words, stock buybacks should be considered in addition to paid dividends, as stock buybacks represent another way for the firm to transfer free cash flow to shareholders. Focusing on dividends alone without considering stock buybacks could understate the cash flow component of the model, and ultimately understate the implied ERP. The market dividend yield plus the market buyback yield gives us the gross cash yield to use as our cash flow in the numerator of the discount model. This gross cash yield is increased each year over the next five years by the growth rate. These cash flows must be discounted to determine their present value. The discount rate in each denominator is the risk-free rate (R_F) plus the discount rate (K). Equation 1 below shows how the implied return is calculated. Since the current value of the S&P is known, we can solve for K , the implied market return.⁵³

**Equation 1:
Implied Market Return**

$$V_{500} = \frac{CY_1(1+g)^1}{(1+R_F+K)^1} + \frac{CY_2(1+g)^2}{(1+R_F+K)^2} + \dots + \frac{CY_5(1+g)^5 + TV}{(1+R_F+K)^5}$$

where:

V_{500}	=	current value of index (S&P 500)
CY_{1-5}	=	average cash yield over last five years (includes dividends and buybacks)
g	=	compound growth rate in earnings over last five years
R_F	=	risk-free rate
K	=	implied market return (this is what we are solving for)
TV	=	terminal value = $CY_5 (1+R_F) / K$

The discount rate is called the “implied” return because it is based on the current value of the index as well as the value of free cash flow to investors projected over the next five years. Thus, based on these inputs, the market is “implying” the expected return; or in

⁵³ See Exhibit DJG-9 for detailed calculation.

other words, based on the current value of all stocks (the index price) and the projected value of future cash flows, the market is telling us the return expected by investors for investing in the market portfolio. After solving for the implied market return (K), we simply subtract the risk-free rate from it to arrive at the implied ERP as shown in the following equation.

**Equation 2:
Implied Equity Risk Premium**

$$\text{Implied Expected Market Return} - R_F = \text{Implied ERP}$$

Q. Discuss the results of your implied ERP calculation.

A. After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current required return on the U.S. equity market of 9.9%. I subtracted the risk-free rate to arrive at the implied equity risk premium of 5.0%.⁵⁴ Dr. Damodaran, one of the world's leading experts on the ERP, promotes the implied ERP method discussed above. He calculates monthly and annual implied ERPs with this method and publishes his results. Dr. Damodaran's average ERP estimate for June of 2025 using several implied ERP variations was 4.3%.⁵⁵ Additionally, Kroll (formerly Duff & Phelps) recently published an ERP estimate of 5.5%.⁵⁶

⁵⁴ *Id.*

⁵⁵ <http://pages.stern.nyu.edu/~adamodar/>

⁵⁶ Kroll, Cost of Capital Inputs Updated to Reflect Heightened Uncertainty in Global Economy (April 15, 2025).

1 **Q. What are the results of your final ERP estimate?**

2 A. For the final ERP estimate I used in my CAPM analysis, I considered the results of the
3 ERP surveys, the estimated ERP reported by Kroll, the estimated ERP calculated by Dr.
4 Damodaran, and the implied ERP based on my calculations.⁵⁷ The results are presented in
5 the following figure:

6 **Figure 7:**
7 **Equity Risk Premium Results**

IESE Business School Survey	5.5%
Kroll (Duff & Phelps) Report	5.5%
Damodaran (average)	4.3%
Garrett	5.0%
Average	5.1%

8 I used the average ERP of 5.1% from these sources in my CAPM.

9 **Q. Please explain the final results of your CAPM analysis.**

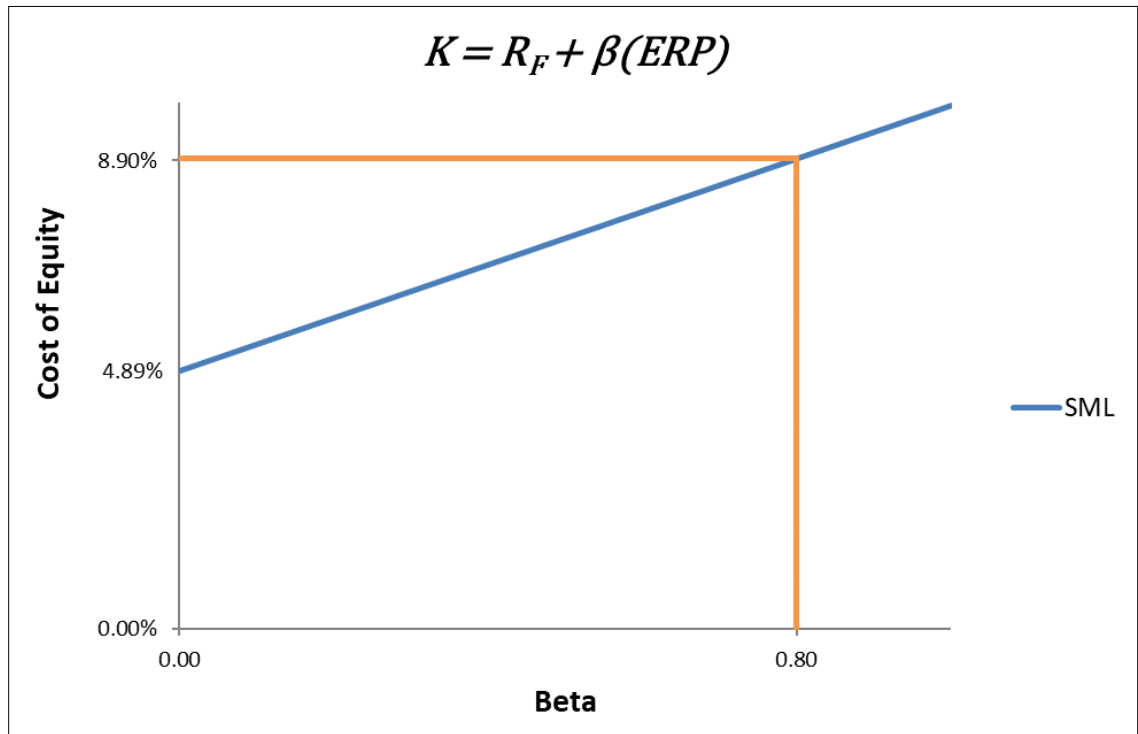
10 A. Using the inputs for the risk-free rate, beta, and equity risk premium discussed above, I
11 estimate that the Company’s CAPM cost of equity is 8.9%, but only if the proxy group
12 average debt ratio is assumed; otherwise, the Company’s CAPM cost of equity estimate is
13 only 8.7%.⁵⁸ The CAPM can be displayed graphically through what is known as the
14 Security Market Line (“SML”). The figure below shows the expected return (cost of
15 equity) on the y-axis, and the average beta for the proxy group on the x-axis. The SML

⁵⁷ See also Exhibit DJG-10.

⁵⁸ Exhibits DJG-11 and DJG-12.

intercepts the y-axis at the level of the risk-free rate. The slope of the SML is the equity risk premium.

**Figure 8:
CAPM Graph**



The SML provides the rate of return that will compensate investors for the beta risk of that investment. Thus, at an average beta of 0.80 for the proxy group, and assuming the proxy group's average capital structure is used, the CAPM result is 9.6%.

D. Response to Mr. Rea's CAPM Analysis and Other Issues

Q. Please summarize the results of Mr. Rea's CAPM analysis

A. Mr. Rea's traditional CAPM analysis produced a result of 11.05% for the Gas LDC Group. Mr. Rea also conducted another variation of the CAPM called the "empirical CAPM" ("ECAPM"), which produced a result of 11.21% for the Gas LDC Group. Mr. Rea also

1 conducted another type of risk premium analysis, which produced a result of 11.23% for
2 the LDC Group. Finally, Mr. Rea also applied a size premium to his final results, which
3 caused his CAPM results to be as high as 11.66%.⁵⁹ I will discuss each of these issues
4 below.

5 **Q. Do the results of Mr. Rea's CAPM and other risk premium analyses indicate a**
6 **reasonable cost of equity estimate for Columbia?**

7 A. No. The primary factors which cause Mr. Rea's CAPM results to be unreasonably high
8 are his use of high, outdated beta estimates and his use of an unreasonably high ERP
9 estimate. Also, the size premium Mr. Rea applies to his CAPM results is unreasonable and
10 unnecessary. I will discuss these issues below as well as the results of Mr. Rea's other risk
11 premium analysis.

12 **1. Beta**

13 **Q. Describe Mr. Rea's beta input to the CAPM.**

14 A. Mr. Rea and I both relied on betas published by Value Line. However, since the time Mr.
15 Rea conducted his analysis, Value Line betas have been notably reduced. This indicates
16 the relative stability of utility stock prices during times of market volatility, and is not
17 surprising. Mr. Rea used an average beta of 0.91 for the Gas LDC Group.⁶⁰ Using the
18 same proxy group with more recent market data from Value Line, I used an average beta
19 of 0.80 in my analysis. Thus, while I agree with Mr. Rea that Value Line can be a reliable
20 source for beta estimates, the more recent betas published by Value Line are considerably

⁵⁹ Columbia Statement No. 8, Direct Testimony of Vincent V. Rea, p. 8, Table VVR-1.

⁶⁰ *Id.* at Exhibit VVR-11.

1 lower than those used by Mr. Rea in his CAPM analysis. This one factor causing Mr. Rea's
2 CAPM results to be overstated.

3 **2. Equity Risk Premium**

4 **Q. Did Mr. Rea rely on a reasonable measure for the ERP?**

5 A. No, he did not. Mr. Rea considered several risk premia indicators in his CAPM analyses,
6 ranging from 6.83% - 7.17%.⁶¹ All of the risk premia considered by Mr. Rea are notably
7 higher than the ERPs I considered from objective and reliable sources as discussed above.
8 The ERP is one of three inputs in the CAPM equation, and it is one of the most important
9 factors for estimating the cost of equity in this case. As discussed above, I used three
10 widely accepted methods for estimating the ERP, including consulting expert surveys,
11 calculating the implied ERP based on aggregate market data, and considering the ERPs
12 published by reputable analysts. The average ERP calculated from my research is only
13 5.1%.

14 **Q. Please discuss and illustrate how Mr. Rea's ERP compares with other estimates for**
15 **the ERP.**

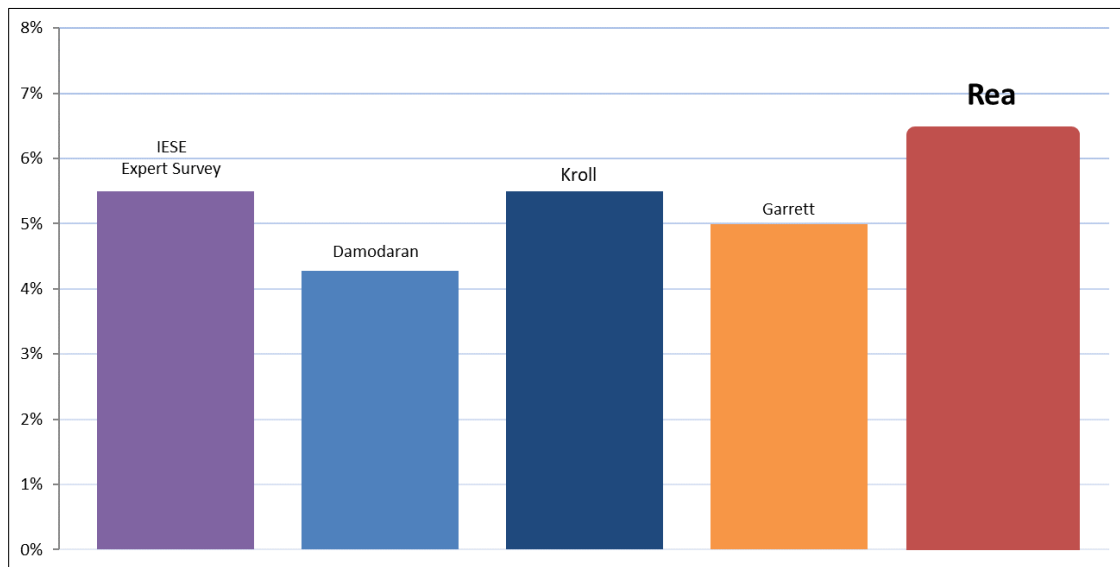
16 A. The 2025 IESE Business School expert survey reports an average ERP of 5.5%. Similarly,
17 Kroll (formerly Duff & Phelps) recently estimated an ERP of 5.5%. Dr. Damodaran, one
18 of the leading experts on the ERP, recently estimated an ERP of only 4.3%.⁶² The chart in

⁶¹ *Id.*

⁶² Aswath Damodaran, *Implied Equity Risk Premium Update*, DAMODARAN ONLINE, <http://pages.stern.nyu.edu/~adamodar/>. Dr. Damodaran estimates several ERPs using various assumptions.

the following figure illustrates that Mr. Rea's ERP estimate higher than other reasonable, objective estimates for the ERP.⁶³

**Figure 9:
Equity Risk Premium Comparison**



When compared with other independent sources for the ERP, as well as my estimate, Mr. Rea's ERP estimate is clearly too high. This factor contributes to Mr. Rea's CAPM results being overstated.

3. Size Effect

Q. Describe Mr. Rea's size premium adjustment to his CAPM.

A. Mr. Rea adds a size premium adjustment of 0.43% to his traditional CAPM results based on his opinion that Columbia's size relative to the proxy group has an increasing effect to its risk relative to the proxy group.⁶⁴

⁶³ The ERP estimated by Dr. Damodaran is the highest of several ERP estimates under slightly differing assumptions.

⁶⁴ Columbia Statement No. 8, Direct Testimony of Vincent V. Rea, p. 8, Table VVR-1.

1 **Q. Do you agree with Mr. Rea’s opinion regarding Columbia’s size?**

2 A. No. Columbia should not receive any upward adjustment or consideration to its cost of
3 equity estimate or authorized ROE due to its size. The “size effect” phenomenon arose
4 from a 1981 study conducted by Banz, which found that “in the 1936 – 1975 period, the
5 common stock of small firms had, on average, higher risk-adjusted returns than the
6 common stock of large firms.”⁶⁵ According to Ibbotson, Banz’s size effect study was
7 “[o]ne of the most remarkable discoveries of modern finance.”⁶⁶ Perhaps there was some
8 merit to this idea at the time, but the size effect phenomenon was short lived. Banz’s 1981
9 publication generated much interest in the size effect and spurred the launch of significant
10 new small cap investment funds. However, this “honeymoon period lasted for
11 approximately two years. . .”⁶⁷ After 1983, U.S. small-cap stocks actually underperformed
12 relative to large cap stocks. In other words, the size effect essentially reversed. In *Triumph*
13 *of the Optimists*, the authors conducted an extensive empirical study of the size effect
14 phenomenon around the world. They found that after the size effect phenomenon was
15 discovered in 1981, it disappeared within a few years:

⁶⁵ Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks* 3-18 (Journal of Financial Economics 9 (1981)).

⁶⁶ 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 99 (Morningstar 2015).

⁶⁷ Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns* 131 (Princeton University Press 2002).

1 It is clear . . . that there was a global reversal of the size effect in virtually
2 every country, with the size premium not just disappearing but going into
3 reverse. Researchers around the world universally fell victim to Murphy's
4 Law, with the very effect they were documenting – and inventing
5 explanations for – promptly reversing itself shortly after their studies were
6 published.⁶⁸

7 In other words, the authors assert that the very discovery of the size effect phenomenon
8 likely caused its own demise. The authors ultimately concluded that it is “inappropriate to
9 use the term ‘size effect’ to imply that we should automatically expect there to be a small-
10 cap premium,” yet, this is exactly what utility witnesses often do in attempting to
11 artificially inflate the cost of equity with a size premium. Other prominent sources have
12 agreed that the size premium is a dead phenomenon. According to Ibbotson:

13 The unpredictability of small-cap returns has given rise to another argument
14 against the existence of a size premium: that markets have changed so that
15 the size premium no longer exists. As evidence, one might observe the last
16 20 years of market data to see that the performance of large-cap stocks was
17 basically equal to that of small cap stocks. In fact, large-cap stocks have
18 outperformed small-cap stocks in five of the last 10 years.⁶⁹

19 In addition to the studies discussed above, other scholars have concluded similar results.

20 According to Kalesnik and Beck:

⁶⁸ *Id.* at 133.

⁶⁹ 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 112 (Morningstar 2015).

1 Today, more than 30 years after the initial publication of Banz's paper, the
2 empirical evidence is extremely weak even before adjusting for possible
3 biases. . . . The U.S. long-term size premium is driven by the extreme
4 outliers, which occurred three-quarters of a century ago. . . . Finally,
5 adjusting for biases . . . makes the size premium vanish. If the size premium
6 were discovered today, rather than in the 1980s, it would be challenging to
7 even publish a paper documenting that small stocks outperform large
8 ones.⁷⁰

9 For all of these reasons, the Commission should reject the arbitrary size premium proposed
10 by the Company.

11 **4. Other Risk Premium Analysis**

12 **Q. Please describe Mr. Rea's other risk premium analysis in addition to the CAPM.**

13 A. In addition to the CAPM, which is a risk premium model, Mr. Rea also conducted another
14 type of risk premium model which ultimately produced the highest result of 11.23% for
15 the Gas LDC Group.⁷¹

16 **Q. Does the result of Mr. Rea's risk premium model indicate a reasonable cost of equity**
17 **for Columbia?**

18 A. No. First, Mr. Rea's personal risk premium model adds no marginal value to estimating
19 cost of equity beyond the CAPM – a risk premium mode that resulted in a Nobel Prize in
20 economics and has been used by investors, managers, and analysts around the world for
21 decades. Furthermore, Mr. Rea's personal risk premium method suffers from the same
22 overestimated betas and risk premiums that were present in his traditional CAPM. Finally,
23 Mr. Rea's risk premium model considers, in part, data as old as 1926.⁷² This contradicts

⁷⁰ Vitali Kalesnik and Noah Beck, *Busting the Myth About Size* (Research Affiliates 2014), available at https://www.researchaffiliates.com/Our%20Ideas/Insights/Fundamentals/Pages/284_Busting_the_Myth_About_Size.aspx (emphasis added).

⁷¹ Columbia Statement No. 8, Direct Testimony of Vincent V. Rea, p. 8, Table VVR-1.

⁷² *Id.* at Exhibit VVR-12, page 6.

1 Mr. Rea’s acknowledgement that cost of equity is a forward-looking process.⁷³ Indeed,
2 the process of estimating the cost of equity is inherently current and forward-looking. It
3 may be helpful to look at a relatively short period in the past to help project future market
4 indicators (such as 30 days of stock prices in the DCF Model, or a few years of market
5 operating earnings for the ERP). However, market data which predates the Great
6 Depression is simply not relevant for estimating Columbia’s cost of equity in 2025. For
7 all of these reasons, the Commission should simply reject the results of Mr. Rea’s risk
8 premium model and focus on the results of the CAPM and DCF Model presented in this
9 case.

10 **VIII. CAPITAL STRUCTURE**

11 **Q. Describe in general the concept of a company’s “capital structure.”**

12 A. “Capital structure” refers to the way a company finances its overall operations through
13 external financing. The primary sources of long-term, external financing are debt capital
14 and equity capital. Debt capital usually comes in the form of contractual bond issues that
15 require the firm to make payments, while equity capital represents an ownership interest in
16 the form of stock. Because a firm cannot pay dividends on common stock until it satisfies
17 its debt obligations to bondholders, stockholders are referred to as “residual claimants.”
18 The fact that stockholders have a lower priority to claims on company assets increases their
19 risk and the required return relative to bondholders. Thus, equity capital has a higher cost
20 than debt capital. Firms can reduce their Weighted Average Cost of Capital (WACC) by

⁷³ See e.g. id. at p. 65, line 10.

recapitalizing and increasing their debt financing. In addition, because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation.

Q. Please explain the concept of the “weighted average cost of capital.”

A. The term “cost of capital” refers to the weighted average cost of all the components of a company's capital structure, including debt and equity. Determining the cost of debt is relatively straightforward. Interest payments on bonds are contractual, “embedded costs” that are generally calculated by dividing total interest payments by the book value of outstanding debt. Determining the cost of equity, on the other hand, is more complex. Unlike the known, contractual cost of debt, there is no explicit “cost” of equity; the cost of equity must be estimated through various financial models. Thus, the overall weighted average cost of capital includes the cost of debt and the estimated cost of equity. It is a “weighted average” because it is based upon the Company's relative levels of debt and equity, or “capital structure.” Companies in the competitive market often use their WACC as the discount rate to determine the value of capital projects, so it is important that this figure be closely estimated. The basic WACC equation used in regulatory proceedings is presented as follows:

**Equation 3:
Weighted Average Cost of Capital**

$$WACC = \left(\frac{D}{D + E} \right) C_D + \left(\frac{E}{D + E} \right) C_E$$

where: $WACC$ = weighted average cost of capital
 D = book value of debt
 C_D = embedded cost of debt capital
 E = book value of equity
 C_E = market-based cost of equity capital

1 Thus, the three components of the weighted average cost of capital include the following:

2 (1) Cost of Equity

3 (2) Cost of Debt

4 (3) Capital Structure

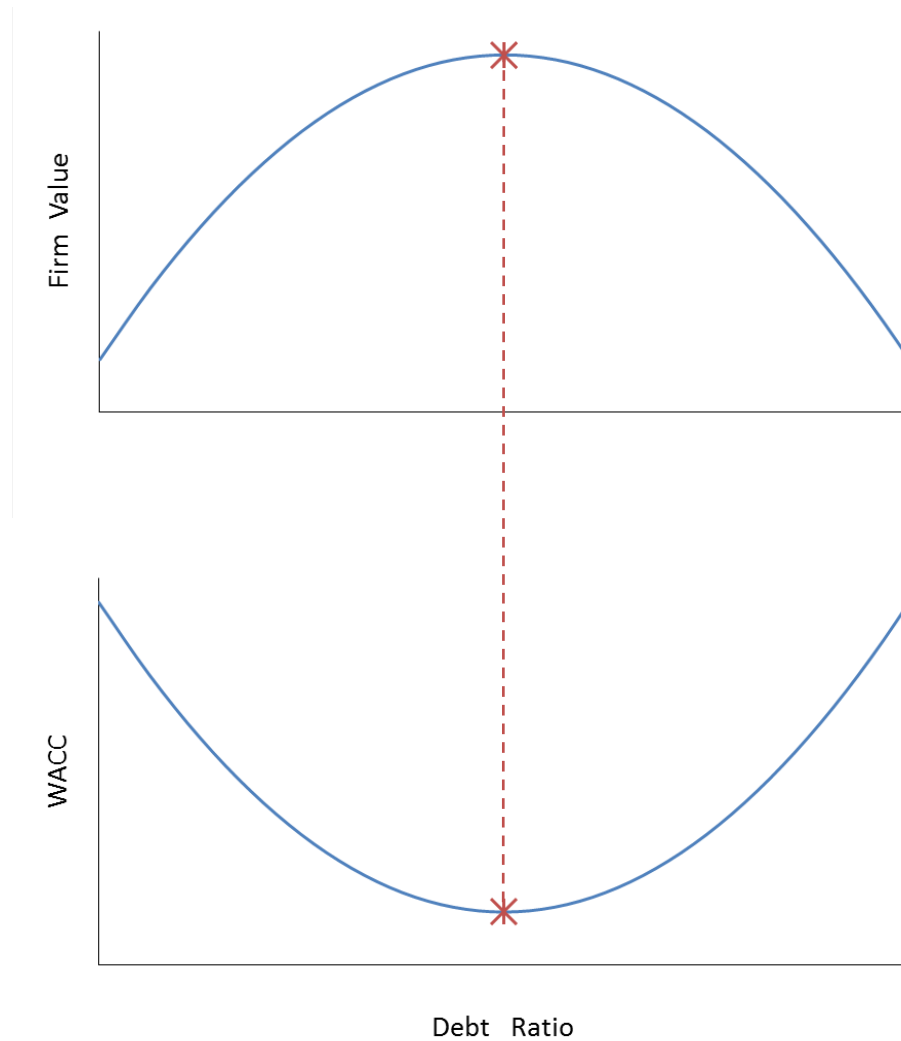
5 The term “cost of capital” is necessarily synonymous with the “weighted average cost of
6 capital,” and the terms are used interchangeably throughout this testimony.

7 **Q. Is it true that, by increasing debt, competitive firms can add value and reduce their**
8 **WACC?**

9 A. Yes, it is. A competitive firm can add value by increasing debt. After a certain point,
10 however, the marginal cost of additional debt outweighs its marginal benefit. This is
11 because the more debt the firm uses, the higher interest expense it must pay, and the
12 likelihood of loss increases. This also increases the risk of non-recovery for both
13 bondholders and shareholders, causing both groups of investors to demand a greater return
14 on their investment. Thus, if debt financing is too high, the firm’s WACC will increase
15 instead of decrease. The following Figure illustrates these concepts.

1
2

**Figure 10:
Optimal Debt Ratio**



3 As shown in this figure, a competitive firm's value is maximized when the WACC is
4 minimized. In both graphs, the debt ratio is shown on the x-axis. By increasing its debt
5 ratio, a competitive firm can minimize its WACC and maximize its value. At a certain
6 point, however, the benefits of increasing debt do not outweigh the costs.

1 **Q. Does the rate base rate of return model effectively incentivize utilities to operate at**
2 **the optimal capital structure?**

3 A. No. While it is true that competitive firms maximize their value by minimizing their
4 WACC, this is not the case for regulated utilities. Under the rate base rate of return model,
5 a higher WACC results in higher rates, all else held constant. The basic revenue
6 requirement equation is as follows:

7 **Equation 4:**
8 **Revenue Requirement for Regulated Utilities**

9
$$RR = O + d + T + r(A - D)$$

where: RR = revenue requirement
 O = operating expenses
 d = depreciation expense
 T = corporate tax
 r = **weighted average cost of capital (WACC)**
 A = plant investments
 D = accumulated depreciation

10 As shown in this equation, utilities can increase their revenue requirement by *increasing*
11 their WACC, not by minimizing it. Thus, because there is no incentive for a regulated
12 utility to minimize its WACC, a Commission standing in the place of competition must
13 ensure that the regulated utility is operating at the lowest reasonable WACC. Left
14 unrestrained, utilities will increase their equity and decrease their debt to unreasonably
15 increase their profits that flow through to shareholders.

16 **Q. Can utilities generally afford to have higher debt levels than other industries?**

17 A. Yes. Because regulated utilities have large amounts of fixed assets, stable earnings, and
18 low risk relative to other industries, they can afford to have relatively higher debt ratios (or
19 “leverage”). As aptly stated by Dr. Damodaran:

1 Since financial leverage multiplies the underlying business risk, it stands to
2 reason that firms that have high business risk should be reluctant to take on
3 financial leverage. It also stands to reason that firms that operate in stable
4 businesses should be much more willing to take on financial leverage.
5 *Utilities*, for instance, have historically had high debt ratios but have not
6 had high betas, mostly because their underlying businesses have been stable
7 and fairly predictable.⁷⁴

8 Note that Dr. Damodaran explicitly contrasts utilities with firms that have high underlying
9 business risk. Because utilities have low levels of risk and operate a stable business, they
10 should generally operate with relatively high levels of debt to achieve their optimal capital
11 structure.

12 **A. Proxy and Industry Debt Ratios**

13 **Q. Please describe the debt ratios of the proxy group.**

14 A. According to Value Line, the average capital structure mix for the proxy group consists of
15 55% debt and 45% equity.⁷⁵ This debt ratio is notably higher than Columbia's proposed
16 capital structure consisting of only 46% debt. More importantly, this means that Columbia
17 has a lower level of financial risk relative to the proxy group – a discrepancy that can be
18 mathematically accounted for in terms of cost of equity estimation through the Hamada
19 Model, which is discussed in more detail below.

⁷⁴ *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, p. 196 (emphasis added).

⁷⁵ Exhibit DJG-13.

1 **Q. Please describe the debt ratios recently observed in competitive U.S. industries.**

2 A. There are nearly 2,000 firms in U.S. industries with higher debt ratios than 50%, and with
3 an average debt ratio of about 63%.⁷⁶ The following figure shows a sample of these
4 industries with debt ratios higher than 56%.

⁷⁶ See Exhibit DJG-14.

1
2

**Figure 11:
Industries with Debt Ratios Greater than 56%**

Industry	# Firms	Debt Ratio
Air Transport	21	84%
Hotel/Gaming	69	82%
Hospitals/Healthcare Facilities	34	82%
Retail (Automotive)	30	78%
Brokerage & Investment Banking	30	76%
Computers/Peripherals	42	71%
Bank (Money Center)	7	68%
Cable TV	10	68%
Food Wholesalers	14	67%
Advertising	58	67%
Oil/Gas Distribution	23	66%
Rubber& Tires	3	65%
Transportation (Railroads)	4	65%
Real Estate (Operations & Services)	60	64%
Retail (Grocery and Food)	13	64%
Retail (Special Lines)	78	64%
Recreation	57	62%
Insurance (Life)	27	61%
Trucking	35	61%
Packaging & Container	25	61%
Power	48	60%
Telecom. Services	49	60%
Telecom (Wireless)	16	60%
R.E.I.T.	223	60%
Auto & Truck	31	59%
Utility (General)	15	59%
Household Products	127	58%
Office Equipment & Services	16	58%
Environmental & Waste Services	62	57%
Utility (Water)	16	57%
Retail (Distributors)	69	57%
Transportation	18	57%
Green & Renewable Energy	19	57%
Total / Average	1,349	65%

3 Many of the industries shown here, like public utilities, are generally well-established
4 industries with large amounts of capital assets. The shareholders of these industries

generally prefer these higher debt ratios in order to maximize their profits. There are several notable industries that are relatively comparable to public utilities. For example, the Cable TV, Telecom, Power, and Telecom industries all have an average debt ratios of at least 60%.

Q. Are you basing your capital structure recommendation on any industry or company outside of the proxy group?

A. No. I am basing my capital structure recommendation on my findings that 50% total debt and 50% equity is equal to the proxy group's average capital structure.⁷⁷ I present the capital structures observed in other competitive industries to show it is not uncommon for firms to operate with relatively higher amounts of leverage.

B. The Hamada Model: Capital Structure's Effect on ROE

Q. Have you considered the impact that your capital structure recommendation could have on the company's indicated cost of equity?

A. Yes. I assessed the impact of my capital structure proposal on the Company's cost of equity estimate by using the Hamada model.

Q. What is the premise of the Hamada model?

A. The Hamada formula can be used to analyze changes in a firm's cost of capital as it adds or reduces financial leverage, or debt, in its capital structure by starting with an "unlevered" beta and then "relevering" the beta at different debt ratios. As leverage increases, equity investors bear increasing amounts of risk, leading to higher betas. Before the effects of financial leverage can be accounted for, however, the effects of leverage must first be

⁷⁷ Exhibit DJG-13.

removed, which is accomplished through the Hamada formula. The Hamada formula for unlevering beta is stated as follows:⁷⁸

**Equation 5:
Hamada Formula**

$$\beta_U = \frac{\beta_L}{\left[1 + (1 - T_c) \left(\frac{D}{E}\right)\right]}$$

where: β_U = unlevered beta (or “asset” beta)
 β_L = average levered beta of proxy group
 T_c = corporate tax rate
 D = book value of debt
 E = book value of equity

Using this equation, the beta for the firm can be unlevered, and then “relevered” based on various debt ratios (by rearranging this equation to solve for β_L).

Q. Please summarize the results of the Hamada formula based on the average capital structure of the proxy group.

A. The average capital structure of the proxy group consists of 55% debt and 45% equity. Because Columbia’s debt ratio is notably lower than that of the proxy group, when Columbia is “relevered” to match the proxy group, it results in a lower ROE than if Columbia had been operating with a capital structure equal to that of the proxy group. This makes sense because Columbia has less financial risk relative to the proxy group due to the lower amount of debt in its capital structure. The results of my Hamada model are presented in the following figure.

⁷⁸ Damodaran *supra* n. 22 at 197. This formula was originally developed by Hamada in 1972.

1
2

**Figure 12:
Hamada Model ROE**

Unlevering Beta			
Proxy Debt Ratio		50%	
Proxy Equity Ratio		50%	
Proxy Debt / Equity Ratio		1.0	
Tax Rate		21%	
Equity Risk Premium		5.1%	
Risk-free Rate		4.9%	
Proxy Group Beta		0.80	
Unlevered Beta		0.45	
Relevered Betas and Cost of Equity Estimates			
Debt Ratio	D/E Ratio	Levered Beta	Cost of Equity
0%	0.0	0.45	7.2%
20%	0.3	0.54	7.6%
25%	0.3	0.56	7.7%
30%	0.4	0.60	7.9%
46%	0.8	0.74	8.7%
50%	1.0	0.80	8.9%
60%	1.5	0.98	9.8%

3 According to the results of the Hamada model, if the Commission were to adopt the
4 Company's proposed capital structure, its indicated cost of equity estimate (under the
5 CAPM) would be 8.7%.⁷⁹

⁷⁹ See Exhibit DJG-15.

1 **IX. MANAGEMENT PERFORMANCE PREMIUM**

2 **Q. Please describe Columbia's proposed premium for managerial performance.**

3 A. The ROE of 11.35% proposed by Columbia includes a 0.25% upward adjustment for
4 management performance.”⁸⁰

5 **Q. Do you agree that managerial performance should affect Columbia's authorized**
6 **ROE?**

7 A. No. As discussed in my testimony, the primary driver of the cost of equity and required
8 rate of return is how the market risk impacts individual firms. Managerial performance and
9 the risk of imprudent management is related to firm-specific risks, which are not rewarded
10 by the market because investors can eliminate such risk through diversification of the
11 portfolio, and do not have a material effect on the cost of equity. As investors in competitive
12 firms in the marketplace cannot expect an additional return on equity simply due to prudent
13 managerial performance, the Company as a regulated firm should not receive any premium
14 in addition to an authorized market-based ROE due to prudent managerial performance.
15 OCA witnesses Alexander and Colton also discuss problems with the Company's
16 management performance premium.

17 **Q. Are you aware of regulators from other jurisdictions who have recognized the**
18 **performance of utility management as having an increasing effect on authorized**
19 **ROE?**

20 A. No, I am not aware of a regulator from another jurisdiction who has specially recognized
21 managerial performance as having an increasing effect on the authorized ROE.

⁸⁰ Columbia Statement No. 8, Direct Testimony of Vincent V. Rea, p. 4, lines 1-2.

X. RATE OF RETURN CONCLUSION

Q. Please summarize your analyses and conclusions regarding Columbia's cost of equity.

A. A utility's awarded ROE should be based on its cost of equity, which can be estimated using various financial models. In estimating Columbia's cost of equity, I performed a cost of equity analysis on a proxy group of utility companies using the two most widely used and widely-accepted financial models for calculating cost of equity in utility rate proceedings: the CAPM and DCF Model. I conducted two variations of both the CAPM and DCF Model. The results are shown in the figure below.

**Figure 13:
Cost of Equity Model Summary**

Model	Cost of Equity
CAPM (at Proxy Debt Ratio)	8.9%
Hamada CAPM (at Company-Proposed Debt Ratio)	8.7%
DCF Model (Analyst Growth)	7.5%
DCF Model (Sustainable Growth)	7.3%
Model Average	8.1%
Model Range	7.3% -- 8.9%
Recommended ROE	8.9%

As shown in this figure, the highest result of my models is 8.9%.

1 **Q. Please summarize your recommendation to the Commission regarding Columbia's**
2 **authorized rate of return.**

3 A. I am recommending an authorized ROE of 8.9% for Columbia. I also recommend the
4 Commission impute a capital structure for Columbia for ratemaking purposes consisting
5 of 50% debt and 50% equity.

6 **Q. Please summarize your rate of return recommendation.**

7 A. My recommendations are summarized in the following table.

8 **Figure 14:**
9 **Awarded Rate of Return Recommendation**

<u>Capital Component</u>	<u>Proposed Ratio</u>	<u>Cost Rate</u>	<u>Weighted Cost</u>
Long-Term Debt	47.68%	5.2%	2.5%
Short-Term Debt	2.32%	5.0%	0.1%
Common Equity	<u>50.00%</u>	8.9%	<u>4.5%</u>
Total	100.0%		7.06%

10 As shown in this figure, adopting my proposed adjustments to the Company's ROE and
11 capital structure would result in a weighted average authorized rate of return of 7.06%.

1 **PART TWO: DEPRECIATION**

2 **XI. REGULATORY STANDARDS**

3 **Q. Please discuss the standard by which regulated utilities are allowed to recover**
4 **depreciation expense.**

5 A. In *Lindheimer v. Illinois Bell Telephone Co.*, the U.S. Supreme Court stated “depreciation
6 is the loss, not restored by current maintenance, which is due to all the factors causing the
7 ultimate retirement of the property. These factors embrace wear and tear, decay,
8 inadequacy, and obsolescence.”⁸¹ The *Lindheimer* Court also recognized that the original
9 cost of plant assets, rather than present value or some other measure, is the proper basis for
10 calculating depreciation expense.⁸² Moreover, the *Lindheimer* Court found:

11 [T]he company has the burden of making a convincing showing that the
12 amounts it has charged to operating expenses for depreciation have not been
13 excessive. That burden is not sustained by proof that its general accounting
14 system has been correct. The calculations are mathematical, but the
15 predictions underlying them are essentially matters of opinion.⁸³

16 Thus, the Commission must ultimately determine if Columbia has met its burden of proof
17 by making a convincing showing that its proposed depreciation rates are not excessive.

⁸¹ *Lindheimer v. Illinois Bell Tel. Co.*, 292 U.S. 151, 167 (1934).

⁸² *Id.* (Referring to the straight-line method, the *Lindheimer* Court stated that “[a]ccording to the principle of this accounting practice, the loss is computed upon the actual cost of the property as entered upon the books, less the expected salvage, and the amount charged each year is one year’s pro rata share of the total amount.”). The original cost standard was reaffirmed by the Court in *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 606 (1944). The *Hope* Court stated: “Moreover, this Court recognized in [*Lindheimer*], *supra*, the propriety of basing annual depreciation on cost. By such a procedure the utility is made whole and the integrity of its investment maintained. No more is required.”

⁸³ *Id.* at 169.

1 **A. Depreciation System**

2 **Q. Please discuss the definition and general purpose of a depreciation system, as well as**
3 **the specific depreciation system you employed for this project.**

4 A. The legal standards set forth above do not mandate a specific procedure for conducting
5 depreciation analysis. These standards, however, direct that analysts use a system for
6 estimating depreciation rates that will result in the “systematic and rational” allocation of
7 capital recovery for the utility. Over the years, analysts have developed “depreciation
8 systems” designed to analyze grouped property in accordance with this standard. A
9 depreciation system may be defined by several primary parameters, including: 1) a method
10 of allocation; 2) a procedure for applying the method of allocation; 3) a technique of
11 applying the depreciation rate; and 4) a model for analyzing the characteristics of vintage
12 property groups.⁸⁴ In this case, I used the straight-line method, the average life group
13 procedure, the remaining life technique, and the broad group model.⁸⁵

14 **Q. Did both Mr. Spanos and you use the same depreciation system?**

15 A. No. Pertinently, Mr. Spanos used the Equal Life Group (“ELG”) method instead of the
16 average life group (“ALG”) method. I discuss the differences between these methods in
17 more detail below.

⁸⁴ See Wolf & W. Chester Fitch, *Depreciation Systems* 70, 140 (Iowa State University Press 1994).

⁸⁵ See Appendix C for further discussion.

1 **B. Average Life vs Equal Life Method**

2 **Q. Explain the primary difference between the ALG and ELG methods.**

3 A. In the ALG method, a constant accrual rate based on the average life of all property in the
4 group is applied to the surviving property.⁸⁶ In the ELG method, property is divided into
5 subgroups that each have a common life. Pertinently, the ELG method results in higher
6 depreciation rates in the early years of a vintage's life. This fact is confirmed by
7 authoritative depreciation literature. According to Wolf:

8 When contrasted with the average life procedure, the equal life group
9 procedure results in annual accruals that are higher during the early years
10 and lower in the later years.⁸⁷

11 The NARUC Public Utility Depreciation Practices also makes the same conclusion about
12 the equal life procedure:

13 [T]he ELG method results in annual accruals that are higher during the early
14 years of a vintage's life, thereby causing an increase in depreciation expense
15 and revenue requirements during these years.⁸⁸

16 In contrast, use of the average life results in the same depreciation rate applied to each age
17 interval.

18 **Q. Based on your experience in other regulatory jurisdictions and knowledge of the**
19 **industry, which method is more commonly used?**

20 A. In my experience, the ALG method is used by analysts and adopted by regulators in the
21 vast majority of jurisdiction and in the vast majority of cases.

⁸⁶ *Id.* at 74-75.

⁸⁷ *Id.* at 93 (emphasis added).

⁸⁸ National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices* 176 (NARUC 1996) (emphasis added).

1 **Q. Does Mr. Spanos typically use the ALG method in depreciation studies you have**
2 **reviewed?**

3 A. In the vast majority of cases in which I have reviewed Mr. Spanos's depreciation studies,
4 he uses the ALG method.

5 **Q. Have you successfully argued for a change from the ELG method to ALG method in**
6 **another jurisdiction?**

7 A. Yes. In Duke Energy Indiana's ("DEI") 2020 rate case, the company proposed ELG
8 depreciation rates, which had been adopted by the Indiana commission in previous cases.
9 In that case, I and other parties argued that the ALG method should be used. The Indiana
10 Commission found as follows:

11 First, with respect to the question of whether the ELG or ALG method
12 should be used, we find the evidence presented by OUCC witness Mr.
13 Garrett and Industrial Group witness Mr. Andrews persuasive, as both
14 witnesses showed that the ELG method results in unreasonably high
15 depreciation rates. ALG depreciation rates result in systematical and
16 rational cost recovery with near term customer rate relief and full cost
17 recovery of utility investments. While we have determined in the past that
18 the ELG methodology was appropriate and acknowledge the weight given
19 to precedent in many prior decisions, we always evaluate each case as it
20 comes before us and do not need to approve the same methodology based
21 on prior decisions, especially in light of a changed landscape. The use of
22 ELG in a higher than average investment cycle has the effect of
23 unnecessarily increasing the near term depreciation expense as compared to
24 the use of ALG.⁸⁹

25 In the DEI case, the Commission correctly noted that the ELG method can result in
26 unreasonably high depreciation rates. In order for the ELG method to be properly applied,
27 a utility would need to revise depreciation each year. When a utility has made substantial,
28 recent capital investments, depreciation expense calculated under the ELG method will
29 always be higher than the expense calculated under the ALG method. The larger the

⁸⁹ Cause No. 45253, Order of the Commission, p. 90, (June 29, 2020).

1 amount of the investments, the larger the discrepancy will be between the two procedures.
2 The Indiana commission's criticism of the ELG method would also apply here. In this
3 case, the difference in the annual depreciation accrual between the ELG and ALG methods
4 alone is \$44 million based on plant balances at the end of the Fully Projected Future Test
5 Year which is December 31, 2025.

6 **Q. Are you aware of other Public Utility Commissions that have rejected the use of ELG?**

7 A. Yes. The Kentucky Public Service Commission ("Kentucky PSC") found that the ELG
8 procedure front-loads depreciation expense in earlier years and decreases it in the later
9 years of an asset's depreciation life, creating a mismatch of revenues and expenses. The
10 Kentucky PSC states reasoning for rejecting the ELG is as follows:

11 Duke Kentucky proposes, as part of developing its depreciation rates, the
12 continued use of the ELG procedure. The Attorney General recommends
13 the Commission adopt the ALG procedure in developing Duke Kentucky's
14 depreciation rates. The Attorney General contends that the ALG
15 methodology is the predominant method that is used in the electric industry
16 for developing depreciation rates. The Attorney General contends that,
17 under the ELG methodology, the capital recovery periods are accelerated
18 and shortened and, thus, the depreciation rates are greater than if the ALG
19 procedure was used. The Attorney General argues that the ALG procedure
20 is as accurate as the ELG procedure and the ALG procedure smooths the
21 data so that the depreciation rates for the group of assets tend to remain
22 constant. Use of the ALG procedure will result in a decrease in Duke
23 Kentucky's depreciation expense of \$6.920 million.

24 Duke Kentucky requested an increase in depreciation expense of \$6.920
25 million, based on its request to utilize the ELG procedure for computing
26 depreciation rates. As was discussed in the rate base section of this Order,
27 this Commission has found that the ELG procedure does not accurately
28 match revenues and expenses, is front-loaded, and Duke Kentucky is the
29 only Kentucky based utility that utilizes the ELG procedure for computing
30 depreciation rates.

31 Regulatory accounting requires the proper matching of revenues and
32 expense in order to produce fair, just and reasonable rates. The Commission
33 finds Duke Kentucky's proposed ELG procedure does not meet that criteria

and that Duke Kentucky's depreciation expense should be reduced by \$6.920 million.⁹⁰

Q. Please provide an example of how the ELG method results in higher depreciation rates in earlier years relative to the ALG method.

A. For the following illustration, assume a group of property containing two units, one with an original cost of \$4,000 and a 4-year life and the second with an original cost of \$6,000 and an 8-year life.⁹¹ Thus, the average life of this group is 6.4 years.⁹² Under the ALG method, the depreciation rate is 15.625% per year ($1/6.4 = 15.625\%$). The following table illustrates this example.

**Figure 1:
ALG Procedure**

Year	Balance	Retired	Rate	Annual Accrual	Accum. Deprec.
1974	10000		15.625%	1563	0
1975	10000		15.625%	1563	1563
1976	10000		15.625%	1563	3125
1977	10000	4000	15.625%	1563	4688
1978	6000		15.625%	938	2250
1979	6000		15.625%	938	3188
1980	6000		15.625%	938	4125
1981	6000	6000	15.625%	938	5063
1982	0				0

As shown in the annual accrual column above, the full \$10,000 is depreciated after eight years. Now, considering the same assumptions presented above, the following tables illustrate the same scenario except that the rate is calculated under the ELG method.

⁹⁰ In the Matter of: Electronic Application of Duke Energy Kentucky, Inc., Kentucky PSC, Order at pages 26-27, Case No. 2017-00321, (https://psc.ky.gov/pscscf/2017%20Cases/2017-00321//20180413_PSC_ORDER.pdf).

⁹¹ See Wolf & W. Chester Fitch, *Depreciation Systems* 82 (Iowa State University Press 1994).

⁹² $AL = [(\$4,000 \times 4) + (\$6,000 \times 8)] / \$10,000 = 6.4$ years.

1
2

**Figure 2:
ELG Procedure**

Year	Balance	Retired	Rate	Annual Accrual	Accum. Deprec.
1974	10000		17.50%	1750	0
1975	10000		17.50%	1750	1750
1976	10000		17.50%	1750	3500
1977	10000	4000	17.50%	1750	5250
1978	6000		12.50%	750	3000
1979	6000		12.50%	750	3750
1980	6000		12.50%	750	4500
1981	6000	6000	12.50%	750	5250
1982	0				0

3 As with the ALG example presented above, the full \$10,000 investment is still fully
4 depreciated after eight years. However, there are higher rates and accrual amounts during
5 the earlier years. The reason there is a 17.5% depreciation rate instead of a 15.625%
6 depreciation rate in the early years is because the two units in this group are treated
7 separately under the ELG method. The following table shows how the rates in this example
8 are calculated.

9
10

**Figure 3:
ELG Rate Development**

Group	Group Amount	Group Life	Group Rate	Annual Accrual	
				1974-77	1978-81
A	4000	4	25.00%	1000	
B	6000	8	12.50%	750	750
Annual accruals				1750	750
Balance during interval				10000	6000
Annual accrual rate %				17.50%	12.50%

1 This example is simplified in an attempt to explain the complexities of the ELG method.
2 In this example, the higher rate of 17.5% stayed the same for four years because there are
3 only two units in this simple example, and the rate drops to 12.5% after the first unit retires.

4 **Q. Please summarize your recommendation regarding the depreciation system that**
5 **should be used to calculate the Company's depreciation rates.**

6 A. As demonstrated above, the ALG method results in a fairer application of depreciation
7 rates compared to the ELG method given the realities of ratemaking proceedings. Mr.
8 Spanos's decision to use the ELG method unnecessarily increases the *annual* depreciation
9 accrual charged to customers by approximately \$1.6 million. In other words, even if no
10 other adjustments are made to the depreciation study except the adoption of the majority-
11 view ALG method, it would result in a decrease of \$1.6 million to the Company's proposed
12 annual depreciation accrual. The Commission should adopt my proposed depreciation
13 rates, which were calculated using the ALG method.

15 **XII. SERVICE LIFE ANALYSIS**

16 **Q. Describe the methodology used to estimate the service lives of grouped depreciable**
17 **assets.**

18 A. The process used to study industrial property retirement is rooted in the actuarial process
19 used to study human mortality. Just as actuarial analysts study historical human mortality
20 data to predict how long a group of people will live, depreciation analysts study historical
21 plant data to estimate the average lives of property groups. The most common actuarial
22 method used by depreciation analysts is called the "retirement rate method." In the
23 retirement rate method, original property data, including additions, retirements, transfers,

1 and other transactions, are organized by vintage and transaction year.⁹³ The retirement rate
2 method is ultimately used to develop an “observed life table,” (“OLT”) which shows the
3 percentage of property surviving at each age interval. This pattern of property retirement
4 is described as a “survivor curve.” The survivor curve derived from the observed life table,
5 however, must be fitted and smoothed with a complete curve in order to determine the
6 ultimate average life of the group.⁹⁴ The most widely used survivor curves for this curve
7 fitting process were developed at Iowa State University in the early 1900s and are
8 commonly known as the “Iowa curves.”⁹⁵ A more detailed explanation of how the Iowa
9 curves are used in the actuarial analysis of depreciable property is set forth in Appendix C.

10 **Q. Describe how you analyzed Columbia’s historical retirement data in order to**
11 **determine the most reasonable Iowa curve to apply to each account.**

12 A. The Company’s aged property data is used to create OLTs for each account. The data
13 points on the OLT can be plotted to form a curve (the “OLT curve”). The OLT curve is
14 not a theoretical curve; rather, it is actual observed data from the Company’s records that
15 indicate the rate of retirement for each property group. An OLT curve by itself, however,
16 is rarely a smooth curve, and is often not a “complete” curve (i.e., it does not end at zero
17 percent surviving). In order to calculate average life (the area under a curve), a complete
18 survivor curve is required. The Iowa curves are empirically derived curves based on the
19 extensive studies of the actual mortality patterns of many different types of industrial

⁹³ The “vintage” year refers to the year that a group of property was placed in service (aka “placement” year). The “transaction” year refers to the accounting year in which a property transaction occurred, such as an addition, retirement, or transfer (aka “experience” year).

⁹⁴ See Appendix C for a more detailed discussion of the actuarial analysis used to determine the average lives of grouped industrial property.

⁹⁵ See Appendix B for a more detailed discussion of the Iowa curves.

property. The curve-fitting process involves selecting the best Iowa curve to fit the OLT curve. This can be accomplished through a combination of visual and mathematical curve-fitting techniques, as well as professional judgment.

Q. Is mathematical fitting an important part of the curve-fitting process?

A. Yes. Mathematical curve fitting promotes objective, unbiased results. While mathematical curve-fitting is important, it may not always yield the optimum result. Simply determining which Iowa curve best fits an OLT curve ignores professional judgment that may be needed for specific situations. For example, if there is insufficient historical data in a particular account and the OLT curve derived from that data is relatively short and flat, the mathematically “best” curve may be one with a very long average life. However, when there is sufficient data available, mathematical curve fitting can be used as part of an objective service life analysis.

Q. Should every portion of the OLT curve be given equal weight?

A. Not necessarily. Many analysts have observed that the points towards the end of OLT curves may often have less analytical value than other portions of the curve. Indeed, “[p]oints at the end of the curve are often based on fewer exposures and may be given less weight than points based on larger samples. The weight placed on those points will depend on the size of the exposures.”⁹⁶ In accordance with this standard, an analyst may decide to truncate the tail end of the OLT curve at a certain percent of initial exposures, such as one percent. Using this approach puts greater emphasis on the most valuable portions of the curve. For my analysis in this case, I not only considered the entirety of the OLT curve,

⁹⁶ Wolf & W. Chester Fitch, *Depreciation Systems* 46 (Iowa State University Press 1994).

1 but also conducted further analyses that involved fitting Iowa curves to the most significant
2 part of the OLT curve for certain accounts.

3 **Q. Are you recommending service life adjustments in this case based on the following**
4 **analyses?**

5 A. No. In this case, I believe it is more important for the Commission to focus on the ALG
6 vs ELG issue and limit the accelerated form of cost recovery that would unfairly burden
7 customers under the ELG method proposed by Mr. Spanos.

8 **Q. What is your recommendation to the Commission regarding the Company's**
9 **depreciation rates.**

10 A. I recommend the Commission adopt the depreciation rates presented in my exhibits, which
11 were calculated using the same service life parameters proposed in the Company's
12 depreciation study, but using the ALG method instead of the ELG method.

13 **Q. Does this conclude your testimony?**

14 A. Yes.

APPENDIX and EXHIBITS

APPENDIX A:

DISCOUNTED CASH FLOW MODEL THEORY

The Discounted Cash Flow (“DCF”) Model is based on a fundamental financial model called the “dividend discount model,” which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. In its most general form, the DCF Model is expressed as follows:¹

Equation 1: General Discounted Cash Flow Model

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n}{(1+k)^n}$$

where:

P_0	=	current stock price
$D_1 \dots D_n$	=	expected future dividends
k	=	discount rate / required return

The General DCF Model would require an estimation of an infinite stream of dividends. Since this would be impractical, analysts use more feasible variations of the General DCF Model, which are discussed further below.

The DCF Models rely on the following four assumptions:

1. Investors evaluate common stocks in the classical valuation framework; that is, they trade securities rationally at prices reflecting their perceptions of value;
2. Investors discount the expected cash flows at the same rate (K) in every future period;

¹ See Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 410 (9th ed., McGraw-Hill/Irwin 2013).

3. The K obtained from the DCF equation corresponds to that specific stream of future cash flows alone; and
4. Dividends, rather than earnings, constitute the source of value.

The General DCF can be rearranged to make it more practical for estimating the cost of equity. Regulators typically rely on some variation of the Constant Growth DCF Model, which is expressed as follows:

**Equation 2:
Constant Growth Discounted Cash Flow Model**

$$K = \frac{D_1}{P_0} + g$$

where: K = discount rate / required return on equity
 D_1 = expected dividend per share one year from now
 P_0 = current stock price
 g = expected growth rate of future dividends

Unlike the General DCF Model, the Constant Growth DCF Model solves directly for the required return (K). In addition, by assuming that dividends grow at a constant rate, the dividend stream from the General DCF Model may be essentially substituted with a term representing the expected constant growth rate of future dividends (g). The Constant Growth DCF Model may be considered in two parts. The first part is the dividend yield (D_1/P_0), and the second part is the growth rate (g). In other words, the required return in the DCF Model is equivalent to the dividend yield plus the growth rate.

In addition to the four assumptions listed above, the Constant Growth DCF Model relies on four additional assumptions as follows:²

² *Id.* at 254-56.

1. The discount rate (K) must exceed the growth rate (g);
2. The dividend growth rate (g) is constant in every year to infinity;
3. Investors require the same return (K) in every year; and
4. There is no external financing; that is, growth is provided only by the retention of earnings.

Because the growth rate in this model is assumed to be constant, it is important not to use growth rates that are unreasonably high. In fact, the constant growth rate estimate for a regulated utility with a defined service territory should not exceed the growth rate for the economy in which it operates.

APPENDIX B:

CAPITAL ASSET PRICING MODEL THEORY

The Capital Asset Pricing Model (“CAPM”) is a market-based model founded on the principle that investors demand higher returns for incurring additional risk.³ The CAPM estimates this required return. The CAPM relies on the following assumptions:

1. Investors are rational, risk-adverse, and strive to maximize profit and terminal wealth;
2. Investors make choices based on risk and return. Return is measured by the mean returns expected from a portfolio of assets; risk is measured by the variance of these portfolio returns;
3. Investors have homogenous expectations of risk and return;
4. Investors have identical time horizons;
5. Information is freely and simultaneously available to investors.
6. There is a risk-free asset, and investors can borrow and lend unlimited amounts at the risk-free rate;
7. There are no taxes, transaction costs, restrictions on selling short, or other market imperfections; and,
8. Total asset quality is fixed, and all assets are marketable and divisible.⁴

³ William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 208 (3rd ed., South Western Cengage Learning 2010).

⁴ *Id.*

While some of these assumptions may appear to be restrictive, they do not outweigh the inherent value of the model. The CAPM has been widely used by firms, analysts, and regulators for decades to estimate the cost of equity capital.

The basic CAPM equation is expressed as follows:

**Equation 3:
Capital Asset Pricing Model**

$$K = R_F + \beta_i(R_M - R_F)$$

where:

K	=	<i>required return</i>
R_F	=	<i>risk-free rate</i>
β	=	<i>beta coefficient of asset i</i>
R_M	=	<i>required return on the overall market</i>

There are essentially three terms within the CAPM equation that are required to calculate the required return (K): (1) the risk-free rate (R_F); (2) the beta coefficient (β); and (3) the equity risk premium ($R_M - R_F$), which is the required return on the overall market less the risk-free rate.

Raw Beta Calculations and Adjustments

A stock's beta equals the covariance of the asset's returns with the returns on a market portfolio, divided by the portfolio's variance, as expressed in the following formula:⁵

**Equation 4:
Beta**

$$\beta_i = \frac{\sigma_{im}}{\sigma_m^2}$$

where:

β_i	=	<i>beta of asset i</i>
σ_{im}	=	<i>covariance of asset i returns with market portfolio returns</i>
σ_m^2	=	<i>variance of market portfolio</i>

⁵ John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180-81 (3rd ed., South Western Cengage Learning 2010).

Betas that are published by various research firms are typically calculated through a regression analysis that considers the movements in price of an individual stock and movements in the price of the overall market portfolio. The betas produced by this regression analysis are considered “raw” betas. There is empirical evidence that raw betas should be adjusted to account for beta’s natural tendency to revert to an underlying mean.⁶ Some analysts use an adjustment method proposed by Blume, which adjusts raw betas toward the market mean of one.⁷ While the Blume adjustment method is popular due to its simplicity, it is arguably arbitrary, and some would say not useful at all. According to Dr. Damodaran: “While we agree with the notion that betas move toward 1.0 over time, the [Blume adjustment] strikes us as arbitrary and not particularly useful.”⁸ The Blume adjustment method is especially arbitrary when applied to industries with consistently low betas, such as the utility industry. For industries with consistently low betas, it is better to employ an adjustment method that adjusts raw betas toward an industry average, rather than the market average. Vasicek proposed such a method, which is preferable to the Blume adjustment method because it allows raw betas to be adjusted toward an industry average, and also accounts for the statistical accuracy of the raw beta calculation.⁹ In other words, “[t]he Vasicek adjustment seeks to overcome one weakness of the Blume model by not applying the same adjustment to every security; rather, a security-specific adjustment is made depending on the

⁶ See Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 84-92 (Financial Management Autumn 1990).

⁷ See Marshall Blume, *On the Assessment of Risk*, Vol. 26, No. 1, The Journal of Finance 1 (1971).

⁸ See Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 187 (3rd ed., John Wiley & Sons, Inc. 2012).

⁹ Oldrich A. Vasicek, *A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas* 1233-1239 (Journal of Finance, Vol. 28, No. 5, December 1973).

statistical quality of the regression.”¹⁰ The Vasicek beta adjustment equation is expressed as follows:

**Equation 5:
Vasicek Beta Adjustment**

$$\beta_{i1} = \frac{\sigma_{\beta_{i0}}^2}{\sigma_{\beta_0}^2 + \sigma_{\beta_{i0}}^2} \beta_0 + \frac{\sigma_{\beta_0}^2}{\sigma_{\beta_0}^2 + \sigma_{\beta_{i0}}^2} \beta_{i0}$$

where:

β_{i1}	=	<i>Vasicek adjusted beta for security i</i>
β_{i0}	=	<i>historical beta for security i</i>
β_0	=	<i>beta of industry or proxy group</i>
$\sigma_{\beta_0}^2$	=	<i>variance of betas in the industry or proxy group</i>
$\sigma_{\beta_{i0}}^2$	=	<i>square of standard error of the historical beta for security i</i>

The Vasicek beta adjustment is an improvement on the Blume model because the Vasicek model does not apply the same adjustment to every security. A higher standard error produced by the regression analysis indicates a lower statistical significance of the beta estimate. Thus, a beta with a high standard error should receive a greater adjustment than a beta with a low standard error. As stated in Ibbotson:

¹⁰ 2012 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook 77-78 (Morningstar 2012).

While the Vasicek formula looks intimidating, it is really quite simple. The adjusted beta for a company is a weighted average of the company's historical beta and the beta of the market, industry, or peer group. How much weight is given to the company and historical beta depends on the statistical significance of the company beta statistic. If a company beta has a low standard error, then it will have a higher weighting in the Vasicek formula. If a company beta has a high standard error, then it will have lower weighting in the Vasicek formula. An advantage of this adjustment methodology is that it does not force an adjustment to the market as a whole. Instead, the adjustment can be toward an industry or some other peer group. *This is most useful in looking at companies in industries that on average have high or low betas.*¹¹

Thus, the Vasicek adjustment method is statistically more accurate, and is the preferred method to use when analyzing companies in an industry that has inherently low betas, such as the utility industry. The Vasicek method was also confirmed by Gombola, who conducted a study specifically related to utility companies. Gombola concluded that “[t]he strong evidence of autoregressive tendencies in *utility* betas lends support to the application of adjustment procedures such as the . . . adjustment procedure presented by Vasicek.”¹² Gombola also concluded that adjusting raw betas toward the market mean of 1.0 is *too high*, and that “[i]nstead, they should be adjusted toward a value that is less than one.”¹³ In conducting the Vasicek adjustment on betas in previous

¹¹ *Id.* at 78 (emphasis added).

¹² Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 92 (Financial Management Autumn 1990) (emphasis added).

¹³ *Id.* at 91-92.

cases, it reveals that utility betas are even lower than those published by Value Line.¹⁴ Gombola's findings are particularly important here, because his study was conducted specifically on utility companies. This evidence indicates that using Value Line's betas in a CAPM cost of equity estimate for a utility company may lead to overestimated results. Regardless, adjusting betas to a level that is *higher* than Value Line's betas is not reasonable, and it would produce CAPM cost of equity results that are too high.

¹⁴ See e.g. Responsive Testimony of David J. Garrett, filed March 21, 2016 in Cause No. PUD 201500273 before the Corporation Commission of Oklahoma (the Company's 2015 rate case), at pp. 56 – 59.

APPENDIX C: THE DEPRECIATION SYSTEM

A depreciation accounting system may be thought of as a dynamic system in which estimates of life and salvage are inputs to the system, and the accumulated depreciation account is a measure of the state of the system at any given time.¹⁵ The primary objective of the depreciation system is the timely recovery of capital. The process for calculating the annual accruals is determined by the factors required to define the system. A depreciation system should be defined by four primary factors: 1) a *method* of allocation; 2) a *procedure* for applying the method of allocation to a group of property; 3) a *technique* for applying the depreciation rate; and 4) a *model* for analyzing the characteristics of vintage groups comprising a continuous property group.¹⁶ The figure below illustrates the basic concept of a depreciation system and includes some of the available parameters.¹⁷

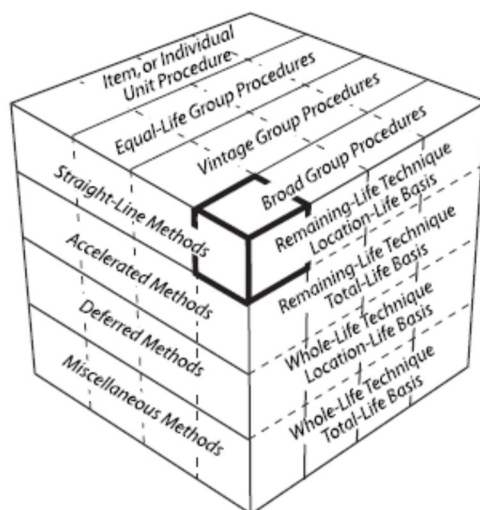
There are hundreds of potential combinations of methods, procedures, techniques, and models, but in practice, analysts use only a few combinations. Ultimately, the system selected must result in the systematic and rational allocation of capital recovery for the utility. Each of the four primary factors defining the parameters of a depreciation system is discussed further below.

¹⁵ See Frank K. Wolf & W. Chester Fitch, *Depreciation Systems* 69-70 (Iowa State University Press 1994).

¹⁶ *Id.* at 70, 139-40.

¹⁷ Edison Electric Institute, *Introduction to Depreciation* (inside cover) (EEI April 2013). Some definitions of the terms shown in this diagram are not consistent among depreciation practitioners and literature due to the fact that depreciation analysis is a relatively small and fragmented field. This diagram simply illustrates the some of the available parameters of a depreciation system.

**Figure 1:
The Depreciation System Cube**



1. Allocation Methods

The “method” refers to the pattern of depreciation in relation to the accounting periods. The method most commonly used in the regulatory context is the “straight-line method” — a type of age-life method in which the depreciable cost of plant is charged in equal amounts to each accounting period over the service life of plant.¹⁸ Because group depreciation rates and plant balances often change, the amount of the annual accrual rarely remains the same, even when the straight-line method is employed.¹⁹ The basic formula for the straight-line method is as follows:²⁰

Equation 6: Straight-Line Accrual

$$\text{Annual Accrual} = \frac{\text{Gross Plant} - \text{Net Salvage}}{\text{Service Life}}$$

¹⁸ National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices* 56 (NARUC 1996).

¹⁹ *Id.*

²⁰ *Id.*

Gross plant is a known amount from the utility's records, while both net salvage and service life must be estimated in order to calculate the annual accrual. The straight-line method differs from accelerated methods of recovery, such as the "sum-of-the-years-digits" method and the "declining balance" method. Accelerated methods are primarily used for tax purposes and are rarely used in the regulatory context for determining annual accruals.²¹ In practice, the annual accrual is expressed as a rate which is applied to the original cost of plant in order to determine the annual accrual in dollars. The formula for determining the straight-line rate is as follows:²²

**Equation 7:
Straight-Line Rate**

$$\text{Depreciation Rate \%} = \frac{100 - \text{Net Salvage \%}}{\text{Service Life}}$$

2. Grouping Procedures

The "procedure" refers to the way the allocation method is applied through subdividing the total property into groups.²³ While single units may be analyzed for depreciation, a group plan of depreciation is particularly adaptable to utility property. Employing a grouping procedure allows for a composite application of depreciation rates to groups of similar property, rather than excessively conducting calculations for each unit. Whereas an individual unit of property has a single life, a group of property displays a dispersion of lives and the life characteristics of the group must be described statistically.²⁴ When analyzing mass property categories, it is important that

²¹ *Id.* at 57.

²² *Id.* at 56.

²³ Wolf *supra* n. 15, at 74-75.

²⁴ *Id.* at 74.

each group contains homogenous units of plant that are used in the same general manner throughout the plant and operated under the same general conditions.²⁵

The “average life” and “equal life” grouping procedures are the two most common. In the average life procedure, a constant annual accrual rate based on the average life of all property in the group is applied to the surviving property. While property having shorter lives than the group average will not be fully depreciated, and likewise, property having longer lives than the group average will be over-depreciated, the ultimate result is that the group will be fully depreciated by the time of the final retirement.²⁶ Thus, the average life procedure treats each unit as though its life is equal to the average life of the group. In contrast, the equal life procedure treats each unit in the group as though its life was known.²⁷ Under the equal life procedure the property is divided into subgroups that each has a common life.²⁸

3. Application Techniques

The third factor of a depreciation system is the “technique” for applying the depreciation rate. There are two commonly used techniques: “whole life” and “remaining life.” The whole life technique applies the depreciation rate on the estimated average service life of a group, while the remaining life technique seeks to recover undepreciated costs over the remaining life of the plant.²⁹

In choosing the application technique, consideration should be given to the proper level of the accumulated depreciation account. Depreciation accrual rates are calculated using estimates of service life and salvage. Periodically these estimates must be revised due to changing

²⁵ NARUC *supra* n. 18, at 61-62.

²⁶ See Wolf *supra* n. 15, at 74-75.

²⁷ *Id.* at 75.

²⁸ *Id.*

²⁹ NARUC *supra* n. 18, at 63-64.

conditions, which cause the accumulated depreciation account to be higher or lower than necessary. Unless some corrective action is taken, the annual accruals will not equal the original cost of the plant at the time of final retirement.³⁰ Analysts can calculate the level of imbalance in the accumulated depreciation account by determining the “calculated accumulated depreciation,” (a.k.a. “theoretical reserve” and referred to in these appendices as “CAD”). The CAD is the calculated balance that would be in the accumulated depreciation account at a point in time using *current* depreciation parameters.³¹ An imbalance exists when the actual accumulated depreciation account does not equal the CAD. The choice of application technique will affect how the imbalance is dealt with.

Use of the whole life technique requires that an adjustment be made to accumulated depreciation after calculation of the CAD. The adjustment can be made in a lump sum or over a period of time. With use of the remaining life technique, however, adjustments to accumulated depreciation are amortized over the remaining life of the property and are automatically included in the annual accrual.³² This is one reason that the remaining life technique is popular among practitioners and regulators. The basic formula for the remaining life technique is as follows:³³

³⁰ Wolf *supra* n. 15, at 83.

³¹ NARUC *supra* n. 18, at 325.

³² NARUC *supra* n. 18, at 65 (“The desirability of using the remaining life technique is that any necessary adjustments of [accumulated depreciation] . . . are accrued automatically over the remaining life of the property. Once commenced, adjustments to the depreciation reserve, outside of those inherent in the remaining life rate would require regulatory approval.”).

³³ *Id.* at 64.

**Equation 8:
Remaining Life Accrual**

$$\text{Annual Accrual} = \frac{\text{Gross Plant} - \text{Accumulated Depreciation} - \text{Net Salvage}}{\text{Average Remaining Life}}$$

The remaining life accrual formula is similar to the basic straight-line accrual formula above with two notable exceptions. First, the numerator has an additional factor in the remaining life formula: the accumulated depreciation. Second, the denominator is “average remaining life” instead of “average life.” Essentially, the future accrual of plant (gross plant less accumulated depreciation) is allocated over the remaining life of plant. Thus, the adjustment to accumulated depreciation is “automatic” in the sense that it is built into the remaining life calculation.³⁴

4. Analysis Model

The fourth parameter of a depreciation system, the “model,” relates to the way of viewing the life and salvage characteristics of the vintage groups that have been combined to form a continuous property group for depreciation purposes.³⁵ A continuous property group is created when vintage groups are combined to form a common group. Over time, the characteristics of the property may change, but the continuous property group will continue. The two analysis models used among practitioners, the “broad group” and the “vintage group,” are two ways of viewing the life and salvage characteristics of the vintage groups that have been combined to form a continuous property group.

The broad group model views the continuous property group as a collection of vintage groups that each has the same life and salvage characteristics. Thus, a single survivor curve and a

³⁴ Wolf *supra* n. 15, at 178.

³⁵ See Wolf *supra* n. 15, at 139 (I added the term “model” to distinguish this fourth depreciation system parameter from the other three parameters).

single salvage schedule are chosen to describe all the vintages in the continuous property group. In contrast, the vintage group model views the continuous property group as a collection of vintage groups that may have different life and salvage characteristics. Typically, there is not a significant difference between vintage group and broad group results unless vintages within the applicable property group experienced dramatically different retirement levels than anticipated in the overall estimated life for the group. For this reason, many analysts utilize the broad group procedure because it is more efficient.

APPENDIX D:

IOWA CURVES

Early work in the analysis of the service life of industrial property was based on models that described the life characteristics of human populations.³⁶ This explains why the word “mortality” is often used in the context of depreciation analysis. In fact, a group of property installed during the same accounting period is analogous to a group of humans born during the same calendar year. Each period the group will incur a certain fraction of deaths / retirements until there are no survivors. Describing this pattern of mortality is part of actuarial analysis and is regularly used by insurance companies to determine life insurance premiums. The pattern of mortality may be described by several mathematical functions, particularly the survivor curve and frequency curve. Each curve may be derived from the other so that if one curve is known, the other may be obtained. A survivor curve is a graph of the percent of units remaining in service expressed as a function of age.³⁷ A frequency curve is a graph of the frequency of retirements as a function of age. Several types of survivor and frequency curves are illustrated in the figures below.

1. Development

The survivor curves used by analysts today were developed over several decades from extensive analysis of utility and industrial property. In 1931 Edwin Kurtz and Robley Winfrey used extensive data from a range of 65 industrial property groups to create survivor curves representing the life characteristics of each group of property.³⁸ They generalized the 65 curves

³⁶ Wolf *supra* n. 15, at 276.

³⁷ *Id.* at 23.

³⁸ *Id.* at 34.

into 13 survivor curve types and published their results in *Bulletin 103: Life Characteristics of Physical Property*. The 13 type curves were designed to be used as valuable aids in forecasting probable future service lives of industrial property. Over the next few years, Winfrey continued gathering additional data, particularly from public utility property, and expanded the examined property groups from 65 to 176.³⁹ This resulted in 5 additional survivor curve types for a total of 18 curves. In 1935, Winfrey published *Bulletin 125: Statistical Analysis of Industrial Property Retirements*. According to Winfrey, “[t]he 18 type curves are expected to represent quite well all survivor curves commonly encountered in utility and industrial practices.”⁴⁰ These curves are known as the “Iowa curves” and are used extensively in depreciation analysis in order to obtain the average service lives of property groups. (Use of Iowa curves in actuarial analysis is further discussed in Exhibit DJG-23, Appendix E.)

In 1942, Winfrey published *Bulletin 155: Depreciation of Group Properties*. In Bulletin 155, Winfrey made some slight revisions to a few of the 18 curve types, and published the equations, tables of the percent surviving, and probable life of each curve at five-percent intervals.⁴¹ Rather than using the original formulas, analysts typically rely on the published tables containing the percentages surviving. This is because absent knowledge of the integration technique applied to each age interval, it is not possible to recreate the exact original published table values. In the 1970s, John Russo collected data from over 2,000 property accounts reflecting

³⁹ *Id.*

⁴⁰ Robley Winfrey, *Bulletin 125: Statistical Analyses of Industrial Property Retirements* 85, Vol. XXXIV, No. 23 (Iowa State College of Agriculture and Mechanic Arts 1935).

⁴¹ Robley Winfrey, *Bulletin 155: Depreciation of Group Properties* 121-28, Vol XLI, No. 1 (The Iowa State College Bulletin 1942); see also Wolf *supra* n. 15, at 305-38 (publishing the percent surviving for each Iowa curve, including “O” type curve, at one percent intervals).

observations during the period 1965 – 1975 as part of his Ph.D. dissertation at Iowa State. Russo essentially repeated Winfrey’s data collection, testing, and analysis methods used to develop the original Iowa curves, except that Russo studied industrial property in service several decades after Winfrey published the original Iowa curves. Russo drew three major conclusions from his research:⁴²

1. No evidence was found to conclude that the Iowa curve set, as it stands, is not a valid system of standard curves;
2. No evidence was found to conclude that new curve shapes could be produced at this time that would add to the validity of the Iowa curve set; and
3. No evidence was found to suggest that the number of curves within the Iowa curve set should be reduced.

Prior to Russo’s study, some had criticized the Iowa curves as being potentially obsolete because their development was rooted in the study of industrial property in existence during the early 1900s. Russo’s research, however, negated this criticism by confirming that the Iowa curves represent a sufficiently wide range of life patterns, and that though technology will change over time, the underlying patterns of retirements remain constant and can be adequately described by the Iowa curves.⁴³

Over the years, several more curve types have been added to Winfrey’s 18 Iowa curves. In 1967, Harold Cowles added four origin-modal curves. In addition, a square curve is sometimes used to depict retirements which are all planned to occur at a given age. Finally, analysts

⁴² See Wolf *supra* n. 15, at 37.

⁴³ *Id.*

commonly rely on several “half curves” derived from the original Iowa curves. Thus, the term “Iowa curves” could be said to describe up to 31 standardized survivor curves.

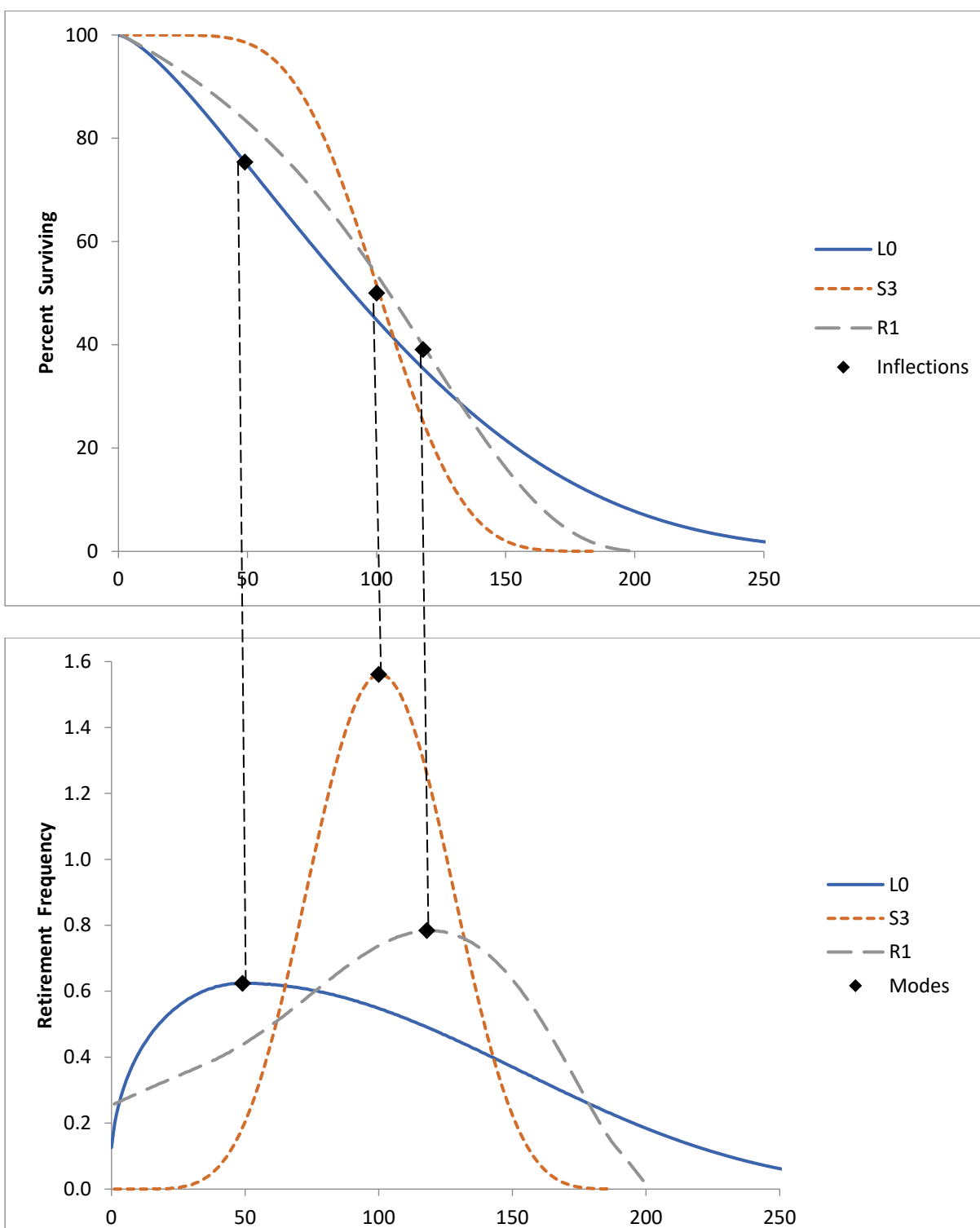
2. Classification

The Iowa curves are classified by three variables: modal location, average life, and variation of life. First, the mode is the percent life that results in the highest point of the frequency curve and the “inflection point” on the survivor curve. The modal age is the age at which the greatest rate of retirement occurs. As illustrated in the figure below, the modes appear at the steepest point of each survivor curve in the top graph, as well as the highest point of each corresponding frequency curve in the bottom graph.

The classification of the survivor curves was made according to whether the mode of the retirement frequency curves was to the left, to the right, or coincident with average service life. There are three modal “families” of curves: six left modal curves (L0, L1, L2, L3, L4, L5); five right modal curves (R1, R2, R3, R4, R5); and seven symmetrical curves (S0, S1, S2, S3, S4, S5, S6).⁴⁴ In the figure below, one curve from each family is shown: L0, S3 and R1, with average life at 100 on the x-axis. It is clear from the graphs that the modes for the L0 and R1 curves appear to the left and right of average life respectively, while the S3 mode is coincident with average life.

⁴⁴ In 1967, Harold A. Cowles added four origin-modal curves known as “O type” curves. There are also several “half” curves and a square curve, so the total amount of survivor curves commonly called “Iowa” curves is about 31 (see NARUC *supra* n. 119, at 68).

Figure 2:
Modal Age Illustration



The second Iowa curve classification variable is average life. The Iowa curves were designed using a single parameter of age expressed as a percent of average life instead of actual age. This was necessary in order for the curves to be of practical value. As Winfrey notes:

Since the location of a particular survivor on a graph is affected by both its span in years and the shape of the curve, it is difficult to classify a group of curves unless one of these variables can be controlled. This is easily done by expressing the age in percent of average life.”⁴⁵

Because age is expressed in terms of percent of average life, any particular Iowa curve type can be modified to forecast property groups with various average lives.

The third variable, variation of life, is represented by the numbers next to each letter. A lower number (e.g., L1) indicates a relatively low mode, large variation, and large maximum life; a higher number (e.g., L5) indicates a relatively high mode, small variation, and small maximum life. All three classification variables – modal location, average life, and variation of life — are used to describe each Iowa curve. For example, a 13-L1 Iowa curve describes a group of property with a 13-year average life, with the greatest number of retirements occurring before (or to the left of) the average life, and a relatively low mode. The graphs below show these 18 survivor curves, organized by modal family.

⁴⁵ Winfrey *supra* n. 40, at 60.

Figure 3:
Type L Survivor and Frequency Curves

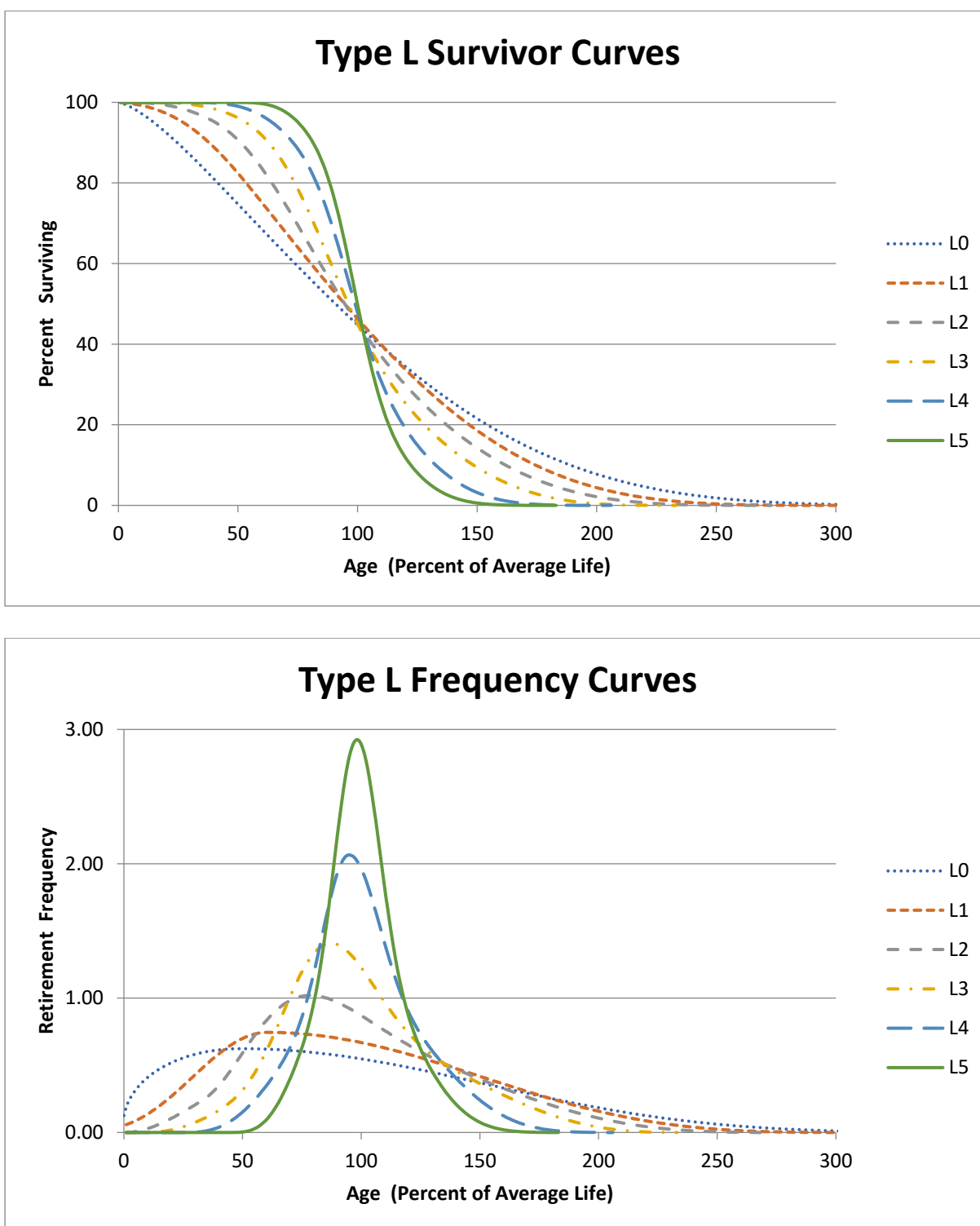


Figure 4:
Type S Survivor and Frequency Curves

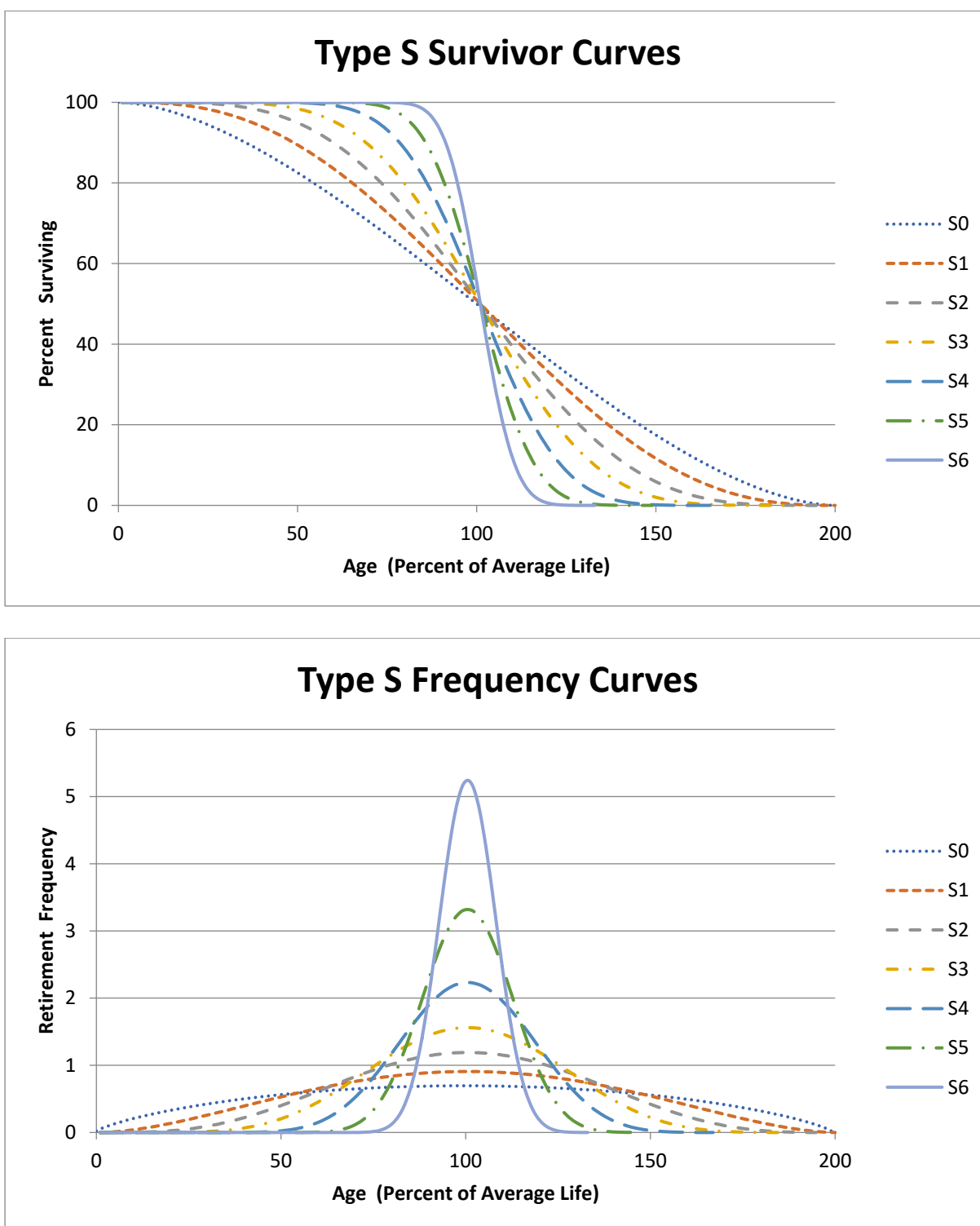
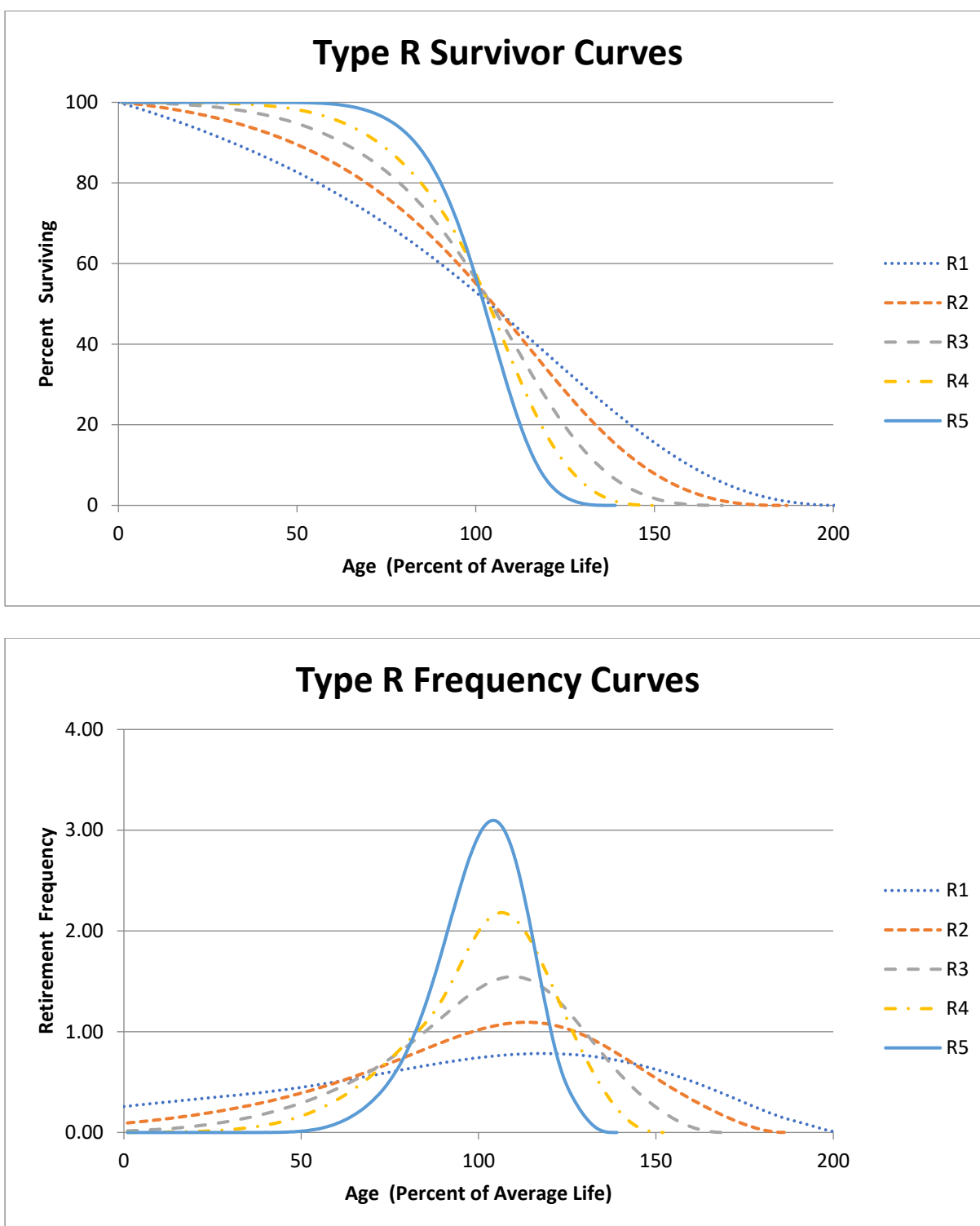


Figure 5:
Type R Survivor and Frequency Curves



As shown in the graphs above, the modes for the L family frequency curves occur to the left of average life (100% on the x-axis), while the S family modes occur at the average, and the R family modes occur after the average.

3. Types of Lives

Several other important statistical analyses and types of lives may be derived from an Iowa curve. These include: 1) average life; 2) realized life; 3) remaining life; and 4) probable life. The figure below illustrates these concepts. It shows the frequency curve, survivor curve, and probable life curve. Age M_x on the x-axis represents the modal age, while age AL_x represents the average age. Thus, this figure illustrates an “L type” Iowa curve since the mode occurs before the average.⁴⁶

First, average life is the area under the survivor curve from age zero to maximum life. Because the survivor curve is measured in percent, the area under the curve must be divided by 100% to convert it from percent-years to years. The formula for average life is as follows:⁴⁷

**Equation 9:
Average Life**

$$\text{Average Life} = \frac{\text{Area Under Survivor Curve from Age 0 to Max Life}}{100\%}$$

Thus, average life may not be determined without a complete survivor curve. Many property groups being analyzed will not have experienced full retirement. This results in a “stub” survivor

⁴⁶ From age zero to age M_x on the survivor curve, it could be said that the percent surviving from this property group is decreasing at an increasing rate. Conversely, from point M_x to maximum on the survivor curve, the percent surviving is decreasing at a decreasing rate.

⁴⁷ See NARUC *supra* n. 18, at 71.

curve. Iowa curves are used to extend stub curves to maximum life in order for the average life calculation to be made (see Exhibit DJG-23, Appendix E).

Realized life is similar to average life, except that realized life is the average years of service experienced to date from the vintage's original installations.⁴⁸ As shown in the figure below, realized life is the area under the survivor curve from zero to age RL_x . Likewise, unrealized life is the area under the survivor curve from age RL_x to maximum life. Thus, it could be said that average life equals realized life plus unrealized life.

Average remaining life represents the future years of service expected from the surviving property.⁴⁹ Remaining life is sometimes referred to as "average remaining life" and "life expectancy." To calculate average remaining life at age x , the area under the estimated future portion of the survivor curve is divided by the percent surviving at age x (denoted S_x). Thus, the average remaining life formula is:

**Equation 10:
Average Remaining Life**

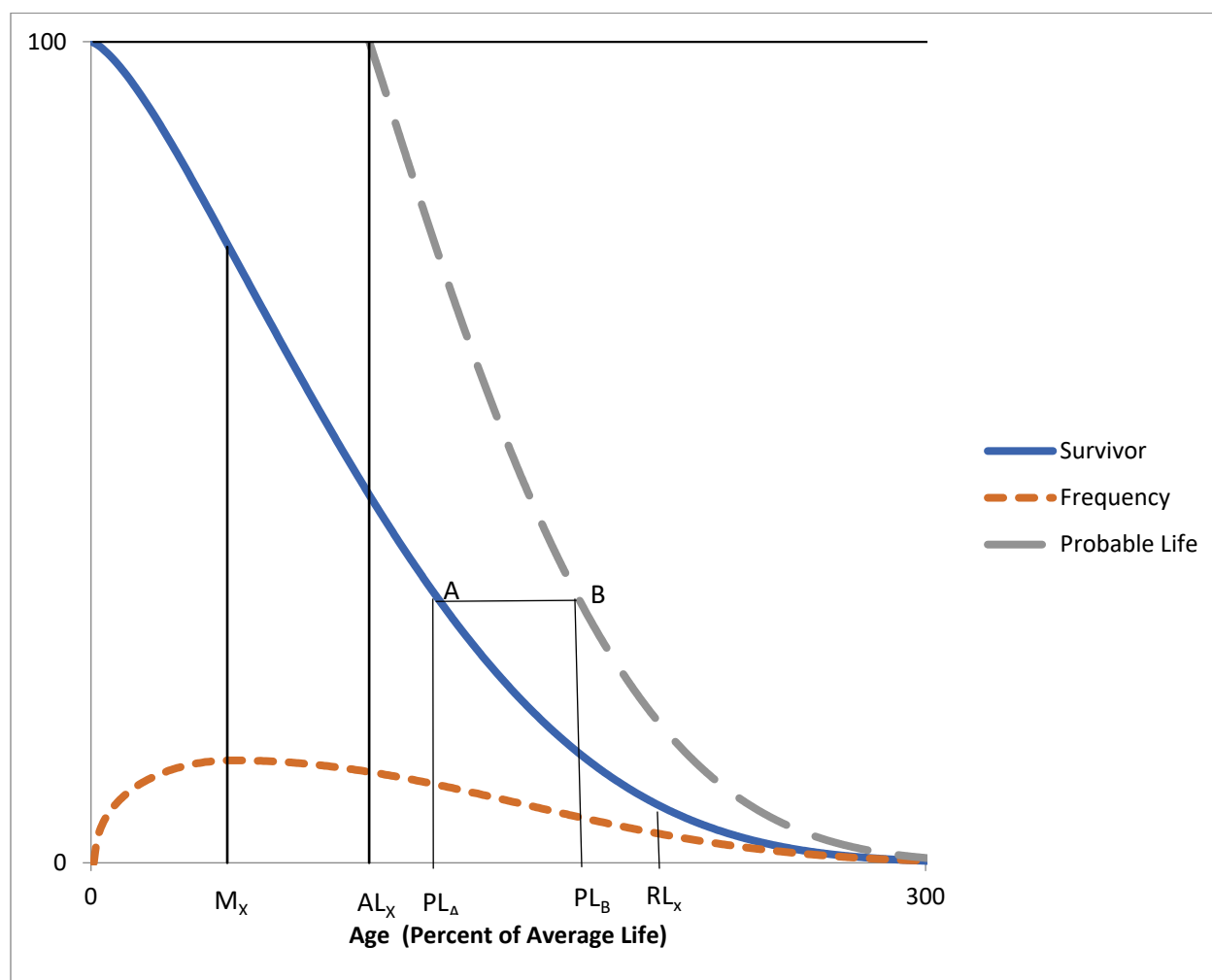
$$\text{Average Remaining Life} = \frac{\text{Area Under Survivor Curve from Age } x \text{ to Max Life}}{S_x}$$

It is necessary to determine average remaining life in order to calculate the annual accrual under the remaining life technique.

⁴⁸ *Id.* at 73.

⁴⁹ *Id.* at 74.

**Figure 6:
Iowa Curve Derivations**



Finally, the probable life may also be determined from the Iowa curve. The probable life of a property group is the total life expectancy of the property surviving at any age and is equal to the remaining life plus the current age.⁵⁰ The probable life is also illustrated in this figure. The probable life at age PL_A is the age at point PL_B . Thus, to read the probable life at age PL_A , see the corresponding point on the survivor curve above at point “A,” then horizontally to point “B” on

⁵⁰ Wolf *supra* n. 15, at 28.

the probable life curve, and back down to the age corresponding to point “B.” It is no coincidence that the vertical line from AL_X connects at the top of the probable life curve. This is because at age zero, probable life equals average life.

APPENDIX E: ACTUARIAL ANALYSIS

Actuarial science is a discipline that applies various statistical methods to assess risk probabilities and other related functions. Actuaries often study human mortality. The results from historical mortality data are used to predict how long similar groups of people who are alive will live today. Insurance companies rely of actuarial analysis in determining premiums for life insurance policies.

The study of human mortality is analogous to estimating service lives of industrial property groups. While some humans die solely from chance, most deaths are related to age; that is, death rates generally increase as age increases. Similarly, physical plant is also subject to forces of retirement. These forces include physical, functional, and contingent factors, as shown in the table below.⁵¹

**Figure 7:
Forces of Retirement**

<u>Physical Factors</u>	<u>Functional Factors</u>	<u>Contingent Factors</u>
Wear and tear Decay or deterioration Action of the elements	Inadequacy Obsolescence Changes in technology Regulations Managerial discretion	Casualties or disasters Extraordinary obsolescence

While actuaries study historical mortality data in order to predict how long a group of people will live, depreciation analysts must look at a utility’s historical data in order to estimate the average lives of property groups. A utility’s historical data is often contained in the Continuing Property Records (“CPR”). Generally, a CPR should contain 1) an inventory of property record

⁵¹ NARUC *supra* n. 18, at 14-15.

units; 2) the association of costs with such units; and 3) the dates of installation and removal of plant. Since actuarial analysis includes the examination of historical data to forecast future retirements, the historical data used in the analysis should not contain events that are anomalous or unlikely to recur.⁵² Historical data is used in the retirement rate actuarial method, which is discussed further below.

The Retirement Rate Method

There are several systematic actuarial methods that use historical data in order to calculate observed survivor curves for property groups. Of these methods, the retirement rate method is superior, and is widely employed by depreciation analysts.⁵³ The retirement rate method is ultimately used to develop an observed survivor curve, which can be fitted with an Iowa curve discussed in Exhibit DJG-23, Appendix D in order to forecast average life. The observed survivor curve is calculated by using an observed life table (“OLT”). The figures below illustrate how the OLT is developed. First, historical property data are organized in a matrix format, with placement years on the left forming rows, and experience years on the top forming columns. The placement year (a.k.a. “vintage year” or “installation year”) is the year of placement of a group of property. The experience year (a.k.a. “activity year”) refers to the accounting data for a particular calendar year. The two matrices below use aged data — that is, data for which the dates of placements, retirements, transfers, and other transactions are known. Without aged data, the retirement rate actuarial method may not be employed. The first matrix is the exposure matrix, which shows the

⁵² *Id.* at 112-13.

⁵³ Anson Marston, Robley Winfrey & Jean C. Hempstead, *Engineering Valuation and Depreciation* 154 (2nd ed., McGraw-Hill Book Company, Inc. 1953).

exposures at the beginning of each year.⁵⁴ An exposure is simply the depreciable property subject to retirement during a period. The second matrix is the retirement matrix, which shows the annual retirements during each year. Each matrix covers placement years 2003–2015, and experience years 2008–2015. In the exposure matrix, the number in the 2009 experience column and the 2003 placement row is \$192,000. This means at the beginning of 2012, there was \$192,000 still exposed to retirement from the vintage group placed in 2003. Likewise, in the retirement matrix, \$19,000 of the dollars invested in 2003 was retired during 2012.

**Figure 8:
Exposure Matrix**

Placement Years	Experience Years Exposures at January 1 of Each Year (Dollars in 000's)								Total at Start of Age Interval	Age Interval
	2008	2009	2010	2011	2012	2013	2014	2015		
2003	261	245	228	211	192	173	152	131	131	11.5 - 12.5
2004	267	252	236	220	202	184	165	145	297	10.5 - 11.5
2005	304	291	277	263	248	232	216	198	536	9.5 - 10.5
2006	345	334	322	310	298	284	270	255	847	8.5 - 9.5
2007	367	357	347	335	324	312	299	286	1,201	7.5 - 8.5
2008	375	366	357	347	336	325	314	302	1,581	6.5 - 7.5
2009		377	366	356	346	336	327	319	1,986	5.5 - 6.5
2010			381	369	358	347	336	327	2,404	4.5 - 5.5
2011				386	372	359	346	334	2,559	3.5 - 4.5
2012					395	380	366	352	2,722	2.5 - 3.5
2013						401	385	370	2,866	1.5 - 2.5
2014							410	393	2,998	0.5 - 1.5
2015								416	3,141	0.0 - 0.5
Total	1919	2222	2514	2796	3070	3333	3586	3827	23,268	

⁵⁴ Technically, the last numbers in each column are “gross additions” rather than exposures. Gross additions do not include adjustments and transfers applicable to plant placed in a previous year. Once retirements, adjustments, and transfers are factored in, the balance at the beginning of the next account period is called an “exposure” rather than an addition.

**Figure 9:
Retirement Matrix**

Placement Years	Experience Years Retirements During the Year (Dollars in 000's)								Total During Age Interval	Age Interval
	2008	2009	2010	2011	2012	2013	2014	2015		
2003	16	17	18	19	19	20	21	23	23	11.5 - 12.5
2004	15	16	17	17	18	19	20	21	43	10.5 - 11.5
2005	13	14	14	15	16	17	17	18	59	9.5 - 10.5
2006	11	12	12	13	13	14	15	15	71	8.5 - 9.5
2007	10	11	11	12	12	13	13	14	82	7.5 - 8.5
2008	9	9	10	10	11	11	12	13	91	6.5 - 7.5
2009		11	10	10	9	9	9	8	95	5.5 - 6.5
2010			12	11	11	10	10	9	100	4.5 - 5.5
2011				14	13	13	12	11	93	3.5 - 4.5
2012					15	14	14	13	91	2.5 - 3.5
2013						16	15	14	93	1.5 - 2.5
2014							17	16	100	0.5 - 1.5
2015								18	112	0.0 - 0.5
Total	74	89	104	121	139	157	175	194	1,052	

These matrices help visualize how exposure and retirement data are calculated for each age interval. An age interval is typically one year. A common convention is to assume that any unit installed during the year is installed in the middle of the calendar year (i.e., July 1st). This convention is called the “half-year convention” and effectively assumes that all units are installed uniformly during the year.⁵⁵ Adoption of the half-year convention leads to age intervals of 0-0.5 years, 0.5-1.5 years, etc., as shown in the matrices.

The purpose of the matrices is to calculate the totals for each age interval, which are shown in the second column from the right in each matrix. This column is calculated by adding each number from the corresponding age interval in the matrix. For example, in the exposure matrix, the total amount of exposures at the beginning of the 8.5-9.5 age interval is \$847,000. This number was calculated by adding the numbers shown on the “stairs” to the left (192+184+216+255=847).

⁵⁵ Wolf *supra* n. 15, at 22.

The same calculation is applied to each number in the column. The amounts retired during the year in the retirements matrix affect the exposures at the beginning of each year in the exposures matrix. For example, the amount exposed to retirement in 2008 from the 2003 vintage is \$261,000. The amount retired during 2008 from the 2003 vintage is \$16,000. Thus, the amount exposed to retirement in 2009 from the 2003 vintage is \$245,000 ($\$261,000 - \$16,000$). The company's property records may contain other transactions which affect the property, including sales, transfers, and adjusting entries. Although these transactions are not shown in the matrices above, they would nonetheless affect the amount exposed to retirement at the beginning of each year.

The totaled amounts for each age interval in both matrices are used to form the exposure and retirement columns in the OLT, as shown in the chart below. This chart also shows the retirement ratio and the survivor ratio for each age interval. The retirement ratio for an age interval is the ratio of retirements during the interval to the property exposed to retirement at the beginning of the interval. The retirement ratio represents the probability that the property surviving at the beginning of an age interval will be retired during the interval. The survivor ratio is simply the complement to the retirement ratio ($1 - \text{retirement ratio}$). The survivor ratio represents the probability that the property surviving at the beginning of an age interval will survive to the next age interval.

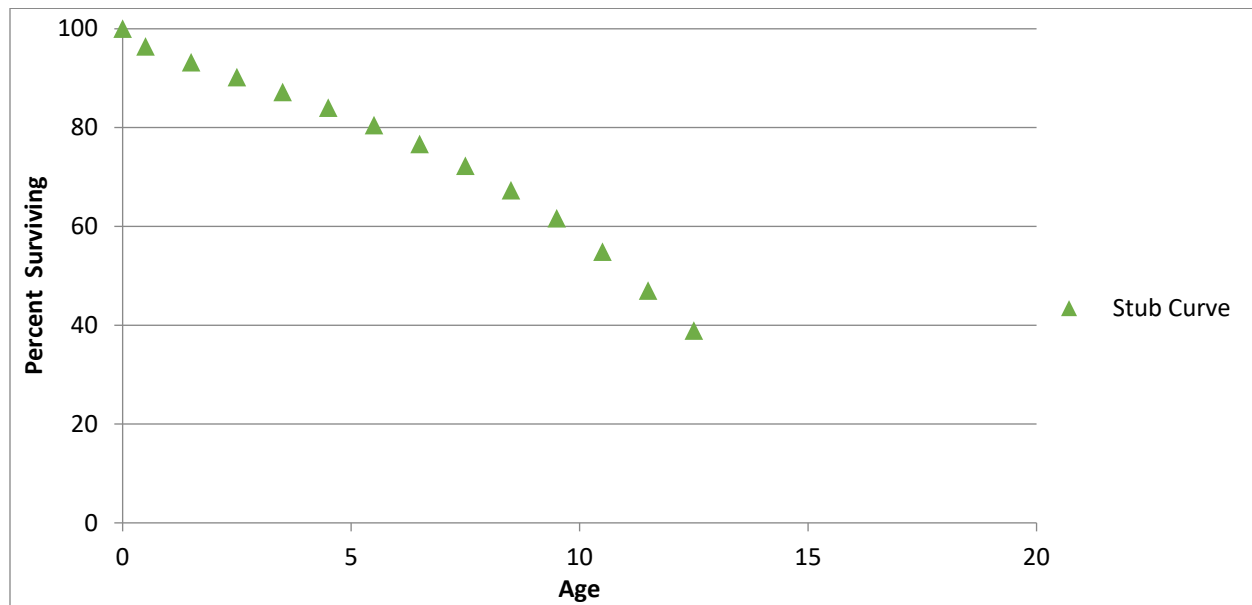
**Figure 10:
Observed Life Table**

Age at Start of Interval	Exposures at Start of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Start of Age Interval
A	B	C	D = C / B	E = 1 - D	F
0.0	3,141	112	0.036	0.964	100.00
0.5	2,998	100	0.033	0.967	96.43
1.5	2,866	93	0.032	0.968	93.21
2.5	2,722	91	0.033	0.967	90.19
3.5	2,559	93	0.037	0.963	87.19
4.5	2,404	100	0.042	0.958	84.01
5.5	1,986	95	0.048	0.952	80.50
6.5	1,581	91	0.058	0.942	76.67
7.5	1,201	82	0.068	0.932	72.26
8.5	847	71	0.084	0.916	67.31
9.5	536	59	0.110	0.890	61.63
10.5	297	43	0.143	0.857	54.87
11.5	131	23	0.172	0.828	47.01
Total	23,268	1,052			38.91

Column F on the right shows the percentages surviving at the beginning of each age interval. This column starts at 100% surviving. Each consecutive number below is calculated by multiplying the percent surviving from the previous age interval by the corresponding survivor ratio for that age interval. For example, the percent surviving at the start of age interval 1.5 is 93.21%, which was calculated by multiplying the percent surviving for age interval 0.5 (96.43%) by the survivor ratio for age interval 0.5 (0.967).

The percentages surviving in Column F are the numbers that are used to form the original survivor curve. This particular curve starts at 100% surviving and ends at 38.91% surviving. An observed survivor curve such as this that does not reach zero percent surviving is called a “stub” curve. The figure below illustrates the stub survivor curve derived from the OLT table above.

**Figure 11:
Original “Stub” Survivor Curve**



The matrices used to develop the basic OLT and stub survivor curve provide a basic illustration of the retirement rate method in that only a few placement and experience years were used. In reality, analysts may have several decades of aged property data to analyze. In that case, it may be useful to use a technique called “banding” in order to identify trends in the data.

Banding

The forces of retirement and characteristics of industrial property are constantly changing. A depreciation analyst may examine the magnitude of these changes. Analysts often use a technique called “banding” to assist with this process. Banding refers to the merging of several years of data into a single data set for further analysis, and it is a common technique associated with the retirement rate method.⁵⁶ There are three primary benefits of using bands in depreciation analysis:

⁵⁶ NARUC *supra* n. 18, at 113.

1. Increasing the sample size. In statistical analyses, the larger the sample size in relation to the body of total data, the greater the reliability of the result;
2. Smooth the observed data. Generally, the data obtained from a single activity or vintage year will not produce an observed life table that can be easily fit; and
3. Identify trends. By looking at successive bands, the analyst may identify broad trends in the data that may be useful in projecting the future life characteristics of the property.⁵⁷

Two common types of banding methods are the “placement band” method and the “experience band” method.” A placement band, as the name implies, isolates selected placement years for analysis. The figure below illustrates the same exposure matrix shown above, except that only the placement years 2005-2008 are considered in calculating the total exposures at the beginning of each age interval.

⁵⁷ *Id.*

**Figure 12:
Placement Bands**

Placement Years	Experience Years Exposures at January 1 of Each Year (Dollars in 000's)								Total at Start of Age Interval	Age Interval
	2008	2009	2010	2011	2012	2013	2014	2015		
2003	261	245	228	211	192	173	152	131		11.5 - 12.5
2004	267	252	236	220	202	184	165	145		10.5 - 11.5
2005	304	291	277	263	248	232	216	198	198	9.5 - 10.5
2006	345	334	322	310	298	284	270	255	471	8.5 - 9.5
2007	367	357	347	335	324	312	299	286	788	7.5 - 8.5
2008	375	366	357	347	336	325	314	302	1,133	6.5 - 7.5
2009		377	366	356	346	336	327	319	1,186	5.5 - 6.5
2010			381	369	358	347	336	327	1,237	4.5 - 5.5
2011				386	372	359	346	334	1,285	3.5 - 4.5
2012					395	380	366	352	1,331	2.5 - 3.5
2013						401	385	370	1,059	1.5 - 2.5
2014							410	393	733	0.5 - 1.5
2015								416	375	0.0 - 0.5
Total	1919	2222	2514	2796	3070	3333	3586	3827	9,796	

The shaded cells within the placement band equal the total exposures at the beginning of age interval 4.5–5.5 (\$1,237). The same placement band would be used for the retirement matrix covering the same placement years of 2005 – 2008. This of course would result in a different OLT and original stub survivor curve than those that were calculated above without the restriction of a placement band.

Analysts often use placement bands for comparing the survivor characteristics of properties with different physical characteristics.⁵⁸ Placement bands allow analysts to isolate the effects of changes in technology and materials that occur in successive generations of plant. For example, if in 2005 an electric utility began placing transmission poles with a special chemical treatment that extended the service lives of the poles, an analyst could use placement bands to isolate and analyze the effect of that change in the property group's physical characteristics. While placement

⁵⁸ Wolf *supra* n. 15, at 182.

bands are very useful in depreciation analysis, they also possess an intrinsic dilemma. A fundamental characteristic of placement bands is that they yield fairly complete survivor curves for older vintages. However, with newer vintages, which are arguably more valuable for forecasting, placement bands yield shorter survivor curves. Longer “stub” curves are considered more valuable for forecasting average life. Thus, an analyst must select a band width broad enough to provide confidence in the reliability of the resulting curve fit yet narrow enough so that an emerging trend may be observed.⁵⁹

Analysts also use “experience bands.” Experience bands show the composite retirement history for all vintages during a select set of activity years. The figure below shows the same data presented in the previous exposure matrices, except that the experience band from 2011 – 2013 is isolated, resulting in different interval totals.

⁵⁹ NARUC *supra* n. 18, at 114.

**Figure 13:
Experience Bands**

Placement Years	Experience Years Exposures at January 1 of Each Year (Dollars in 000's)								Total at Start of Age Interval	Age Interval
	2008	2009	2010	2011	2012	2013	2014	2015		
2003	261	245	228	211	192	173	152	131		11.5 - 12.5
2004	267	252	236	220	202	184	165	145		10.5 - 11.5
2005	304	291	277	263	248	232	216	198	173	9.5 - 10.5
2006	345	334	322	310	298	284	270	255	376	8.5 - 9.5
2007	367	357	347	335	324	312	299	286	645	7.5 - 8.5
2008	375	366	357	347	336	325	314	302	752	6.5 - 7.5
2009		377	366	356	346	336	327	319	872	5.5 - 6.5
2010			381	369	358	347	336	327	959	4.5 - 5.5
2011				386	372	359	346	334	1,008	3.5 - 4.5
2012					395	380	366	352	1,039	2.5 - 3.5
2013						401	385	370	1,072	1.5 - 2.5
2014							410	393	1,121	0.5 - 1.5
2015								416	1,182	0.0 - 0.5
Total	1919	2222	2514	2796	3070	3333	3586	3827	9,199	

The shaded cells within the experience band equal the total exposures at the beginning of age interval 4.5–5.5 (\$1,237). The same experience band would be used for the retirement matrix covering the same experience years of 2011 – 2013. This of course would result in a different OLT and original stub survivor than if the band had not been used. Analysts often use experience bands to isolate and analyze the effects of an operating environment over time.⁶⁰ Likewise, the use of experience bands allows analysis of the effects of an unusual environmental event. For example, if an unusually severe ice storm occurred in 2013, destruction from that storm would affect an electric utility's line transformers of all ages. That is, each of the line transformers from each placement year would be affected, including those recently installed in 2012, as well as those installed in 2003. Using experience bands, an analyst could isolate or even eliminate the 2013 experience year from the analysis. In contrast, a placement band would not effectively isolate the

⁶⁰ *Id.*

ice storm's effect on life characteristics. Rather, the placement band would show an unusually large rate of retirement during 2013, making it more difficult to accurately fit the data with a smooth Iowa curve. Experience bands tend to yield the most complete stub curves for recent bands because they have the greatest number of vintages included. Longer stub curves are better for forecasting. The experience bands, however, may also result in more erratic retirement dispersion making the curve fitting process more difficult.

Depreciation analysts must use professional judgment in determining the types of bands to use and the band widths. In practice, analysts may use various combinations of placement and experience bands in order to increase the data sample size, identify trends and changes in life characteristics, and isolate unusual events. Regardless of which bands are used, observed survivor curves in depreciation analysis rarely reach zero percent. This is because, as seen in the OLT above, relatively newer vintage groups have not yet been fully retired at the time the property is studied. An analyst could confine the analysis to older, fully retired vintage groups in order to get complete survivor curves, but such analysis would ignore some the property currently in service and would arguably not provide an accurate description of life characteristics for current plant in service. Because a complete curve is necessary to calculate the average life of the property group, however, curve fitting techniques using Iowa curves or other standardized curves may be employed in order to complete the stub curve.

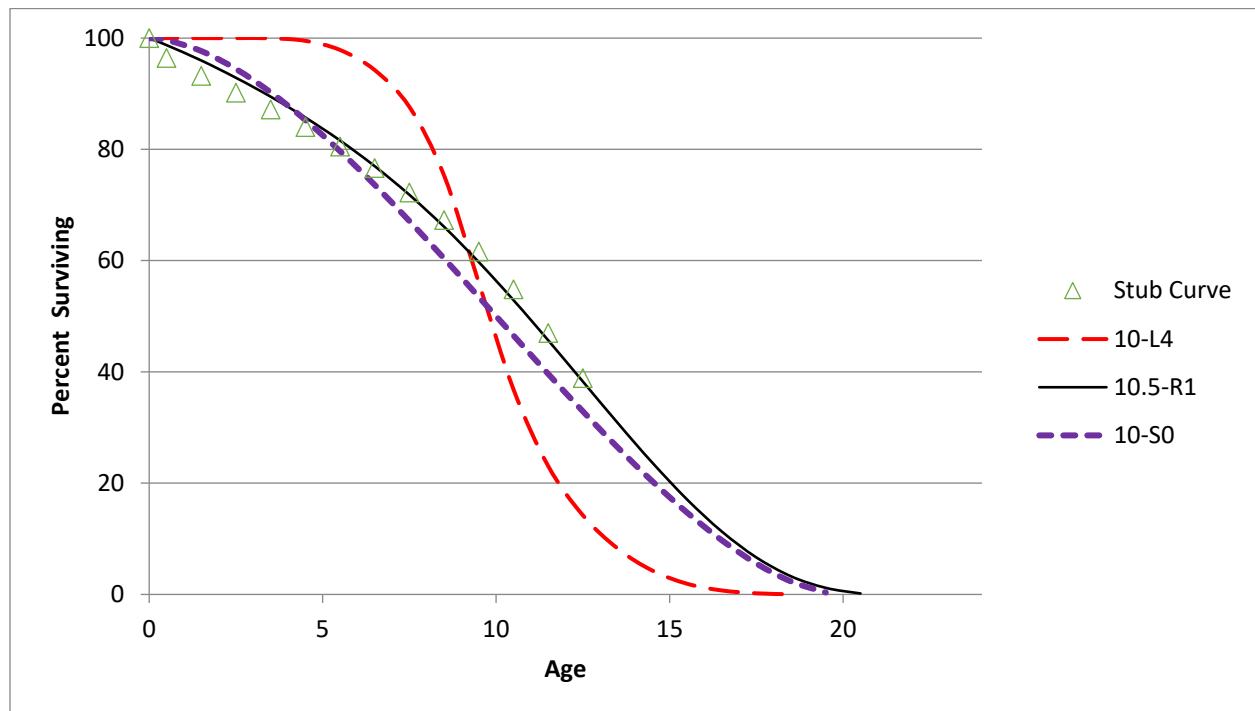
Curve Fitting

Depreciation analysts typically use the survivor curve rather than the frequency curve to fit the observed stub curves. The most commonly used generalized survivor curves used in the curve fitting process are the Iowa curves discussed above. As Wolf notes, if “the Iowa curves are

adopted as a model, an underlying assumption is that the process describing the retirement pattern is one of the 22 [or more] processes described by the Iowa curves.”⁶¹

Curve fitting may be done through visual matching or mathematical matching. In visual curve fitting, the analyst visually examines the plotted data to make an initial judgment about the Iowa curves that may be a good fit. The figure below illustrates the stub survivor curve shown above. It also shows three different Iowa curves: the 10-L4, the 10.5-R1, and the 10-S0. Visually, it is clear that the 10.5-R1 curve is a better fit than the other two curves.

**Figure 14:
Visual Curve Fitting**



In mathematical fitting, the least squares method is used to calculate the best fit. This mathematical method would be excessively time consuming if done by hand. With the use of

⁶¹ Wolf *supra* n. 15, at 46 (22 curves includes Winfrey’s 18 original curves plus Cowles’s four “O” type curves).

modern computer software however, mathematical fitting is an efficient and useful process. The typical logic for a computer program, as well as the software employed for the analysis in this testimony is as follows:

First (an Iowa curve) curve is arbitrarily selected. . . . If the observed curve is a stub curve, . . . calculate the area under the curve and up to the age at final data point. Call this area the realized life. Then systematically vary the average life of the theoretical survivor curve and calculate its realized life at the age corresponding to the study date. This trial and error procedure ends when you find an average life such that the realized life of the theoretical curve equals the realized life of the observed curve. Call this the average life.

Once the average life is found, calculate the difference between each percent surviving point on the observed survivor curve and the corresponding point on the Iowa curve. Square each difference and sum them. The sum of squares is used as a measure of goodness of fit for that particular Iowa type curve. This procedure is repeated for the remaining 21 Iowa type curves. The “best fit” is declared to be the type of curve that minimizes the sum of differences squared.⁶²

Mathematical fitting requires less judgment from the analyst and is thus less subjective. Blind reliance on mathematical fitting, however, may lead to poor estimates. Thus, analysts should employ both mathematical and visual curve fitting in reaching their final estimates. This way, analysts may utilize the objective nature of mathematical fitting while still employing professional judgment. As Wolf notes: “The results of mathematical curve fitting serve as a guide for the analyst and speed the visual fitting process. But the results of the mathematical fitting should be checked visually and the final determination of the best fit be made by the analyst.”⁶³

In the graph above, visual fitting was sufficient to determine that the 10.5-R1 Iowa curve was a better fit than the 10-L4 and the 10-S0 curves. Using the sum of least squares method, mathematical fitting confirms the same result. In the chart below, the percentages surviving from

⁶² Wolf *supra* n. 15, at 47.

⁶³ *Id.* at 48.

the OLT that formed the original stub curve are shown in the left column, while the corresponding percentages surviving for each age interval are shown for the three Iowa curves. The right portion of the chart shows the differences between the points on each Iowa curve and the stub curve. These differences are summed at the bottom. Curve 10.5-R1 is the best fit because the sum of the squared differences for this curve is less than the same sum of the other two curves. Curve 10-L4 is the worst fit, which was also confirmed visually.

**Figure 15:
Mathematical Fitting**

Age Interval	Stub Curve	Iowa Curves			Squared Differences		
		10-L4	10-S0	10.5-R1	10-L4	10-S0	10.5-R1
0.0	100.0	100.0	100.0	100.0	0.0	0.0	0.0
0.5	96.4	100.0	99.7	98.7	12.7	10.3	5.3
1.5	93.2	100.0	97.7	96.0	46.1	19.8	7.6
2.5	90.2	100.0	94.4	92.9	96.2	18.0	7.2
3.5	87.2	100.0	90.2	89.5	162.9	9.3	5.2
4.5	84.0	99.5	85.3	85.7	239.9	1.6	2.9
5.5	80.5	97.9	79.7	81.6	301.1	0.7	1.2
6.5	76.7	94.2	73.6	77.0	308.5	9.5	0.1
7.5	72.3	87.6	67.1	71.8	235.2	26.5	0.2
8.5	67.3	75.2	60.4	66.1	62.7	48.2	1.6
9.5	61.6	56.0	53.5	59.7	31.4	66.6	3.6
10.5	54.9	36.8	46.5	52.9	325.4	69.6	3.9
11.5	47.0	23.1	39.6	45.7	572.6	54.4	1.8
12.5	38.9	14.2	32.9	38.2	609.6	36.2	0.4
SUM					3004.2	371.0	41.0

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EDUCATION

University of Oklahoma Master of Business Administration Areas of Concentration: Finance, Energy	Norman, OK 2014
University of Oklahoma College of Law Juris Doctor Member, American Indian Law Review	Norman, OK 2007
University of Oklahoma Bachelor of Business Administration Major: Finance	Norman, OK 2003

PROFESSIONAL DESIGNATIONS

Society of Depreciation Professionals
Certified Depreciation Professional (CDP)

Society of Utility and Regulatory Financial Analysts
Certified Rate of Return Analyst (CRRA)

WORK EXPERIENCE

Resolve Utility Consulting PLLC <u>Managing Member</u> Provide expert analysis and testimony specializing in depreciation and cost of capital issues for clients in utility regulatory proceedings.	Oklahoma City, OK 2016 – Present
Oklahoma Corporation Commission <u>Public Utility Regulatory Analyst</u> <u>Assistant General Counsel</u> Represented commission staff in utility regulatory proceedings and provided legal opinions to commissioners. Provided expert analysis and testimony in depreciation, cost of capital, incentive compensation, payroll and other issues.	Oklahoma City, OK 2012 – 2016 2011 – 2012
Perebus Counsel, PLLC <u>Managing Member</u> Represented clients in the areas of family law, estate planning, debt negotiations, business organization, and utility regulation.	Oklahoma City, OK 2009 – 2011

Moricoli & Schovanec, P.C.

Associate Attorney

Represented clients in the areas of contracts, oil and gas, business structures and estate administration.

Oklahoma City, OK
2007 – 2009

TEACHING EXPERIENCE

University of Oklahoma

Adjunct Instructor – “Conflict Resolution”

Adjunct Instructor – “Ethics in Leadership”

Norman, OK
2014 – 2021

Rose State College

Adjunct Instructor – “Legal Research”

Adjunct Instructor – “Oil & Gas Law”

Midwest City, OK
2013 – 2015

PROFESSIONAL ASSOCIATIONS

Oklahoma Bar Association

2007 – Present

Society of Depreciation Professionals

Board Member – President

Participate in management of operations, attend meetings,
review performance, organize presentation agenda.

2014 – Present
2017

Society of Utility Regulatory Financial Analysts

2014 – Present

Utility Regulatory Proceedings

Exhibit DJG-1

Page 3 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Pennsylvania Public Utility Commission	Veolia Water Pennsylvania, Inc.	R-2024-3045192 R-2024-3045193	Cost of capital, depreciation rates, net salvage	Pennsylvania Office of Consumer Advocate
Pennsylvania Public Utility Commission	PECO Energy Company - Gas Division	R-2024-3046932	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Pennsylvania Public Utility Commission	PECO Energy Company - Electric Division	R-2024-3046931	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 2023-000087	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Maryland Public Service Commission	Maryland Water Service, Inc.	9729	Cost of capital, awarded rate of return, capital structure	Maryland Office of People's Counsel
Kansas Corporation Commission	Kansas Gas Service	24-KGSG-610-RTS	Depreciation rates, service lives, net salvage	The Citizens' Utility Ratepayer Board
Pennsylvania Public Utility Commission	FirstEnergy Pennsylvania Electric Company	R-2024-3047068	Depreciation rates, service lives, net salvage	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Chesapeake Utilities Corporation Sandpiper Energy, Inc. Elkton Gas Company	9721	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Pennsylvania Public Utility Commission	Duquesne Light Company	R-2024-3046523	Cost of capital, depreciation rates, net salvage	Pennsylvania Office of Consumer Advocate
Public Utility Commission of Texas	CenterPoint Energy Houston Electric	PUC 56211	Depreciation rates, service lives, net salvage	Texas Coast Utilities Coalition
Washington Utilities & Transportation Commission	Avista Corporation	UE-240006 UG-240007	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Public Utility Commission of Texas	AEP Texas Inc.	PUC 56165	Depreciation rates, service lives, net salvage	Cities Served by AEP Texas
Public Utilities Commission of Nevada	Southwest Gas Corporation	23-09012	Depreciation rates, service lives, net salvage	Bureau of Consumer Protection
Public Utilities Commission of the State of California	Southern California Edison	A.23-05-010	Depreciation rates, service lives, net salvage	The Utility Reform Network

Utility Regulatory Proceedings

Exhibit DJG-1
Page 4 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Pennsylvania Public Utility Commission	Pennsylvania-American Water Company	R-2023-3043189 R-2023-3043190	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45967	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Massachusetts Department of Public Utilities	Massachusetts Electric Company and Nantucket Electric Company D/B/A National Grid	D.P.U. 23-150	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Iowa Utilities Board	Interstate Power and Light Company	RPU-2023-0002	Depreciation rates, service lives, net salvage	Office of Consumer Advocate
Public Service Commission of South Carolina	Duke Energy Carolinas	2023-388-E 2023-403-E	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Indiana Utility Regulatory Commission	Citizens Energy Group	45988	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Railroad Commission of Texas	CenterPoint Energy Resources Corp.	OS-23-00015513	Depreciation rates, service lives, net salvage	Alliance of CenterPoint Municipalities
Indiana Utility Regulatory Commission	CenterPoint Energy Indiana South	45990	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Delaware Public Service Commission	Artesian Water Company, Inc.	23-0601	Cost of capital, depreciation rates, net salvage	Division of the Public Advocate
Maryland Public Service Commission	Washington Gas Light Company	9704	Cost of capital, awarded rate of return, capital structure	Maryland Office of People's Counsel
Delaware Public Service Commission	Veolia Water Delaware Inc.	23-0598	Cost of capital, awarded rate of return, capital structure	Division of the Public Advocate
Connecticut Public Utilities Regulatory Authority	United Illuminating Company	22-08-08	Depreciation rates, service lives, net salvage	PURA Staff
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 54634	Depreciation rates, service lives, net salvage	Alliance of Xcel Municipalities
Railroad Commission of Texas	SiEnergy, LP	OS-23-00013504	Depreciation rates, service lives, net salvage	Texas municipal intervenor group

Utility Regulatory Proceedings

Exhibit DJG-1
Page 5 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Pennsylvania Public Utility Commission	Aqua Pennsylvania, Inc.	A-2022-3034143	Fair market value review	Pennsylvania Office of Consumer Advocate
Wyoming Public Service Commission	Rocky Mountain Power	20000-633-ER-23	Cost of capital and authorized rate of return	Wyoming Industrial Energy Consumers
Maryland Public Service Commission	Potomac Electric Power Company	9702	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Public Utilities Commission of Nevada	Nevada Power Company d/b/a NV Energy	23-06007 23-06008	Depreciation rates, service lives, net salvage	Bureau of Consumer Protection
Public Utilities Commission of Ohio	Northeast Ohio Natural Gas Corp.	23-0154-GA-AIR	Cost of capital, awarded rate of return, capital structure	Office of the Ohio Consumers' Counsel
New York State Public Service Commission	The Brooklyn Union Gas Company and Keyspan Gas East Corporation d/b/a Nation Grid	23-G-0225 23-G-0226	Depreciation rates, service lives, net salvage, depreciation reserve	The City of New York
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-23-11	Cost of capital, awarded rate of return, capital structure	Micron Technology, Inc.
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45933	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Massachusetts Department of Public Utilities	Fitchburg Gas and Electric Company d/b/a Unitil	D.P.U. 23-80; D.P.U. 23-81	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Kansas Corporation Commission	Eversource Kansas Central, Eversource Kansas South, and Eversource Metro	23-EKCE-775-RTS	Depreciation rates, service lives, net salvage	The Citizens' Utility Ratepayer Board
Delaware Public Service Commission	Delmarva Power & Light Company	22-0897	Cost of capital, awarded rate of return, capital structure	Division of the Public Advocate
Connecticut Public Utilities Regulatory Authority	Connecticut Water Company	23-08-32	Depreciation rates, service lives, net salvage	PURA Staff
Connecticut Public Utilities Regulatory Authority	Connecticut Natural Gas Corporation and The Southern Connecticut Gas Company	23-11-02	Depreciation rates, service lives, net salvage	PURA Staff
Railroad Commission of Texas	Atmos Pipeline – Texas	OS-23-00013758	Depreciation rates, service lives, net salvage	Atmos Texas Municipalities

Utility Regulatory Proceedings

Exhibit DJG-1
Page 6 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Wyoming Public Service Commission	Black Hills Wyoming Gas	30026-78-GR-23	Depreciation rates, service lives, net salvage	Wyoming Office of Consumer Advocate
Indiana Utility Regulatory Commission	Indianapolis Power & Light Company d/b/a AES Indiana	45911	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
New Mexico Public Regulation Commission	Southwestern Public Service Company	22-00286-UT	Cost of capital, depreciation rates, net salvage	The New Mexico Large Customer Group; Occidental Permian
Public Utilities Commission of the State of California	Southern California Gas Company San Diego Gas & Electric Company	A.22-05-015 A.22-05-016	Depreciation rates, service lives, net salvage	The Utility Reform Network
Public Utilities Commission of the State of Colorado	Public Service Company of Colorado	22AL-0530E 22AL-0478E	Cost of capital, awarded rate of return, capital structure	Colorado Energy Consumers
New Mexico Public Regulatory Commission	Public Service Company of New Mexico	22-00270-UT	Cost of capital, depreciation rates, net salvage	The Albuquerque Bernalillo County Water Utility Authority
Florida Public Service Commission	Peoples Gas System	20230023-GU 20220219-GU 20220212-GU	Cost of capital, depreciation rates, net salvage	Florida Office of Public Counsel
Maryland Public Service Commission	Potomac Edison Company	9695	Cost of capital, depreciation rates, net salvage	Maryland Office of People's Counsel
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	2022.11.099	Depreciation rates, service lives, net salvage	Montana Consumer Counsel and Denbury Onshore
Indiana Utility Regulatory Commission	Indiana-American Water Company	45870	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Service Commission of South Carolina	Dominion Energy South Carolina	2023-70-G	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Maryland Public Service Commission	Columbia Gas of Maryland	9701	Cost of capital, awarded rate of return, capital structure	Maryland Office of People's Counsel
Pennsylvania Public Utility Commission	Columbia Water Company	R-2023-3040258	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Baltimore Gas and Electric Company	9692	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel

Utility Regulatory Proceedings

Exhibit DJG-1
Page 7 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Arizona Corporation Commission	Arizona Public Service Company	E-01345A-22-0144	Cost of capital, awarded rate of return, capital structure	Residential Utility Consumer Office
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 2022-000093	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Public Service Commission of the State of Montana	NorthWestern Energy	2022.07.078	Cost of capital, depreciation rates, net salvage	Montana Consumer Counsel and Montana Large Customer Group
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45772	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Public Service Commission of South Carolina	Duke Energy Progress	2022-254-E	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Wyoming Public Service Commission	Cheyenne Light, Fuel and Power Company D/B/A Black Hills Energy	20003-214-ER-22	Depreciation rates, service lives, net salvage	Wyoming Office of Consumer Advocate
Railroad Commission of Texas	Texas Gas Services Company	OS-22-00009896	Depreciation rates, service lives, net salvage	The City of El Paso
Public Utilities Commission of Nevada	Sierra Pacific Power Company	22-06014	Depreciation rates, service lives, net salvage	Bureau of Consumer Protection
Washington Utilities & Transportation Commission	Puget Sound Energy	UE-220066 UG-220067 UG-210918	Depreciation rates, service lives, net salvage	Washington Office of Attorney General
Public Utility Commission of Texas	Oncor Electric Delivery Company LLC	PUC 53601	Depreciation rates, service lives, net salvage	Alliance of Oncor Cities
Florida Public Service Commission	Florida Public Utilities Company	20220067-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Public Utility Commission of Texas	Entergy Texas, Inc.	PUC 53719	Depreciation rates, decommissioning costs	Texas Municipal Group
Florida Public Service Commission	Florida City Gas	2020069-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Connecticut Public Utilities Regulatory Authority	Aquarion Water Company of Connecticut	22-07-01	Depreciation rates, service lives, net salvage	PURA Staff

Utility Regulatory Proceedings

Exhibit DJG-1
Page 8 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Washington Utilities & Transportation Commission	Avista Corporation	UE-220053 UG-220054 UE-210854	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Federal Energy Regulatory Commission	ANR Pipeline Company	RP22-501-000	Depreciation rates, service lives, net salvage	Ascent Resources - Utica, LLC
Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	R-2022-3031211	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Public Service Commission of South Carolina	Piedmont Natural Gas Company	2022-89-G	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	UGI Utilities, Inc. - Gas Division	R-2021-3030218	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Public Utilities Commission of the State of California	Pacific Gas & Electric Company	A.21-06-021	Depreciation rates, service lives, net salvage	The Utility Reform Network
Pennsylvania Public Utility Commission	PECO Energy Company - Gas Division	R-2022-3031113	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 202100164	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Massachusetts Department of Public Utilities	NSTAR Electric Company D/B/A Eversource Energy	D.P.U. 22-22	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Michigan Public Service Company	DTE Electric Company	U-20836	Cost of capital, awarded rate of return, capital structure	Michigan Environmental Council and Citizens Utility Board of Michigan
New York State Public Service Commission	Consolidated Edison Company of New York, Inc.	22-E-0064 22-G-0065	Depreciation rates, service lives, net salvage, depreciation reserve	The City of New York
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater / East Whiteland Township	A-2021-3026132	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
Public Service Commission of South Carolina	Kiawah Island Utility, Inc.	2021-324-WS	Cost of capital, awarded rate of return, capital structure	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater / Willistown Township	A-2021-3027268	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate

Utility Regulatory Proceedings

Exhibit DJG-1

Page 9 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45621	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Arkansas Public Service Commission	Southwestern Electric Power Company	21-070-U	Cost of capital, depreciation rates, net salvage	Western Arkansas Large Energy Consumers
Federal Energy Regulatory Commission	Southern Star Central Gas Pipeline	RP21-778-002	Depreciation rates, service lives, net salvage	Consumer-Owned Shippers
Railroad Commission of Texas	Participating Texas gas utilities in consolidated proceeding	OS-21-00007061	Securitization of extraordinary gas costs arising from winter storms	The City of El Paso
Public Service Commission of South Carolina	Palmetto Wastewater Reclamation, Inc.	2021-153-S	Cost of capital, awarded rate of return, capital structure, ring-fencing	South Carolina Office of Regulatory Staff
Public Utilities Commission of the State of Colorado	Public Service Company of Colorado	21AL-0317E	Cost of capital, depreciation rates, net salvage	Colorado Energy Consumers
Pennsylvania Public Utility Commission	City of Lancaster - Water Department	R-2021-3026682	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 51802	Depreciation rates, service lives, net salvage	The Alliance of Xcel Municipalities
Pennsylvania Public Utility Commission	The Borough of Hanover - Hanover Municipal Waterworks	R-2021-3026116	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Delmarva Power & Light Company	9670	Cost of capital and authorized rate of return	Maryland Office of People's Counsel
Oklahoma Corporation Commission	Oklahoma Natural Gas Company	PUD 202100063	Cost of capital, awarded rate of return, capital structure	Oklahoma Industrial Energy Consumers
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45576	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	El Paso Electric Company	PUC 52195	Depreciation rates, service lives, net salvage	The City of El Paso
Pennsylvania Public Utility Commission	Aqua Pennsylvania	R-2021-3027385	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate

Utility Regulatory Proceedings

Exhibit DJG-1
Page 10 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Public Service Commission of the State of Montana	NorthWestern Energy	D2021.02.022	Cost of capital, awarded rate of return, capital structure	Montana Consumer Counsel
Pennsylvania Public Utility Commission	PECO Energy Company	R-2021-3024601	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Southwestern Public Service Company	20-00238-UT	Cost of capital and authorized rate of return	The New Mexico Large Customer Group; Occidental Permian
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 202100055	Cost of capital, depreciation rates, net salvage	Oklahoma Industrial Energy Consumers
Pennsylvania Public Utility Commission	Duquesne Light Company	R-2021-3024750	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Maryland Public Service Commission	Columbia Gas of Maryland	9664	Cost of capital and authorized rate of return	Maryland Office of People's Counsel
Indiana Utility Regulatory Commission	Southern Indiana Gas Company, d/b/a Vectren Energy Delivery of Indiana, Inc.	45447	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Southwestern Electric Power Company	PUC 51415	Depreciation rates, service lives, net salvage	Cities Advocating Reasonable Deregulation
New Mexico Public Regulatory Commission	Avangrid, Inc., Avangrid Networks, Inc., NM Green Holdings, Inc., PNM, and PNM Resources	20-00222-UT	Ring fencing and capital structure	The Albuquerque Bernalillo County Water Utility Authority
Indiana Utility Regulatory Commission	Indiana Gas Company, d/b/a Vectren Energy Delivery of Indiana, Inc.	45468	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of Nevada	Nevada Power Company and Sierra Pacific Power Company, d/b/a NV Energy	20-07023	Construction work in progress	MGM Resorts International, Caesars Enterprise Services, LLC, and the Southern Nevada Water Authority
Massachusetts Department of Public Utilities	Boston Gas Company, d/b/a National Grid	D.P.U. 20-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Public Service Commission of the State of Montana	ABACO Energy Services, LLC	D2020.07.082	Cost of capital and authorized rate of return	Montana Consumer Counsel
Maryland Public Service Commission	Washington Gas Light Company	9651	Cost of capital and authorized rate of return	Maryland Office of People's Counsel

Utility Regulatory Proceedings

Exhibit DJG-1
Page 11 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Florida Public Service Commission	Utilities, Inc. of Florida	20200139-WS	Cost of capital and authorized rate of return	Florida Office of Public Counsel
New Mexico Public Regulatory Commission	El Paso Electric Company	20-00104-UT	Cost of capital, depreciation rates, net salvage	City of Las Cruces and Doña Ana County
Public Utilities Commission of Nevada	Nevada Power Company	20-06003	Cost of capital, awarded rate of return, capital structure, earnings sharing	MGM Resorts International, Caesars Enterprise Services, LLC, Wynn Las Vegas, LLC, Smart Energy Alliance, and Circus Circus Las Vegas, LLC
Wyoming Public Service Commission	Rocky Mountain Power	20000-578-ER-20	Cost of capital and authorized rate of return	Wyoming Industrial Energy Consumers
Florida Public Service Commission	Peoples Gas System	20200051-GU 20200166-GU	Cost of capital, depreciation rates, net salvage	Florida Office of Public Counsel
Wyoming Public Service Commission	Rocky Mountain Power	20000-539-EA-18	Depreciation rates, service lives, net salvage	Wyoming Industrial Energy Consumers
Public Service Commission of South Carolina	Dominion Energy South Carolina	2020-125-E	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Pennsylvania Public Utility Commission	The City of Bethlehem	2020-3020256	Cost of capital, awarded rate of return, capital structure	Pennsylvania Office of Consumer Advocate
Railroad Commission of Texas	Texas Gas Services Company	GUD 10928	Depreciation rates, service lives, net salvage	Gulf Coast Service Area Steering Committee
Public Utilities Commission of the State of California	Southern California Edison	A.19-08-013	Depreciation rates, service lives, net salvage	The Utility Reform Network
Massachusetts Department of Public Utilities	NSTAR Gas Company	D.P.U. 19-120	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy
Georgia Public Service Commission	Liberty Utilities (Peach State Natural Gas)	42959	Depreciation rates, service lives, net salvage	Public Interest Advocacy Staff
Florida Public Service Commission	Florida Public Utilities Company	20190155-El 20190156-El 20190174-El	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Illinois Commerce Commission	Commonwealth Edison Company	20-0393	Depreciation rates, service lives, net salvage	The Office of the Illinois Attorney General

Utility Regulatory Proceedings

Exhibit DJG-1
Page 12 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 49831	Depreciation rates, service lives, net salvage	Alliance of Xcel Municipalities
Public Service Commission of South Carolina	Blue Granite Water Company	2019-290-WS	Depreciation rates, service lives, net salvage	South Carolina Office of Regulatory Staff
Railroad Commission of Texas	CenterPoint Energy Resources	GUD 10920	Depreciation rates and grouping procedure	Alliance of CenterPoint Municipalities
Pennsylvania Public Utility Commission	Aqua Pennsylvania Wastewater / East Norriton Township	A-2019-3009052	Fair market value estimates for wastewater assets	Pennsylvania Office of Consumer Advocate
New Mexico Public Regulation Commission	Southwestern Public Service Company	19-00170-UT	Cost of capital and authorized rate of return	The New Mexico Large Customer Group; Occidental Permian
Indiana Utility Regulatory Commission	Duke Energy Indiana	45253	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Maryland Public Service Commission	Columbia Gas of Maryland	9609	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-190334	Cost of capital, awarded rate of return, capital structure	Washington Office of Attorney General
Indiana Utility Regulatory Commission	Indiana Michigan Power Company	45235	Cost of capital, depreciation rates, net salvage	Indiana Office of Utility Consumer Counselor
Public Utilities Commission of the State of California	Pacific Gas & Electric Company	18-12-009	Depreciation rates, service lives, net salvage	The Utility Reform Network
Oklahoma Corporation Commission	The Empire District Electric Company	PUD 201800133	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Arkansas Public Service Commission	Southwestern Electric Power Company	19-008-U	Cost of capital, depreciation rates, net salvage	Western Arkansas Large Energy Consumers
Public Utility Commission of Texas	CenterPoint Energy Houston Electric	PUC 49421	Depreciation rates, service lives, net salvage	Texas Coast Utilities Coalition
Massachusetts Department of Public Utilities	Massachusetts Electric Company and Nantucket Electric Company	D.P.U. 18-150	Depreciation rates, service lives, net salvage	Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy

Utility Regulatory Proceedings

Exhibit DJG-1
Page 13 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201800140	Cost of capital, authorized ROE, depreciation rates	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2018.9.60	Depreciation rates, service lives, net salvage	Montana Consumer Counsel and Denbury Onshore
Indiana Utility Regulatory Commission	Northern Indiana Public Service Company	45159	Depreciation rates, grouping procedure, demolition costs	Indiana Office of Utility Consumer Counselor
Public Service Commission of the State of Montana	NorthWestern Energy	D2018.2.12	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Oklahoma Corporation Commission	Public Service Company of Oklahoma	PUD 201800097	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Wal-Mart
Nevada Public Utilities Commission	Southwest Gas Corporation	18-05031	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	Texas-New Mexico Power Company	PUC 48401	Depreciation rates, service lives, net salvage	Alliance of Texas-New Mexico Power Municipalities
Oklahoma Corporation Commission	Oklahoma Gas & Electric Company	PUD 201700496	Depreciation rates, service lives, net salvage	Oklahoma Industrial Energy Consumers and Oklahoma Energy Results
Maryland Public Service Commission	Washington Gas Light Company	9481	Depreciation rates, service lives, net salvage	Maryland Office of People's Counsel
Indiana Utility Regulatory Commission	Citizens Energy Group	45039	Depreciation rates, service lives, net salvage	Indiana Office of Utility Consumer Counselor
Public Utility Commission of Texas	Entergy Texas, Inc.	PUC 48371	Depreciation rates, decommissioning costs	Texas Municipal Group
Washington Utilities & Transportation Commission	Avista Corporation	UE-180167	Depreciation rates, service lives, net salvage	Washington Office of Attorney General
New Mexico Public Regulation Commission	Southwestern Public Service Company	17-00255-UT	Cost of capital and authorized rate of return	HollyFrontier Navajo Refining; Occidental Permian
Public Utility Commission of Texas	Southwestern Public Service Company	PUC 47527	Depreciation rates, plant service lives	Alliance of Xcel Municipalities

Utility Regulatory Proceedings

Exhibit DJG-1
Page 14 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Public Service Commission of the State of Montana	Montana-Dakota Utilities Company	D2017.9.79	Depreciation rates, service lives, net salvage	Montana Consumer Counsel
Florida Public Service Commission	Florida City Gas	20170179-GU	Cost of capital, depreciation rates	Florida Office of Public Counsel
Washington Utilities & Transportation Commission	Avista Corporation	UE-170485	Cost of capital and authorized rate of return	Washington Office of Attorney General
Wyoming Public Service Commission	Powder River Energy Corporation	10014-182-CA-17	Credit analysis, cost of capital	Private customer
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201700151	Depreciation, terminal salvage, risk analysis	Oklahoma Industrial Energy Consumers
Public Utility Commission of Texas	Oncor Electric Delivery Company	PUC 46957	Depreciation rates, simulated analysis	Alliance of Oncor Cities
Nevada Public Utilities Commission	Nevada Power Company	17-06004	Depreciation rates, service lives, net salvage	Nevada Bureau of Consumer Protection
Public Utility Commission of Texas	El Paso Electric Company	PUC 46831	Depreciation rates, interim retirements	City of El Paso
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-24	Accelerated depreciation of North Valmy plant	Micron Technology, Inc.
Idaho Public Utilities Commission	Idaho Power Company	IPC-E-16-23	Depreciation rates, service lives, net salvage	Micron Technology, Inc.
Public Utility Commission of Texas	Southwestern Electric Power Company	PUC 46449	Depreciation rates, decommissioning costs	Cities Advocating Reasonable Deregulation
Massachusetts Department of Public Utilities	Eversource Energy	D.P.U. 17-05	Cost of capital, capital structure, and rate of return	Sunrun Inc.; Energy Freedom Coalition of America
Railroad Commission of Texas	Atmos Pipeline - Texas	GUD 10580	Depreciation rates, grouping procedure	City of Dallas
Public Utility Commission of Texas	Sharyland Utility Company	PUC 45414	Depreciation rates, simulated analysis	City of Mission

Utility Regulatory Proceedings

Exhibit DJG-1
Page 15 of 15

Regulatory Agency	Utility Applicant	Docket Number	Issues Addressed	Parties Represented
Oklahoma Corporation Commission	Empire District Electric Company	PUD 201600468	Cost of capital, depreciation rates	Oklahoma Industrial Energy Consumers
Railroad Commission of Texas	CenterPoint Energy Texas Gas	GUD 10567	Depreciation rates, simulated plant analysis	Texas Coast Utilities Coalition
Arkansas Public Service Commission	Oklahoma Gas & Electric Company	160-159-GU	Cost of capital, depreciation rates, terminal salvage	Arkansas River Valley Energy Consumers; Wal-Mart
Florida Public Service Commission	Peoples Gas	160-159-GU	Depreciation rates, service lives, net salvage	Florida Office of Public Counsel
Arizona Corporation Commission	Arizona Public Service Company	E-01345A-16-0036	Cost of capital, depreciation rates, terminal salvage	Energy Freedom Coalition of America
Nevada Public Utilities Commission	Sierra Pacific Power Company	16-06008	Depreciation rates, net salvage, theoretical reserve	Northern Nevada Utility Customers
Oklahoma Corporation Commission	Oklahoma Gas & Electric Co.	PUD 201500273	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Public Service Co. of Oklahoma	PUD 201500208	Cost of capital, depreciation rates, terminal salvage	Public Utility Division
Oklahoma Corporation Commission	Oklahoma Natural Gas Company	PUD 201500213	Cost of capital, depreciation rates, net salvage	Public Utility Division

Proxy Group Summary

Exhibit DJG-2

Company	Ticker	Market Cap. (\$ millions)	Market Category	Value Line Safety Rank	Financial Strength
Atmos Energy Corp	ATO	24,700	Large Cap	1	A
NiSource Inc	NI	18,000	Large Cap	2	A
Northwest Natural Holding Company	NWN	1,700	Small Cap	2	A
ONE Gas Inc	OGS	4,500	Mid Cap	2	A
Southwest Gas Holdings Inc	SWX	5,000	Mid Cap	2	A
Spire Inc.	SR	4,300	Mid Cap	2	B++

Value Line Investment Survey

DCF - Stock and Index Prices

Exhibit DJG-3

Ticker	^GSPC	ATO	NI	NWN	OGS	SWX	SR
30-day Average	5817	156.36	39.15	41.57	75.45	71.51	74.62
Standard Deviation	153.8	3.14	0.55	1.38	2.27	2.05	1.59
06/09/25	6006	151.97	39.35	39.97	73.61	71.27	73.84
06/06/25	6000	152.18	39.28	39.70	73.44	71.09	73.63
06/05/25	5939	152.35	38.99	39.81	73.41	71.48	73.60
06/04/25	5971	152.15	39.08	39.76	73.49	71.97	73.31
06/03/25	5970	154.61	39.43	40.70	75.30	73.68	75.21
06/02/25	5936	154.64	39.59	40.72	74.67	71.64	74.65
05/30/25	5912	154.68	39.54	40.97	74.76	71.83	75.28
05/29/25	5912	154.34	38.99	40.90	74.33	71.90	74.79
05/28/25	5889	153.72	38.75	40.96	73.54	71.00	73.74
05/27/25	5922	156.49	39.28	41.41	75.21	72.40	75.40
05/23/25	5803	156.41	39.02	40.76	74.46	70.81	74.62
05/22/25	5842	154.43	38.50	40.45	73.49	69.10	73.47
05/21/25	5845	156.09	38.85	40.95	74.79	69.06	74.24
05/20/25	5940	158.22	39.51	41.76	76.13	71.06	75.14
05/19/25	5964	159.10	39.92	41.54	75.73	71.35	74.45
05/16/25	5958	156.81	39.08	41.10	74.62	69.02	73.31
05/15/25	5917	155.11	38.69	40.73	73.49	69.18	72.59
05/14/25	5893	151.41	37.88	39.78	71.18	67.46	71.03
05/13/25	5887	152.81	37.82	40.53	72.64	67.48	71.79
05/12/25	5844	154.37	38.32	41.22	73.94	69.16	72.19
05/09/25	5660	158.98	39.58	42.83	76.35	74.99	74.66
05/08/25	5664	160.36	39.61	43.57	79.00	75.26	75.02
05/07/25	5631	161.76	40.48	43.95	80.66	75.74	76.11
05/06/25	5607	161.06	39.36	43.63	80.15	73.02	76.62
05/05/25	5650	160.51	39.31	43.55	77.55	72.37	76.04
05/02/25	5687	160.61	39.30	43.20	77.74	73.39	76.48
05/01/25	5604	159.29	38.96	42.94	77.18	72.63	76.29
04/30/25	5569	159.74	39.11	43.10	77.81	71.55	76.54
04/29/25	5561	158.81	39.44	43.29	77.59	72.21	77.06
04/28/25	5529	157.85	39.45	43.27	77.28	72.09	77.39

All prices are adjusted closing prices reported by Yahoo! Finance, <http://finance.yahoo.com>

DCF - Dividend Yields

Exhibit DJG-4

Company	Ticker	[1]	[2]	[3]
		Annualized Dividend	Stock Price	Dividend Yield
Atmos Energy Corp	ATO	3.48	156.36	2.23%
NiSource Inc	NI	1.12	39.15	2.86%
Northwest Natural Holding Company	NWN	1.96	41.57	4.72%
ONE Gas Inc	OGS	2.68	75.45	3.55%
Southwest Gas Holdings Inc	SWX	2.48	71.51	3.47%
Spire Inc.	SR	3.14	74.62	4.21%
Average		\$2.48	\$76.44	3.50%

[1] Yahoo Finance

[2] Average stock price from Exhibit DJG-3

[3] = [1] / [2]

DCF - Terminal Growth Rate Determinants

Exhibit DJG-5

Terminal Growth Determinants	Rate
Nominal GDP	3.7%
Real GDP	1.6%
Long-Term Growth Ceiling	3.7%

CBO, The 2024 Long-Term Budget Outlook: 2025-2055, , p. 32

DCF - Final Result

Exhibit DJG-6

		[1]	[2]	[3]	[4]	[5]
Company	Ticker	Dividend Yield	Analyst Growth	Sustainable Growth	DCF Result (Analyst Growth)	DCF Result (Sustainable Growth)
Atmos Energy Corp	ATO	2.2%	7.0%	3.7%	9.4%	6.0%
NiSource Inc	NI	2.9%	4.5%	3.7%	7.5%	6.7%
Northwest Natural Holding Company	NWN	4.7%	0.5%	3.7%	5.2%	8.6%
ONE Gas Inc	OGS	3.6%	2.0%	3.7%	5.6%	7.4%
Southwest Gas Holdings Inc	SWX	3.5%	5.5%	3.7%	9.2%	7.3%
Spire Inc.	SR	4.2%	4.0%	3.7%	8.4%	8.1%
Average		3.5%	3.9%	3.7%	7.5%	7.3%

[1] Dividend Yield from Exhibit DJG-4

[2] Forecasted dividend growth rates - Value Line

[3] Sustainable growth rate from Exhibit DJG-5

[4] Annual Compounding DCF = $D_0 (1 + g) / P_0 + g$ (using analyst growth rate)

[5] Annual Compounding DCF = $D_0 (1 + g) / P_0 + g$ (using sustainable growth rate)

CAPM - Risk-Free Rate Estimate

Exhibit DJG-7

Date	Rate
04/28/25	4.69%
04/29/25	4.64%
04/30/25	4.66%
05/01/25	4.74%
05/02/25	4.79%
05/05/25	4.83%
05/06/25	4.81%
05/07/25	4.77%
05/08/25	4.83%
05/09/25	4.83%
05/12/25	4.89%
05/13/25	4.94%
05/14/25	4.97%
05/15/25	4.91%
05/16/25	4.89%
05/19/25	4.92%
05/20/25	4.96%
05/21/25	5.08%
05/22/25	5.05%
05/23/25	5.04%
05/27/25	4.94%
05/28/25	4.97%
05/29/25	4.92%
05/30/25	4.92%
06/02/25	4.99%
06/03/25	4.98%
06/04/25	4.89%
06/05/25	4.88%
06/06/25	4.97%
06/09/25	4.95%
Average	4.89%

*Daily Treasury Yield Curve Rates on 30-year T-bonds,
<http://www.treasury.gov/resources-center/data-chart-center/interest-rates/>

CAPM - Beta Coefficients

Exhibit DJG-8

Company	Ticker	Beta
Atmos Energy Corp	ATO	0.75
NiSource Inc	NI	0.85
Northwest Natural Holding Company	NWN	0.80
ONE Gas Inc	OGS	0.80
Southwest Gas Holdings Inc	SWX	0.80
Spire Inc.	SR	0.80
Average		0.80

Betas from Value Line Investment Survey

CAPM - Implied Equity Risk Premium Estimate

Exhibit DJG-9

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Year	Market Value	Operating Earnings	Dividends	Buybacks	Earnings Yield	Dividend Yield	Buyback Yield	Gross Cash Yield
2014	18,245	1,004	350	553	5.50%	1.92%	3.03%	4.95%
2015	17,900	885	382	572	4.95%	2.14%	3.20%	5.33%
2016	19,268	920	397	536	4.77%	2.06%	2.78%	4.85%
2017	22,821	1,066	420	519	4.67%	1.84%	2.28%	4.12%
2018	21,027	1,282	456	806	6.10%	2.17%	3.84%	6.01%
2019	26,760	1,305	485	729	4.88%	1.81%	2.72%	4.54%
2020	31,659	1,019	480	520	3.22%	1.52%	1.64%	3.16%
2021	40,356	1,739	511	882	4.31%	1.27%	2.18%	3.45%
2022	32,133	1,656	565	923	5.15%	1.76%	2.87%	4.63%
2023	36,870	1,790	588	795	4.85%	1.60%	2.16%	3.75%
2024	49,805	1,968	630	943	3.95%	1.26%	1.89%	3.16%
Cash Yield	4.36%	[9]						
Growth Rate	6.96%	[10]						
Risk-free Rate	4.89%	[11]						
Current Index Value	5,817	[12]						
	[13]	[14]	[15]	[16]	[17]			
Year	1	2	3	4	5			
Expected Dividends	271	290	310	332	355			
Expected Terminal Value					7446			
Present Value	247	240	234	228	4869			
Intrinsic Index Value	5817	[18]						
Required Return on Market	9.9%	[19]						
Implied Equity Risk Premium	5.0%	[20]						

[1-4] S&P Quarterly Press Releases, data found at <https://us.spindices.com/indices/equity/sp-500> (additional info tab) (all dollar figures are in \$ billions)

[1] Market value of S&P 500

[5] = [2] / [1]

[6] = [3] / [1]

[7] = [4] / [1]

[8] = [6] + [7]

[9] = Average of [8]

[10] = Compound annual growth rate of [2] = $(\text{end value} / \text{beginning value})^{1/10} - 1$

[11] Risk-free rate from DJG risk-free rate exhibit

[12] 30-day average of closing index prices from DJG stock price exhibit

[13-16] Expected dividends = $[9] * [12] * (1 + [10])^0$; Present value = $\text{expected dividend} / (1 + [11] + [19])^0$

[17] Expected terminal value = $\text{expected dividend} * (1 + [11]) / [19]$; Present value = $(\text{expected dividend} + \text{expected terminal value}) / (1 + [11] + [19])^0$

[18] = Sum([13-17]) present values.

[19] = [20] + [11]

[20] Internal rate of return calculation setting [18] equal to [12] and solving for the discount rate

CAPM - Equity Risk Premium Results

IESE Business School Survey	5.5%	[1]
Kroll (Duff & Phelps) Report	5.5%	[2]
Damodaran (average)	4.3%	[3]
Garrett	<u>5.0%</u>	[4]
Average	5.1%	

CAPM - Final Results

Exhibit DJG-11

		[1]	[2]
Company	Ticker	Beta	CAPM Result
Atmos Energy Corp	ATO	0.75	8.7%
NiSource Inc	NI	0.85	9.2%
Northwest Natural Holding Company	NWN	0.80	8.9%
ONE Gas Inc	OGS	0.80	8.9%
Southwest Gas Holdings Inc	SWX	0.80	8.9%
Spire Inc.	SR	0.80	8.9%
Average			8.9%
Risk-free Rate	[3]	4.9%	
Equity Risk Premium	[4]	5.1%	

[1] From Exhibit DJG-8

[2] = [3] + [1] * [4]

[3] From Exhibit DJG-7

[4] From Exhibit DJG-10

Cost of Equity Summary

Exhibit DJG-12

Model	Cost of Equity
CAPM (at Proxy Debt Ratio)	8.9%
Hamada CAPM (at Company-Proposed Debt Ratio)	8.7%
DCF Model (Analyst Growth)	7.5%
DCF Model (Sustainable Growth)	7.3%
Model Average	8.1%
Model Range	7.3% -- 8.9%
Recommended ROE	8.9%

Proxy Company Debt Ratios

Exhibit DJG-13

Company	Ticker	Debt Ratio
Atmos Energy Corp	ATO	39%
NiSource Inc	NI	54%
Northwest Natural Holding Company	NWN	55%
ONE Gas Inc	OGS	44%
Southwest Gas Holdings Inc	SWX	54%
Spire Inc.	SR	53%
Average		50%

Debt ratios from Value Line Investment Survey - 2024

Competitive Industry Debt Ratios

Exhibit DJG-14

Industry	# Firms	Debt Ratio
Financial Svcs. (Non-bank & Insurance)	166	92%
Hotel/Gaming	65	86%
Brokerage & Investment Banking	30	80%
Retail (Automotive)	29	80%
Hospitals/Healthcare Facilities	33	76%
Air Transport	24	76%
Bank (Money Center)	15	71%
Rubber& Tires	3	67%
Recreation	50	66%
Food Wholesalers	14	66%
Transportation	21	66%
Computers/Peripherals	35	65%
Cable TV	9	65%
Advertising	54	64%
Retail (Grocery and Food)	17	64%
Retail (Special Lines)	98	64%
Telecom (Wireless)	11	63%
Power	48	62%
R.E.I.T.	192	62%
Oil/Gas Distribution	24	62%
Transportation (Railroads)	4	62%
Telecom. Services	32	62%
Chemical (Diversified)	4	61%
Auto & Truck	34	61%
Aerospace/Defense	67	60%
Broadcasting	22	60%
Packaging & Container	22	60%
Apparel	37	59%
Beverage (Soft)	29	59%
Utility (General)	14	59%
Retail (Distributors)	66	58%
Farming/Agriculture	35	57%
Green & Renewable Energy	18	57%
Information Services	16	57%
Office Equipment & Services	14	56%
Environmental & Waste Services	50	56%
Utility (Water)	15	55%
Real Estate (Development)	15	55%
Computer Services	63	54%
Household Products	101	52%
Retail (REITs)	28	52%
Drugs (Biotechnology)	535	50%
Software (Internet)	29	50%
Furn/Home Furnishings	28	50%
Total / Average	2,216	63%

Hamada Model Results

Exhibit DJG-15

Unlevering Beta			
Proxy Debt Ratio	50%	[1]	
Proxy Equity Ratio	50%	[2]	
Proxy Debt / Equity Ratio	1.0	[3]	
Tax Rate	21%	[4]	
Equity Risk Premium	5.1%	[5]	
Risk-free Rate	4.9%	[6]	
Proxy Group Beta	0.80	[7]	
Unlevered Beta	0.45	[8]	
	[9]	[10]	[11]
			[12]
Relevered Betas and Cost of Equity Estimates			
Debt Ratio	D/E Ratio	Levered Beta	Cost of Equity
0%	0.0	0.45	7.2%
20%	0.3	0.54	7.6%
25%	0.3	0.56	7.7%
30%	0.4	0.60	7.9%
46%	0.8	0.74	8.7%
50%	1.0	0.80	8.9%
60%	1.5	0.98	9.8%

[1] Proxy group average debt ratio

[2] Proxy group average equity ratio

[3] = [1] / [2]

[4] Company assumed tax rate

[5] Equity risk premium from Exhibit DJG-11

[6] Risk-free rate from Exhibit DJG-11

[7] Average proxy beta from Exhibit DJG-11

[8] = [7] / (1 + (1 - [4]) * [3])

[9] Various debt ratios (Garrett proposed highlighted)

[10] = [9] / (1 - [9])

[11] = [8] * (1 + (1 - [4]) * [10])

[12] = [6] + [11] * [5]

Final Rate of Return Recommendation

Exhibit DJG-16

<u>Capital Component</u>	<u>Proposed Ratio</u>	<u>Cost Rate</u>	<u>Weighted Cost</u>
Long-Term Debt	47.68%	5.2%	2.5%
Short-Term Debt	2.32%	5.0%	0.1%
Common Equity	<u>50.00%</u>	8.9%	<u>4.5%</u>
Total	100.0%		7.06%

Summary Rate and Accrual Adjustment

Exhibit DJG-17

Page 1 of 1

<u>2024 DEPRECIATION STUDY</u>							
Plant Function	Plant 11/30/2024	Columbia Position		OCA Position		OCA Adjustment	
		Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
Underground Storage	7,142,447	11.91%	850,896	11.69%	835,280	-0.22%	(15,616)
Distribution	4,235,546,921	2.58%	109,087,106	1.64%	69,668,279	-0.93%	(39,418,827)
General	33,308,476	3.94%	1,312,807	3.94%	1,313,365	0.00%	558
TOTAL PLANT STUDIED	\$ 4,275,997,843	2.60%	\$ 111,250,809	1.68%	\$ 71,816,924	-0.92%	\$ (39,433,885)

<u>2025 DEPRECIATION STUDY</u>							
Plant Function	Plant 11/30/2025	Columbia Position		OCA Position		OCA Adjustment	
		Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
Underground Storage	7,590,256	2.37%	180,222	2.38%	180,756	0.01%	534
Distribution	4,624,978,561	2.55%	118,128,719	1.63%	75,559,095	-0.92%	(42,569,624)
General	40,170,092	4.28%	1,721,226	4.28%	1,720,074	0.00%	(1,152)
TOTAL PLANT STUDIED	\$ 4,672,738,908	2.57%	\$ 120,030,167	1.66%	\$ 77,459,925	-0.91%	\$ (42,570,242)

<u>2026 DEPRECIATION STUDY</u>							
Plant Function	Plant 12/31/2026	Columbia Position		OCA Position		OCA Adjustment	
		Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
Underground Storage	8,104,684	2.53%	205,013	2.51%	203,741	-0.02%	(1,272)
Distribution	5,048,090,022	2.54%	128,040,495	1.63%	82,237,903	-0.91%	(45,802,592)
General	55,647,899	4.39%	2,444,091	4.39%	2,445,532	0.00%	1,441
TOTAL PLANT STUDIED	\$ 5,111,842,605	2.56%	\$ 130,689,599	1.66%	\$ 84,887,176	-0.90%	\$ (45,802,423)

Detailed Rate Comparison - 2024

Exhibit DJG-18

Page 1 of 3

Account No.	Description	[1]	[2]		[3]		[4]	
		Plant 11/30/2024	Columbia Position		OCA Position		OCA Adjustment	
			Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	Underground Storage Plant							
350.20	RIGHTS OF WAY	1,932	0.05%	1	0.06%	1	0.01%	0
351.00	COMPRESSOR STATION STRUCTURES WELLS	3,294,840	6.33%	208,581	6.25%	205,770	-0.08%	-2,811
352.01	CONSTRUCTION	1,126,772	16.58%	186,825	16.28%	183,427	-0.30%	-3,398
352.02	EQUIPMENT	1,072,322	39.66%	425,290	38.84%	416,467	-0.82%	-8,823
	TOTAL ACCOUNT 352.00	2,199,094	27.83%	612,115	27.28%	599,895	-0.56%	-12,220
352.10	STORAGE LEASEHOLDS AND RIGHTS	206,941	0.00%	8	0.00%	8	0.00%	0
353.00	LINES	387,525	0.35%	1,348	0.34%	1,312	-0.01%	-36
354.00	COMPRESSOR STATION EQUIPMENT	947,638	3.04%	28,843	2.99%	28,294	-0.05%	-549
355.00	MEASURING AND REGULATING EQUIPMENT	104,477	0.00%	0	0.00%	0	0.00%	0
	Total Underground Storage Plant	7,142,447	11.91%	850,896	11.69%	835,280	-0.22%	-15,616
	Distribution Plant							
	LAND AND LAND RIGHTS							
374.40	LAND RIGHTS	9,033,561	1.64%	148,442	1.32%	118,979	-0.32%	-29,463
374.50	RIGHTS OF WAY	3,233,314	1.07%	34,683	1.13%	36,592	0.06%	1,909
	TOTAL ACCOUNT 374.00	12,266,875	1.49%	183,125	1.27%	155,571	-0.22%	-27,554
	STRUCTURES AND IMPROVEMENTS							
375.34	MEASURING AND REGULATING	6,568,365	2.30%	150,764	1.49%	98,011	-0.81%	-52,753
375.60	INDUSTRIAL MEASURING AND REGULATING	85,565	0.57%	486	0.64%	544	0.07%	58
	TOTAL ACCOUNT 375.00	6,653,930	2.27%	151,250	1.48%	98,555	-0.79%	-52,695
375.70	OTHER DISTRIBUTION SYSTEMS							
	COMPANY STATIONS	46,202,517	2.62%	1,211,332	0.98%	453,584	-1.64%	-757,748
	PORTABLE SUBSTATIONS	4,894,349	2.81%	137,634	2.42%	118,224	-0.39%	-19,410
	TOTAL ACCOUNT 375.70	51,096,866	2.64%	1,348,966	1.12%	571,807	-1.52%	-777,159

Detailed Rate Comparison - 2024

Exhibit DJG-18

Page 2 of 3

Account No.	Description	[1]	[2]		[3]		[4]	
		Plant 11/30/2024	Columbia Position		OCA Position		OCA Adjustment	
			Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
375.80	COMMUNICATION	16,515	2.10%	346	1.86%	307	-0.24%	-39
376.00	MAINS							
	BARE STEEL	59,766,126	3.42%	2,043,858	1.33%	794,197	-2.09%	-1,249,661
	OTHER	2,916,324,440	2.31%	67,351,650	1.48%	43,150,127	-0.83%	-24,201,523
	TOTAL ACCOUNT 376.00	2,976,090,566	2.33%	69,395,508	1.48%	43,944,324	-0.86%	-25,451,184
378.00	M&R EQUIPMENT - GENERAL	150,201,783	3.05%	4,574,528	1.91%	2,868,444	-1.14%	-1,706,084
379.10	M&R EQUIPMENT - CITY GATE	119,158	8.84%	10,539	7.67%	9,137	-1.17%	-1,402
380.00	SERVICES							
	BARE STEEL	740,936	5.38%	39,873	4.40%	32,574	-0.98%	-7,299
	OTHER	861,993,753	3.31%	28,493,350	2.08%	17,953,790	-1.23%	-10,539,560
	TOTAL ACCOUNT 380.00	862,734,689	3.31%	28,533,223	2.08%	17,986,364	-1.22%	-10,546,859
381.00	METERS	45,617,357	2.51%	1,144,821	2.09%	952,240	-0.42%	-192,581
381.10	METERS - AMR	26,290,014	2.52%	662,824	2.36%	619,646	-0.16%	-43,178
382.00	METER INSTALLATIONS	52,607,899	1.94%	1,018,910	1.73%	910,041	-0.21%	-108,869
383.00	HOUSE REGULATORS	19,231,006	2.01%	387,345	1.80%	346,143	-0.21%	-41,202
384.00	HOUSE REGULATOR INSTALLATIONS	3,484,788	1.34%	46,778	1.52%	53,015	0.18%	6,237
385.00	INDUSTRIAL M&R EQUIPMENT - NON METERS	8,621,532	5.10%	439,545	3.19%	274,781	-1.91%	-164,764
	OTHER EQUIPMENT							
387.00	GENERAL	136,698	2.96%	4,053	2.29%	3,131	-0.67%	-922
387.40	COMMUNICATION EQUIPMENT	18,175,872	5.74%	1,043,651	4.10%	745,432	-1.64%	-298,219
387.50	GPS EQUIPMENT	2,201,372	6.44%	141,694	5.88%	129,339	-0.56%	-12,355
	TOTAL ACCOUNT 387.00	20,513,942	5.80%	1,189,398	4.28%	877,902	-1.52%	-311,496
	Total Distribution Plant	4,235,546,921	2.58%	109,087,106	1.64%	69,668,279	-0.93%	-39,418,827
	General Plant							
390.10	STRUCTURES AND IMPROVEMENTS - COMM	49,821	0.00%	0	0.00%	0	0.00%	0
	OFFICE FURNITURE AND EQUIPMENT							
391.10	FURNITURE	7,030,304	4.99%	350,854	5.00%	351,534	0.01%	680
391.11	EQUIPMENT	91,304	6.40%	5,840	6.36%	5,808	-0.04%	-32

Detailed Rate Comparison - 2024

Exhibit DJG-18

Page 3 of 3

Account No.	Description	[1]	[2]		[3]		[4]	
		Plant 11/30/2024	Columbia Position		OCA Position		OCA Adjustment	
			Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
391.12	INFORMATION SYSTEMS	554,702	0.19%	1,064	0.19%	1,056	0.00%	-8
	TOTAL ACCOUNT 391.00	7,676,310	4.66%	357,758	4.67%	358,398	0.01%	640
392.00	TRANSPORTATION EQUIPMENT - TRAILERS	25,617	0.00%	0	0.00%	0	0.00%	0
	TOOLS, SHOP AND GARAGE EQUIPMENT							
394.00	EQUIPMENT	22,408,085	3.88%	870,095	3.88%	869,785	0.00%	-310
394.12	CNG FACILITIES	18,450	0.00%	0	0.00%	0	0.00%	0
	TOTAL ACCOUNT 394.00	22,426,535	3.88%	870,095	3.88%	869,785	0.00%	-310
395.00	LABORATORY EQUIPMENT	264,921	5.39%	14,288	5.38%	14,245	-0.01%	-43
396.00	POWER OPERATED EQUIPMENT	948,698	0.00%	0	0.00%	0	0.00%	0
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	769,399	0.01%	102	0.01%	102	0.00%	0
398.00	MISCELLANEOUS EQUIPMENT	1,147,173	6.15%	70,564	6.17%	70,835	0.02%	271
	Total General Plant	33,308,476	3.94%	1,312,807	3.94%	1,313,365	0.00%	558
	TOTAL PLANT STUDIED	4,275,997,843	2.60%	111,250,809	1.68%	71,816,924	-0.92%	-39,433,885

[1], [2] From Company depreciation study

[3] From Exhibit DJG-19

[4] = [3] - [2]

Depreciation Rate Development - 2024

Exhibit DJG-19

Page 1 of 3

		[1]	[2]		[3]	[4]	[5]	[6]		[7]
Account No.	Description	Plant 11/30/2024	Iowa Curve Type AL		Book Reserve	Future Accruals	Remaining Life	Total		
								Accrual	Rate	
Underground Storage Plant										
350.20	RIGHTS OF WAY	1,932	SQ	-	1,931	1	1.00	1	0.06%	
351.00	COMPRESSOR STATION STRUCTURES WELLS	3,294,840	R3	- 65	3,068,493	226,347	1.10	205,770	6.25%	
352.01	CONSTRUCTION	1,126,772	SQ	-	925,002	201,770	1.10	183,427	16.28%	
352.02	EQUIPMENT	1,072,322	S2.5	- 55	614,208	458,114	1.10	416,467	38.84%	
	TOTAL ACCOUNT 352.00	2,199,094			1,539,210	659,884	1.10	599,895	27.28%	
352.10	STORAGE LEASEHOLDS AND RIGHTS	206,941	SQ	-	206,932	9	1.10	8	0.00%	
353.00	LINES	387,525	R3	- 60	386,082	1,443	1.10	1,312	0.34%	
354.00	COMPRESSOR STATION EQUIPMENT	947,638	R2.5	- 60	916,514	31,124	1.10	28,294	2.99%	
355.00	MEASURING AND REGULATING EQUIPMENT	104,477	R1.5	- 42	104,477	0				
	Total Underground Storage Plant	7,142,447			6,223,639	918,808	1.10	835,280	11.69%	
Distribution Plant										
	LAND AND LAND RIGHTS									
374.40	LAND RIGHTS	9,033,561	R2.5	- 75	1,111,944	7,921,617	66.58	118,979	1.32%	
374.50	RIGHTS OF WAY	3,233,314	S4	- 80	1,896,227	1,337,087	36.54	36,592	1.13%	
	TOTAL ACCOUNT 374.00	12,266,875			3,008,171	9,258,704	59.51	155,571	1.27%	
	STRUCTURES AND IMPROVEMENTS									
375.34	MEASURING AND REGULATING	6,568,365	R0.5	- 60	1,568,833	4,999,532	51.01	98,011	1.49%	
375.60	INDUSTRIAL MEASURING AND REGULATING	85,565	R1	- 55	76,125	9,440	17.35	544	0.64%	
	TOTAL ACCOUNT 375.00	6,653,930			1,644,958	5,008,972	50.82	98,555	1.48%	
375.70	OTHER DISTRIBUTION SYSTEMS									
	COMPANY STATIONS	46,202,517	R1.5	- 90	7,457,407	38,745,110	85.42	453,584	0.98%	
	PORTABLE SUBSTATIONS	4,894,349	S1.5	- 38	1,406,749	3,487,600	29.50	118,224	2.42%	
	TOTAL ACCOUNT 375.70	51,096,866			8,864,156	42,232,710	73.86	571,807	1.12%	
375.80	COMMUNICATION	16,515	R3	- 45	9,309	7,206	23.45	307	1.86%	
376.00	MAINS									
	BARE STEEL	59,766,126	R1	- 65	40,093,873	19,672,253	24.77	794,197	1.33%	

Depreciation Rate Development - 2024

Exhibit DJG-19

Page 2 of 3

Account No.	Description	[1]	[2]		[3]	[4]	[5]	[6]		[7]
		Plant	Iowa Curve		Book	Future	Remaining	Total		
		11/30/2024	Type	AL	Reserve	Accruals	Life	Accrual	Rate	
	OTHER	2,916,324,440	R1	- 65	377,802,447	2,538,521,993	58.83	43,150,127	1.48%	
	TOTAL ACCOUNT 376.00	2,976,090,566			417,896,320	2,558,194,246	58.21	43,944,324	1.48%	
378.00	M&R EQUIPMENT - GENERAL	150,201,783	R0.5	- 45	34,316,641	115,885,142	40.40	2,868,444	1.91%	
379.10	M&R EQUIPMENT - CITY GATE	119,158	S2	- 35	33,540	85,618	9.37	9,137	7.67%	
380.00	SERVICES									
	BARE STEEL	740,936	R0.5	- 45	512,918	228,018	7.00	32,574	4.40%	
	OTHER	861,993,753	R0.5	- 45	168,797,908	693,195,845	38.61	17,953,790	2.08%	
	TOTAL ACCOUNT 380.00	862,734,689			169,310,826	693,423,863	38.55	17,986,364	2.08%	
381.00	METERS	45,617,357	S1	- 44	18,097,612	27,519,745	28.90	952,240	2.09%	
381.10	METERS - AMR	26,290,014	S2.5	- 20	20,638,844	5,651,170	9.12	619,646	2.36%	
382.00	METER INSTALLATIONS	52,607,899	R3	- 55	16,415,562	36,192,337	39.77	910,041	1.73%	
383.00	HOUSE REGULATORS	19,231,006	S2	- 50	5,946,035	13,284,971	38.38	346,143	1.80%	
384.00	HOUSE REGULATOR INSTALLATIONS	3,484,788	S4	- 40	2,928,666	556,122	10.49	53,015	1.52%	
385.00	INDUSTRIAL M&R EQUIPMENT - NON METERS	8,621,532	R0.5	- 30	2,705,497	5,916,035	21.53	274,781	3.19%	
	OTHER EQUIPMENT									
387.00	GENERAL	136,698	R1	- 32	87,448	49,250	15.73	3,131	2.29%	
387.40	COMMUNICATION EQUIPMENT	18,175,872	R1.5	- 25	2,782,702	15,393,170	20.65	745,432	4.10%	
387.50	GPS EQUIPMENT	2,201,372	S3	- 10	1,945,280	256,092	1.98	129,339	5.88%	
	TOTAL ACCOUNT 387.00	20,513,942			4,815,430	15,698,512	17.88	877,902	4.28%	
	Total Distribution Plant	4,235,546,921			706,631,567	3,528,915,354	50.65	69,668,279	1.64%	
	General Plant									
390.10	STRUCTURES AND IMPROVEMENTS - COMM	49,821	R2	- 45	49,821	0				
	OFFICE FURNITURE AND EQUIPMENT									
391.10	FURNITURE	7,030,304	SQ	- 20	1,265,141	5,765,163	16.40	351,534	5.00%	
391.11	EQUIPMENT	91,304	SQ	- 15	64,588	26,716	4.60	5,808	6.36%	
391.12	INFORMATION SYSTEMS	554,702	SQ	- 5	551,957	2,745	2.60	1,056	0.19%	
	TOTAL ACCOUNT 391.00	7,676,310			1,881,686	5,794,624	16.17	358,398	4.67%	
392.00	TRANSPORTATION EQUIPMENT - TRAILERS	25,617	L4	- 13	25,737	-120				
	TOOLS, SHOP AND GARAGE EQUIPMENT									
394.00	EQUIPMENT	22,408,085	SQ	- 25	7,795,690	14,612,395	16.80	869,785	3.88%	

Depreciation Rate Development - 2024

Exhibit DJG-19

Page 3 of 3

Account No.	Description	[1] Plant 11/30/2024	[2] Iowa Curve		[3] Book Reserve	[4] Future Accruals	[5] Remaining Life	[6] Total		[7]
			Type	AL				Accrual	Rate	
394.12	CNG FACILITIES	18,450	S1.5	- 12	17,341	1,109				
	TOTAL ACCOUNT 394.00	22,426,535			7,813,031	14,613,504	16.80	869,785	3.88%	
395.00	LABORATORY EQUIPMENT	264,921	SQ	- 20	118,197	146,724	10.30	14,245	5.38%	
396.00	POWER OPERATED EQUIPMENT	948,698	L2.5	- 13	991,329	-42,631				
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	769,399	R2	- 21	768,266	1,133	11.10	102	0.01%	
398.00	MISCELLANEOUS EQUIPMENT	1,147,173	SQ	- 15	651,331	495,842	7.00	70,835	6.17%	
	Total General Plant	33,308,476			12,299,398	21,009,078	16.00	1,313,365	3.94%	
	TOTAL PLANT STUDIED	4,275,997,843			725,154,604	3,550,843,239	49.44	71,816,924	1.68%	

[1], [3] From Company depreciation study

[2] Average life and Iowa curve shape developed through actuarial analysis and professional judgment

[4] = [1] - [3]

[5] Composite remaining life based on Iowa cuve in [2]; see remaining life exhibit for detailed calculations

[6] = [4] / [5]; (some unadjusted figures may be hard coded to match Company proposal)

[7] = [6] / [1]; (some unadjusted figures may hard coded to match Company proposal)

Detailed Rate Comparison - 2025

Exhibit DJG-20

Page 1 of 3

Account No.	Description	[1]	[2]		[3]		[4]	
		Plant 11/30/2025	Columbia Position		OCA Position		OCA Adjustment	
			Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	Underground Storage Plant							
350.20	RIGHTS OF WAY	1,932	0.00%	0	0.00%	0	0.00%	0
351.00	COMPRESSOR STATION STRUCTURES	3,294,840	0.49%	16,192	0.49%	16,191	0.00%	-1
	WELLS				0.00%	0		
352.01	CONSTRUCTION	1,126,772	2.01%	22,613	2.01%	22,613	0.00%	0
352.02	EQUIPMENT	1,072,322	4.65%	49,899	4.65%	49,899	0.00%	0
	TOTAL ACCOUNT 352.00	2,199,094	3.30%	72,512	3.30%	72,512	0.00%	0
352.10	STORAGE LEASEHOLDS AND RIGHTS	206,941	0.00%	9	0.00%	9	0.00%	0
353.00	LINES	385,797	0.02%	90	0.02%	90	0.00%	0
354.00	COMPRESSOR STATION EQUIPMENT	947,638	0.22%	2,048	0.22%	2,047	0.00%	-1
354.10	COMPRESSOR STATION EQUIPMENT - NEW	449,537	19.88%	89,371	20.00%	89,907	0.12%	536
355.00	MEASURING AND REGULATING EQUIPMENT	104,477	0.00%	0	0.00%	0	0.00%	0
	Total Underground Storage Plant	7,590,256	2.37%	180,222	2.38%	180,756	0.01%	534
	Distribution Plant							
	LAND AND LAND RIGHTS							
374.40	LAND RIGHTS	11,008,773	1.64%	180,466	1.32%	145,050	-0.32%	-35,416
374.50	RIGHTS OF WAY	3,233,314	1.07%	34,573	1.13%	36,382	0.06%	1,809
	TOTAL ACCOUNT 374.00	14,242,087	1.51%	215,039	1.27%	181,432	-0.24%	-33,607
	STRUCTURES AND IMPROVEMENTS							
375.34	MEASURING AND REGULATING	7,887,262	2.49%	196,055	1.51%	119,121	-0.98%	-76,934
375.60	INDUSTRIAL MEASURING AND REGULATING	85,565	0.54%	465	0.62%	529	0.08%	64
	TOTAL ACCOUNT 375.00	7,972,827	2.46%	196,520	1.50%	119,650	-0.96%	-76,870
375.70	OTHER DISTRIBUTION SYSTEMS							
	COMPANY STATIONS	46,560,797	2.58%	1,201,906	0.96%	447,435	-1.62%	-754,471
	PORTABLE SUBSTATIONS	5,053,856	2.81%	141,762	2.41%	121,627	-0.40%	-20,135
	TOTAL ACCOUNT 375.70	51,614,653	2.60%	1,343,668	1.10%	569,062	-1.50%	-774,606

Detailed Rate Comparison - 2025

Exhibit DJG-20

Page 2 of 3

Account No.	Description	[1]	[2]		[3]		[4]	
		Plant 11/30/2025	Columbia Position		OCA Position		OCA Adjustment	
			Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
375.80	COMMUNICATION	16,515	2.05%	339	1.83%	303	-0.22%	-36
376.00	MAINS							
	BARE STEEL	49,802,958	3.43%	1,706,576	1.24%	615,851	-2.19%	-1,090,725
	OTHER	3,206,626,779	2.30%	73,645,123	1.47%	47,297,488	-0.83%	-26,347,635
	TOTAL ACCOUNT 376.00	3,256,429,737	2.31%	75,351,699	1.47%	47,913,340	-0.84%	-27,438,359
378.00	M&R EQUIPMENT - GENERAL	178,796,716	3.25%	5,803,722	1.93%	3,458,992	-1.32%	-2,344,730
379.10	M&R EQUIPMENT - CITY GATE	119,158	8.11%	9,667	7.07%	8,429	-1.04%	-1,238
380.00	SERVICES							
	BARE STEEL	599,391	5.13%	30,766	4.15%	24,868	-0.98%	-5,898
	OTHER	927,987,646	3.25%	30,120,301	2.05%	19,045,838	-1.20%	-11,074,463
	TOTAL ACCOUNT 380.00	928,587,037	3.25%	30,151,067	2.05%	19,070,706	-1.19%	-11,080,361
381.00	METERS	50,186,337	2.58%	1,295,105	2.13%	1,067,057	-0.45%	-228,048
381.10	METERS - AMR	27,384,527	2.52%	690,594	2.49%	681,368	-0.03%	-9,226
382.00	METER INSTALLATIONS	54,955,719	1.93%	1,061,761	1.73%	949,921	-0.20%	-111,840
383.00	HOUSE REGULATORS	20,499,492	2.03%	417,136	1.81%	371,682	-0.22%	-45,454
384.00	HOUSE REGULATOR INSTALLATIONS	3,509,385	1.31%	46,094	1.52%	53,258	0.21%	7,164
385.00	INDUSTRIAL M&R EQUIPMENT - NON METERS	9,513,778	4.89%	464,816	3.06%	291,167	-1.83%	-173,649
	OTHER EQUIPMENT							
387.00	GENERAL	136,698	2.56%	3,504	2.18%	2,975	-0.38%	-529
387.40	COMMUNICATION EQUIPMENT	18,812,522	5.34%	1,003,687	3.98%	749,105	-1.36%	-254,582
387.50	GPS EQUIPMENT	2,201,372	3.38%	74,301	3.21%	70,649	-0.17%	-3,652
	TOTAL ACCOUNT 387.00	21,150,593	5.11%	1,081,492	3.89%	822,729	-1.22%	-258,763
	Total Distribution Plant	4,624,978,561	2.55%	118,128,719	1.63%	75,559,095	-0.92%	-42,569,624
	General Plant							
390.10	STRUCTURES AND IMPROVEMENTS - COMM	49,821	0.00%	0	0.00%	0	0.00%	0
	OFFICE FURNITURE AND EQUIPMENT							
391.10	FURNITURE	7,142,560	5.00%	357,261	5.00%	357,368	0.00%	107

Detailed Rate Comparison - 2025

Exhibit DJG-20

Page 3 of 3

Account No.	Description	[1]	[2]		[3]		[4]	
		Plant 11/30/2025	Columbia Position		OCA Position		OCA Adjustment	
			Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
391.11	EQUIPMENT	91,304	5.66%	5,166	5.72%	5,218	0.06%	52
391.12	INFORMATION SYSTEMS	129,970	1.05%	1,360	1.03%	1,343	-0.02%	-17
	TOTAL ACCOUNT 391.00	7,363,834	4.94%	363,787	4.94%	363,930	0.00%	143
392.00	TRANSPORTATION EQUIPMENT - TRAILERS	25,617	0.00%	0	0.00%	0	0.00%	0
394.00	EQUIPMENT	27,287,535	3.97%	1,082,359	3.96%	1,081,850	-0.01%	-509
395.00	LABORATORY EQUIPMENT	264,921	5.40%	14,310	5.38%	14,259	-0.02%	-51
396.00	POWER OPERATED EQUIPMENT	948,698	0.00%	0	0.00%	0	0.00%	0
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	3,043,267	6.08%	185,054	6.07%	184,806	-0.01%	-248
398.00	MISCELLANEOUS EQUIPMENT	1,186,398	6.38%	75,716	6.34%	75,230	-0.04%	-486
	Total General Plant	40,170,092	4.28%	1,721,226	4.28%	1,720,074	0.00%	-1,152
	TOTAL PLANT STUDIED	4,672,738,908	2.57%	120,030,167	1.66%	77,459,925	-0.91%	-42,570,242

[1], [2] From Company depreciation study

[3] From Exhibit DJG-19

[4] = [3] - [2]

Depreciation Rate Development - 2025

Exhibit DJG-21

Page 1 of 3

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Account No.	Description	Plant 11/30/2025	Iowa Curve Type AL	Book Reserve	Future Accruals	Remaining Life	Total	
							Accrual	Rate
	Underground Storage Plant							
350.20	RIGHTS OF WAY	1,932	SQ -	1,932	0			
351.00	COMPRESSOR STATION STRUCTURES	3,294,840	R3 - 65	3,278,649	16,191	1.00	16,191	0.49%
	WELLS							
352.01	CONSTRUCTION	1,126,772	SQ -	1,104,159	22,613	1.00	22,613	2.01%
352.02	EQUIPMENT	1,072,322	S2.5 - 55	1,022,423	49,899	1.00	49,899	4.65%
	TOTAL ACCOUNT 352.00	2,199,094		2,126,582	72,512	1.00	72,512	3.30%
352.10	STORAGE LEASEHOLDS AND RIGHTS	206,941	SQ -	206,932	9	1.00	9	0.00%
353.00	LINES	385,797	R3 - 60	385,707	90	1.00	90	0.02%
354.00	COMPRESSOR STATION EQUIPMENT	947,638	R2.5 - 60	945,591	2,047	1.00	2,047	0.22%
354.10	COMPRESSOR STATION EQUIPMENT - NEW	449,537	R2.5 - 60	0	449,537	5.00	89,907	20.00%
355.00	MEASURING AND REGULATING EQUIPMENT	104,477	R1.5 - 42	104,477	0			
	Total Underground Storage Plant	7,590,256		7,049,870	540,386	2.99	180,756	2.38%
	Distribution Plant							
	LAND AND LAND RIGHTS							
374.40	LAND RIGHTS	11,008,773	R2.5 - 75	1,273,044	9,735,729	67.12	145,050	1.32%
374.50	RIGHTS OF WAY	3,233,314	S4 - 80	1,930,823	1,302,491	35.80	36,382	1.13%
	TOTAL ACCOUNT 374.00	14,242,087		3,203,867	11,038,220	60.84	181,432	1.27%
	STRUCTURES AND IMPROVEMENTS							
375.34	MEASURING AND REGULATING	7,887,262	R0.5 - 60	1,689,421	6,197,841	52.03	119,121	1.51%
375.60	INDUSTRIAL MEASURING AND REGULATING	85,565	R1 - 55	76,620	8,945	16.90	529	0.62%
	TOTAL ACCOUNT 375.00	7,972,827		1,766,041	6,206,786	51.87	119,650	1.50%
375.70	OTHER DISTRIBUTION SYSTEMS							
	COMPANY STATIONS	46,560,797	R1.5 - 90	8,685,411	37,875,386	84.65	447,435	0.96%
	PORTABLE SUBSTATIONS	5,053,856	S1.5 - 38	1,538,839	3,515,017	28.90	121,627	2.41%
	TOTAL ACCOUNT 375.70	51,614,653		10,224,250	41,390,403	72.73	569,062	1.10%
375.80	COMMUNICATION	16,515	R3 - 45	9,656	6,859	22.64	303	1.83%
376.00	MAINS							

Depreciation Rate Development - 2025

Exhibit DJG-21

Page 2 of 3

Account No.	Description	[1]	[2]		[3]	[4]	[5]	[6]		[7]
		Plant	Iowa Curve		Book	Future	Remaining	Total		
		11/30/2025	Type	AL	Reserve	Accruals	Life	Accrual	Rate	
	BARE STEEL	49,802,958	R1	- 65	34,425,149	15,377,809	24.97	615,851	1.24%	
	OTHER	3,206,626,779	R1	- 65	428,372,320	2,778,254,459	58.74	47,297,488	1.47%	
	TOTAL ACCOUNT 376.00	3,256,429,737			462,797,469	2,793,632,268	58.31	47,913,340	1.47%	
378.00	M&R EQUIPMENT - GENERAL	178,796,716	R0.5	- 45	37,739,029	141,057,687	40.78	3,458,992	1.93%	
379.10	M&R EQUIPMENT - CITY GATE	119,158	S2	- 35	43,635	75,523	8.96	8,429	7.07%	
380.00	SERVICES									
	BARE STEEL	599,391	R0.5	- 45	434,019	165,372	6.65	24,868	4.15%	
	OTHER	927,987,646	R0.5	- 45	194,151,516	733,836,130	38.53	19,045,838	2.05%	
	TOTAL ACCOUNT 380.00	928,587,037			194,585,535	734,001,502	38.49	19,070,706	2.05%	
381.00	METERS	50,186,337	S1	- 44	17,182,262	33,004,075	30.93	1,067,057	2.13%	
381.10	METERS - AMR	27,384,527	S2.5	- 20	21,272,655	6,111,872	8.97	681,368	2.49%	
382.00	METER INSTALLATIONS	54,955,719	R3	- 55	17,253,364	37,702,355	39.69	949,921	1.73%	
383.00	HOUSE REGULATORS	20,499,492	S2	- 50	6,249,223	14,250,269	38.34	371,682	1.81%	
384.00	HOUSE REGULATOR INSTALLATIONS	3,509,385	S4	- 40	2,972,542	536,843	10.08	53,258	1.52%	
385.00	INDUSTRIAL M&R EQUIPMENT - NON METERS	9,513,778	R0.5	- 30	3,105,196	6,408,582	22.01	291,167	3.06%	
	OTHER EQUIPMENT									
387.00	GENERAL	136,698	R1	- 32	91,475	45,223	15.20	2,975	2.18%	
387.40	COMMUNICATION EQUIPMENT	18,812,522	R1.5	- 25	3,800,468	15,012,054	20.04	749,105	3.98%	
387.50	GPS EQUIPMENT	2,201,372	S3	- 10	2,085,507	115,865	1.64	70,649	3.21%	
	TOTAL ACCOUNT 387.00	21,150,593			5,977,450	15,173,143	18.44	822,729	3.89%	
	Total Distribution Plant	4,624,978,561			784,382,174	3,840,596,387	50.83	75,559,095	1.63%	
	General Plant									
390.10	STRUCTURES AND IMPROVEMENTS - COMM	49,821	R2	- 45	49,821	0				
	OFFICE FURNITURE AND EQUIPMENT									
391.10	FURNITURE	7,142,560	SQ	- 20	1,603,355	5,539,205	15.50	357,368	5.00%	
391.11	EQUIPMENT	91,304	SQ	- 15	70,430	20,874	4.00	5,218	5.72%	
391.12	INFORMATION SYSTEMS	129,970	SQ	- 5	127,821	2,149	1.60	1,343	1.03%	
	TOTAL ACCOUNT 391.00	7,363,834			1,801,606	5,562,228	15.28	363,930	4.94%	
392.00	TRANSPORTATION EQUIPMENT - TRAILERS	25,617	L4	- 13	25,921	-304				
394.00	EQUIPMENT	27,287,535	SQ	- 25	8,463,352	18,824,183	17.40	1,081,850	3.96%	

Depreciation Rate Development - 2025

Exhibit DJG-21

Page 3 of 3

Account No.	Description	[1]	[2]		[3]	[4]	[5]	[6]		[7]
		Plant	Iowa Curve		Book	Future	Remaining	Total		
		11/30/2025	Type	AL	Reserve	Accruals	Life	Accrual	Rate	
395.00	LABORATORY EQUIPMENT	264,921	SQ	- 20	132,315	132,606	9.30	14,259	5.38%	
396.00	POWER OPERATED EQUIPMENT	948,698	L2.5	- 13	985,456	-36,758				
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	3,043,267	R2	- 21	585,348	2,457,919	13.30	184,806	6.07%	
398.00	MISCELLANEOUS EQUIPMENT	1,186,398	SQ	- 15	697,403	488,995	6.50	75,230	6.34%	
	Total General Plant	40,170,092			12,741,222	27,428,870	15.95	1,720,074	4.28%	
	TOTAL PLANT STUDIED	4,672,738,908			804,173,266	3,868,565,642	49.94	77,459,925	1.66%	

[1], [3] From Company depreciation study

[2] Average life and Iowa curve shape developed through actuarial analysis and professional judgment

[4] = [1] - [3]

[5] Composite remaining life based on Iowa curve in [2]; see remaining life exhibit for detailed calculations

[6] = [4] / [5]; (some unadjusted figures may be hard coded to match Company proposal)

[7] = [6] / [1]; (some unadjusted figures may be hard coded to match Company proposal)

Detailed Rate Comparison - 2026

Exhibit DJG-22

Page 1 of 3

Account No.	Description	[1]	[2]		[3]		[4]	
		Plant 12/31/2026	Columbia Position		OCA Position		OCA Adjustment	
			Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
	Underground Storage Plant							
350.20	RIGHTS OF WAY	1,932	0.00%	0	0.00%	0	0.00%	0
351.00	COMPRESSOR STATION STRUCTURES	3,294,840	0.00%	0	0.00%	0	0.00%	0
	WELLS				0.00%	0		
352.01	CONSTRUCTION	1,126,772	0.00%	0	0.00%	0	0.00%	0
352.02	EQUIPMENT	1,072,322	0.00%	0	0.00%	0	0.00%	0
	TOTAL ACCOUNT 352.00	2,199,094	0.00%	0	0.00%	0	0.00%	0
352.10	STORAGE LEASEHOLDS AND RIGHTS	206,941	0.00%	0	0.00%	0	0.00%	0
353.00	LINES	385,797	0.00%	0	0.00%	0	0.00%	0
354.00	COMPRESSOR STATION EQUIPMENT	947,638	0.00%	0	0.00%	0	0.00%	0
354.10	COMPRESSOR STATION EQUIPMENT - NEW	963,965	21.27%	205,013	21.14%	203,741	-0.13%	-1,272
355.00	MEASURING AND REGULATING EQUIPMENT	104,477	0.00%	0	0.00%	0	0.00%	0
	Total Underground Storage Plant	8,104,684	2.53%	205,013	2.51%	203,741	-0.02%	-1,272
	Distribution Plant							
	LAND AND LAND RIGHTS							
374.40	LAND RIGHTS	11,364,561	1.62%	184,111	1.31%	149,270	-0.31%	-34,841
374.50	RIGHTS OF WAY	3,233,314	1.07%	34,435	1.12%	36,195	0.05%	1,760
	TOTAL ACCOUNT 374.00	14,597,875	1.50%	218,546	1.27%	185,465	-0.23%	-33,081
	STRUCTURES AND IMPROVEMENTS							
375.34	MEASURING AND REGULATING	8,814,519	2.54%	224,207	1.52%	134,080	-1.02%	-90,127
375.60	INDUSTRIAL MEASURING AND REGULATING	85,565	0.53%	451	0.60%	514	0.07%	63
	TOTAL ACCOUNT 375.00	8,900,084	2.52%	224,658	1.51%	134,594	-1.01%	-90,064
375.70	OTHER DISTRIBUTION SYSTEMS							
	COMPANY STATIONS	46,796,364	2.55%	1,191,931	0.94%	439,131	-1.61%	-752,800
	PORTABLE SUBSTATIONS	5,242,352	2.80%	146,635	2.40%	125,567	-0.40%	-21,068
	TOTAL ACCOUNT 375.70	52,038,716	2.57%	1,338,566	1.09%	564,699	-1.49%	-773,867

Detailed Rate Comparison - 2026

Exhibit DJG-22

Page 2 of 3

Account No.	Description	[1]	[2]		[3]		[4]	
		Plant 12/31/2026	Columbia Position		OCA Position		OCA Adjustment	
			Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
375.80	COMMUNICATION	16,515	2.01%	332	1.81%	298	-0.20%	-34
376.00	MAINS							
	BARE STEEL	27,629,806	3.55%	980,880	1.12%	310,085	-2.43%	-670,795
	OTHER	3,529,481,496	2.29%	80,664,223	1.47%	51,922,860	-0.82%	-28,741,363
	TOTAL ACCOUNT 376.00	3,557,111,302	2.30%	81,645,103	1.47%	52,232,946	-0.83%	-29,412,157
378.00	M&R EQUIPMENT - GENERAL	197,952,465	3.23%	6,401,977	1.94%	3,839,347	-1.29%	-2,562,630
379.10	M&R EQUIPMENT - CITY GATE	119,158	7.36%	8,772	6.40%	7,626	-0.96%	-1,146
380.00	SERVICES							
	BARE STEEL	259,835	4.36%	11,324	3.58%	9,313	-0.78%	-2,011
	OTHER	1,012,593,634	3.23%	32,748,259	2.04%	20,633,587	-1.19%	-12,114,672
	TOTAL ACCOUNT 380.00	1,012,853,468	3.23%	32,759,583	2.04%	20,642,901	-1.20%	-12,116,682
381.00	METERS	59,663,983	2.64%	1,575,424	2.16%	1,287,642	-0.48%	-287,782
381.10	METERS - AMR	29,057,053	2.62%	760,481	2.76%	800,523	0.14%	40,042
382.00	METER INSTALLATIONS	58,083,634	1.94%	1,125,750	1.73%	1,005,773	-0.21%	-119,977
383.00	HOUSE REGULATORS	22,247,918	2.07%	460,972	1.84%	408,656	-0.23%	-52,316
384.00	HOUSE REGULATOR INSTALLATIONS	3,546,998	1.28%	45,444	1.53%	54,122	0.25%	8,678
385.00	INDUSTRIAL M&R EQUIPMENT - NON METERS	10,750,260	4.74%	509,488	2.99%	321,294	-1.75%	-188,194
	OTHER EQUIPMENT							
387.00	GENERAL	136,698	2.21%	3,025	1.94%	2,653	-0.27%	-372
387.40	COMMUNICATION EQUIPMENT	18,812,522	4.99%	938,784	3.84%	723,054	-1.15%	-215,730
387.50	GPS EQUIPMENT	2,201,372	1.07%	23,590	1.20%	26,312	0.13%	2,722
	TOTAL ACCOUNT 387.00	21,150,593	4.56%	965,399	3.56%	752,018	-1.01%	-213,381
	Total Distribution Plant	5,048,090,022	2.54%	128,040,495	1.63%	82,237,903	-0.91%	-45,802,592
	General Plant							
390.10	STRUCTURES AND IMPROVEMENTS - COMM	49,821	0.00%	0	0.00%	0	0.00%	0
	OFFICE FURNITURE AND EQUIPMENT							
391.10	FURNITURE	7,142,560	5.00%	357,073	5.01%	357,800	0.01%	727

Detailed Rate Comparison - 2026

Exhibit DJG-22

Page 3 of 3

Account No.	Description	[1]	[2]		[3]		[4]	
		Plant 12/31/2026	Columbia Position		OCA Position		OCA Adjustment	
			Rate	Annual Accrual	Rate	Annual Accrual	Rate	Annual Accrual
391.11	EQUIPMENT	66,877	6.55%	4,381	6.55%	4,381	0.00%	0
391.12	INFORMATION SYSTEMS	129,970	0.52%	671	0.52%	671	0.00%	0
	TOTAL ACCOUNT 391.00	7,339,407	4.93%	362,125	4.94%	362,852	0.01%	727
392.00	TRANSPORTATION EQUIPMENT - TRAILERS	25,617	0.00%	0	0.00%	0	0.00%	0
394.00	EQUIPMENT	39,447,764	4.00%	1,576,376	4.00%	1,576,861	0.00%	485
395.00	LABORATORY EQUIPMENT	264,921	5.40%	14,309	5.39%	14,281	-0.01%	-28
396.00	POWER OPERATED EQUIPMENT	948,698	0.00%	0	0.00%	0	0.00%	0
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	6,391,394	6.57%	419,983	6.57%	420,132	0.00%	149
398.00	MISCELLANEOUS EQUIPMENT	1,180,276	6.04%	71,298	6.05%	71,406	0.01%	108
	Total General Plant	55,647,899	4.39%	2,444,091	4.39%	2,445,532	0.00%	1,441
	TOTAL PLANT STUDIED	5,111,842,605	2.56%	130,689,599	1.66%	84,887,176	-0.90%	-45,802,423

[1], [2] From Company depreciation study

[3] From Exhibit DJG-19

[4] = [3] - [2]

Page 1 of 3

		[1]	[2]	[3]	[4]	[5]	[6]	[7]
Account No.	Description	Plant 12/31/2026	Iowa Curve Type AL	Book Reserve	Future Accruals	Remaining Life	Total	
							Accrual	Rate
	Underground Storage Plant							
350.20	RIGHTS OF WAY	1,932	SQ -	1,932	0			
351.00	COMPRESSOR STATION STRUCTURES	3,294,840	R3 - 65	3,294,840	0			
	WELLS							
352.01	CONSTRUCTION	1,126,772	SQ -	1,126,772	0			
352.02	EQUIPMENT	1,072,322	S2.5 - 55	1,072,322	0			
	TOTAL ACCOUNT 352.00	2,199,094		2,199,094	0		0	0.00%
352.10	STORAGE LEASEHOLDS AND RIGHTS	206,941	SQ -	206,941	0			
353.00	LINES	385,797	R3 - 60	385,797	0			
354.00	COMPRESSOR STATION EQUIPMENT	947,638	R2.5 - 60	947,638	0			
354.10	COMPRESSOR STATION EQUIPMENT - NEW	963,965	R2.5 - 60	149,000	814,965	4.00	203,741	21.14%
355.00	MEASURING AND REGULATING EQUIPMENT	104,477	R1.5 - 42	104,477	0			
	Total Underground Storage Plant	8,104,684		7,289,719	814,965	4.00	203,741	2.51%
	Distribution Plant							
	LAND AND LAND RIGHTS							
374.40	LAND RIGHTS	11,364,561	R2.5 - 75	1,435,147	9,929,414	66.52	149,270	1.31%
374.50	RIGHTS OF WAY	3,233,314	S4 - 80	1,968,302	1,265,012	34.95	36,195	1.12%
	TOTAL ACCOUNT 374.00	14,597,875		3,403,449	11,194,426	60.36	185,465	1.27%
	STRUCTURES AND IMPROVEMENTS							
375.34	MEASURING AND REGULATING	8,814,519	R0.5 - 60	1,771,276	7,043,243	52.53	134,080	1.52%
375.60	INDUSTRIAL MEASURING AND REGULATING	85,565	R1 - 55	77,121	8,444	16.43	514	0.60%
	TOTAL ACCOUNT 375.00	8,900,084		1,848,397	7,051,687	52.39	134,594	1.51%
375.70	OTHER DISTRIBUTION SYSTEMS							
	COMPANY STATIONS	46,796,364	R1.5 - 90	9,997,183	36,799,181	83.80	439,131	0.94%
	PORTABLE SUBSTATIONS	5,242,352	S1.5 - 38	1,687,537	3,554,815	28.31	125,567	2.40%
	TOTAL ACCOUNT 375.70	52,038,716		11,684,720	40,353,996	71.46	564,699	1.09%
375.80	COMMUNICATION	16,515	R3 - 45	10,023	6,492	21.77	298	1.81%
376.00	MAINS							

Depreciation Rate Development - 2026

Exhibit DJG-23

Page 2 of 3

Account No.	Description	[1]	[2]		[3]	[4]	[5]	[6]		[7]
		Plant	Iowa Curve		Book	Future	Remaining	Total		
		12/31/2026	Type	AL	Reserve	Accruals	Life	Accrual	Rate	
	BARE STEEL	27,629,806	R1	- 65	19,586,190	8,043,616	25.94	310,085	1.12%	
	OTHER	3,529,481,496	R1	- 65	486,282,657	3,043,198,839	58.61	51,922,860	1.47%	
	TOTAL ACCOUNT 376.00	3,557,111,302			505,868,847	3,051,242,455	58.42	52,232,946	1.47%	
378.00	M&R EQUIPMENT - GENERAL	197,952,465	R0.5	- 45	41,268,709	156,683,756	40.81	3,839,347	1.94%	
379.10	M&R EQUIPMENT - CITY GATE	119,158	S2	- 35	54,111	65,047	8.53	7,626	6.40%	
380.00	SERVICES									
	BARE STEEL	259,835	R0.5	- 45	192,219	67,616	7.26	9,313	3.58%	
	OTHER	1,012,593,634	R0.5	- 45	217,375,176	795,218,458	38.54	20,633,587	2.04%	
	TOTAL ACCOUNT 380.00	1,012,853,468			217,567,395	795,286,073	38.53	20,642,901	2.04%	
381.00	METERS	59,663,983	S1	- 44	17,467,960	42,196,023	32.77	1,287,642	2.16%	
381.10	METERS - AMR	29,057,053	S2.5	- 20	21,820,323	7,236,730	9.04	800,523	2.76%	
382.00	METER INSTALLATIONS	58,083,634	R3	- 55	17,993,514	40,090,120	39.86	1,005,773	1.73%	
383.00	HOUSE REGULATORS	22,247,918	S2	- 50	6,465,627	15,782,291	38.62	408,656	1.84%	
384.00	HOUSE REGULATOR INSTALLATIONS	3,546,998	S4	- 40	3,017,148	529,850	9.79	54,122	1.53%	
385.00	INDUSTRIAL M&R EQUIPMENT - NON METERS	10,750,260	R0.5	- 30	3,489,012	7,261,248	22.60	321,294	2.99%	
	OTHER EQUIPMENT									
387.00	GENERAL	136,698	R1	- 32	95,266	41,432	15.62	2,653	1.94%	
387.40	COMMUNICATION EQUIPMENT	18,812,522	R1.5	- 25	4,900,968	13,911,554	19.24	723,054	3.84%	
387.50	GPS EQUIPMENT	2,201,372	S3	- 10	2,166,114	35,258	1.34	26,312	1.20%	
	TOTAL ACCOUNT 387.00	21,150,593			7,162,348	13,988,245	18.60	752,018	3.56%	
	Total Distribution Plant	5,048,090,022			859,121,583	4,188,968,439	50.94	82,237,903	1.63%	
	General Plant									
390.10	STRUCTURES AND IMPROVEMENTS - COMM	49,821	R2	- 45	49,821	0				
	OFFICE FURNITURE AND EQUIPMENT									
391.10	FURNITURE	7,142,560	SQ	- 20	1,990,244	5,152,316	14.40	357,800	5.01%	
391.11	EQUIPMENT	66,877	SQ	- 15	51,544	15,333	3.50	4,381	6.55%	
391.12	INFORMATION SYSTEMS	129,970	SQ	- 5	129,299	671	1.00	671	0.52%	
	TOTAL ACCOUNT 391.00	7,339,407			2,171,087	5,168,320	14.24	362,852	4.94%	
392.00	TRANSPORTATION EQUIPMENT - TRAILERS	25,617	L4	- 13	26,131	-514				
394.00	EQUIPMENT	39,447,764	SQ	- 25	9,645,093	29,802,671	18.90	1,576,861	4.00%	

Depreciation Rate Development - 2026

Exhibit DJG-23

Page 3 of 3

Account No.	Description	[1]	[2]		[3]	[4]	[5]	[6]		[7]
		Plant	Iowa Curve		Book	Future	Remaining	Total		
		12/31/2026	Type	AL	Reserve	Accruals	Life	Accrual	Rate	
395.00	LABORATORY EQUIPMENT	264,921	SQ	- 20	147,813	117,108	8.20	14,281	5.39%	
396.00	POWER OPERATED EQUIPMENT	948,698	L2.5	- 13	979,094	-30,396				
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	6,391,394	R2	- 21	383,504	6,007,890	14.30	420,132	6.57%	
398.00	MISCELLANEOUS EQUIPMENT	1,180,276	SQ	- 15	773,264	407,012	5.70	71,406	6.05%	
	Total General Plant	55,647,899			14,175,807	41,472,092	16.96	2,445,532	4.39%	
	TOTAL PLANT STUDIED	5,111,842,605			880,587,109	4,231,255,496	49.85	84,887,176	1.66%	

[1], [3] From Company depreciation study

[2] Average life and Iowa curve shape developed through actuarial analysis and professional judgment

[4] = [1] - [3]

[5] Composite remaining life based on Iowa curve in [2]; see remaining life exhibit for detailed calculations

[6] = [4] / [5]; (some unadjusted figures may be hard coded to match Company proposal)

[7] = [6] / [1]; (some unadjusted figures may be hard coded to match Company proposal)

***Columbia Gas of Pennsylvania
Gas Division***

374.40 Land and Land Rights

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 75

Survivor Curve: R2.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1920	1,634.55	75.00	21.79	8.54	186.07
1953	2.00	75.00	0.03	19.64	0.52
1957	3,252.89	75.00	43.37	21.73	942.57
1961	830.30	75.00	11.07	24.00	265.66
1962	323.97	75.00	4.32	24.59	106.23
1963	5,684.12	75.00	75.79	25.19	1,909.31
1964	3,704.51	75.00	49.39	25.80	1,274.48
1965	1,137.81	75.00	15.17	26.43	400.92
1966	2,376.11	75.00	31.68	27.06	857.18
1967	11,417.90	75.00	152.24	27.69	4,216.05
1968	1,994.09	75.00	26.59	28.34	753.63
1969	12,188.98	75.00	162.52	29.00	4,713.16
1970	8,052.25	75.00	107.36	29.66	3,184.83
1971	20,628.93	75.00	275.05	30.34	8,345.15
1972	11,627.89	75.00	155.04	31.02	4,809.40
1973	5,483.64	75.00	73.12	31.71	2,318.36
1974	16,629.52	75.00	221.73	32.41	7,185.70
1975	25,260.98	75.00	336.81	33.11	11,152.36
1976	24,345.48	75.00	324.61	33.82	10,978.75
1977	54,299.74	75.00	724.00	34.54	25,009.29
1978	21,191.48	75.00	282.55	35.27	9,965.29
1979	36,560.99	75.00	487.48	36.00	17,549.49
1980	22,946.84	75.00	305.96	36.74	11,241.79
1981	39,985.17	75.00	533.14	37.49	19,986.68
1982	62,650.36	75.00	835.34	38.24	31,944.15
1983	40,130.50	75.00	535.07	39.00	20,869.62
1984	44,787.52	75.00	597.17	39.77	23,748.70

***Columbia Gas of Pennsylvania
Gas Division***

374.40 Land and Land Rights

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 75

Survivor Curve: R2.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1985	66,040.22	75.00	880.54	40.54	35,697.29
1986	39,814.42	75.00	530.86	41.32	21,935.95
1987	63,884.90	75.00	851.80	42.11	35,865.90
1988	98,844.45	75.00	1,317.92	42.90	56,533.87
1989	131,102.83	75.00	1,748.04	43.70	76,381.20
1990	83,991.22	75.00	1,119.88	44.50	49,832.35
1991	49,174.56	75.00	655.66	45.31	29,705.08
1992	13,465.78	75.00	179.54	46.12	8,280.94
1993	43,267.14	75.00	576.89	46.94	27,080.46
1994	35,296.72	75.00	470.62	47.77	22,479.96
1995	19,271.18	75.00	256.95	48.60	12,487.58
1996	46,023.19	75.00	613.64	49.44	30,335.63
1997	37,722.81	75.00	502.97	50.28	25,287.40
1998	9,168.06	75.00	122.24	51.12	6,249.52
1999	6,027.94	75.00	80.37	51.98	4,177.45
2000	14,218.67	75.00	189.58	52.83	10,016.01
2001	13,623.43	75.00	181.65	53.70	9,753.53
2002	3,026.59	75.00	40.35	54.56	2,201.79
2003	43,663.62	75.00	582.18	55.43	32,271.19
2004	45,205.64	75.00	602.74	56.31	33,939.54
2005	25,590.76	75.00	341.21	57.19	19,513.17
2006	32,821.94	75.00	437.63	58.07	25,413.66
2007	66,976.43	75.00	893.02	58.96	52,653.80
2008	16,456.19	75.00	219.42	59.85	13,132.87
2009	133,402.95	75.00	1,778.70	60.75	108,055.74
2010	80,507.25	75.00	1,073.43	61.65	66,178.43
2011	76,852.69	75.00	1,024.70	62.56	64,100.52

***Columbia Gas of Pennsylvania
Gas Division***

374.40 Land and Land Rights

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 75

Survivor Curve: R2.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2012	208,077.90	75.00	2,774.37	63.46	176,068.58
2013	199,508.04	75.00	2,660.10	64.38	171,244.66
2014	75,477.27	75.00	1,006.36	65.29	65,705.13
2015	135,848.29	75.00	1,811.31	66.21	119,921.99
2016	172,118.26	75.00	2,294.91	67.13	154,056.90
2017	345,514.12	75.00	4,606.85	68.05	313,515.44
2018	193,139.07	75.00	2,575.19	68.98	177,639.57
2019	231,601.40	75.00	3,088.02	69.91	215,891.76
2020	224,281.44	75.00	2,990.42	70.85	211,858.75
2021	2,659,446.60	75.00	35,459.26	71.78	2,545,320.46
2022	475,517.56	75.00	6,340.23	72.72	461,068.65
2023	1,800,405.64	75.00	24,005.39	73.66	1,768,289.95
2024	538,055.52	75.00	7,174.07	74.57	534,943.52
<i>Total</i>	9,033,561.21	75.00	120,447.37	66.58	8,019,001.49

Composite Average Remaining Life ... 66.58 Years

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1883	866.25	0.00	0.00	0.00	0.00
1884	2,319.40	0.00	0.00	0.00	0.00
1885	952.00	0.00	0.00	0.00	0.00
1886	9,401.15	80.00	117.51	0.50	58.76
1887	4,690.00	80.00	58.63	0.94	55.06
1888	6,579.75	80.00	82.25	1.42	116.97
1889	6,551.18	80.00	81.89	1.25	102.36
1890	1,679.50	80.00	20.99	1.38	28.87
1891	8,350.23	80.00	104.38	1.56	162.91
1892	1,354.95	80.00	16.94	1.64	27.73
1893	650.85	80.00	8.14	1.66	13.53
1894	1,616.78	80.00	20.21	1.79	36.21
1895	1,133.20	80.00	14.17	1.92	27.17
1896	4,260.56	80.00	53.26	2.04	108.63
1897	2,267.65	80.00	28.35	2.05	58.19
1898	1,633.73	80.00	20.42	2.18	44.58
1899	934.25	80.00	11.68	2.31	27.00
1900	8,185.42	80.00	102.32	2.44	249.29
1901	15,227.76	80.00	190.35	2.47	470.01
1902	7,330.74	80.00	91.63	2.60	238.39
1903	15,446.32	80.00	193.08	2.73	527.91
1904	8,443.31	80.00	105.54	2.87	302.55
1905	13,211.32	80.00	165.14	2.92	482.06
1906	5,826.89	80.00	72.84	3.06	222.56
1907	4,318.72	80.00	53.98	3.19	172.45
1908	5,084.82	80.00	63.56	3.33	211.96
1909	5,578.23	80.00	69.73	3.41	237.61

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1910	944.58	80.00	11.81	3.55	41.93
1911	1,805.52	80.00	22.57	3.70	83.46
1912	1,590.08	80.00	19.88	3.85	76.48
1913	4,199.64	80.00	52.50	3.94	206.92
1914	6,522.34	80.00	81.53	4.09	333.84
1915	9,299.36	80.00	116.24	4.25	494.31
1916	2,131.53	80.00	26.64	4.41	117.61
1917	2,947.27	80.00	36.84	4.53	166.89
1918	969.85	80.00	12.12	4.70	56.93
1919	713.16	80.00	8.91	4.87	43.39
1920	1,116.43	80.00	13.96	5.04	70.38
1921	2,386.50	80.00	29.83	5.18	154.62
1922	5,478.84	80.00	68.49	5.36	367.41
1923	5,748.64	80.00	71.86	5.55	399.02
1924	2,962.36	80.00	37.03	5.75	212.80
1925	8,085.67	80.00	101.07	5.91	597.71
1926	3,690.49	80.00	46.13	6.12	282.12
1927	3,441.21	80.00	43.02	6.32	272.06
1928	3,616.30	80.00	45.20	6.54	295.66
1929	9,736.71	80.00	121.71	6.74	820.07
1930	3,705.73	80.00	46.32	6.96	322.61
1931	4,695.61	80.00	58.70	7.20	422.56
1932	2,031.20	80.00	25.39	7.44	188.95
1933	2,540.95	80.00	31.76	7.67	243.76
1934	4,020.82	80.00	50.26	7.93	398.64
1935	866.62	80.00	10.83	8.20	88.80
1936	4,994.63	80.00	62.43	8.47	529.00

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1937	3,607.79	80.00	45.10	8.75	394.45
1938	1,245.49	80.00	15.57	9.04	140.74
1939	956.06	80.00	11.95	9.34	111.68
1940	13,850.45	80.00	173.13	9.66	1,672.44
1941	4,887.61	80.00	61.10	9.98	609.79
1942	8,169.68	80.00	102.12	10.32	1,053.78
1943	1,693.42	80.00	21.17	10.67	225.85
1944	978.40	80.00	12.23	11.03	134.93
1945	1,004.81	80.00	12.56	11.41	143.29
1946	344.00	80.00	4.30	11.80	50.74
1947	142.29	80.00	1.78	12.20	21.71
1948	3,080.71	80.00	38.51	12.62	486.15
1949	16,198.32	80.00	202.48	13.06	2,645.13
1950	20,911.66	80.00	261.40	13.52	3,533.10
1951	11,956.42	80.00	149.46	13.99	2,090.15
1952	8,038.39	80.00	100.48	14.47	1,454.00
1953	5,949.87	80.00	74.37	14.98	1,114.21
1954	21,585.01	80.00	269.81	15.50	4,183.27
1955	32,149.56	80.00	401.87	16.05	6,448.15
1956	51,702.96	80.00	646.29	16.60	10,731.45
1957	19,916.61	80.00	248.96	17.19	4,280.51
1958	63,499.25	80.00	793.74	17.79	14,124.12
1959	28,371.09	80.00	354.64	18.41	6,530.42
1960	26,305.63	80.00	328.82	19.05	6,265.24
1961	15,768.03	80.00	197.10	19.72	3,887.74
1962	18,087.78	80.00	226.10	20.41	4,613.97
1963	27,374.57	80.00	342.18	21.11	7,223.08

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1964	40,027.79	80.00	500.35	21.83	10,922.69
1965	17,574.04	80.00	219.68	22.58	4,960.87
1966	18,597.25	80.00	232.47	23.35	5,427.10
1967	96,910.77	80.00	1,211.38	24.13	29,227.57
1968	82,637.79	80.00	1,032.97	24.93	25,749.01
1969	46,057.56	80.00	575.72	25.75	14,827.55
1970	45,097.36	80.00	563.72	26.59	14,990.28
1971	54,600.87	80.00	682.51	27.44	18,731.45
1972	80,822.88	80.00	1,010.29	28.31	28,604.51
1973	31,060.02	80.00	388.25	29.20	11,338.59
1974	42,716.26	80.00	533.95	30.10	16,073.51
1975	53,203.52	80.00	665.04	31.01	20,625.52
1976	46,796.87	80.00	584.96	31.94	18,681.46
1977	50,016.13	80.00	625.20	32.88	20,553.51
1978	27,600.77	80.00	345.01	33.82	11,667.87
1979	28,400.77	80.00	355.01	34.77	12,344.19
1980	24,054.08	80.00	300.68	35.73	10,743.59
1981	55,235.53	80.00	690.44	36.70	25,340.42
1982	47,534.94	80.00	594.19	37.67	22,385.93
1983	27,148.25	80.00	339.35	38.65	13,117.06
1984	30,306.87	80.00	378.84	39.64	15,015.39
1985	72,105.59	80.00	901.32	40.62	36,614.68
1986	17,533.91	80.00	219.17	41.61	9,120.43
1987	27,416.83	80.00	342.71	42.60	14,601.00
1988	11,339.22	80.00	141.74	43.60	6,179.62
1989	70,129.19	80.00	876.61	44.59	39,091.91
1990	44,760.66	80.00	559.51	45.59	25,508.41

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1991	35,224.46	80.00	440.31	46.59	20,513.09
1992	54,141.31	80.00	676.77	47.59	32,204.96
1993	58,993.43	80.00	737.42	48.59	35,827.83
1994	184,531.84	80.00	2,306.65	49.58	114,374.47
1995	584,928.49	80.00	7,311.61	50.58	369,851.46
1996	126,940.88	80.00	1,586.76	51.58	81,851.16
1997	68,030.65	80.00	850.38	52.58	44,716.24
1998	40,132.45	80.00	501.66	53.58	26,880.46
2000	15,568.19	80.00	194.60	55.58	10,816.66
2001	39,714.12	80.00	496.43	56.58	28,089.48
2002	181,571.19	80.00	2,269.64	57.58	130,693.45
2003	1,938.28	80.00	24.23	58.58	1,419.39
<i>Total</i>	3,233,313.87	78.00	40,364.70	36.54	1,475,123.54

Composite Average Remaining Life ... 36.54 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1913	430.94	60.00	7.18	4.13	29.68
1914	264.24	60.00	4.40	4.59	20.20
1925	211.96	60.00	3.53	9.25	32.67
1928	563.20	60.00	9.39	10.45	98.06
1929	4,189.96	60.00	69.83	10.84	757.20
1930	4,437.35	60.00	73.95	11.24	831.18
1931	1,147.03	60.00	19.12	11.64	222.45
1932	1,627.26	60.00	27.12	12.03	326.29
1933	1,875.00	60.00	31.25	12.43	388.32
1934	1,102.49	60.00	18.37	12.82	235.63
1935	15.51	60.00	0.26	13.22	3.42
1936	1,998.78	60.00	33.31	13.62	453.61
1938	618.55	60.00	10.31	14.42	148.61
1939	4,103.04	60.00	68.38	14.82	1,013.20
1940	554.29	60.00	9.24	15.22	140.61
1941	897.54	60.00	14.96	15.62	233.72
1942	116.21	60.00	1.94	16.03	31.05
1943	181.83	60.00	3.03	16.44	49.82
1945	639.53	60.00	10.66	17.26	184.02
1946	1,024.41	60.00	17.07	17.68	301.88
1947	2,307.10	60.00	38.45	18.10	695.95
1948	6,715.12	60.00	111.92	18.52	2,072.82
1949	1,156.73	60.00	19.28	18.95	365.24
1950	5,042.16	60.00	84.03	19.37	1,627.97
1951	7,765.78	60.00	129.43	19.80	2,563.05
1952	15,602.82	60.00	260.04	20.24	5,262.34
1953	22,140.86	60.00	369.01	20.67	7,628.54

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1954	12,486.51	60.00	208.10	21.11	4,393.73
1955	12,140.88	60.00	202.34	21.56	4,361.80
1956	22,115.23	60.00	368.58	22.00	8,109.93
1957	27,692.39	60.00	461.53	22.45	10,362.96
1958	34,787.56	60.00	579.78	22.91	13,281.12
1959	21,123.27	60.00	352.05	23.36	8,225.46
1960	25,160.28	60.00	419.33	23.83	9,990.86
1961	35,273.82	60.00	587.89	24.29	14,279.91
1962	32,249.38	60.00	537.48	24.76	13,307.42
1963	19,927.14	60.00	332.11	25.23	8,379.64
1964	40,470.81	60.00	674.50	25.71	17,339.43
1965	27,828.79	60.00	463.80	26.19	12,145.73
1966	27,208.84	60.00	453.47	26.67	12,094.57
1967	18,571.27	60.00	309.52	27.16	8,405.89
1968	8,481.65	60.00	141.36	27.65	3,908.55
1969	15,585.00	60.00	259.75	28.15	7,310.64
1970	5,033.19	60.00	83.88	28.64	2,402.82
1971	20,648.66	60.00	344.14	29.15	10,030.80
1972	10,177.69	60.00	169.63	29.65	5,030.18
1973	12,609.98	60.00	210.16	30.17	6,339.56
1974	6,724.78	60.00	112.08	30.68	3,438.54
1975	16,872.99	60.00	281.21	31.20	8,773.40
1976	22,562.45	60.00	376.03	31.72	11,927.92
1977	14,410.77	60.00	240.18	32.25	7,744.83
1978	21,032.60	60.00	350.54	32.78	11,489.34
1979	29,714.20	60.00	495.23	33.31	16,495.62
1980	12,380.66	60.00	206.34	33.85	6,983.89

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1981	27,705.54	60.00	461.75	34.39	15,878.21
1982	37,398.35	60.00	623.29	34.93	21,771.89
1983	11,742.20	60.00	195.70	35.48	6,943.03
1984	14,547.02	60.00	242.45	36.03	8,735.03
1985	12,792.93	60.00	213.21	36.58	7,799.73
1986	26,393.61	60.00	439.89	37.14	16,337.11
1987	3,272.42	60.00	54.54	37.70	2,056.12
1988	16,513.79	60.00	275.22	38.26	10,530.73
1989	14,462.96	60.00	241.04	38.83	9,359.43
1990	8,288.97	60.00	138.15	39.40	5,442.63
1991	15,500.94	60.00	258.34	39.97	10,325.59
1992	129.79	60.00	2.16	40.54	87.70
1993	21,326.29	60.00	355.43	41.12	14,615.01
1995	13,604.01	60.00	226.73	42.28	9,585.77
1996	11,828.32	60.00	197.14	42.86	8,449.52
1997	8,754.75	60.00	145.91	43.45	6,339.21
1998	59,658.50	60.00	994.29	44.03	43,781.69
1999	2,550.99	60.00	42.52	44.62	1,897.12
2000	20,323.55	60.00	338.72	45.21	15,314.01
2001	26,614.83	60.00	443.57	45.80	20,317.08
2002	14,721.25	60.00	245.35	46.40	11,383.34
2003	62,637.02	60.00	1,043.93	46.99	49,054.71
2004	25,048.70	60.00	417.47	47.59	19,865.80
2005	48,475.82	60.00	807.92	48.18	38,927.67
2006	54,846.16	60.00	914.09	48.78	44,589.36
2007	94,487.25	60.00	1,574.76	49.38	77,760.40
2008	346,196.17	60.00	5,769.83	49.98	288,371.23

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2009	94,413.46	60.00	1,573.53	50.58	79,588.62
2010	139,758.47	60.00	2,329.26	51.18	119,216.10
2011	199,439.56	60.00	3,323.93	51.79	172,129.88
2012	228,719.76	60.00	3,811.93	52.39	199,702.84
2013	220,809.82	60.00	3,680.10	52.99	195,025.27
2014	340,293.95	60.00	5,671.46	53.60	303,998.20
2015	877,803.55	60.00	14,629.79	54.21	793,066.47
2016	386,902.15	60.00	6,448.25	54.82	353,483.29
2017	357,772.27	60.00	5,962.76	55.43	330,510.79
2018	165,117.37	60.00	2,751.91	56.04	154,218.83
2019	668,475.98	60.00	11,141.06	56.65	631,188.60
2020	289,730.40	60.00	4,828.75	57.27	276,538.05
2021	249,341.29	60.00	4,155.61	57.88	240,546.91
2022	297,826.96	60.00	4,963.69	58.50	290,389.00
2023	309,187.08	60.00	5,153.02	59.12	304,655.79
2024	102,950.50	60.00	1,715.81	59.72	102,461.47
<i>Total</i>	6,568,365.18	60.00	109,470.72	51.01	5,584,511.30

Composite Average Remaining Life ... 51.01 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.60 Structures - Industrial M&R

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1928	87.15	55.00	1.58	4.56	7.22
1930	127.57	55.00	2.32	5.16	11.96
1931	263.40	55.00	4.79	5.45	26.11
1934	783.68	55.00	14.25	6.36	90.66
1935	147.25	55.00	2.68	6.68	17.88
1936	21.46	55.00	0.39	6.99	2.73
1937	618.76	55.00	11.25	7.31	82.23
1938	1,433.03	55.00	26.05	7.63	198.83
1940	440.04	55.00	8.00	8.29	66.32
1942	1,018.37	55.00	18.52	8.97	166.01
1944	2,850.41	55.00	51.82	9.66	500.51
1946	377.07	55.00	6.86	10.37	71.09
1947	568.77	55.00	10.34	10.73	110.97
1948	482.71	55.00	8.78	11.10	97.40
1950	1,857.60	55.00	33.77	11.85	400.06
1951	3,131.90	55.00	56.94	12.23	696.21
1952	3,450.55	55.00	62.74	12.61	791.31
1953	4,259.74	55.00	77.45	13.00	1,007.15
1955	4,904.63	55.00	89.17	13.80	1,230.72
1956	2,507.83	55.00	45.60	14.21	647.83
1957	14,375.38	55.00	261.36	14.62	3,821.15
1958	1,667.93	55.00	30.33	15.04	456.00
1959	5,902.55	55.00	107.32	15.46	1,659.06
1960	1,345.00	55.00	24.45	15.89	388.51
1961	1,954.81	55.00	35.54	16.32	580.07
1963	3,416.99	55.00	62.13	17.20	1,068.87
1967	1,614.49	55.00	29.35	19.04	558.98

***Columbia Gas of Pennsylvania
Gas Division***

375.60 Structures - Industrial M&R

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1970	2,450.11	55.00	44.55	20.48	912.50
1971	7,721.50	55.00	140.39	20.98	2,944.93
1972	1.00	55.00	0.02	21.48	0.39
1980	3,885.67	55.00	70.65	25.69	1,815.25
1988	11,897.69	55.00	216.32	30.32	6,557.96
<i>Total</i>	85,565.04	55.00	1,555.69	17.35	26,986.87

Composite Average Remaining Life ... 17.35 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.71 Distribution Systems - Company Stations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 38

Survivor Curve: S1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1919	142.68	0.00	0.00	0.00	0.00
1953	2,600.92	38.00	68.45	1.24	85.20
1954	2,263.57	38.00	59.57	1.49	89.00
1955	7,045.40	38.00	185.41	1.76	325.58
1956	294.53	38.00	7.75	2.00	15.50
1961	5,869.31	38.00	154.46	3.26	502.94
1966	2,114.98	38.00	55.66	4.53	252.01
1969	1,259.56	38.00	33.15	5.32	176.24
1971	106,649.53	38.00	2,806.57	5.86	16,455.30
1972	9,337.50	38.00	245.72	6.14	1,508.75
1975	5,381.53	38.00	141.62	7.01	992.51
1976	6,723.83	38.00	176.94	7.31	1,293.31
1984	43,036.41	38.00	1,132.54	9.99	11,316.15
1985	3,259.62	38.00	85.78	10.37	889.37
1987	14,383.92	38.00	378.52	11.15	4,221.46
1989	3,973.21	38.00	104.56	11.98	1,252.99
1990	32,260.00	38.00	848.95	12.42	10,542.08
1993	8,113.24	38.00	213.51	13.80	2,947.19
1994	15,147.02	38.00	398.61	14.30	5,698.33
1995	27,857.47	38.00	733.09	14.80	10,851.95
1996	2,392.16	38.00	62.95	15.33	964.78
1997	1,337.50	38.00	35.20	15.87	558.46
1998	56,879.39	38.00	1,496.83	16.42	24,582.26
1999	27,416.01	38.00	721.47	17.00	12,264.70
2000	192,645.29	38.00	5,069.61	17.59	89,195.77
2001	10,788.71	38.00	283.91	18.21	5,168.97
2004	9,680.31	38.00	254.75	20.16	5,136.80

***Columbia Gas of Pennsylvania
Gas Division***

375.71 Distribution Systems - Company Stations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 38

Survivor Curve: S1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2007	18,396.12	38.00	484.11	22.31	10,799.20
2008	208,679.85	38.00	5,491.58	23.06	126,658.39
2010	21,628.69	38.00	569.18	24.64	14,023.58
2011	45,764.94	38.00	1,204.34	25.46	30,658.87
2012	5,855.06	38.00	154.08	26.29	4,051.39
2013	612,757.25	38.00	16,125.19	27.15	437,837.97
2014	116,167.32	38.00	3,057.03	28.03	85,685.90
2015	309,088.24	38.00	8,133.90	28.92	235,254.17
2016	431,798.65	38.00	11,363.12	29.83	339,014.24
2017	62,675.61	38.00	1,649.36	30.76	50,735.69
2018	211,266.41	38.00	5,559.64	31.70	176,261.28
2019	547,609.83	38.00	14,410.79	32.66	470,649.70
2020	169,096.94	38.00	4,449.92	33.63	149,635.04
2021	124,256.14	38.00	3,269.90	34.60	113,154.50
2022	485,748.21	38.00	12,782.85	35.59	454,964.10
2023	837,170.74	38.00	22,030.81	36.59	805,999.28
2024	87,535.71	38.00	2,303.57	37.54	86,480.16
<i>Total</i>	4,894,349.31	37.14	128,794.92	29.50	3,799,151.07

Composite Average Remaining Life ... 29.50 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.72 Portable Substations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 90

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1928	539.04	90.00	5.99	26.04	155.95
1931	4,005.57	90.00	44.51	27.36	1,217.72
1933	401.96	90.00	4.47	28.27	126.26
1934	778.19	90.00	8.65	28.74	248.47
1937	77.17	90.00	0.86	30.16	25.86
1939	1,201.91	90.00	13.35	31.14	415.92
1948	244.11	90.00	2.71	35.85	97.22
1949	338.10	90.00	3.76	36.40	136.72
1950	56.50	90.00	0.63	36.95	23.20
1951	94.17	90.00	1.05	37.51	39.25
1955	5,011.58	90.00	55.68	39.82	2,217.08
1957	18,804.17	90.00	208.93	41.00	8,565.71
1958	45,295.26	90.00	503.28	41.60	20,934.23
1959	665.84	90.00	7.40	42.20	312.20
1960	720.61	90.00	8.01	42.81	342.75
1962	275.80	90.00	3.06	44.04	134.97
1963	16,296.83	90.00	181.07	44.67	8,088.20
1964	81,335.93	90.00	903.72	45.30	40,935.63
1965	6,256.39	90.00	69.51	45.93	3,192.81
1968	462.64	90.00	5.14	47.86	246.01
1969	117.03	90.00	1.30	48.51	63.08
1971	1,426.78	90.00	15.85	49.83	789.95
1973	1,166.63	90.00	12.96	51.16	663.22
1976	1,998.47	90.00	22.21	53.20	1,181.25
1978	3,472.31	90.00	38.58	54.57	2,105.47
1979	85,249.40	90.00	947.21	55.27	52,351.21
1981	593,681.70	90.00	6,596.40	56.67	373,805.48

***Columbia Gas of Pennsylvania
Gas Division***

375.72 Portable Substations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 90

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1982	1,111.41	90.00	12.35	57.37	708.49
1983	5,480.40	90.00	60.89	58.08	3,536.75
1984	4,760.67	90.00	52.90	58.79	3,109.94
1985	20,862.34	90.00	231.80	59.51	13,794.29
1986	14,531.65	90.00	161.46	60.23	9,724.46
1987	198,785.72	90.00	2,208.71	60.95	134,620.62
1988	10,177.82	90.00	113.09	61.68	6,974.85
1991	1,625.41	90.00	18.06	63.87	1,153.55
1993	27,303.35	90.00	303.37	65.35	19,825.70
1995	202,894.25	90.00	2,254.36	66.84	150,686.53
1996	54,924.25	90.00	610.26	67.59	41,248.69
1997	59,116.96	90.00	656.85	68.35	44,892.73
1998	292,879.46	90.00	3,254.19	69.10	224,866.40
1999	6,939.23	90.00	77.10	69.86	5,386.21
2000	6,596.38	90.00	73.29	70.62	5,175.82
2001	38,452.52	90.00	427.25	71.38	30,497.58
2005	152,784.63	90.00	1,697.59	74.46	126,402.32
2006	126,751.26	90.00	1,408.33	75.24	105,959.85
2007	8,637.28	90.00	95.97	76.02	7,295.24
2008	7,810.00	90.00	86.78	76.80	6,664.32
2009	41,747.68	90.00	463.86	77.58	35,987.29
2010	147,736.99	90.00	1,641.51	78.37	128,643.48
2011	33,989.54	90.00	377.66	79.16	29,894.83
2012	781,914.65	90.00	8,687.86	79.95	694,597.10
2013	165,318.56	90.00	1,836.86	80.74	148,316.45
2014	30,907.80	90.00	343.42	81.54	28,002.81
2015	1,432,975.31	90.00	15,921.80	82.34	1,311,049.48

***Columbia Gas of Pennsylvania
Gas Division***

375.72 Portable Substations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 90

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2016	1,332,537.84	90.00	14,805.84	83.15	1,231,038.47
2017	220,104.62	90.00	2,445.58	83.95	205,307.88
2018	2,397,766.58	90.00	26,641.60	84.76	2,258,087.69
2019	7,748,293.91	90.00	86,091.34	85.57	7,366,663.02
2020	52,049.67	90.00	578.32	86.38	49,955.96
2021	22,830,754.88	90.00	253,672.64	87.20	22,119,147.06
2022	307,977.36	90.00	3,421.94	88.01	301,175.78
2023	6,434,577.19	90.00	71,494.62	88.83	6,351,106.25
2024	131,465.00	90.00	1,460.71	89.62	130,911.24
<i>Total</i>	46,202,516.66	90.00	513,356.42	85.42	43,850,824.92

Composite Average Remaining Life ... 85.42 Years

Columbia Gas of Pennsylvania

Gas Division

375.80 Communication

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2001	16,515.16	45.00	367.00	23.45	8,606.56
<i>Total</i>	16,515.16	45.00	367.00	23.45	8,606.56

Composite Average Remaining Life ... 23.45 Years

***Columbia Gas of Pennsylvania
Gas Division***

376.01 Mains - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1901	304,211.47	65.00	4,680.09	2.41	11,291.65
1902	15,807.54	65.00	243.19	2.74	667.41
1903	21,804.43	65.00	335.45	3.09	1,036.46
1904	14,196.17	65.00	218.40	3.41	745.33
1905	21,143.51	65.00	325.28	3.74	1,217.02
1906	16,524.30	65.00	254.22	4.04	1,028.22
1907	32,937.77	65.00	506.73	4.36	2,208.46
1908	13,469.45	65.00	207.22	4.65	963.55
1909	13,177.38	65.00	202.73	4.96	1,004.67
1910	13,530.74	65.00	208.16	5.24	1,091.42
1911	13,738.30	65.00	211.35	5.54	1,170.23
1912	9,506.94	65.00	146.26	5.84	853.64
1913	20,914.71	65.00	321.76	6.13	1,972.81
1914	19,197.03	65.00	295.33	6.43	1,900.22
1915	10,384.34	65.00	159.76	6.73	1,075.55
1916	14,288.67	65.00	219.82	7.04	1,547.54
1917	13,995.81	65.00	215.32	7.34	1,581.13
1918	2,744.90	65.00	42.23	7.66	323.32
1919	8,714.92	65.00	134.07	7.97	1,067.97
1920	7,972.02	65.00	122.64	8.28	1,016.10
1921	13,540.23	65.00	208.31	8.60	1,791.56
1922	45,290.37	65.00	696.76	8.93	6,219.61
1923	21,333.71	65.00	328.20	9.25	3,035.54
1924	46,563.98	65.00	716.36	9.58	6,860.83
1925	50,654.55	65.00	779.29	9.91	7,724.00
1926	77,296.79	65.00	1,189.16	10.25	12,185.39
1927	50,370.07	65.00	774.91	10.59	8,205.21

***Columbia Gas of Pennsylvania
Gas Division***

376.01 Mains - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1928	84,870.71	65.00	1,305.68	10.93	14,272.70
1929	108,046.32	65.00	1,662.22	11.28	18,750.20
1930	116,555.18	65.00	1,793.12	11.63	20,854.58
1931	123,528.91	65.00	1,900.41	11.99	22,779.89
1932	21,376.00	65.00	328.86	12.34	4,059.59
1933	19,946.04	65.00	306.86	12.71	3,899.78
1934	23,763.82	65.00	365.59	13.07	4,779.89
1935	23,566.11	65.00	362.55	13.45	4,875.01
1936	26,963.01	65.00	414.81	13.82	5,732.73
1937	42,871.38	65.00	659.55	14.20	9,364.84
1938	24,900.39	65.00	383.08	14.58	5,586.16
1939	36,828.13	65.00	566.58	14.97	8,481.27
1940	73,657.89	65.00	1,133.18	15.36	17,406.97
1941	141,234.33	65.00	2,172.79	15.76	34,236.02
1942	66,887.77	65.00	1,029.02	16.16	16,626.02
1943	35,307.40	65.00	543.18	16.56	8,995.77
1944	12,639.59	65.00	194.45	16.97	3,299.93
1945	8,406.65	65.00	129.33	17.38	2,248.23
1946	52,651.04	65.00	810.00	17.80	14,419.34
1947	43,581.18	65.00	670.47	18.22	12,218.61
1948	155,590.92	65.00	2,393.66	18.65	44,644.49
1949	432,933.23	65.00	6,660.38	19.08	127,099.89
1950	864,410.32	65.00	13,298.37	19.52	259,578.32
1951	524,573.81	65.00	8,070.21	19.96	161,087.91
1952	1,350,584.66	65.00	20,777.83	20.41	424,015.04
1953	895,974.87	65.00	13,783.96	20.86	287,505.41
1954	1,253,042.00	65.00	19,277.20	21.31	410,877.08

***Columbia Gas of Pennsylvania
Gas Division***

376.01 Mains - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1955	3,695,055.75	65.00	56,845.92	21.77	1,237,809.37
1956	2,106,318.28	65.00	32,404.28	22.24	720,706.89
1957	2,943,775.83	65.00	45,287.99	22.71	1,028,568.75
1958	3,471,764.81	65.00	53,410.74	23.19	1,238,505.31
1959	2,704,916.98	65.00	41,613.31	23.67	984,947.97
1960	3,041,203.95	65.00	46,786.86	24.16	1,130,188.43
1961	3,193,642.36	65.00	49,132.02	24.65	1,210,962.21
1962	2,820,460.46	65.00	43,390.87	25.14	1,091,053.27
1963	3,569,304.26	65.00	54,911.32	25.65	1,408,326.35
1964	3,548,772.21	65.00	54,595.45	26.15	1,427,916.63
1965	2,874,004.54	65.00	44,214.61	26.67	1,179,104.56
1966	4,017,686.91	65.00	61,809.38	27.19	1,680,320.18
1967	3,726,910.03	65.00	57,335.98	27.71	1,588,758.24
1968	2,922,425.99	65.00	44,959.54	28.24	1,269,566.85
1969	2,135,452.29	65.00	32,852.48	28.77	945,263.46
1970	1,040,765.89	65.00	16,011.48	29.31	469,327.66
1971	2,469,238.60	65.00	37,987.56	29.86	1,134,226.17
1972	910,830.11	65.00	14,012.50	30.41	426,084.17
1973	615,217.81	65.00	9,464.71	30.96	293,066.79
1974	1,343.82	65.00	20.67	31.52	651.73
1975	814.03	65.00	12.52	32.09	401.90
1976	259.38	65.00	3.99	32.66	130.34
1977	2,040.32	65.00	31.39	33.24	1,043.39
1978	175,486.56	65.00	2,699.74	33.82	91,314.03
1979	18,317.33	65.00	281.80	34.41	9,696.74
1980	209,396.00	65.00	3,221.42	35.00	112,759.46
1981	46.15	65.00	0.71	35.60	25.28

***Columbia Gas of Pennsylvania
Gas Division***

376.01 Mains - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1983	1,401.95	65.00	21.57	36.81	793.91
1984	207.92	65.00	3.20	37.42	119.70
1985	36.16	65.00	0.56	38.04	21.16
1986	32.16	65.00	0.49	38.66	19.13
1988	0.10	65.00	0.00	39.92	0.06
1989	28.65	65.00	0.44	40.55	17.87
1990	11,903.30	65.00	183.12	41.19	7,542.79
1992	45,851.46	65.00	705.39	42.48	29,964.01
1997	4,061.62	65.00	62.49	45.76	2,859.58
1998	670.88	65.00	10.32	46.43	479.21
2008	78.49	65.00	1.21	53.24	64.29
2011	28,401.13	65.00	436.93	55.33	24,174.20
<i>Total</i>	59,766,126.23	65.00	919,461.24	24.77	22,774,262.55

Composite Average Remaining Life ... 24.77 Years

Columbia Gas of Pennsylvania

Gas Division

376.02 Mains - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1952	121,566.29	65.00	1,870.21	20.41	38,165.65
1954	25,880.17	65.00	398.15	21.31	8,486.20
1955	97,948.69	65.00	1,506.87	21.77	32,811.90
1956	66,375.17	65.00	1,021.14	22.24	22,711.21
1957	85,516.56	65.00	1,315.61	22.71	29,879.88
1958	77,221.90	65.00	1,188.01	23.19	27,547.87
1959	80,271.34	65.00	1,234.92	23.67	29,229.40
1960	57,024.03	65.00	877.28	24.16	21,191.57
1961	15,456.74	65.00	237.79	24.65	5,860.87
1962	68,754.06	65.00	1,057.73	25.14	26,596.49
1963	99,169.74	65.00	1,525.66	25.65	39,129.01
1964	157,323.74	65.00	2,420.32	26.15	63,302.23
1965	55,655.11	65.00	856.22	26.67	22,833.36
1966	98,484.71	65.00	1,515.12	27.19	41,189.33
1967	45,593.14	65.00	701.42	27.71	19,436.07
1968	253,757.38	65.00	3,903.88	28.24	110,237.85
1969	542,850.04	65.00	8,351.38	28.77	240,293.97
1970	550,860.87	65.00	8,474.62	29.31	248,407.68
1971	1,192,547.22	65.00	18,346.53	29.86	547,787.59
1972	895,028.91	65.00	13,769.41	30.41	418,692.41
1973	1,962,197.46	65.00	30,187.07	30.96	934,717.59
1974	2,472,129.10	65.00	38,032.03	31.52	1,198,933.67
1975	2,352,041.06	65.00	36,184.55	32.09	1,161,228.54
1976	2,031,648.37	65.00	31,255.53	32.66	1,020,929.80
1977	4,115,862.03	65.00	63,319.74	33.24	2,104,783.72
1978	4,280,999.96	65.00	65,860.28	33.82	2,227,608.59
1979	5,283,221.80	65.00	81,278.78	34.41	2,796,806.91

Columbia Gas of Pennsylvania

Gas Division

376.02 Mains - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1980	6,847,446.41	65.00	105,343.31	35.00	3,687,340.52
1981	7,496,448.70	65.00	115,327.77	35.60	4,105,654.20
1982	7,260,975.76	65.00	111,705.18	36.20	4,044,061.79
1983	6,306,424.69	65.00	97,020.06	36.81	3,571,258.04
1984	7,116,690.26	65.00	109,485.44	37.42	4,097,203.37
1985	6,546,215.70	65.00	100,709.08	38.04	3,830,794.39
1986	7,532,159.00	65.00	115,877.15	38.66	4,479,864.51
1987	7,485,535.58	65.00	115,159.88	39.29	4,524,090.98
1988	8,697,356.46	65.00	133,802.92	39.92	5,340,942.91
1989	7,742,448.34	65.00	119,112.31	40.55	4,830,157.37
1990	6,255,638.30	65.00	96,238.74	41.19	3,964,023.51
1991	6,309,213.43	65.00	97,062.96	41.83	4,060,384.12
1992	6,981,132.42	65.00	107,399.98	42.48	4,562,182.74
1993	7,687,823.16	65.00	118,271.94	43.13	5,100,960.32
1994	9,700,345.58	65.00	149,233.23	43.78	6,533,767.60
1995	9,639,625.65	65.00	148,299.09	44.44	6,590,413.04
1996	9,993,945.22	65.00	153,750.06	45.10	6,934,103.84
1997	12,018,048.74	65.00	184,889.51	45.76	8,461,300.80
1998	10,600,813.87	65.00	163,086.32	46.43	7,572,104.14
1999	9,160,819.32	65.00	140,932.98	47.10	6,637,973.80
2000	9,082,617.55	65.00	139,729.90	47.77	6,675,138.69
2001	10,467,796.42	65.00	161,039.94	48.45	7,801,952.21
2002	7,038,194.88	65.00	108,277.85	49.12	5,319,142.18
2003	10,358,425.50	65.00	159,357.34	49.80	7,936,704.04
2004	15,903,390.05	65.00	244,662.85	50.49	12,352,265.82
2005	21,541,328.62	65.00	331,398.70	51.17	16,957,991.97
2006	10,980,076.11	65.00	168,921.01	51.86	8,759,912.08

Columbia Gas of Pennsylvania

Gas Division

376.02 Mains - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2007	35,523,808.66	65.00	546,509.66	52.55	28,717,232.63
2008	55,656,923.39	65.00	856,243.95	53.24	45,585,096.98
2009	33,874,395.78	65.00	521,134.56	53.93	28,105,708.37
2010	44,381,633.07	65.00	682,781.27	54.63	37,299,465.18
2011	81,454,455.66	65.00	1,253,121.45	55.33	69,331,628.10
2012	88,577,444.14	65.00	1,362,703.79	56.03	76,351,674.56
2013	116,323,425.82	65.00	1,789,556.87	56.73	101,527,645.02
2014	123,763,510.41	65.00	1,904,017.51	57.44	109,369,794.74
2015	118,634,081.02	65.00	1,825,104.73	58.15	106,134,033.06
2016	167,281,691.22	65.00	2,573,515.16	58.87	151,491,164.40
2017	181,470,227.63	65.00	2,791,796.15	59.58	166,341,951.06
2018	156,167,482.44	65.00	2,402,530.61	60.30	144,876,904.59
2019	230,274,409.63	65.00	3,542,615.33	61.03	216,189,060.01
2020	228,206,761.47	65.00	3,510,805.97	61.75	216,796,257.75
2021	207,371,730.81	65.00	3,190,273.18	62.48	199,332,872.50
2022	271,357,627.66	65.00	4,174,652.72	63.21	263,896,794.88
2023	316,430,233.17	65.00	4,868,064.13	63.95	311,319,801.50
2024	185,738,276.36	65.00	2,857,457.18	64.66	184,764,047.72
<i>Total</i>	2,916,324,439.65	65.00	44,865,669.96	58.83	2,639,601,621.38

Composite Average Remaining Life ... 58.83 Years

***Columbia Gas of Pennsylvania
Gas Division***

378.00 M&R Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1894	756.79	0.00	0.00	0.00	0.00
1912	38.19	0.00	0.00	0.00	0.00
1914	12.38	0.00	0.00	0.00	0.00
1920	86.01	0.00	0.00	0.00	0.00
1928	88.16	0.00	0.00	0.00	0.00
1929	428.62	0.00	0.00	0.00	0.00
1930	205.41	0.00	0.00	0.00	0.00
1931	99.05	0.00	0.00	0.00	0.00
1932	357.90	0.00	0.00	0.00	0.00
1933	112.36	0.00	0.00	0.00	0.00
1934	281.77	0.00	0.00	0.00	0.00
1935	187.38	45.00	4.16	0.50	2.08
1936	261.36	45.00	5.81	0.86	5.00
1938	261.39	45.00	5.81	1.78	10.36
1939	370.50	45.00	8.23	2.25	18.52
1940	609.41	45.00	13.54	2.71	36.76
1941	864.91	45.00	19.22	3.17	60.98
1942	265.90	45.00	5.91	3.63	21.42
1943	0.02	45.00	0.00	4.07	0.00
1944	1,145.13	45.00	25.45	4.51	114.71
1945	154.75	45.00	3.44	4.94	16.97
1946	222.75	45.00	4.95	5.36	26.52
1947	666.24	45.00	14.80	5.78	85.51
1948	258.66	45.00	5.75	6.19	35.57
1949	1,189.10	45.00	26.42	6.60	174.27
1950	4,774.89	45.00	106.11	7.00	742.44
1951	9,601.58	45.00	213.36	7.40	1,578.47

***Columbia Gas of Pennsylvania
Gas Division***

378.00 M&R Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1952	46,150.49	45.00	1,025.54	7.80	7,995.99
1953	38,785.89	45.00	861.88	8.19	7,062.47
1954	18,507.86	45.00	411.27	8.59	3,532.48
1955	111,794.56	45.00	2,484.26	8.98	22,320.50
1956	46,508.29	45.00	1,033.49	9.38	9,694.79
1957	27,744.09	45.00	616.52	9.78	6,027.77
1958	29,397.31	45.00	653.26	10.17	6,646.61
1959	37,212.15	45.00	826.91	10.57	8,742.35
1960	61,521.97	45.00	1,367.12	10.97	15,000.94
1961	71,237.34	45.00	1,583.01	11.38	18,007.08
1962	67,956.65	45.00	1,510.11	11.78	17,789.31
1963	44,316.31	45.00	984.78	12.19	12,001.68
1964	49,539.39	45.00	1,100.85	12.60	13,867.99
1965	34,016.24	45.00	755.90	13.01	9,835.11
1966	38,724.46	45.00	860.52	13.43	11,555.24
1967	38,908.75	45.00	864.62	13.85	11,973.89
1968	30,557.06	45.00	679.03	14.27	9,691.70
1969	43,785.68	45.00	972.99	14.70	14,304.13
1970	29,828.22	45.00	662.83	15.13	10,031.07
1971	100,179.56	45.00	2,226.15	15.57	34,661.98
1972	60,014.87	45.00	1,333.63	16.01	21,353.34
1973	62,099.12	45.00	1,379.94	16.46	22,709.89
1974	54,931.72	45.00	1,220.67	16.91	20,638.39
1975	39,059.43	45.00	867.96	17.36	15,069.94
1976	35,277.20	45.00	783.92	17.82	13,971.12
1977	60,167.03	45.00	1,337.01	18.29	24,450.21
1978	26,279.93	45.00	583.98	18.76	10,953.78

***Columbia Gas of Pennsylvania
Gas Division***

378.00 M&R Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1979	26,821.95	45.00	596.03	19.23	11,462.69
1980	39,712.90	45.00	882.48	19.71	17,395.23
1981	83,267.64	45.00	1,850.34	20.20	37,371.39
1982	189,525.73	45.00	4,211.57	20.69	87,125.72
1983	83,739.75	45.00	1,860.83	21.18	39,417.24
1984	112,862.67	45.00	2,507.99	21.68	54,380.85
1985	178,070.00	45.00	3,957.00	22.19	87,800.31
1986	146,802.48	45.00	3,262.19	22.70	74,051.42
1987	137,486.81	45.00	3,055.18	23.22	70,928.54
1988	293,700.49	45.00	6,526.50	23.74	154,917.86
1989	193,277.47	45.00	4,294.94	24.26	104,206.30
1990	165,793.36	45.00	3,684.20	24.79	91,345.61
1991	191,293.69	45.00	4,250.85	25.33	107,672.57
1992	74,351.01	45.00	1,652.20	25.87	42,742.42
1993	135,638.68	45.00	3,014.11	26.41	79,617.58
1994	240,649.82	45.00	5,347.63	26.96	144,195.15
1995	68,868.01	45.00	1,530.36	27.52	42,113.54
1996	370,772.26	45.00	8,239.16	28.08	231,329.11
1997	55,495.57	45.00	1,233.20	28.64	35,317.41
1998	22,839.51	45.00	507.53	29.20	14,822.25
1999	490,305.18	45.00	10,895.37	29.77	324,405.96
2000	912,280.45	45.00	20,272.34	30.35	615,220.02
2001	193,655.72	45.00	4,303.34	30.92	133,076.85
2002	227,738.97	45.00	5,060.73	31.50	159,430.13
2003	372,878.80	45.00	8,285.97	32.09	265,859.97
2004	282,388.83	45.00	6,275.13	32.67	205,014.38
2005	113,274.79	45.00	2,517.15	33.26	83,715.93

***Columbia Gas of Pennsylvania
Gas Division***

378.00 M&R Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2006	475,831.37	45.00	10,573.74	33.85	357,897.37
2007	472,558.40	45.00	10,501.01	34.44	361,646.93
2008	1,251,245.58	45.00	27,804.69	35.03	974,081.21
2009	426,314.70	45.00	9,473.40	35.63	337,519.07
2010	1,398,532.05	45.00	31,077.64	36.22	1,125,777.82
2011	2,051,554.06	45.00	45,588.84	36.82	1,678,704.26
2012	702,236.19	45.00	15,604.82	37.42	583,964.49
2013	3,095,172.95	45.00	68,779.73	38.02	2,615,227.00
2014	10,293,898.20	45.00	228,747.01	38.63	8,835,472.44
2015	9,138,482.53	45.00	203,071.81	39.23	7,966,369.08
2016	8,945,499.32	45.00	198,783.41	39.83	7,918,473.22
2017	16,802,682.81	45.00	373,382.69	40.44	15,100,355.99
2018	16,848,889.10	45.00	374,409.47	41.05	15,369,827.75
2019	21,145,576.79	45.00	469,888.80	41.66	19,576,218.04
2020	18,334,347.96	45.00	407,418.76	42.27	17,223,095.38
2021	9,180,199.87	45.00	203,998.84	42.89	8,749,062.43
2022	10,171,770.71	45.00	226,033.14	43.50	9,833,410.34
2023	8,142,914.56	45.00	180,948.69	44.12	7,983,876.36
2024	4,592,781.10	45.00	102,059.00	44.72	4,563,714.98
<i>Total</i>	150,201,782.97	40.05	3,337,670.89	40.40	134,852,449.92

Composite Average Remaining Life ... 40.40 Years

***Columbia Gas of Pennsylvania
Gas Division***

379.10 M&R Equipment - City Gate

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 35

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1976	591.42	35.00	16.90	4.57	77.26
1983	26,406.23	35.00	754.46	6.59	4,975.06
1984	1,074.83	35.00	30.71	6.92	212.47
1987	6,793.84	35.00	194.11	7.96	1,544.73
1988	15,907.49	35.00	454.50	8.33	3,785.15
1989	20,307.27	35.00	580.21	8.71	5,054.47
1996	48,076.94	35.00	1,373.63	11.83	16,245.70
<i>Total</i>	119,158.02	35.00	3,404.52	9.37	31,894.85

Composite Average Remaining Life ... 9.37 Years

***Columbia Gas of Pennsylvania
Gas Division***

380.01 Services - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1887	2,008.32	0.00	0.00	0.00	0.00
1888	837.89	0.00	0.00	0.00	0.00
1889	897.79	0.00	0.00	0.00	0.00
1890	3,939.45	0.00	0.00	0.00	0.00
1891	266.58	0.00	0.00	0.00	0.00
1892	940.37	0.00	0.00	0.00	0.00
1893	481.29	0.00	0.00	0.00	0.00
1894	938.71	0.00	0.00	0.00	0.00
1895	368.90	0.00	0.00	0.00	0.00
1896	548.36	0.00	0.00	0.00	0.00
1897	445.21	0.00	0.00	0.00	0.00
1898	1,815.93	0.00	0.00	0.00	0.00
1899	1,741.16	0.00	0.00	0.00	0.00
1900	1,196.66	0.00	0.00	0.00	0.00
1902	1,568.27	0.00	0.00	0.00	0.00
1903	860.48	0.00	0.00	0.00	0.00
1904	1,259.57	0.00	0.00	0.00	0.00
1905	1,178.58	0.00	0.00	0.00	0.00
1906	1,195.57	0.00	0.00	0.00	0.00
1907	1,326.53	0.00	0.00	0.00	0.00
1908	1,907.05	0.00	0.00	0.00	0.00
1909	1,673.93	0.00	0.00	0.00	0.00
1910	1,749.65	0.00	0.00	0.00	0.00
1911	1,166.79	0.00	0.00	0.00	0.00
1912	1,095.74	0.00	0.00	0.00	0.00
1913	1,545.26	0.00	0.00	0.00	0.00
1914	1,143.30	0.00	0.00	0.00	0.00

Columbia Gas of Pennsylvania

Gas Division

380.01 Services - Bare Steel

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1915	1,351.98	0.00	0.00	0.00	0.00
1916	831.08	0.00	0.00	0.00	0.00
1917	718.92	0.00	0.00	0.00	0.00
1918	619.10	0.00	0.00	0.00	0.00
1919	1,174.96	0.00	0.00	0.00	0.00
1920	1,421.70	0.00	0.00	0.00	0.00
1921	1,060.61	0.00	0.00	0.00	0.00
1922	2,331.88	0.00	0.00	0.00	0.00
1923	3,861.07	0.00	0.00	0.00	0.00
1924	3,472.43	0.00	0.00	0.00	0.00
1925	6,352.14	0.00	0.00	0.00	0.00
1926	6,005.65	0.00	0.00	0.00	0.00
1927	5,741.57	0.00	0.00	0.00	0.00
1928	6,789.60	0.00	0.00	0.00	0.00
1929	8,376.70	0.00	0.00	0.00	0.00
1930	4,232.42	0.00	0.00	0.00	0.00
1931	2,561.20	0.00	0.00	0.00	0.00
1932	1,450.45	0.00	0.00	0.00	0.00
1933	1,978.78	0.00	0.00	0.00	0.00
1934	2,005.01	0.00	0.00	0.00	0.00
1935	1,761.49	45.00	39.14	0.50	19.57
1936	3,136.60	45.00	69.70	0.86	59.95
1937	4,242.02	45.00	94.26	1.32	124.11
1938	7,769.39	45.00	172.65	1.78	307.87
1939	11,856.73	45.00	263.48	2.25	592.83
1940	9,383.79	45.00	208.52	2.71	566.05
1941	12,024.53	45.00	267.20	3.17	847.77

***Columbia Gas of Pennsylvania
Gas Division***

380.01 Services - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1942	13,759.16	45.00	305.75	3.63	1,108.55
1943	4,599.88	45.00	102.22	4.07	416.10
1944	4,388.05	45.00	97.51	4.51	439.58
1945	5,089.98	45.00	113.11	4.94	558.27
1946	11,016.95	45.00	244.81	5.36	1,311.86
1947	23,272.38	45.00	517.15	5.78	2,986.87
1948	31,817.26	45.00	707.03	6.19	4,374.85
1949	48,445.80	45.00	1,076.54	6.60	7,100.17
1950	64,779.30	45.00	1,439.50	7.00	10,072.37
1951	85,181.94	45.00	1,892.88	7.40	14,003.61
1952	90,339.15	45.00	2,007.48	7.80	15,652.08
1953	82,751.44	45.00	1,838.87	8.19	15,068.10
1954	128,885.56	45.00	2,864.04	8.59	24,599.61
<i>Total</i>	740,935.99	13.43	14,321.86	7.00	100,210.18

Composite Average Remaining Life ... 7.00 Years

Columbia Gas of Pennsylvania

Gas Division

380.02 Services - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1955	225,912.19	45.00	5,020.13	8.98	45,104.81
1956	263,912.55	45.00	5,864.56	9.38	55,013.33
1957	242,789.03	45.00	5,395.16	9.78	52,749.10
1958	336,506.68	45.00	7,477.72	10.17	76,082.80
1959	437,168.81	45.00	9,714.60	10.57	102,705.21
1960	328,076.83	45.00	7,290.40	10.97	79,995.17
1961	417,351.80	45.00	9,274.23	11.38	105,496.47
1962	466,659.56	45.00	10,369.93	11.78	122,159.52
1963	628,982.19	45.00	13,977.00	12.19	170,340.02
1964	639,406.39	45.00	14,208.64	12.60	178,994.54
1965	631,659.52	45.00	14,036.49	13.01	182,631.54
1966	769,346.90	45.00	17,096.13	13.43	229,570.45
1967	890,239.37	45.00	19,782.55	13.85	273,964.91
1968	964,002.06	45.00	21,421.68	14.27	305,749.78
1969	680,556.44	45.00	15,123.06	14.70	222,327.62
1970	484,131.31	45.00	10,758.18	15.13	162,810.68
1971	410,410.56	45.00	9,119.98	15.57	142,001.45
1972	398,537.98	45.00	8,856.16	16.01	141,800.15
1973	308,540.49	45.00	6,856.27	16.46	112,834.48
1974	73,183.18	45.00	1,626.25	16.91	27,495.65
1975	113,138.02	45.00	2,514.11	17.36	43,651.00
1976	273,520.39	45.00	6,078.06	17.82	108,324.55
1977	1,498,065.22	45.00	33,289.42	18.29	608,772.20
1978	1,067,243.92	45.00	23,715.88	18.76	444,839.55
1979	1,328,762.89	45.00	29,527.25	19.23	567,862.95
1980	1,894,374.81	45.00	42,096.06	19.71	829,783.13
1981	2,207,850.95	45.00	49,062.01	20.20	990,906.56

Columbia Gas of Pennsylvania

Gas Division

380.02 Services - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1982	1,817,326.45	45.00	40,383.92	20.69	835,432.07
1983	1,849,002.24	45.00	41,087.81	21.18	870,346.02
1984	2,327,356.01	45.00	51,717.60	21.68	1,121,394.74
1985	2,767,427.25	45.00	61,496.69	22.19	1,364,524.96
1986	3,118,152.06	45.00	69,290.36	22.70	1,572,886.20
1987	3,809,096.17	45.00	84,644.26	23.22	1,965,087.70
1988	4,628,210.15	45.00	102,846.29	23.74	2,441,236.73
1989	4,459,117.71	45.00	99,088.78	24.26	2,404,150.59
1990	4,621,618.81	45.00	102,699.82	24.79	2,546,329.92
1991	4,328,505.67	45.00	96,186.37	25.33	2,436,365.38
1992	5,025,038.06	45.00	111,664.44	25.87	2,888,760.88
1993	5,291,904.60	45.00	117,594.65	26.41	3,106,257.22
1994	6,387,430.40	45.00	141,939.00	26.96	3,827,289.27
1995	5,582,775.34	45.00	124,058.27	27.52	3,413,928.21
1996	5,392,372.31	45.00	119,827.20	28.08	3,364,363.57
1997	5,642,473.64	45.00	125,384.86	28.64	3,590,873.59
1998	6,190,355.22	45.00	137,559.67	29.20	4,017,380.04
1999	6,585,101.03	45.00	146,331.56	29.77	4,356,972.21
2000	6,798,159.56	45.00	151,066.06	30.35	4,584,515.52
2001	6,660,084.61	45.00	147,997.81	30.92	4,576,694.50
2002	5,653,248.31	45.00	125,624.29	31.50	3,957,592.77
2003	5,476,496.25	45.00	121,696.57	32.09	3,904,703.44
2004	7,952,053.35	45.00	176,707.44	32.67	5,773,193.29
2005	8,411,486.92	45.00	186,916.80	33.26	6,216,523.74
2006	8,205,006.39	45.00	182,328.47	33.85	6,171,409.36
2007	11,800,562.69	45.00	262,227.52	34.44	9,030,920.36
2008	13,820,170.82	45.00	307,106.47	35.03	10,758,854.14

***Columbia Gas of Pennsylvania
Gas Division***

380.02 Services - Other

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2009	12,625,390.52	45.00	280,556.53	35.63	9,995,691.23
2010	14,919,198.19	45.00	331,528.63	36.22	12,009,522.72
2011	22,176,598.71	45.00	492,799.77	36.82	18,146,219.74
2012	28,113,904.71	45.00	624,736.27	37.42	23,378,917.64
2013	33,465,202.22	45.00	743,650.73	38.02	28,275,996.78
2014	35,125,485.92	45.00	780,544.91	38.63	30,148,953.96
2015	40,307,331.86	45.00	895,693.88	39.23	35,137,461.95
2016	31,201,720.71	45.00	693,352.52	39.83	27,619,474.45
2017	49,157,205.84	45.00	1,092,352.34	40.44	44,176,951.74
2018	47,913,338.27	45.00	1,064,711.60	41.05	43,707,318.12
2019	59,547,480.53	45.00	1,323,240.99	41.66	55,128,052.26
2020	60,334,752.45	45.00	1,340,735.44	42.27	56,677,837.61
2021	64,880,032.02	45.00	1,441,738.88	42.89	61,833,016.55
2022	64,796,879.48	45.00	1,439,891.10	43.50	62,641,434.10
2023	70,502,974.71	45.00	1,566,689.73	44.12	69,125,990.30
2024	54,345,394.71	45.00	1,207,642.26	44.72	54,001,461.57
<i>Total</i>	861,993,752.91	45.00	19,154,890.48	38.61	739,486,254.76

Composite Average Remaining Life ... 38.61 Years

Columbia Gas of Pennsylvania

Gas Division

381.00 Meters

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1914	16.80	0.00	0.00	0.00	0.00
1919	111.73	0.00	0.00	0.00	0.00
1920	287.36	0.00	0.00	0.00	0.00
1921	132.11	0.00	0.00	0.00	0.00
1922	336.90	0.00	0.00	0.00	0.00
1923	867.34	0.00	0.00	0.00	0.00
1924	836.68	0.00	0.00	0.00	0.00
1925	573.62	0.00	0.00	0.00	0.00
1926	930.89	0.00	0.00	0.00	0.00
1927	21.75	0.00	0.00	0.00	0.00
1928	2,240.22	0.00	0.00	0.00	0.00
1929	1,048.34	0.00	0.00	0.00	0.00
1930	367.68	0.00	0.00	0.00	0.00
1931	23.47	0.00	0.00	0.00	0.00
1934	122.80	0.00	0.00	0.00	0.00
1935	25.42	0.00	0.00	0.00	0.00
1936	446.25	0.00	0.00	0.00	0.00
1937	73.25	44.00	1.66	0.50	0.83
1938	221.34	44.00	5.03	0.53	2.69
1939	405.31	44.00	9.21	0.77	7.12
1941	1,890.44	44.00	42.96	1.27	54.77
1942	1,688.00	44.00	38.36	1.52	58.16
1943	1,364.12	44.00	31.00	1.79	55.47
1944	19.19	44.00	0.44	2.06	0.90
1945	678.05	44.00	15.41	2.33	35.89
1946	4,096.95	44.00	93.11	2.61	242.78
1947	1,993.19	44.00	45.30	2.89	130.85

Columbia Gas of Pennsylvania

Gas Division

381.00 Meters

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1948	14,859.68	44.00	337.72	3.17	1,071.33
1949	13,550.94	44.00	307.98	3.45	1,062.42
1950	28,319.21	44.00	643.62	3.74	2,405.53
1951	53,793.08	44.00	1,222.57	4.03	4,924.89
1952	34,451.07	44.00	782.98	4.32	3,383.93
1953	18,661.71	44.00	424.13	4.61	1,955.67
1954	53,145.64	44.00	1,207.86	4.91	5,929.76
1955	61,641.47	44.00	1,400.94	5.21	7,300.00
1956	29,529.30	44.00	671.12	5.51	3,698.63
1957	78,240.98	44.00	1,778.20	5.82	10,344.90
1958	106,674.12	44.00	2,424.41	6.13	14,855.75
1959	143,817.48	44.00	3,268.58	6.44	21,052.71
1960	160,890.30	44.00	3,656.60	6.75	24,696.93
1961	148,474.00	44.00	3,374.41	7.07	23,868.84
1962	140,022.35	44.00	3,182.33	7.40	23,538.60
1963	114,303.80	44.00	2,597.81	7.72	20,064.50
1964	198,080.95	44.00	4,501.84	8.05	36,245.63
1965	193,311.32	44.00	4,393.44	8.39	36,840.61
1966	188,154.87	44.00	4,276.25	8.72	37,304.28
1967	162,503.05	44.00	3,693.25	9.06	33,476.79
1968	134,444.71	44.00	3,055.56	9.41	28,754.42
1969	126,724.95	44.00	2,880.11	9.76	28,113.64
1970	99,830.07	44.00	2,268.87	10.12	22,953.51
1971	258,456.83	44.00	5,874.02	10.48	61,533.73
1972	215,839.31	44.00	4,905.44	10.84	53,176.69
1973	137,441.31	44.00	3,123.67	11.21	35,017.17
1974	173,057.01	44.00	3,933.11	11.59	45,566.99

Columbia Gas of Pennsylvania

Gas Division

381.00 Meters

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1975	188,104.01	44.00	4,275.09	11.97	51,152.40
1976	72,834.86	44.00	1,655.34	12.35	20,445.61
1977	166,757.50	44.00	3,789.94	12.74	48,296.32
1978	151,754.29	44.00	3,448.96	13.14	45,322.72
1979	300,076.33	44.00	6,819.92	13.55	92,376.99
1980	549,974.15	44.00	12,499.41	13.96	174,440.33
1981	581,460.59	44.00	13,215.01	14.37	189,943.17
1982	359,558.28	44.00	8,171.78	14.80	120,924.15
1983	271,803.59	44.00	6,177.36	15.23	94,077.80
1984	371,934.65	44.00	8,453.06	15.67	132,447.88
1985	514,904.35	44.00	11,702.37	16.12	188,589.87
1986	523,096.81	44.00	11,888.57	16.57	197,006.81
1987	521,340.23	44.00	11,848.64	17.03	201,837.75
1988	603,596.20	44.00	13,718.10	17.51	240,160.80
1989	673,813.61	44.00	15,313.95	17.99	275,479.46
1990	363,353.37	44.00	8,258.03	18.48	152,605.90
1991	468,114.65	44.00	10,638.97	18.98	201,930.27
1992	694,406.37	44.00	15,781.96	19.49	307,603.07
1993	841,480.02	44.00	19,124.55	20.01	382,740.86
1994	327,442.26	44.00	7,441.87	20.55	152,896.17
1995	8,146.20	44.00	185.14	21.09	3,904.42
1996	1,677,449.98	44.00	38,123.87	21.64	825,152.53
1997	583,758.43	44.00	13,267.24	22.21	294,706.17
1998	902,769.99	44.00	20,517.50	22.79	467,664.17
1999	961,268.18	44.00	21,847.01	23.39	510,928.97
2001	253,312.74	44.00	5,757.11	24.62	141,719.10
2002	1,100,365.41	44.00	25,008.31	25.25	631,511.32

Columbia Gas of Pennsylvania

Gas Division

381.00 Meters

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2003	794,975.62	44.00	18,067.63	25.90	467,997.67
2004	712,811.35	44.00	16,200.26	26.57	430,450.64
2005	346,488.43	44.00	7,874.74	27.25	214,611.35
2006	495,464.69	44.00	11,260.56	27.95	314,754.12
2007	1,017,565.54	44.00	23,126.49	28.67	662,974.93
2008	1,046,231.34	44.00	23,777.99	29.40	699,139.11
2009	1,356,960.16	44.00	30,840.01	30.15	929,948.84
2010	1,082,617.21	44.00	24,604.94	30.92	760,860.07
2011	1,018,090.79	44.00	23,138.43	31.71	733,779.10
2012	1,311,784.36	44.00	29,813.28	32.52	969,513.61
2013	933,478.50	44.00	21,215.42	33.35	707,431.10
2014	1,107,362.90	44.00	25,167.34	34.19	860,459.55
2015	2,484,258.00	44.00	56,460.42	35.06	1,979,231.22
2016	1,239,698.91	44.00	28,174.98	35.94	1,012,553.02
2017	1,214,696.61	44.00	27,606.74	36.84	1,017,007.59
2018	1,067,043.37	44.00	24,250.99	37.76	915,667.22
2019	1,451,532.26	44.00	32,989.37	38.70	1,276,561.95
2020	1,980,605.17	44.00	45,013.76	39.65	1,784,734.49
2021	1,697,074.64	44.00	38,569.88	40.62	1,566,538.28
2022	1,939,916.79	44.00	44,089.02	41.60	1,833,938.57
2023	2,116,651.59	44.00	48,105.72	42.59	2,048,647.11
2024	2,060,133.07	44.00	46,821.21	43.54	2,038,679.77
<i>Total</i>	45,617,357.06	36.74	1,036,567.56	28.90	29,961,071.64

Composite Average Remaining Life ... 28.90 Years

Columbia Gas of Pennsylvania

Gas Division

381.10 Meters - AMR

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2000	296,427.01	20.00	14,821.35	3.54	52,539.26
2001	278,746.25	20.00	13,937.31	3.86	53,782.69
2003	514.10	20.00	25.71	4.54	116.77
2004	107,825.28	20.00	5,391.26	4.92	26,503.63
2005	169,036.06	20.00	8,451.80	5.31	44,907.09
2007	107,411.45	20.00	5,370.57	6.19	33,238.48
2008	485,486.24	20.00	24,274.31	6.67	161,971.65
2009	420,783.25	20.00	21,039.16	7.19	151,275.71
2010	824,868.47	20.00	41,243.43	7.74	319,417.06
2011	11,263,089.05	20.00	563,154.48	8.34	4,695,955.86
2012	8,735,379.14	20.00	436,768.98	8.97	3,919,819.69
2013	353,334.08	20.00	17,666.70	9.65	170,562.31
2014	306,936.92	20.00	15,346.85	10.38	159,294.60
2015	372,440.91	20.00	18,622.05	11.15	207,646.72
2016	392,723.42	20.00	19,636.17	11.97	234,978.20
2017	189,201.48	20.00	9,460.07	12.83	121,330.47
2018	497,031.94	20.00	24,851.60	13.72	341,054.88
2019	124,689.93	20.00	6,234.50	14.66	91,370.84
2020	81,944.64	20.00	4,097.23	15.61	63,978.22
2021	377,543.79	20.00	18,877.19	16.59	313,250.57
2022	390,670.32	20.00	19,533.52	17.59	343,511.55
2023	368,399.23	20.00	18,419.96	18.58	342,308.45
2024	145,531.03	20.00	7,276.55	19.54	142,195.96
<i>Total</i>	26,290,013.99	20.00	1,314,500.76	9.12	11,991,010.66

Composite Average Remaining Life ... 9.12 Years

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1937	4,749.28	55.00	86.35	1.34	116.02
1938	12,721.71	55.00	231.30	1.58	364.41
1939	9,392.36	55.00	170.77	1.82	310.09
1940	8,251.67	55.00	150.03	2.06	309.31
1941	11,712.89	55.00	212.96	2.32	494.95
1942	8,759.99	55.00	159.27	2.56	408.47
1943	3,963.87	55.00	72.07	2.81	202.72
1944	3,997.40	55.00	72.68	3.07	222.82
1945	5,300.88	55.00	96.38	3.32	320.14
1946	12,830.81	55.00	233.29	3.59	837.54
1947	18,676.09	55.00	339.57	3.84	1,304.07
1948	23,712.95	55.00	431.14	4.09	1,764.86
1949	30,584.40	55.00	556.08	4.35	2,418.06
1950	35,528.38	55.00	645.97	4.61	2,974.74
1951	30,962.56	55.00	562.96	4.86	2,737.99
1952	32,228.26	55.00	585.97	5.13	3,006.30
1953	38,526.30	55.00	700.48	5.39	3,775.44
1954	36,169.40	55.00	657.63	5.65	3,718.54
1955	45,374.68	55.00	824.99	5.93	4,888.40
1956	47,867.16	55.00	870.31	6.20	5,398.92
1957	43,972.72	55.00	799.50	6.49	5,192.08
1958	46,951.91	55.00	853.67	6.79	5,793.51
1959	68,439.89	55.00	1,244.36	7.09	8,822.88
1960	49,854.41	55.00	906.44	7.41	6,713.18
1961	43,164.15	55.00	784.80	7.73	6,070.21
1962	61,702.89	55.00	1,121.87	8.08	9,061.28
1963	65,682.02	55.00	1,194.22	8.43	10,072.09

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1964	117,746.10	55.00	2,140.84	8.80	18,849.73
1965	156,218.11	55.00	2,840.33	9.19	26,107.19
1966	144,702.96	55.00	2,630.96	9.59	25,243.32
1967	131,757.43	55.00	2,395.59	10.01	23,990.48
1968	171,134.21	55.00	3,111.53	10.45	32,514.58
1969	161,914.98	55.00	2,943.91	10.90	32,099.85
1970	148,287.12	55.00	2,696.13	11.38	30,669.27
1971	129,449.80	55.00	2,353.63	11.86	27,923.68
1972	81,360.67	55.00	1,479.28	12.37	18,298.85
1973	75,626.18	55.00	1,375.02	12.89	17,728.27
1974	12,843.71	55.00	233.52	13.43	3,136.44
1975	22,116.24	55.00	402.11	13.99	5,625.00
1976	41,182.63	55.00	748.77	14.56	10,903.97
1977	38,747.98	55.00	704.51	15.15	10,674.76
1978	39,434.11	55.00	716.98	15.76	11,297.61
1979	96,018.12	55.00	1,745.78	16.37	28,586.56
1980	201,406.79	55.00	3,661.94	17.01	62,291.57
1981	284,295.11	55.00	5,169.00	17.66	91,286.74
1982	233,235.83	55.00	4,240.65	18.32	77,705.03
1983	266,865.99	55.00	4,852.11	19.00	92,191.77
1984	331,629.95	55.00	6,029.63	19.69	118,720.58
1985	341,003.56	55.00	6,200.06	20.39	126,413.97
1986	409,947.40	55.00	7,453.59	21.10	157,296.70
1987	466,325.08	55.00	8,478.64	21.83	185,081.98
1988	566,331.57	55.00	10,296.93	22.57	232,360.61
1989	668,315.34	55.00	12,151.18	23.31	283,286.99
1990	708,359.74	55.00	12,879.26	24.07	309,998.24

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1991	648,257.08	55.00	11,786.49	24.84	292,761.76
1992	722,340.25	55.00	13,133.46	25.62	336,451.06
1993	621,320.46	55.00	11,296.73	26.41	298,309.03
1994	726,188.89	55.00	13,203.43	27.20	359,199.14
1995	645,807.29	55.00	11,741.95	28.01	328,922.94
1996	741,663.65	55.00	13,484.79	28.83	388,741.48
1997	715,583.37	55.00	13,010.60	29.65	385,826.18
1998	617,914.00	55.00	11,234.80	30.49	342,550.26
1999	520,924.33	55.00	9,471.35	31.33	296,776.04
2000	1,120,378.80	55.00	20,370.52	32.19	655,655.39
2001	1,027,437.84	55.00	18,680.68	33.05	617,316.47
2002	1,002,750.76	55.00	18,231.83	33.92	618,334.96
2003	1,101,765.60	55.00	20,032.10	34.79	696,964.32
2004	1,072,402.59	55.00	19,498.22	35.68	695,642.59
2005	753,142.32	55.00	13,693.49	36.57	500,763.92
2006	211,740.05	55.00	3,849.82	37.47	144,248.47
2007	2,948,958.51	55.00	53,617.41	38.37	2,057,535.71
2008	1,400,822.14	55.00	25,469.49	39.29	1,000,644.79
2009	1,742,215.81	55.00	31,676.64	40.21	1,273,652.74
2010	1,428,380.30	55.00	25,970.54	41.13	1,068,273.08
2011	1,541,504.07	55.00	28,027.34	42.07	1,178,996.90
2012	1,664,714.84	55.00	30,267.53	43.00	1,301,583.24
2013	1,021,707.23	55.00	18,576.49	43.95	816,359.68
2014	1,231,165.01	55.00	22,384.81	44.89	1,004,944.72
2015	1,326,660.22	55.00	24,121.09	45.85	1,105,877.71
2016	1,385,322.25	55.00	25,187.67	46.80	1,178,889.06
2017	1,941,377.48	55.00	35,297.76	47.77	1,686,020.05

Columbia Gas of Pennsylvania

Gas Division

382.00 Meter Installations

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2024

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2018	1,446,094.06	55.00	26,292.61	48.73	1,281,251.89
2019	1,086,825.13	55.00	19,760.45	49.70	982,087.15
2020	790,378.45	55.00	14,370.51	50.67	728,183.52
2021	1,294,197.77	55.00	23,530.86	51.65	1,215,310.87
2022	1,836,412.26	55.00	33,389.30	52.63	1,757,138.45
2023	2,637,381.23	55.00	47,952.37	53.61	2,570,547.21
2024	6,786,829.06	55.00	123,396.86	54.55	6,731,128.78
<i>Total</i>	52,607,898.84	55.00	956,506.97	39.77	38,044,472.35

Composite Average Remaining Life ... 39.77 Years

***Columbia Gas of Pennsylvania
Gas Division***

383.00 House Regulators

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 50

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1918	113.14	0.00	0.00	0.00	0.00
1939	77.64	50.00	1.55	2.78	4.32
1949	77.13	50.00	1.54	4.97	7.67
1955	432.93	50.00	8.66	6.46	55.91
1957	490.94	50.00	9.82	6.99	68.62
1958	704.49	50.00	14.09	7.26	102.32
1960	177.29	50.00	3.55	7.82	27.74
1961	925.50	50.00	18.51	8.11	150.19
1962	4,029.43	50.00	80.59	8.41	677.71
1963	11,335.62	50.00	226.71	8.71	1,974.93
1964	16,073.66	50.00	321.47	9.02	2,899.42
1965	20,111.70	50.00	402.23	9.33	3,754.37
1966	50,322.33	50.00	1,006.45	9.66	9,717.54
1967	39,700.39	50.00	794.01	9.98	7,927.32
1968	52,162.89	50.00	1,043.26	10.32	10,766.42
1969	47,765.97	50.00	955.32	10.66	10,187.32
1970	51,769.23	50.00	1,035.38	11.02	11,405.39
1971	43,670.04	50.00	873.40	11.38	9,935.60
1972	25,239.19	50.00	504.78	11.74	5,928.49
1973	22,264.55	50.00	445.29	12.12	5,398.02
1974	1,736.16	50.00	34.72	12.51	434.38
1975	1,510.06	50.00	30.20	12.91	389.80
1976	2,447.44	50.00	48.95	13.31	651.69
1977	2,281.08	50.00	45.62	13.73	626.44
1978	3,645.72	50.00	72.91	14.16	1,032.45
1979	9,356.22	50.00	187.12	14.60	2,731.92
1980	14,491.54	50.00	289.83	15.05	4,362.23

***Columbia Gas of Pennsylvania
Gas Division***

383.00 House Regulators

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 50

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1981	23,594.94	50.00	471.90	15.51	7,321.31
1982	26,640.20	50.00	532.80	15.99	8,519.93
1983	30,452.34	50.00	609.05	16.48	10,037.05
1984	31,570.57	50.00	631.41	16.98	10,722.98
1985	30,504.03	50.00	610.08	17.50	10,675.84
1986	47,275.83	50.00	945.52	18.03	17,047.59
1987	57,459.16	50.00	1,149.18	18.58	21,346.70
1988	77,258.06	50.00	1,545.16	19.14	29,568.77
1989	85,724.02	50.00	1,714.48	19.71	33,797.26
1990	86,233.61	50.00	1,724.67	20.31	35,020.05
1991	73,801.41	50.00	1,476.03	20.91	30,870.05
1992	82,318.53	50.00	1,646.37	21.54	35,462.87
1993	59,674.42	50.00	1,193.49	22.18	26,475.07
1994	70,970.50	50.00	1,419.41	22.84	32,424.03
1995	79,834.55	50.00	1,596.69	23.52	37,556.47
1996	84,375.40	50.00	1,687.51	24.22	40,867.28
1997	98,659.14	50.00	1,973.18	24.93	49,194.97
1998	34,877.95	50.00	697.56	25.66	17,902.37
1999	19,187.53	50.00	383.75	26.42	10,136.83
2000	180,100.00	50.00	3,602.00	27.18	97,917.78
2001	69,874.21	50.00	1,397.48	27.97	39,089.90
2002	379,371.04	50.00	7,587.42	28.78	218,343.12
2003	547,418.01	50.00	10,948.36	29.60	324,072.35
2004	899,832.50	50.00	17,996.65	30.44	547,827.60
2005	719,634.22	50.00	14,392.69	31.30	450,460.29
2006	426,570.73	50.00	8,531.42	32.17	274,468.32
2007	856,063.23	50.00	17,121.27	33.06	566,041.62

***Columbia Gas of Pennsylvania
Gas Division***

383.00 House Regulators

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 50

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2008	554,169.07	50.00	11,083.38	33.96	376,444.79
2009	786,051.96	50.00	15,721.04	34.88	548,393.75
2010	623,275.77	50.00	12,465.52	35.81	446,436.75
2011	697,779.86	50.00	13,955.60	36.76	512,960.11
2012	686,844.51	50.00	13,736.89	37.71	518,020.84
2013	507,572.30	50.00	10,151.45	38.67	392,590.83
2014	642,392.15	50.00	12,847.84	39.64	509,352.21
2015	542,572.07	50.00	10,851.44	40.62	440,825.51
2016	545,190.75	50.00	10,903.82	41.61	453,689.88
2017	688,343.40	50.00	13,766.87	42.60	586,438.90
2018	754,571.81	50.00	15,091.44	43.59	657,851.42
2019	937,657.60	50.00	18,753.15	44.59	836,146.28
2020	997,970.55	50.00	19,959.41	45.58	909,845.55
2021	978,284.73	50.00	19,565.70	46.58	911,444.09
2022	1,022,443.39	50.00	20,448.87	47.58	973,027.13
2023	1,392,820.76	50.00	27,856.42	48.58	1,353,357.61
2024	1,270,877.21	50.00	25,417.55	49.54	1,259,227.49
<i>Total</i>	19,231,006.30	49.30	384,617.89	38.38	14,760,439.73

Composite Average Remaining Life ... 38.38 Years

***Columbia Gas of Pennsylvania
Gas Division***

384.00 House Regulator Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 40

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1975	25,717.11	40.00	642.93	3.04	1,953.62
1976	13,626.03	40.00	340.65	3.23	1,101.03
1978	1,304.20	40.00	32.61	3.68	119.88
1979	41,749.48	40.00	1,043.74	3.93	4,098.35
1980	78,231.18	40.00	1,955.78	4.19	8,185.00
1981	103,540.67	40.00	2,588.52	4.47	11,569.86
1982	111,541.38	40.00	2,788.53	4.77	13,300.59
1983	94,279.56	40.00	2,356.99	5.10	12,012.34
1984	100,051.83	40.00	2,501.30	5.45	13,621.18
1985	116,774.98	40.00	2,919.37	5.82	16,998.77
1986	125,389.90	40.00	3,134.75	6.23	19,527.37
1987	160,772.64	40.00	4,019.32	6.67	26,791.68
1988	175,315.37	40.00	4,382.88	7.14	31,286.41
1989	145,310.01	40.00	3,632.75	7.64	27,764.97
1990	142,228.97	40.00	3,555.72	8.19	29,119.71
1991	135,142.11	40.00	3,378.55	8.77	29,630.61
1992	132,043.34	40.00	3,301.08	9.40	31,019.47
1993	112,250.88	40.00	2,806.27	10.06	28,226.89
1994	183,968.70	40.00	4,599.22	10.77	49,521.31
1995	147,476.46	40.00	3,686.91	11.51	42,438.84
1996	122,299.49	40.00	3,057.49	12.30	37,603.54
1997	182,246.23	40.00	4,556.16	13.12	59,769.72
1998	181,143.04	40.00	4,528.58	13.98	63,296.10
1999	139,857.78	40.00	3,496.44	14.86	51,963.13
2000	194,710.12	40.00	4,867.75	15.78	76,797.42
2001	229,158.59	40.00	5,728.97	16.71	95,737.01
2002	154,765.04	40.00	3,869.13	17.67	68,352.69

***Columbia Gas of Pennsylvania
Gas Division***

384.00 House Regulator Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 40

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2003	133,893.06	40.00	3,347.33	18.63	62,372.80
<i>Total</i>	3,484,788.15	40.00	87,119.71	10.49	914,180.31

Composite Average Remaining Life ... 10.49 Years

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1902	24.00	0.00	0.00	0.00	0.00
1922	10.69	0.00	0.00	0.00	0.00
1928	109.16	0.00	0.00	0.00	0.00
1929	721.42	0.00	0.00	0.00	0.00
1930	776.51	0.00	0.00	0.00	0.00
1931	19.20	0.00	0.00	0.00	0.00
1933	232.71	0.00	0.00	0.00	0.00
1934	12.20	0.00	0.00	0.00	0.00
1935	119.38	0.00	0.00	0.00	0.00
1937	880.24	0.00	0.00	0.00	0.00
1938	199.96	0.00	0.00	0.00	0.00
1939	55.79	0.00	0.00	0.00	0.00
1941	371.05	0.00	0.00	0.00	0.00
1942	668.42	0.00	0.00	0.00	0.00
1943	3,823.68	0.00	0.00	0.00	0.00
1944	964.96	0.00	0.00	0.00	0.00
1945	441.81	0.00	0.00	0.00	0.00
1946	57.67	0.00	0.00	0.00	0.00
1947	577.57	0.00	0.00	0.00	0.00
1948	950.89	0.00	0.00	0.00	0.00
1950	1,560.50	0.00	0.00	0.00	0.00
1951	2,584.48	0.00	0.00	0.00	0.00
1952	4,004.87	0.00	0.00	0.00	0.00
1953	3,688.41	0.00	0.00	0.00	0.00
1954	11,684.47	0.00	0.00	0.00	0.00
1955	20,603.30	0.00	0.00	0.00	0.00
1956	21,254.48	0.00	0.00	0.00	0.00

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1957	23,333.57	0.00	0.00	0.00	0.00
1958	19,955.93	0.00	0.00	0.00	0.00
1959	19,137.50	0.00	0.00	0.00	0.00
1960	21,431.04	0.00	0.00	0.00	0.00
1961	28,058.00	0.00	0.00	0.00	0.00
1962	11,859.24	0.00	0.00	0.00	0.00
1963	33,456.81	0.00	0.00	0.00	0.00
1964	21,791.40	0.00	0.00	0.00	0.00
1965	28,198.72	30.00	939.91	0.50	469.95
1966	24,898.19	30.00	829.90	0.86	711.68
1967	44,447.01	30.00	1,481.49	1.31	1,934.79
1968	46,564.94	30.00	1,552.08	1.76	2,738.43
1969	40,147.69	30.00	1,338.18	2.22	2,971.01
1970	39,726.67	30.00	1,324.15	2.66	3,528.76
1971	92,452.39	30.00	3,081.58	3.10	9,552.64
1972	56,994.82	30.00	1,899.73	3.52	6,696.08
1973	33,289.31	30.00	1,109.58	3.94	4,370.89
1974	20,418.05	30.00	680.57	4.35	2,958.94
1975	18,558.43	30.00	618.58	4.75	2,938.86
1976	737.80	30.00	24.59	5.15	126.62
1977	519.78	30.00	17.33	5.55	96.08
1978	10,078.47	30.00	335.93	5.94	1,995.84
1979	31,003.78	30.00	1,033.40	6.34	6,547.57
1980	53,345.83	30.00	1,778.10	6.73	11,970.92
1981	66,297.15	30.00	2,209.79	7.13	15,757.96
1982	96,431.02	30.00	3,214.20	7.53	24,208.43
1983	67,112.00	30.00	2,236.95	7.94	17,753.41

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1984	27,643.43	30.00	921.40	8.35	7,689.38
1985	36,301.09	30.00	1,209.97	8.76	10,597.65
1986	71,794.02	30.00	2,393.01	9.18	21,961.34
1987	15,358.13	30.00	511.91	9.60	4,915.19
1988	46,779.01	30.00	1,559.22	10.03	15,641.95
1989	60,129.86	30.00	2,004.22	10.47	20,981.51
1990	45,611.90	30.00	1,520.32	10.91	16,589.74
1991	81,384.87	30.00	2,712.68	11.36	30,822.73
1992	67,599.95	30.00	2,253.21	11.82	26,632.87
1993	92,826.77	30.00	3,094.06	12.28	38,009.86
1994	128,300.03	30.00	4,276.44	12.76	54,556.02
1995	104,686.74	30.00	3,489.37	13.24	46,190.07
1996	90,339.22	30.00	3,011.15	13.73	41,328.03
1997	27,944.00	30.00	931.42	14.22	13,245.44
1999	411.21	30.00	13.71	15.23	208.81
2000	101,376.58	30.00	3,379.04	15.75	53,232.35
2001	3,134.80	30.00	104.49	16.28	1,701.04
2002	165,725.15	30.00	5,523.88	16.81	92,873.41
2003	353,316.05	30.00	11,776.57	17.35	204,369.87
2004	2,341.98	30.00	78.06	17.90	1,397.41
2005	51,666.77	30.00	1,722.13	18.46	31,782.32
2006	117,288.46	30.00	3,909.41	19.02	74,340.08
2007	151,171.60	30.00	5,038.78	19.58	98,668.01
2008	197,347.02	30.00	6,577.88	20.15	132,564.54
2009	135,560.41	30.00	4,518.44	20.73	93,666.20
2010	200,411.20	30.00	6,680.02	21.31	142,355.77
2011	165,881.34	30.00	5,529.08	21.90	121,062.46

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2012	144,857.27	30.00	4,828.32	22.48	108,561.46
2013	276,694.38	30.00	9,222.65	23.08	212,821.34
2014	136,858.03	30.00	4,561.69	23.67	107,976.04
2015	304,402.15	30.00	10,146.20	24.27	246,218.00
2016	499,780.60	30.00	16,658.46	24.87	414,226.05
2017	489,185.41	30.00	16,305.31	25.47	415,241.08
2018	495,305.95	30.00	16,509.32	26.07	430,396.31
2019	116,935.64	30.00	3,897.65	26.68	103,971.17
2020	940,111.75	30.00	31,335.38	27.28	854,932.54
2021	45,149.99	30.00	1,504.92	27.89	41,978.37
2022	371,159.80	30.00	12,371.33	28.51	352,674.96
2023	1,031,112.31	30.00	34,368.57	29.12	1,000,934.54
2024	201,003.50	30.00	6,699.76	29.72	199,094.80
<i>Total</i>	8,621,531.73	18.83	278,855.45	21.53	6,003,739.56

Composite Average Remaining Life ... 21.53 Years

***Columbia Gas of Pennsylvania
Gas Division***

387.00 Other Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 32

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1941	38.38	0.00	0.00	0.00	0.00
1942	67.31	0.00	0.00	0.00	0.00
1950	90.19	0.00	0.00	0.00	0.00
1955	4,288.05	0.00	0.00	0.00	0.00
1957	14,374.70	0.00	0.00	0.00	0.00
1959	188.29	0.00	0.00	0.00	0.00
1962	7,626.48	32.00	238.32	0.71	170.38
1967	445.13	32.00	13.91	2.28	31.65
1972	7,910.24	32.00	247.19	3.77	932.43
1981	13,548.93	32.00	423.39	6.85	2,901.02
1985	14,556.64	32.00	454.88	8.43	3,834.71
1992	2,228.63	32.00	69.64	11.55	804.61
2010	68,488.09	32.00	2,140.18	21.92	46,917.25
2015	2,847.08	32.00	88.97	25.29	2,250.04
<i>Total</i>	136,698.14	18.29	3,676.47	15.73	57,842.09

Composite Average Remaining Life ... 15.73 Years

***Columbia Gas of Pennsylvania
Gas Division***

387.40 Other Equipment - Communication

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 25

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1973	917.13	0.00	0.00	0.00	0.00
1974	11,561.27	0.00	0.00	0.00	0.00
1975	3,189.09	25.00	127.56	0.50	63.78
1976	6,308.81	25.00	252.35	0.69	173.73
1980	1,144.78	25.00	45.79	1.87	85.52
1983	10,695.21	25.00	427.80	2.54	1,088.73
1984	4,730.23	25.00	189.20	2.79	527.42
1985	27,353.09	25.00	1,094.09	3.04	3,329.12
1986	61,596.14	25.00	2,463.78	3.31	8,153.61
1987	40,005.58	25.00	1,600.18	3.59	5,737.85
1989	3,425.59	25.00	137.02	4.16	570.63
1990	37,952.71	25.00	1,518.07	4.47	6,781.80
1991	31,594.95	25.00	1,263.76	4.78	6,041.45
1992	6,510.50	25.00	260.41	5.11	1,329.55
1993	1,718.09	25.00	68.72	5.44	374.14
1994	4,082.11	25.00	163.28	5.80	946.77
2000	47,842.64	25.00	1,913.65	8.32	15,917.43
2001	142,467.12	25.00	5,698.52	8.81	50,202.63
2003	2,326.24	25.00	93.05	9.86	917.09
2004	89,547.93	25.00	3,581.82	10.41	37,286.42
2005	219,536.12	25.00	8,781.20	10.98	96,447.45
2006	13,325.90	25.00	533.02	11.58	6,170.26
2007	9,937.59	25.00	397.49	12.19	4,844.27
2008	0.11	25.00	0.00	12.82	0.06
2009	5,832.45	25.00	233.29	13.46	3,140.47
2010	108,042.35	25.00	4,321.57	14.12	61,035.35
2011	42,386.12	25.00	1,695.40	14.80	25,092.81

***Columbia Gas of Pennsylvania
Gas Division***

387.40 Other Equipment - Communication

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 25

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2012	86,817.14	25.00	3,472.59	15.49	53,797.71
2013	486,171.83	25.00	19,446.32	16.20	314,975.93
2014	1,524,759.24	25.00	60,988.65	16.91	1,031,618.70
2015	689,976.13	25.00	27,598.27	17.64	486,955.77
2016	698,561.46	25.00	27,941.67	18.38	513,704.68
2017	1,709,491.37	25.00	68,377.72	19.14	1,308,449.75
2018	1,961,116.84	25.00	78,442.46	19.90	1,560,698.15
2019	714,683.51	25.00	28,586.53	20.67	590,773.14
2020	1,079,074.68	25.00	43,161.77	21.45	925,633.65
2021	567,278.96	25.00	22,690.52	22.23	504,515.89
2022	2,166,903.12	25.00	86,673.68	23.03	1,996,354.07
2023	2,922,926.21	25.00	116,913.75	23.84	2,787,295.53
2024	2,634,081.85	25.00	105,360.30	24.62	2,594,323.10
<i>Total</i>	18,175,872.19	23.75	726,515.25	20.65	15,005,354.36

Composite Average Remaining Life ... 20.65 Years

***Columbia Gas of Pennsylvania
Gas Division***

387.50 Other Equipment - GPS

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2024
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 10

Survivor Curve: S3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2014	1,942,103.70	10.00	194,210.38	1.85	359,657.57
2015	112,834.83	10.00	11,283.48	2.23	25,206.15
2016	33,669.32	10.00	3,366.93	2.70	9,091.77
2017	34,335.00	10.00	3,433.50	3.27	11,220.24
2018	78,429.10	10.00	7,842.91	3.95	30,970.17
<i>Total</i>	2,201,371.95	10.00	220,137.21	1.98	436,145.89

Composite Average Remaining Life ... 1.98 Years

***Columbia Gas of Pennsylvania
Gas Division***

374.40 Land and Land Rights

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 75

Survivor Curve: R2.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1920	1,449.27	75.00	19.32	8.32	160.70
1953	1.93	75.00	0.03	19.14	0.49
1957	3,164.50	75.00	42.19	21.19	894.22
1961	811.93	75.00	10.83	23.42	253.50
1962	317.14	75.00	4.23	24.00	101.47
1963	5,570.56	75.00	74.27	24.59	1,826.53
1964	3,634.14	75.00	48.46	25.19	1,220.72
1965	1,117.26	75.00	14.90	25.80	384.38
1966	2,335.42	75.00	31.14	26.43	822.90
1967	11,231.58	75.00	149.75	27.06	4,051.77
1968	1,963.26	75.00	26.18	27.69	724.93
1969	12,009.53	75.00	160.13	28.34	4,538.77
1970	7,939.54	75.00	105.86	29.00	3,070.02
1971	20,354.77	75.00	271.40	29.66	8,050.73
1972	11,480.46	75.00	153.07	30.34	4,644.26
1973	5,417.78	75.00	72.24	31.02	2,240.84
1974	16,438.96	75.00	219.19	31.71	6,950.01
1975	24,985.76	75.00	333.14	32.41	10,796.48
1976	24,093.18	75.00	321.24	33.11	10,636.80
1977	53,762.68	75.00	716.84	33.82	24,244.63
1978	20,992.78	75.00	279.90	34.54	9,668.82
1979	36,233.50	75.00	483.11	35.27	17,038.79
1980	22,751.51	75.00	303.35	36.00	10,920.86
1981	39,660.95	75.00	528.81	36.74	19,430.13
1982	62,165.80	75.00	828.88	37.49	31,073.72
1983	39,835.96	75.00	531.15	38.24	20,311.55
1984	44,473.43	75.00	592.98	39.00	23,128.13

***Columbia Gas of Pennsylvania
Gas Division***

374.40 Land and Land Rights

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 75

Survivor Curve: R2.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1985	65,600.64	75.00	874.67	39.77	34,784.91
1986	39,561.77	75.00	527.49	40.54	21,384.67
1987	63,498.73	75.00	846.65	41.32	34,984.94
1988	98,277.24	75.00	1,310.36	42.11	55,174.25
1989	130,384.32	75.00	1,738.46	42.90	74,573.03
1990	83,555.23	75.00	1,114.07	43.70	48,679.71
1991	48,931.13	75.00	652.41	44.50	29,031.05
1992	13,402.41	75.00	178.70	45.31	8,096.05
1993	43,073.87	75.00	574.32	46.12	26,488.79
1994	35,146.29	75.00	468.62	46.94	21,997.70
1995	19,193.60	75.00	255.91	47.77	12,224.12
1996	45,846.49	75.00	611.29	48.60	29,708.17
1997	37,585.50	75.00	501.14	49.44	24,774.03
1998	9,136.39	75.00	121.82	50.28	6,124.56
1999	6,008.12	75.00	80.11	51.12	4,095.51
2000	14,174.54	75.00	188.99	51.98	9,823.16
2001	13,583.16	75.00	181.11	52.83	9,568.34
2002	3,018.13	75.00	40.24	53.70	2,160.79
2003	43,547.88	75.00	580.64	54.56	31,680.37
2004	45,091.90	75.00	601.22	55.43	33,326.81
2005	25,530.01	75.00	340.40	56.31	19,167.45
2006	32,747.83	75.00	436.64	57.19	24,970.50
2007	66,833.89	75.00	891.12	58.07	51,748.74
2008	16,422.97	75.00	218.97	58.96	12,910.99
2009	133,148.06	75.00	1,775.31	59.85	106,258.83
2010	80,362.14	75.00	1,071.49	60.75	65,092.94
2011	76,721.11	75.00	1,022.95	61.65	63,066.15

***Columbia Gas of Pennsylvania
Gas Division***

374.40 Land and Land Rights

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 75

Survivor Curve: R2.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2012	207,743.08	75.00	2,769.91	62.56	173,272.27
2013	199,203.51	75.00	2,656.04	63.46	168,559.37
2014	75,368.51	75.00	1,004.91	64.38	64,691.40
2015	135,663.61	75.00	1,808.85	65.29	118,099.07
2016	171,896.35	75.00	2,291.95	66.21	151,743.93
2017	345,096.18	75.00	4,601.28	67.13	308,883.26
2018	192,917.47	75.00	2,572.23	68.05	175,051.04
2019	231,351.14	75.00	3,084.68	68.98	212,785.11
2020	232,499.08	75.00	3,099.98	69.91	216,728.55
2021	2,656,880.47	75.00	35,425.04	70.85	2,509,718.91
2022	652,359.86	75.00	8,698.12	71.78	624,364.82
2023	1,798,860.25	75.00	23,984.78	72.72	1,744,200.73
2024	2,093,017.20	75.00	27,906.87	73.66	2,055,681.90
2025	251,339.37	75.00	3,351.19	74.57	249,885.67
<i>Total</i>	11,008,773.01	75.00	146,783.51	67.12	9,852,748.71

Composite Average Remaining Life ... 67.12 Years

Columbia Gas of Pennsylvania

Gas Division

374.50 Rights of Way

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1883	866.25	0.00	0.00	0.00	0.00
1884	2,319.40	0.00	0.00	0.00	0.00
1885	952.00	0.00	0.00	0.00	0.00
1886	9,401.15	0.00	0.00	0.00	0.00
1887	4,690.00	80.00	58.63	0.50	29.31
1888	6,579.75	80.00	82.25	0.94	77.25
1889	6,551.18	80.00	81.89	1.42	116.46
1890	1,679.50	80.00	20.99	1.25	26.24
1891	8,350.23	80.00	104.38	1.38	143.52
1892	1,354.95	80.00	16.94	1.56	26.44
1893	650.85	80.00	8.14	1.64	13.32
1894	1,616.78	80.00	20.21	1.66	33.62
1895	1,133.20	80.00	14.17	1.79	25.38
1896	4,260.56	80.00	53.26	1.92	102.16
1897	2,267.65	80.00	28.35	2.04	57.82
1898	1,633.73	80.00	20.42	2.05	41.92
1899	934.25	80.00	11.68	2.18	25.49
1900	8,185.42	80.00	102.32	2.31	236.59
1901	15,227.76	80.00	190.35	2.44	463.76
1902	7,330.74	80.00	91.63	2.47	226.26
1903	15,446.32	80.00	193.08	2.60	502.31
1904	8,443.31	80.00	105.54	2.73	288.57
1905	13,211.32	80.00	165.14	2.87	473.41
1906	5,826.89	80.00	72.84	2.92	212.62
1907	4,318.72	80.00	53.98	3.06	164.96
1908	5,084.82	80.00	63.56	3.19	203.04
1909	5,578.23	80.00	69.73	3.33	232.53

Columbia Gas of Pennsylvania

Gas Division

374.50 Rights of Way

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1910	944.58	80.00	11.81	3.41	40.24
1911	1,805.52	80.00	22.57	3.55	80.14
1912	1,590.08	80.00	19.88	3.70	73.50
1913	4,199.64	80.00	52.50	3.85	202.00
1914	6,522.34	80.00	81.53	3.94	321.36
1915	9,299.36	80.00	116.24	4.09	475.98
1916	2,131.53	80.00	26.64	4.25	113.30
1917	2,947.27	80.00	36.84	4.41	162.62
1918	969.85	80.00	12.12	4.53	54.92
1919	713.16	80.00	8.91	4.70	41.86
1920	1,116.43	80.00	13.96	4.87	67.92
1921	2,386.50	80.00	29.83	5.04	150.44
1922	5,478.84	80.00	68.49	5.18	354.96
1923	5,748.64	80.00	71.86	5.36	385.51
1924	2,962.36	80.00	37.03	5.55	205.62
1925	8,085.67	80.00	101.07	5.75	580.84
1926	3,690.49	80.00	46.13	5.91	272.81
1927	3,441.21	80.00	43.02	6.12	263.07
1928	3,616.30	80.00	45.20	6.32	285.90
1929	9,736.71	80.00	121.71	6.54	796.04
1930	3,705.73	80.00	46.32	6.74	312.11
1931	4,695.61	80.00	58.70	6.96	408.79
1932	2,031.20	80.00	25.39	7.20	182.79
1933	2,540.95	80.00	31.76	7.44	236.37
1934	4,020.82	80.00	50.26	7.67	385.73
1935	866.62	80.00	10.83	7.93	85.92
1936	4,994.63	80.00	62.43	8.20	511.80

Columbia Gas of Pennsylvania

Gas Division

374.50 Rights of Way

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1937	3,607.79	80.00	45.10	8.47	382.12
1938	1,245.49	80.00	15.57	8.75	136.17
1939	956.06	80.00	11.95	9.04	108.04
1940	13,850.45	80.00	173.13	9.34	1,617.85
1941	4,887.61	80.00	61.10	9.66	590.18
1942	8,169.68	80.00	102.12	9.98	1,019.27
1943	1,693.42	80.00	21.17	10.32	218.43
1944	978.40	80.00	12.23	10.67	130.49
1945	1,004.81	80.00	12.56	11.03	138.57
1946	344.00	80.00	4.30	11.41	49.06
1947	142.29	80.00	1.78	11.80	20.99
1948	3,080.71	80.00	38.51	12.20	469.98
1949	16,198.32	80.00	202.48	12.62	2,556.15
1950	20,911.66	80.00	261.40	13.06	3,414.80
1951	11,956.42	80.00	149.46	13.52	2,020.08
1952	8,038.39	80.00	100.48	13.99	1,405.22
1953	5,949.87	80.00	74.37	14.47	1,076.22
1954	21,585.01	80.00	269.81	14.98	4,042.15
1955	32,149.56	80.00	401.87	15.50	6,230.72
1956	51,702.96	80.00	646.29	16.05	10,369.92
1957	19,916.61	80.00	248.96	16.60	4,133.88
1958	63,499.25	80.00	793.74	17.19	13,647.35
1959	28,371.09	80.00	354.64	17.79	6,310.57
1960	26,305.63	80.00	328.82	18.41	6,055.00
1961	15,768.03	80.00	197.10	19.05	3,755.49
1962	18,087.78	80.00	226.10	19.72	4,459.70
1963	27,374.57	80.00	342.18	20.41	6,982.91

Columbia Gas of Pennsylvania

Gas Division

374.50 Rights of Way

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1964	40,027.79	80.00	500.35	21.11	10,561.77
1965	17,574.04	80.00	219.68	21.83	4,795.56
1966	18,597.25	80.00	232.47	22.58	5,249.70
1967	96,910.77	80.00	1,211.38	23.35	28,280.75
1968	82,637.79	80.00	1,032.97	24.13	24,922.95
1969	46,057.56	80.00	575.72	24.93	14,351.02
1970	45,097.36	80.00	563.72	25.75	14,518.43
1971	54,600.87	80.00	682.51	26.59	18,149.23
1972	80,822.88	80.00	1,010.29	27.44	27,727.21
1973	31,060.02	80.00	388.25	28.31	10,992.64
1974	42,716.26	80.00	533.95	29.20	15,593.75
1975	53,203.52	80.00	665.04	30.10	20,019.71
1976	46,796.87	80.00	584.96	31.01	18,141.84
1977	50,016.13	80.00	625.20	31.94	19,966.60
1978	27,600.77	80.00	345.01	32.88	11,342.20
1979	28,400.77	80.00	355.01	33.82	12,006.06
1980	24,054.08	80.00	300.68	34.77	10,454.93
1981	55,235.53	80.00	690.44	35.73	24,670.57
1982	47,534.94	80.00	594.19	36.70	21,807.62
1983	27,148.25	80.00	339.35	37.67	12,785.10
1984	30,306.87	80.00	378.84	38.65	14,643.19
1985	72,105.59	80.00	901.32	39.64	35,724.36
1986	17,533.91	80.00	219.17	40.62	8,903.59
1987	27,416.83	80.00	342.71	41.61	14,261.12
1988	11,339.22	80.00	141.74	42.60	6,038.77
1989	70,129.19	80.00	876.61	43.60	38,218.82
1990	44,760.66	80.00	559.51	44.59	24,950.81

Columbia Gas of Pennsylvania

Gas Division

374.50 Rights of Way

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1991	35,224.46	80.00	440.31	45.59	20,073.87
1992	54,141.31	80.00	676.77	46.59	31,529.38
1993	58,993.43	80.00	737.42	47.59	35,091.15
1994	184,531.84	80.00	2,306.65	48.59	112,069.70
1995	584,928.49	80.00	7,311.61	49.58	362,543.86
1996	126,940.88	80.00	1,586.76	50.58	80,264.97
1997	68,030.65	80.00	850.38	51.58	43,865.99
1998	40,132.45	80.00	501.66	52.58	26,378.88
2000	15,568.19	80.00	194.60	54.58	10,622.06
2001	39,714.12	80.00	496.43	55.58	27,593.06
2002	181,571.19	80.00	2,269.64	56.58	128,423.85
2003	1,938.28	80.00	24.23	57.58	1,395.16
<i>Total</i>	3,233,313.87	77.33	40,247.19	35.80	1,441,047.06

Composite Average Remaining Life ... 35.80 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1913	395.64	60.00	6.59	3.67	24.19
1914	249.85	60.00	4.16	4.13	17.21
1925	203.64	60.00	3.39	8.84	30.01
1928	542.82	60.00	9.05	10.05	90.90
1929	4,042.19	60.00	67.37	10.45	703.81
1930	4,284.96	60.00	71.41	10.84	774.37
1931	1,108.62	60.00	18.48	11.24	207.66
1932	1,574.17	60.00	26.24	11.64	305.28
1933	1,815.34	60.00	30.26	12.03	364.00
1934	1,068.29	60.00	17.80	12.43	221.25
1935	15.04	60.00	0.25	12.82	3.21
1936	1,939.80	60.00	32.33	13.22	427.38
1938	601.17	60.00	10.02	14.02	140.43
1939	3,990.56	60.00	66.51	14.42	958.75
1940	539.46	60.00	8.99	14.82	133.21
1941	874.10	60.00	14.57	15.22	221.73
1942	113.25	60.00	1.89	15.62	29.49
1943	177.30	60.00	2.95	16.03	47.37
1945	624.35	60.00	10.41	16.85	175.35
1946	1,000.67	60.00	16.68	17.26	287.93
1947	2,254.88	60.00	37.58	17.68	664.47
1948	6,566.69	60.00	109.44	18.10	1,980.88
1949	1,131.75	60.00	18.86	18.52	349.35
1950	4,935.82	60.00	82.26	18.95	1,558.50
1951	7,605.74	60.00	126.76	19.37	2,455.68
1952	15,288.75	60.00	254.81	19.80	5,045.96
1953	21,705.25	60.00	361.75	20.24	7,320.50

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1954	12,246.55	60.00	204.11	20.67	4,219.49
1955	11,912.79	60.00	198.54	21.11	4,191.85
1956	21,709.34	60.00	361.82	21.56	7,799.43
1957	27,195.45	60.00	453.25	22.00	9,972.91
1958	31,186.32	60.00	519.76	22.45	11,670.45
1959	20,761.11	60.00	346.01	22.91	7,926.13
1960	24,738.71	60.00	412.30	23.36	9,633.33
1961	34,695.82	60.00	578.25	23.83	13,777.31
1962	31,732.84	60.00	528.87	24.29	12,846.42
1963	19,614.97	60.00	326.91	24.76	8,093.95
1964	39,850.92	60.00	664.17	25.23	16,757.86
1965	27,411.86	60.00	456.86	25.71	11,744.42
1966	26,810.15	60.00	446.83	26.19	11,701.15
1967	18,305.07	60.00	305.08	26.67	8,136.76
1968	8,362.71	60.00	139.38	27.16	3,785.20
1969	15,371.17	60.00	256.18	27.65	7,083.41
1970	4,965.60	60.00	82.76	28.15	2,329.27
1971	20,377.36	60.00	339.62	28.64	9,728.05
1972	10,046.76	60.00	167.44	29.15	4,880.56
1973	12,451.23	60.00	207.52	29.65	6,153.85
1974	4,462.56	60.00	74.37	30.17	2,243.51
1975	16,669.34	60.00	277.82	30.68	8,523.44
1976	22,295.57	60.00	371.59	31.20	11,592.97
1977	14,243.90	60.00	237.39	31.72	7,530.21
1978	20,793.79	60.00	346.56	32.25	11,175.28
1979	29,383.84	60.00	489.72	32.78	16,051.32
1980	12,245.62	60.00	204.09	33.31	6,798.07

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1981	27,409.53	60.00	456.82	33.85	15,461.62
1982	34,083.99	60.00	568.06	34.39	19,533.74
1983	11,621.52	60.00	193.69	34.93	6,765.60
1984	14,400.21	60.00	240.00	35.48	8,514.69
1985	12,666.33	60.00	211.10	36.03	7,605.73
1986	26,137.02	60.00	435.61	36.58	15,935.50
1987	3,241.20	60.00	54.02	37.14	2,006.24
1988	16,358.97	60.00	272.64	37.70	10,278.62
1989	14,329.80	60.00	238.83	38.26	9,138.02
1990	8,213.94	60.00	136.90	38.83	5,315.49
1991	15,363.04	60.00	256.05	39.40	10,087.55
1992	128.65	60.00	2.14	39.97	85.70
1993	21,142.74	60.00	352.37	40.54	14,286.09
1995	13,490.59	60.00	224.84	41.70	9,375.18
1996	11,731.22	60.00	195.52	42.28	8,266.15
1997	8,683.96	60.00	144.73	42.86	6,203.35
1998	59,183.25	60.00	986.37	43.45	42,853.88
1999	2,530.96	60.00	42.18	44.03	1,857.40
2000	20,166.25	60.00	336.10	44.62	14,997.27
2001	26,411.66	60.00	440.19	45.21	19,901.46
2002	14,610.43	60.00	243.50	45.80	11,153.23
2003	62,171.70	60.00	1,036.18	46.40	48,074.84
2004	24,865.14	60.00	414.41	46.99	19,473.35
2005	48,125.09	60.00	802.07	47.59	38,167.39
2006	54,454.63	60.00	907.56	48.18	43,728.85
2007	93,821.13	60.00	1,563.66	48.78	76,275.61
2008	343,788.28	60.00	5,729.70	49.38	282,928.28

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2009	93,764.86	60.00	1,562.72	49.98	78,103.37
2010	138,811.32	60.00	2,313.48	50.58	117,015.11
2011	198,104.48	60.00	3,301.68	51.18	168,986.13
2012	227,209.31	60.00	3,786.75	51.79	196,097.06
2013	219,369.43	60.00	3,656.09	52.39	191,538.75
2014	338,103.90	60.00	5,634.96	52.99	298,622.61
2015	872,223.57	60.00	14,536.79	53.60	779,192.22
2016	384,475.36	60.00	6,407.80	54.21	347,360.77
2017	355,555.90	60.00	5,925.82	54.82	324,844.58
2018	164,107.95	60.00	2,735.08	55.43	151,603.28
2019	664,440.03	60.00	11,073.79	56.04	620,583.81
2020	288,003.95	60.00	4,799.98	56.65	271,939.18
2021	247,874.03	60.00	4,131.16	57.27	236,587.53
2022	296,096.99	60.00	4,934.86	57.88	285,653.52
2023	437,393.23	60.00	7,289.75	58.50	426,469.73
2024	613,863.82	60.00	10,230.87	59.12	604,867.34
2025	734,240.99	60.00	12,237.12	59.72	730,753.22
<i>Total</i>	7,887,261.80	60.00	131,451.92	52.03	6,839,374.52

Composite Average Remaining Life ... 52.03 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.60 Structures - Industrial M&R

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1928	87.15	55.00	1.58	4.26	6.75
1930	127.57	55.00	2.32	4.85	11.26
1931	263.40	55.00	4.79	5.16	24.69
1934	783.68	55.00	14.25	6.06	86.28
1935	147.25	55.00	2.68	6.36	17.03
1936	21.46	55.00	0.39	6.68	2.61
1937	618.76	55.00	11.25	6.99	78.65
1938	1,433.03	55.00	26.05	7.31	190.44
1940	440.04	55.00	8.00	7.96	63.67
1942	1,018.37	55.00	18.52	8.63	159.74
1944	2,850.41	55.00	51.82	9.31	482.46
1946	377.07	55.00	6.86	10.01	68.63
1947	568.77	55.00	10.34	10.37	107.24
1948	482.71	55.00	8.78	10.73	94.18
1950	1,857.60	55.00	33.77	11.47	387.36
1951	3,131.90	55.00	56.94	11.85	674.50
1952	3,450.55	55.00	62.74	12.23	767.05
1953	4,259.74	55.00	77.45	12.61	976.88
1955	4,904.63	55.00	89.17	13.40	1,194.94
1956	2,507.83	55.00	45.60	13.80	629.29
1957	14,375.38	55.00	261.36	14.21	3,713.46
1958	1,667.93	55.00	30.33	14.62	443.36
1959	5,902.55	55.00	107.32	15.04	1,613.72
1960	1,345.00	55.00	24.45	15.46	378.05
1961	1,954.81	55.00	35.54	15.89	564.66
1963	3,416.99	55.00	62.13	16.76	1,041.24
1967	1,614.49	55.00	29.35	18.57	545.24

***Columbia Gas of Pennsylvania
Gas Division***

375.60 Structures - Industrial M&R

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1970	2,450.11	55.00	44.55	20.00	890.82
1971	7,721.50	55.00	140.39	20.48	2,875.74
1972	1.00	55.00	0.02	20.98	0.38
1980	3,885.67	55.00	70.65	25.14	1,776.39
1988	11,897.69	55.00	216.32	29.72	6,428.37
<i>Total</i>	85,565.04	55.00	1,555.69	16.90	26,295.06

Composite Average Remaining Life ... 16.90 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.71 Distribution Systems - Company Stations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 90

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1928	539.04	90.00	5.99	25.61	153.38
1931	4,005.57	90.00	44.51	26.91	1,197.84
1933	401.96	90.00	4.47	27.81	124.22
1934	778.19	90.00	8.65	28.27	244.45
1937	77.17	90.00	0.86	29.68	25.45
1939	1,201.91	90.00	13.35	30.65	409.34
1948	244.11	90.00	2.71	35.30	95.75
1949	338.10	90.00	3.76	35.85	134.66
1950	56.50	90.00	0.63	36.40	22.85
1951	94.17	90.00	1.05	36.95	38.66
1955	5,011.58	90.00	55.68	39.23	2,184.61
1957	18,804.17	90.00	208.93	40.40	8,441.71
1958	45,295.26	90.00	503.28	41.00	20,632.97
1959	665.84	90.00	7.40	41.60	307.73
1960	720.61	90.00	8.01	42.20	337.88
1962	275.80	90.00	3.06	43.42	133.07
1963	16,296.83	90.00	181.07	44.04	7,975.23
1964	81,335.93	90.00	903.72	44.67	40,367.46
1965	6,256.39	90.00	69.51	45.30	3,148.78
1968	462.64	90.00	5.14	47.21	242.68
1969	117.03	90.00	1.30	47.86	62.23
1971	1,426.78	90.00	15.85	49.17	779.47
1973	1,166.63	90.00	12.96	50.49	654.54
1976	1,998.47	90.00	22.21	52.52	1,166.12
1978	3,472.31	90.00	38.58	53.88	2,078.87
1979	85,249.40	90.00	947.21	54.57	51,691.90
1981	593,681.70	90.00	6,596.40	55.97	369,179.00

***Columbia Gas of Pennsylvania
Gas Division***

375.71 Distribution Systems - Company Stations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 90

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1982	1,111.41	90.00	12.35	56.67	699.79
1983	5,480.40	90.00	60.89	57.37	3,493.60
1984	4,760.67	90.00	52.90	58.08	3,072.27
1985	20,862.34	90.00	231.80	58.79	13,628.45
1986	14,531.65	90.00	161.46	59.51	9,608.40
1987	198,785.72	90.00	2,208.71	60.23	133,025.77
1988	10,177.82	90.00	113.09	60.95	6,892.57
1991	1,625.41	90.00	18.06	63.14	1,140.27
1993	27,303.35	90.00	303.37	64.61	19,600.95
1995	202,894.25	90.00	2,254.36	66.10	149,003.59
1996	54,924.25	90.00	610.26	66.84	40,791.42
1997	59,116.96	90.00	656.85	67.59	44,397.46
1998	292,879.46	90.00	3,254.19	68.35	222,409.26
1999	6,939.23	90.00	77.10	69.10	5,327.79
2000	6,596.38	90.00	73.29	69.86	5,120.09
2001	38,452.52	90.00	427.25	70.62	30,171.59
2005	152,784.63	90.00	1,697.59	73.69	125,089.36
2006	126,751.26	90.00	1,408.33	74.46	104,864.30
2007	8,637.28	90.00	95.97	75.24	7,220.48
2008	7,810.00	90.00	86.78	76.02	6,596.50
2009	41,747.68	90.00	463.86	76.80	35,623.55
2010	147,736.99	90.00	1,641.51	77.58	127,352.07
2011	33,989.54	90.00	377.66	78.37	29,596.74
2012	781,914.65	90.00	8,687.86	79.16	687,717.53
2013	165,318.56	90.00	1,836.86	79.95	146,857.19
2014	30,907.80	90.00	343.42	80.74	27,729.10
2015	1,432,975.31	90.00	15,921.80	81.54	1,298,291.32

***Columbia Gas of Pennsylvania
Gas Division***

375.71 Distribution Systems - Company Stations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 90

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2016	1,332,537.84	90.00	14,805.84	82.34	1,219,157.81
2017	220,104.62	90.00	2,445.58	83.15	203,339.26
2018	2,397,766.58	90.00	26,641.60	83.95	2,236,574.50
2019	7,748,293.91	90.00	86,091.34	84.76	7,296,926.75
2020	52,049.67	90.00	578.32	85.57	49,486.04
2021	22,830,754.88	90.00	253,672.64	86.38	21,912,383.41
2022	307,977.36	90.00	3,421.94	87.20	298,378.07
2023	6,434,577.19	90.00	71,494.62	88.01	6,292,471.61
2024	303,625.27	90.00	3,373.58	88.83	299,686.57
2025	186,120.28	90.00	2,067.98	89.62	185,336.31
<i>Total</i>	46,560,797.21	90.00	517,337.28	84.65	43,790,892.57

Composite Average Remaining Life ... 84.65 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.72 Portable Substations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 38

Survivor Curve: S1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1953	2,600.92	38.00	68.45	1.02	69.52
1954	2,263.57	38.00	59.57	1.24	74.15
1955	7,045.40	38.00	185.41	1.49	277.01
1956	294.53	38.00	7.75	1.76	13.61
1961	5,869.31	38.00	154.46	3.01	465.14
1966	2,114.98	38.00	55.66	4.27	237.49
1969	1,259.56	38.00	33.15	5.05	167.34
1971	106,649.53	38.00	2,806.57	5.59	15,677.12
1972	9,337.50	38.00	245.72	5.86	1,440.71
1975	5,381.53	38.00	141.62	6.71	950.90
1976	6,723.83	38.00	176.94	7.01	1,240.06
1984	43,036.41	38.00	1,132.54	9.63	10,901.92
1985	3,259.62	38.00	85.78	9.99	857.10
1987	14,383.92	38.00	378.52	10.75	4,070.87
1989	3,973.21	38.00	104.56	11.56	1,208.89
1990	32,260.00	38.00	848.95	11.98	10,173.53
1993	8,113.24	38.00	213.51	13.33	2,845.62
1994	15,147.02	38.00	398.61	13.80	5,502.26
1995	27,857.47	38.00	733.09	14.30	10,480.02
1996	2,392.16	38.00	62.95	14.80	931.87
1997	1,337.50	38.00	35.20	15.33	539.42
1998	56,879.39	38.00	1,496.83	15.87	23,749.40
1999	27,416.01	38.00	721.47	16.42	11,848.71
2000	192,645.29	38.00	5,069.61	17.00	86,180.89
2001	10,788.71	38.00	283.91	17.59	4,995.23
2004	9,680.31	38.00	254.75	19.49	4,965.68
2007	18,396.12	38.00	484.11	21.57	10,443.75

***Columbia Gas of Pennsylvania
Gas Division***

375.72 Portable Substations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 38

Survivor Curve: S1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2008	208,679.85	38.00	5,491.58	22.31	122,502.75
2010	21,628.69	38.00	569.18	23.84	13,568.95
2011	45,764.94	38.00	1,204.34	24.64	29,673.00
2012	5,855.06	38.00	154.08	25.46	3,922.42
2013	612,757.25	38.00	16,125.19	26.29	423,995.84
2014	116,167.32	38.00	3,057.03	27.15	83,005.90
2015	309,088.24	38.00	8,133.90	28.03	227,985.85
2016	431,798.65	38.00	11,363.12	28.92	328,651.89
2017	62,675.61	38.00	1,649.36	29.83	49,207.94
2018	211,266.41	38.00	5,559.64	30.76	171,019.44
2019	547,609.83	38.00	14,410.79	31.70	456,875.32
2020	169,096.94	38.00	4,449.92	32.66	145,332.35
2021	124,256.14	38.00	3,269.90	33.63	109,955.11
2022	485,748.21	38.00	12,782.85	34.60	442,349.11
2023	837,170.74	38.00	22,030.81	35.59	784,115.36
2024	98,255.59	38.00	2,585.67	36.59	94,597.11
2025	148,929.72	38.00	3,919.20	37.54	147,133.84
<i>Total</i>	5,053,856.23	38.00	132,996.22	28.90	3,844,200.39

Composite Average Remaining Life ... 28.90 Years

Columbia Gas of Pennsylvania

Gas Division

375.80 Communication

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2001	16,515.16	45.00	367.00	22.64	8,307.93
<i>Total</i>	16,515.16	45.00	367.00	22.64	8,307.93

Composite Average Remaining Life ... 22.64 Years

***Columbia Gas of Pennsylvania
Gas Division***

376.01 Mains - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1946	1,122.58	65.00	17.27	17.38	300.22
1947	17,956.17	65.00	276.24	17.80	4,917.59
1948	82,027.94	65.00	1,261.94	18.22	22,997.71
1949	270,040.72	65.00	4,154.39	18.65	77,484.16
1950	517,464.61	65.00	7,960.84	19.08	151,916.49
1951	379,534.10	65.00	5,838.87	19.52	113,972.29
1952	992,131.16	65.00	15,263.26	19.96	304,667.02
1953	672,306.30	65.00	10,342.98	20.41	211,070.06
1954	950,201.30	65.00	14,618.20	20.86	304,905.89
1955	2,925,866.95	65.00	45,012.47	21.31	959,402.54
1956	1,713,169.83	65.00	26,355.95	21.77	573,895.99
1957	2,443,177.77	65.00	37,586.63	22.24	835,968.17
1958	2,931,215.56	65.00	45,094.76	22.71	1,024,180.14
1959	2,313,280.44	65.00	35,588.25	23.19	825,231.63
1960	2,628,120.57	65.00	40,431.85	23.67	956,983.91
1961	2,783,938.03	65.00	42,828.99	24.16	1,034,581.90
1962	2,489,841.43	65.00	38,304.52	24.65	944,095.65
1963	3,159,643.77	65.00	48,608.97	25.14	1,222,261.30
1964	3,160,572.95	65.00	48,623.27	25.65	1,247,054.85
1965	2,583,801.11	65.00	39,750.02	26.15	1,039,641.98
1966	3,615,720.44	65.00	55,625.40	26.67	1,483,404.91
1967	3,387,070.94	65.00	52,107.79	27.19	1,416,577.19
1968	2,673,374.99	65.00	41,128.06	27.71	1,139,642.90
1969	1,944,864.03	65.00	29,920.41	28.24	844,892.19
1970	964,179.46	65.00	14,833.25	28.77	426,796.52
1971	2,297,563.33	65.00	35,346.45	29.31	1,036,073.57
1972	849,547.11	65.00	13,069.71	29.86	390,233.07

***Columbia Gas of Pennsylvania
Gas Division***

376.01 Mains - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1973	576,786.37	65.00	8,873.47	30.41	269,819.30
1974	1,241.33	65.00	19.10	30.96	591.32
1975	768.11	65.00	11.82	31.52	372.52
1976	245.47	65.00	3.78	32.09	121.19
1977	1,936.21	65.00	29.79	32.66	972.97
1978	166,965.70	65.00	2,568.65	33.24	85,383.50
1979	16,282.83	65.00	250.50	33.82	8,472.73
1980	200,184.10	65.00	3,079.70	34.41	105,972.51
1981	44.22	65.00	0.68	35.00	23.81
1983	1,348.69	65.00	20.75	36.20	751.16
1984	200.40	65.00	3.08	36.81	113.48
1985	34.91	65.00	0.54	37.42	20.10
1986	31.10	65.00	0.48	38.04	18.20
1988	0.10	65.00	0.00	39.29	0.06
1989	27.84	65.00	0.43	39.92	17.10
1990	11,581.79	65.00	178.18	40.55	7,225.35
1992	44,727.77	65.00	688.11	41.83	28,785.19
1997	3,983.38	65.00	61.28	45.10	2,763.79
1998	658.56	65.00	10.13	45.76	463.66
2008	77.56	65.00	1.19	52.55	62.70
2011	28,098.27	65.00	432.27	54.63	23,614.51
<i>Total</i>	49,802,958.30	65.00	766,184.67	24.97	19,128,714.98

Composite Average Remaining Life ... 24.97 Years

Columbia Gas of Pennsylvania

Gas Division

376.02 Mains - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1952	120,794.95	65.00	1,858.35	19.96	37,094.13
1954	25,602.45	65.00	393.88	20.86	8,215.46
1955	97,420.61	65.00	1,498.75	21.31	31,944.58
1956	65,788.99	65.00	1,012.12	21.77	22,038.70
1957	85,070.12	65.00	1,308.75	22.24	29,107.96
1958	76,824.72	65.00	1,181.90	22.71	26,842.91
1959	79,864.55	65.00	1,228.66	23.19	28,490.60
1960	56,697.12	65.00	872.25	23.67	20,645.26
1961	15,307.66	65.00	235.50	24.16	5,688.71
1962	68,420.80	65.00	1,052.61	24.65	25,943.73
1963	98,696.57	65.00	1,518.38	25.14	38,179.30
1964	156,475.14	65.00	2,407.26	25.65	61,739.78
1965	53,103.81	65.00	816.97	26.15	21,367.34
1966	98,034.31	65.00	1,508.19	26.67	40,220.08
1967	44,977.82	65.00	691.95	27.19	18,811.11
1968	251,740.08	65.00	3,872.85	27.71	107,315.21
1969	533,292.35	65.00	8,204.34	28.24	231,674.06
1970	547,114.87	65.00	8,416.99	28.77	242,181.81
1971	1,170,420.15	65.00	18,006.12	29.31	527,794.54
1972	886,876.84	65.00	13,644.00	29.86	407,380.20
1973	1,941,035.54	65.00	29,861.51	30.41	908,011.83
1974	2,453,884.77	65.00	37,751.35	30.96	1,168,939.06
1975	2,310,122.84	65.00	35,539.67	31.52	1,120,363.84
1976	2,011,114.00	65.00	30,939.62	32.09	992,909.10
1977	3,993,756.03	65.00	61,441.22	32.66	2,006,914.49
1978	4,251,720.75	65.00	65,409.83	33.24	2,174,259.62
1979	5,205,802.25	65.00	80,087.73	33.82	2,708,827.36

Columbia Gas of Pennsylvania

Gas Division

376.02 Mains - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1980	6,796,762.80	65.00	104,563.58	34.41	3,598,038.07
1981	7,425,151.25	65.00	114,230.91	35.00	3,998,433.79
1982	7,165,424.84	65.00	110,235.19	35.60	3,924,359.09
1983	6,226,057.32	65.00	95,783.66	36.20	3,467,655.22
1984	7,049,096.18	65.00	108,445.56	36.81	3,991,824.63
1985	6,481,453.93	65.00	99,712.76	37.42	3,731,486.68
1986	7,460,668.68	65.00	114,777.32	38.04	4,365,925.14
1987	7,441,258.18	65.00	114,478.70	38.66	4,425,799.88
1988	8,602,645.13	65.00	132,345.85	39.29	5,199,247.11
1989	7,658,642.18	65.00	117,823.01	39.92	4,703,080.86
1990	6,208,732.67	65.00	95,517.13	40.55	3,873,342.71
1991	6,223,290.56	65.00	95,741.10	41.19	3,943,525.65
1992	6,905,573.30	65.00	106,237.55	41.83	4,444,180.00
1993	7,589,387.34	65.00	116,757.57	42.48	4,959,678.44
1994	9,635,546.68	65.00	148,236.34	43.13	6,393,297.59
1995	9,480,893.25	65.00	145,857.10	43.78	6,385,953.22
1996	9,944,587.12	65.00	152,990.72	44.44	6,798,908.90
1997	11,907,072.05	65.00	183,182.21	45.10	8,261,489.55
1998	10,518,851.82	65.00	161,825.39	45.76	7,405,792.01
1999	9,101,843.41	65.00	140,025.68	46.43	6,501,397.63
2000	9,028,126.96	65.00	138,891.60	47.10	6,541,824.27
2001	10,377,803.70	65.00	159,655.46	47.77	7,627,017.06
2002	7,013,459.68	65.00	107,897.31	48.45	5,227,334.87
2003	10,294,799.44	65.00	158,378.49	49.12	7,780,333.30
2004	15,762,011.57	65.00	242,487.84	49.80	12,076,972.60
2005	21,130,625.93	65.00	325,080.32	50.49	16,412,293.71
2006	9,743,708.25	65.00	149,900.33	51.17	7,670,544.80

Columbia Gas of Pennsylvania

Gas Division

376.02 Mains - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2007	35,340,032.06	65.00	543,682.38	51.86	28,194,301.25
2008	55,421,322.07	65.00	852,619.38	52.55	44,802,262.44
2009	33,687,685.53	65.00	518,262.15	53.24	27,591,471.44
2010	44,228,152.36	65.00	680,420.07	53.93	36,696,257.55
2011	80,897,895.00	65.00	1,244,559.15	54.63	67,988,670.29
2012	88,315,110.99	65.00	1,358,667.98	55.33	75,171,215.38
2013	115,281,036.00	65.00	1,773,520.41	56.03	99,369,542.99
2014	123,303,599.04	65.00	1,896,942.09	56.73	107,619,973.75
2015	118,261,012.04	65.00	1,819,365.32	57.44	104,507,237.80
2016	164,455,974.08	65.00	2,530,043.42	58.15	147,127,837.47
2017	180,762,842.34	65.00	2,780,913.51	58.87	163,699,764.55
2018	155,651,450.46	65.00	2,394,591.81	59.58	142,675,557.82
2019	229,399,559.70	65.00	3,529,156.36	60.30	212,814,457.94
2020	227,478,540.98	65.00	3,499,602.79	61.03	213,564,208.13
2021	206,705,526.78	65.00	3,180,024.08	61.75	196,370,100.40
2022	270,708,423.46	65.00	4,164,665.16	62.48	260,214,289.80
2023	316,167,139.17	65.00	4,864,016.61	63.21	307,474,292.85
2024	261,646,848.64	65.00	4,025,258.99	63.95	257,421,183.07
2025	229,041,193.68	65.00	3,523,643.14	64.66	227,839,833.92
<i>Total</i>	3,206,626,778.69	65.00	49,331,774.19	58.74	2,897,865,096.38

Composite Average Remaining Life ... 58.74 Years

***Columbia Gas of Pennsylvania
Gas Division***

378.00 M&R Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1966	85.48	45.00	1.90	13.01	24.71
1967	5,846.34	45.00	129.92	13.43	1,744.53
1968	9,225.15	45.00	205.00	13.85	2,838.98
1969	18,291.82	45.00	406.47	14.27	5,801.56
1970	15,087.46	45.00	335.27	14.70	4,928.85
1971	56,631.84	45.00	1,258.45	15.13	19,044.97
1972	37,762.40	45.00	839.14	15.57	13,065.73
1973	40,352.66	45.00	896.70	16.01	14,357.51
1974	38,070.60	45.00	845.99	16.46	13,922.57
1975	28,603.73	45.00	635.62	16.91	10,746.71
1976	26,626.31	45.00	591.68	17.36	10,272.98
1977	46,580.94	45.00	1,035.10	17.82	18,447.84
1978	20,793.32	45.00	462.06	18.29	8,449.83
1979	21,635.22	45.00	480.77	18.76	9,017.81
1980	32,600.79	45.00	724.44	19.23	13,932.34
1981	69,464.32	45.00	1,543.61	19.71	30,427.09
1982	159,751.63	45.00	3,549.94	20.20	71,698.20
1983	71,992.27	45.00	1,599.78	20.69	33,095.13
1984	98,382.32	45.00	2,186.21	21.18	46,309.66
1985	157,259.76	45.00	3,494.57	21.68	75,772.79
1986	130,031.43	45.00	2,889.51	22.19	64,114.11
1987	122,912.31	45.00	2,731.31	22.70	62,000.53
1988	268,392.76	45.00	5,964.12	23.22	138,462.06
1989	178,342.06	45.00	3,963.05	23.74	94,069.88
1990	154,337.57	45.00	3,429.63	24.26	83,211.70
1991	179,503.80	45.00	3,988.86	24.79	98,899.52
1992	69,264.33	45.00	1,539.17	25.33	38,986.48

***Columbia Gas of Pennsylvania
Gas Division***

378.00 M&R Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1993	128,509.39	45.00	2,855.69	25.87	73,876.63
1994	230,241.63	45.00	5,116.34	26.41	135,147.89
1995	66,223.66	45.00	1,471.60	26.96	39,680.61
1996	358,131.95	45.00	7,958.27	27.52	219,001.61
1997	53,815.07	45.00	1,195.86	28.08	33,575.85
1998	22,224.86	45.00	493.87	28.64	14,143.91
1999	477,663.60	45.00	10,614.46	29.20	309,991.29
2000	892,878.36	45.00	19,841.20	29.77	590,764.85
2001	189,988.02	45.00	4,221.84	30.35	128,123.36
2002	223,897.52	45.00	4,975.36	30.92	153,858.49
2003	366,824.49	45.00	8,151.43	31.50	256,797.84
2004	278,616.81	45.00	6,191.31	32.09	198,651.83
2005	109,784.31	45.00	2,439.58	32.67	79,703.44
2006	470,831.05	45.00	10,462.62	33.26	347,968.49
2007	468,163.81	45.00	10,403.35	33.85	352,130.20
2008	1,240,977.69	45.00	27,576.52	34.44	949,714.94
2009	423,237.96	45.00	9,405.03	35.03	329,486.19
2010	1,389,694.59	45.00	30,881.25	35.63	1,100,239.87
2011	2,039,897.66	45.00	45,329.81	36.22	1,642,058.57
2012	698,880.33	45.00	15,530.25	36.82	571,865.70
2013	3,082,389.51	45.00	68,495.66	37.42	2,563,248.73
2014	10,257,352.63	45.00	227,934.91	38.02	8,666,819.58
2015	9,069,559.97	45.00	201,540.24	38.63	7,784,596.82
2016	8,919,109.60	45.00	198,196.99	39.23	7,775,133.20
2017	16,765,056.63	45.00	372,546.58	39.83	14,840,273.00
2018	16,818,248.74	45.00	373,728.59	40.44	15,114,344.89
2019	21,113,562.81	45.00	469,177.39	41.05	19,260,131.72

***Columbia Gas of Pennsylvania
Gas Division***

378.00 M&R Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2020	18,278,128.72	45.00	406,169.48	41.66	16,921,583.02
2021	9,170,788.59	45.00	203,789.70	42.27	8,614,943.22
2022	10,163,547.91	45.00	225,850.42	42.89	9,686,228.67
2023	8,139,359.03	45.00	180,869.68	43.50	7,868,606.12
2024	13,722,753.62	45.00	304,941.70	44.12	13,454,736.31
2025	21,108,546.86	45.00	469,065.93	44.72	20,974,958.19
<i>Total</i>	178,796,716.00	45.00	3,973,151.20	40.78	162,036,029.11

Composite Average Remaining Life ... 40.78 Years

***Columbia Gas of Pennsylvania
Gas Division***

379.10 M&R Equipment - City Gate

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 35

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1976	591.42	35.00	16.90	4.31	72.89
1983	26,406.23	35.00	754.46	6.28	4,737.71
1984	1,074.83	35.00	30.71	6.59	202.50
1987	6,793.84	35.00	194.11	7.60	1,475.31
1988	15,907.49	35.00	454.50	7.96	3,616.92
1989	20,307.27	35.00	580.21	8.33	4,832.07
1996	48,076.94	35.00	1,373.63	11.33	15,562.62
<i>Total</i>	119,158.02	35.00	3,404.52	8.96	30,500.04

Composite Average Remaining Life ... 8.96 Years

***Columbia Gas of Pennsylvania
Gas Division***

380.01 Services - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1932	373.90	0.00	0.00	0.00	0.00
1933	1,124.15	0.00	0.00	0.00	0.00
1934	1,384.85	0.00	0.00	0.00	0.00
1935	1,320.73	0.00	0.00	0.00	0.00
1936	2,503.93	45.00	55.64	0.50	27.82
1937	3,516.20	45.00	78.14	0.86	67.21
1938	6,585.98	45.00	146.35	1.32	192.69
1939	10,227.29	45.00	227.27	1.78	405.27
1940	8,220.46	45.00	182.67	2.25	411.02
1941	10,640.40	45.00	236.45	2.71	641.86
1942	12,261.66	45.00	272.47	3.17	864.49
1943	4,132.57	45.00	91.83	3.63	332.95
1944	3,959.96	45.00	88.00	4.07	358.21
1945	4,638.48	45.00	103.07	4.51	464.66
1946	10,073.07	45.00	223.84	4.94	1,104.82
1947	21,371.58	45.00	474.91	5.36	2,544.86
1948	29,391.25	45.00	653.12	5.78	3,772.19
1949	44,867.60	45.00	997.03	6.19	6,169.27
1950	60,219.32	45.00	1,338.17	6.60	8,825.69
1951	79,503.57	45.00	1,766.70	7.00	12,361.81
1952	84,502.33	45.00	1,877.78	7.40	13,891.88
1953	77,627.43	45.00	1,725.01	7.80	13,449.66
1954	120,944.25	45.00	2,687.58	8.19	22,022.58
<i>Total</i>	599,390.96	37.17	13,226.02	6.65	87,908.93

Composite Average Remaining Life ... 6.65 Years

Columbia Gas of Pennsylvania

Gas Division

380.02 Services - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1955	223,091.96	45.00	4,957.46	8.59	42,580.21
1956	260,044.93	45.00	5,778.62	8.98	51,919.63
1957	239,910.88	45.00	5,331.21	9.38	50,010.11
1958	332,876.01	45.00	7,397.04	9.78	72,321.68
1959	431,623.55	45.00	9,591.37	10.17	97,588.34
1960	324,205.00	45.00	7,204.36	10.57	76,166.33
1961	412,740.99	45.00	9,171.77	10.97	100,638.89
1962	447,804.69	45.00	9,950.94	11.38	113,194.22
1963	622,264.50	45.00	13,827.72	11.78	162,892.91
1964	633,353.26	45.00	14,074.13	12.19	171,523.79
1965	624,795.10	45.00	13,883.95	12.60	174,904.28
1966	761,988.70	45.00	16,932.62	13.01	220,313.58
1967	881,799.63	45.00	19,595.01	13.43	263,125.95
1968	954,990.76	45.00	21,221.43	13.85	293,891.70
1969	674,450.23	45.00	14,987.37	14.27	213,913.45
1970	315,925.74	45.00	7,020.38	14.70	103,208.22
1971	398,762.59	45.00	8,861.15	15.13	134,101.66
1972	393,966.48	45.00	8,754.57	15.57	136,311.82
1973	302,630.86	45.00	6,724.95	16.01	107,676.31
1974	72,599.10	45.00	1,613.27	16.46	26,549.78
1975	112,229.46	45.00	2,493.92	16.91	42,165.72
1976	270,844.14	45.00	6,018.59	17.36	104,497.29
1977	1,483,184.77	45.00	32,958.76	17.82	587,397.96
1978	1,055,315.37	45.00	23,450.81	18.29	428,850.92
1979	1,312,622.90	45.00	29,168.60	18.76	547,116.33
1980	1,876,970.00	45.00	41,709.30	19.23	802,145.91
1981	2,181,252.09	45.00	48,470.94	19.71	955,442.49

Columbia Gas of Pennsylvania

Gas Division

380.02 Services - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1982	1,800,596.27	45.00	40,012.15	20.20	808,126.41
1983	1,829,185.74	45.00	40,647.46	20.69	840,883.83
1984	2,303,244.57	45.00	51,181.81	21.18	1,084,162.96
1985	2,741,792.63	45.00	60,927.05	21.68	1,321,083.59
1986	3,094,682.70	45.00	68,768.84	22.19	1,525,883.57
1987	3,776,182.82	45.00	83,912.87	22.70	1,904,815.98
1988	4,591,629.74	45.00	102,033.41	23.22	2,368,791.63
1989	4,411,270.40	45.00	98,025.54	23.74	2,326,807.77
1990	4,567,274.58	45.00	101,492.20	24.26	2,462,463.79
1991	4,286,109.19	45.00	95,244.25	24.79	2,361,477.34
1992	4,987,885.86	45.00	110,838.86	25.33	2,807,507.57
1993	5,255,181.84	45.00	116,778.61	25.87	3,021,064.42
1994	6,336,066.68	45.00	140,797.61	26.41	3,719,162.45
1995	5,537,446.96	45.00	123,051.00	26.96	3,317,987.05
1996	5,352,887.14	45.00	118,949.78	27.52	3,273,349.06
1997	5,597,185.24	45.00	124,378.48	28.08	3,492,148.73
1998	6,147,198.88	45.00	136,600.67	28.64	3,912,081.03
1999	6,538,750.36	45.00	145,301.57	29.20	4,243,479.45
2000	6,747,069.39	45.00	149,930.76	29.77	4,464,137.10
2001	6,616,025.26	45.00	147,018.74	30.35	4,461,688.52
2002	5,611,281.94	45.00	124,691.73	30.92	3,855,975.52
2003	5,439,085.60	45.00	120,865.25	31.50	3,807,666.79
2004	7,904,884.62	45.00	175,659.28	32.09	5,636,127.32
2005	8,338,629.04	45.00	185,297.78	32.67	6,053,847.37
2006	8,149,650.27	45.00	181,098.36	33.26	6,023,012.92
2007	11,731,407.00	45.00	260,690.77	33.85	8,823,797.51
2008	13,740,497.65	45.00	305,336.00	34.44	10,515,544.32

Columbia Gas of Pennsylvania

Gas Division

380.02 Services - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2009	12,548,757.56	45.00	278,853.62	35.03	9,769,072.61
2010	14,827,178.90	45.00	329,483.81	35.63	11,738,876.66
2011	22,040,975.75	45.00	489,786.01	36.22	17,742,347.53
2012	27,954,102.19	45.00	621,185.20	36.82	22,873,718.72
2013	33,269,837.93	45.00	739,309.42	37.42	27,666,480.66
2014	34,919,452.01	45.00	775,966.50	38.02	29,504,746.64
2015	40,081,205.81	45.00	890,668.99	38.63	34,402,554.08
2016	31,036,739.63	45.00	689,686.38	39.23	27,055,927.73
2017	48,870,928.38	45.00	1,085,990.79	39.83	43,260,093.59
2018	47,668,793.47	45.00	1,059,277.42	40.44	42,839,334.59
2019	59,231,109.26	45.00	1,316,210.71	41.05	54,031,570.93
2020	60,010,327.85	45.00	1,333,526.20	41.66	55,556,548.50
2021	64,554,042.64	45.00	1,434,494.87	42.27	60,641,394.83
2022	64,448,023.09	45.00	1,432,138.95	42.89	61,421,296.42
2023	70,153,928.21	45.00	1,558,933.35	43.50	67,820,282.49
2024	62,238,395.30	45.00	1,383,037.45	44.12	61,022,825.31
2025	63,098,502.16	45.00	1,402,150.42	44.72	62,699,173.64
<i>Total</i>	927,987,646.20	45.00	20,621,381.15	38.53	794,559,768.40

Composite Average Remaining Life ... 38.53 Years

Columbia Gas of Pennsylvania

Gas Division

381.00 Meters

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1939	126.19	44.00	2.87	0.53	1.53
1941	515.64	44.00	11.72	1.02	11.95
1942	313.75	44.00	7.13	1.27	9.09
1943	357.61	44.00	8.13	1.52	12.32
1945	46.76	44.00	1.06	2.06	2.19
1946	147.60	44.00	3.35	2.33	7.81
1948	1,023.05	44.00	23.25	2.89	67.16
1949	910.18	44.00	20.69	3.17	65.62
1950	4,238.65	44.00	96.33	3.45	332.32
1951	2,530.04	44.00	57.50	3.74	214.91
1952	1,349.60	44.00	30.67	4.03	123.56
1953	758.14	44.00	17.23	4.32	74.47
1954	2,888.45	44.00	65.65	4.61	302.70
1955	2,863.16	44.00	65.07	4.91	319.46
1956	5,237.38	44.00	119.03	5.21	620.25
1957	6,653.50	44.00	151.22	5.51	833.37
1958	55,736.77	44.00	1,266.74	5.82	7,369.43
1959	41,190.17	44.00	936.14	6.13	5,736.26
1960	57,362.99	44.00	1,303.70	6.44	8,397.08
1961	41,363.42	44.00	940.08	6.75	6,349.35
1962	19,875.65	44.00	451.72	7.07	3,195.23
1963	47,546.77	44.00	1,080.61	7.40	7,992.90
1964	140,455.94	44.00	3,192.18	7.72	24,655.16
1965	130,407.05	44.00	2,963.80	8.05	23,862.39
1966	120,067.05	44.00	2,728.80	8.39	22,881.97
1967	72,186.97	44.00	1,640.61	8.72	14,312.05
1968	7,758.59	44.00	176.33	9.06	1,598.33

Columbia Gas of Pennsylvania

Gas Division

381.00 Meters

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1969	12,849.54	44.00	292.04	9.41	2,748.20
1970	5,353.03	44.00	121.66	9.76	1,187.56
1971	245,469.01	44.00	5,578.84	10.12	56,439.66
1972	206,158.00	44.00	4,685.41	10.48	49,082.36
1973	131,632.36	44.00	2,991.64	10.84	32,430.48
1974	165,579.07	44.00	3,763.16	11.21	42,186.08
1975	180,462.63	44.00	4,101.42	11.59	47,516.93
1976	69,724.28	44.00	1,584.64	11.97	18,960.60
1977	160,341.89	44.00	3,644.13	12.35	45,009.88
1978	145,994.23	44.00	3,318.05	12.74	42,282.86
1979	289,872.78	44.00	6,588.02	13.14	86,572.99
1980	531,507.59	44.00	12,079.72	13.55	163,621.93
1981	562,735.52	44.00	12,789.45	13.96	178,487.97
1982	348,303.58	44.00	7,915.99	14.37	113,778.79
1983	262,046.63	44.00	5,955.61	14.80	88,129.71
1984	360,068.22	44.00	8,183.37	15.23	124,628.33
1985	500,754.06	44.00	11,380.78	15.67	178,321.15
1986	508,258.53	44.00	11,551.33	16.12	186,155.76
1987	507,589.96	44.00	11,536.14	16.57	191,166.68
1988	586,803.53	44.00	13,336.45	17.03	227,181.97
1989	657,618.58	44.00	14,945.88	17.51	261,655.40
1990	355,080.63	44.00	8,070.02	17.99	145,169.85
1991	456,819.86	44.00	10,382.27	18.48	191,861.18
1992	679,423.92	44.00	15,441.45	18.98	293,082.60
1993	825,347.47	44.00	18,757.90	19.49	365,606.40
1994	320,159.15	44.00	7,276.35	20.01	145,621.98
1995	8,005.84	44.00	181.95	20.55	3,738.25

Columbia Gas of Pennsylvania

Gas Division

381.00 Meters

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1996	1,649,931.06	44.00	37,498.44	21.09	790,800.79
1997	563,788.32	44.00	12,813.37	21.64	277,332.48
1998	888,729.03	44.00	20,198.39	22.21	448,668.35
1999	942,819.59	44.00	21,427.72	22.79	488,411.17
2001	248,402.39	44.00	5,645.51	23.99	135,463.97
2002	1,087,220.18	44.00	24,709.55	24.62	608,259.45
2003	785,731.38	44.00	17,857.53	25.25	450,939.53
2004	696,237.04	44.00	15,823.57	25.90	409,870.82
2005	340,087.92	44.00	7,729.27	26.57	205,371.40
2006	491,194.13	44.00	11,163.50	27.25	304,240.56
2007	1,006,596.51	44.00	22,877.20	27.95	639,461.10
2008	1,038,637.11	44.00	23,605.39	28.67	676,703.70
2009	1,344,902.21	44.00	30,565.96	29.40	898,724.49
2010	1,075,726.79	44.00	24,448.34	30.15	737,214.63
2011	1,012,467.41	44.00	23,010.63	30.92	711,559.00
2012	1,305,218.74	44.00	29,664.07	31.71	940,723.79
2013	929,389.36	44.00	21,122.49	32.52	686,893.10
2014	1,103,279.71	44.00	25,074.54	33.35	836,113.94
2015	2,476,316.77	44.00	56,279.93	34.19	1,924,184.40
2016	1,236,327.06	44.00	28,098.35	35.06	984,993.15
2017	1,211,946.73	44.00	27,544.25	35.94	989,885.77
2018	1,065,143.28	44.00	24,207.80	36.84	891,793.71
2019	1,449,347.39	44.00	32,939.72	37.76	1,243,735.67
2020	1,978,418.82	44.00	44,964.07	38.70	1,739,936.65
2021	1,695,058.36	44.00	38,524.06	39.65	1,527,426.65
2022	1,937,741.07	44.00	44,039.57	40.62	1,788,693.02
2023	2,111,553.41	44.00	47,989.86	41.60	1,996,198.63

Columbia Gas of Pennsylvania

Gas Division

381.00 Meters

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2024	2,153,555.37	44.00	48,944.45	42.59	2,084,365.23
2025	6,512,698.81	44.00	148,015.90	43.54	6,444,878.48
<i>Total</i>	50,186,336.91	44.00	1,140,598.69	30.93	35,274,818.04

Composite Average Remaining Life ... 30.93 Years

Columbia Gas of Pennsylvania

Gas Division

381.10 Meters - AMR

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2000	289,868.35	20.00	14,493.42	3.25	47,061.37
2001	273,337.58	20.00	13,666.88	3.54	48,446.85
2003	506.57	20.00	25.33	4.19	106.15
2004	106,465.21	20.00	5,323.26	4.54	24,181.50
2005	167,218.55	20.00	8,360.93	4.92	41,102.59
2007	106,599.66	20.00	5,329.98	5.74	30,577.06
2008	482,455.04	20.00	24,122.75	6.19	149,295.73
2009	418,653.69	20.00	20,932.69	6.67	139,674.46
2010	821,503.68	20.00	41,075.19	7.19	295,338.63
2011	11,226,679.01	20.00	561,333.98	7.74	4,347,351.05
2012	8,713,575.17	20.00	435,678.78	8.34	3,632,978.86
2013	352,659.50	20.00	17,632.98	8.97	158,248.62
2014	306,499.85	20.00	15,324.99	9.65	147,954.37
2015	372,060.41	20.00	18,603.02	10.38	193,092.49
2016	392,441.88	20.00	19,622.09	11.15	218,797.85
2017	189,110.15	20.00	9,455.51	11.97	113,150.27
2018	496,881.76	20.00	24,844.09	12.83	318,638.62
2019	124,667.49	20.00	6,233.37	13.72	85,544.72
2020	81,936.70	20.00	4,096.84	14.66	60,041.94
2021	377,527.23	20.00	18,876.36	15.61	294,754.14
2022	390,663.87	20.00	19,533.19	16.59	324,136.38
2023	368,397.69	20.00	18,419.89	17.59	323,927.50
2024	175,514.84	20.00	8,775.74	18.58	163,084.52
2025	1,149,303.27	20.00	57,465.17	19.54	1,122,965.22

Columbia Gas of Pennsylvania

Gas Division

381.10 Meters - AMR

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of November 30, 2025

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 20

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
<i>Total</i>	27,384,527.15	20.00	1,369,226.42	8.97	12,280,450.90

Composite Average Remaining Life ... 8.97 Years

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1937	4,066.01	55.00	73.93	1.13	83.40
1938	11,189.16	55.00	203.44	1.34	273.33
1939	8,314.79	55.00	151.18	1.58	238.18
1940	7,339.98	55.00	133.45	1.82	242.33
1941	10,481.08	55.00	190.57	2.06	392.88
1942	7,872.77	55.00	143.14	2.32	332.68
1943	3,581.64	55.00	65.12	2.56	167.01
1944	3,627.50	55.00	65.95	2.81	185.52
1945	4,833.59	55.00	87.88	3.07	269.44
1946	11,749.34	55.00	213.62	3.32	709.59
1947	17,177.23	55.00	312.31	3.59	1,121.25
1948	21,899.56	55.00	398.17	3.84	1,529.15
1949	28,360.26	55.00	515.64	4.09	2,110.74
1950	33,074.07	55.00	601.35	4.35	2,614.90
1951	28,932.50	55.00	526.05	4.61	2,422.48
1952	30,226.19	55.00	549.57	4.86	2,672.87
1953	36,260.22	55.00	659.28	5.13	3,382.40
1954	34,157.79	55.00	621.05	5.39	3,347.34
1955	42,991.84	55.00	781.67	5.65	4,419.94
1956	45,493.77	55.00	827.16	5.93	4,901.23
1957	41,920.06	55.00	762.18	6.20	4,728.15
1958	44,688.36	55.00	812.52	6.49	5,276.58
1959	65,609.72	55.00	1,192.90	6.79	8,095.74
1960	47,913.79	55.00	871.16	7.09	6,176.77
1961	41,587.61	55.00	756.14	7.41	5,600.01
1962	59,585.18	55.00	1,083.37	7.73	8,379.52
1963	63,568.16	55.00	1,155.78	8.08	9,335.20

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1964	114,191.44	55.00	2,076.21	8.43	17,510.83
1965	151,795.69	55.00	2,759.92	8.80	24,300.66
1966	140,866.73	55.00	2,561.21	9.19	23,541.67
1967	128,479.91	55.00	2,336.00	9.59	22,413.22
1968	167,153.73	55.00	3,039.16	10.01	30,435.46
1969	158,377.33	55.00	2,879.59	10.45	30,090.84
1970	145,261.90	55.00	2,641.12	10.90	28,798.35
1971	126,965.24	55.00	2,308.46	11.38	26,259.40
1972	79,904.40	55.00	1,452.81	11.86	17,236.22
1973	74,351.87	55.00	1,351.85	12.37	16,722.50
1974	12,641.62	55.00	229.85	12.89	2,963.45
1975	21,788.85	55.00	396.16	13.43	5,320.84
1976	40,612.35	55.00	738.41	13.99	10,329.27
1977	38,105.40	55.00	692.83	14.56	10,089.21
1978	38,729.54	55.00	704.17	15.15	10,669.68
1979	94,803.96	55.00	1,723.71	15.76	27,160.70
1980	198,493.96	55.00	3,608.98	16.37	59,095.72
1981	280,148.94	55.00	5,093.62	17.01	86,645.12
1982	230,267.85	55.00	4,186.69	17.66	73,938.67
1983	263,104.64	55.00	4,783.72	18.32	87,656.14
1984	327,889.39	55.00	5,961.62	19.00	113,272.97
1985	336,288.79	55.00	6,114.34	19.69	120,388.41
1986	406,445.47	55.00	7,389.92	20.39	150,674.05
1987	460,540.48	55.00	8,373.46	21.10	176,709.25
1988	558,391.35	55.00	10,152.57	21.83	221,622.60
1989	662,188.49	55.00	12,039.79	22.57	271,689.82
1990	702,234.03	55.00	12,767.89	23.31	297,664.52

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1991	641,196.60	55.00	11,658.12	24.07	280,605.75
1992	717,409.77	55.00	13,043.81	24.84	323,992.06
1993	617,924.47	55.00	11,234.99	25.62	287,816.36
1994	722,604.27	55.00	13,138.26	26.41	346,937.52
1995	643,198.98	55.00	11,694.52	27.20	318,149.34
1996	738,127.74	55.00	13,420.50	28.01	375,943.65
1997	713,075.78	55.00	12,965.01	28.83	373,757.21
1998	615,907.41	55.00	11,198.31	29.65	332,083.19
1999	519,316.83	55.00	9,442.12	30.49	287,891.38
2000	1,117,222.82	55.00	20,313.14	31.33	636,493.54
2001	1,024,767.34	55.00	18,632.13	32.19	599,702.74
2002	1,000,359.54	55.00	18,188.35	33.05	601,046.99
2003	1,099,323.33	55.00	19,987.69	33.92	677,885.35
2004	1,070,209.49	55.00	19,458.35	34.79	677,002.29
2005	751,728.58	55.00	13,667.79	35.68	487,628.83
2006	211,376.85	55.00	3,843.21	36.57	140,544.35
2007	2,944,302.73	55.00	53,532.76	37.47	2,005,813.98
2008	1,398,803.89	55.00	25,432.79	38.37	975,967.94
2009	1,739,919.24	55.00	31,634.89	39.29	1,242,870.94
2010	1,426,664.53	55.00	25,939.35	40.21	1,042,967.92
2011	1,539,820.69	55.00	27,996.73	41.13	1,151,618.37
2012	1,663,060.44	55.00	30,237.45	42.07	1,271,967.52
2013	1,020,790.54	55.00	18,559.82	43.00	798,120.99
2014	1,230,161.12	55.00	22,366.56	43.95	982,917.52
2015	1,325,671.38	55.00	24,103.11	44.89	1,082,086.03
2016	1,384,403.67	55.00	25,170.97	45.85	1,154,011.51
2017	1,940,233.01	55.00	35,276.95	46.80	1,651,110.04

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2018	1,445,322.61	55.00	26,278.59	47.77	1,255,213.33
2019	1,086,312.44	55.00	19,751.13	48.73	962,482.26
2020	790,043.21	55.00	14,364.42	49.70	713,906.28
2021	1,293,713.63	55.00	23,522.06	50.67	1,191,911.23
2022	1,835,799.44	55.00	33,378.16	51.65	1,723,899.59
2023	2,636,607.31	55.00	47,938.30	52.63	2,522,790.87
2024	6,975,953.10	55.00	126,835.47	53.61	6,799,175.10
2025	2,357,860.31	55.00	42,870.17	54.55	2,338,509.08
<i>Total</i>	54,955,718.61	55.00	999,194.58	39.69	39,657,029.20

Composite Average Remaining Life ... 39.69 Years

***Columbia Gas of Pennsylvania
Gas Division***

383.00 House Regulators

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 50

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1949	39.87	50.00	0.80	4.74	3.78
1955	372.65	50.00	7.45	6.20	46.19
1957	428.94	50.00	8.58	6.72	57.65
1958	619.67	50.00	12.39	6.99	86.61
1960	157.85	50.00	3.16	7.54	23.80
1961	828.56	50.00	16.57	7.82	129.66
1962	3,562.02	50.00	71.24	8.11	578.04
1963	10,250.20	50.00	205.00	8.41	1,723.98
1964	14,602.76	50.00	292.06	8.71	2,544.14
1965	18,351.80	50.00	367.04	9.02	3,310.36
1966	46,112.15	50.00	922.24	9.33	8,608.03
1967	36,524.26	50.00	730.49	9.66	7,053.05
1968	48,172.39	50.00	963.45	9.98	9,619.00
1969	44,272.06	50.00	885.44	10.32	9,137.75
1970	48,149.07	50.00	962.98	10.66	10,269.03
1971	40,749.84	50.00	815.00	11.02	8,977.68
1972	23,626.77	50.00	472.54	11.38	5,375.45
1973	20,906.12	50.00	418.12	11.74	4,910.68
1974	1,628.35	50.00	32.57	12.12	394.79
1975	1,426.14	50.00	28.52	12.51	356.81
1976	2,300.17	50.00	46.00	12.91	593.75
1977	2,161.91	50.00	43.24	13.31	575.66
1978	3,433.70	50.00	68.67	13.73	942.98
1979	8,819.25	50.00	176.39	14.16	2,497.57
1980	13,664.42	50.00	273.29	14.60	3,989.87
1981	22,480.37	50.00	449.61	15.05	6,767.02
1982	25,319.01	50.00	506.38	15.51	7,856.27

***Columbia Gas of Pennsylvania
Gas Division***

383.00 House Regulators

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 50

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1983	29,174.12	50.00	583.48	15.99	9,330.32
1984	30,319.80	50.00	606.40	16.48	9,993.36
1985	29,159.02	50.00	583.18	16.98	9,903.89
1986	45,120.12	50.00	902.40	17.50	15,791.20
1987	55,594.71	50.00	1,111.89	18.03	20,047.36
1988	74,922.51	50.00	1,498.45	18.58	27,834.52
1989	83,431.18	50.00	1,668.62	19.14	31,931.40
1990	83,933.95	50.00	1,678.68	19.71	33,091.51
1991	72,039.26	50.00	1,440.79	20.31	29,255.63
1992	80,515.87	50.00	1,610.32	20.91	33,678.62
1993	58,459.16	50.00	1,169.18	21.54	25,184.24
1994	69,682.55	50.00	1,393.65	22.18	30,915.27
1995	78,497.71	50.00	1,569.95	22.84	35,862.96
1996	83,076.39	50.00	1,661.53	23.52	39,081.52
1997	97,233.24	50.00	1,944.66	24.22	47,094.99
1998	34,430.16	50.00	688.60	24.93	17,168.11
1999	18,963.98	50.00	379.28	25.66	9,733.95
2000	178,205.97	50.00	3,564.12	26.42	94,146.71
2001	69,214.33	50.00	1,384.29	27.18	37,630.84
2002	376,173.30	50.00	7,523.47	27.97	210,443.57
2003	543,327.19	50.00	10,866.54	28.78	312,706.40
2004	893,914.77	50.00	17,878.30	29.60	529,198.99
2005	715,400.00	50.00	14,308.00	30.44	435,543.13
2006	424,452.85	50.00	8,489.06	31.30	265,689.36
2007	852,433.12	50.00	17,048.66	32.17	548,480.87
2008	552,182.59	50.00	11,043.65	33.06	365,111.26
2009	783,696.85	50.00	15,673.94	33.96	532,362.08

***Columbia Gas of Pennsylvania
Gas Division***

383.00 House Regulators

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 50

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2010	621,737.38	50.00	12,434.75	34.88	433,758.72
2011	696,384.18	50.00	13,927.68	35.81	498,802.46
2012	685,752.07	50.00	13,715.04	36.76	504,118.10
2013	506,944.01	50.00	10,138.88	37.71	382,339.18
2014	641,790.24	50.00	12,835.81	38.67	496,404.08
2015	542,198.09	50.00	10,843.96	39.64	429,908.42
2016	544,926.01	50.00	10,898.52	40.62	442,738.03
2017	688,118.10	50.00	13,762.36	41.61	572,629.34
2018	754,413.99	50.00	15,088.28	42.60	642,728.20
2019	937,541.27	50.00	18,750.83	43.59	817,368.01
2020	997,904.23	50.00	19,958.09	44.59	889,870.58
2021	978,254.58	50.00	19,565.09	45.58	891,870.59
2022	1,022,431.69	50.00	20,448.64	46.58	952,574.74
2023	1,392,758.00	50.00	27,855.16	47.58	1,325,443.86
2024	1,386,171.28	50.00	27,723.43	48.58	1,346,896.53
2025	1,249,651.71	50.00	24,993.04	49.54	1,238,196.56
<i>Total</i>	20,499,491.83	50.00	409,989.87	38.34	15,719,289.05

Composite Average Remaining Life ... 38.34 Years

***Columbia Gas of Pennsylvania
Gas Division***

384.00 House Regulator Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 40

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1975	25,536.29	40.00	638.41	2.84	1,813.42
1976	13,544.22	40.00	338.61	3.04	1,028.90
1978	1,298.53	40.00	32.46	3.45	112.11
1979	41,599.56	40.00	1,039.99	3.68	3,823.76
1980	77,996.60	40.00	1,949.92	3.93	7,656.56
1981	103,282.73	40.00	2,582.07	4.19	10,806.04
1982	111,319.42	40.00	2,782.99	4.47	12,439.07
1983	94,125.75	40.00	2,353.14	4.77	11,223.89
1984	99,922.15	40.00	2,498.05	5.10	12,731.27
1985	116,656.41	40.00	2,916.41	5.45	15,881.75
1986	125,288.80	40.00	3,132.22	5.82	18,238.12
1987	160,675.27	40.00	4,016.88	6.23	25,022.47
1988	175,233.80	40.00	4,380.85	6.67	29,201.53
1989	145,258.90	40.00	3,631.47	7.14	25,922.60
1990	142,193.08	40.00	3,554.83	7.64	27,169.41
1991	135,116.79	40.00	3,377.92	8.19	27,663.57
1992	132,025.91	40.00	3,300.65	8.77	28,947.37
1993	112,240.60	40.00	2,806.02	9.40	26,367.43
1994	183,956.83	40.00	4,598.92	10.06	46,258.26
1995	147,470.36	40.00	3,686.76	10.77	39,696.57
1996	122,296.10	40.00	3,057.40	11.51	35,192.77
1997	182,242.97	40.00	4,556.07	12.30	56,034.42
1998	181,141.12	40.00	4,528.53	13.12	59,407.29
1999	139,856.85	40.00	3,496.42	13.98	48,869.63
2000	194,709.38	40.00	4,867.73	14.86	72,342.83
2001	229,158.12	40.00	5,728.95	15.78	90,384.37
2002	154,764.85	40.00	3,869.12	16.71	64,657.07

***Columbia Gas of Pennsylvania
Gas Division***

384.00 House Regulator Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 40

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2003	133,892.99	40.00	3,347.32	17.67	59,134.45
2025	26,581.09	40.00	664.53	39.54	26,276.51
<i>Total</i>	3,509,385.47	40.00	87,734.64	10.08	884,303.46

Composite Average Remaining Life ... 10.08 Years

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1902	15.74	0.00	0.00	0.00	0.00
1922	10.10	0.00	0.00	0.00	0.00
1928	104.16	0.00	0.00	0.00	0.00
1929	689.39	0.00	0.00	0.00	0.00
1930	743.02	0.00	0.00	0.00	0.00
1931	18.40	0.00	0.00	0.00	0.00
1933	223.50	0.00	0.00	0.00	0.00
1934	11.73	0.00	0.00	0.00	0.00
1935	114.92	0.00	0.00	0.00	0.00
1937	849.09	0.00	0.00	0.00	0.00
1938	193.07	0.00	0.00	0.00	0.00
1939	53.92	0.00	0.00	0.00	0.00
1941	359.26	0.00	0.00	0.00	0.00
1942	647.73	0.00	0.00	0.00	0.00
1943	3,708.37	0.00	0.00	0.00	0.00
1944	870.12	0.00	0.00	0.00	0.00
1945	429.16	0.00	0.00	0.00	0.00
1946	56.06	0.00	0.00	0.00	0.00
1947	561.86	0.00	0.00	0.00	0.00
1948	925.69	0.00	0.00	0.00	0.00
1950	1,521.19	0.00	0.00	0.00	0.00
1951	2,520.99	0.00	0.00	0.00	0.00
1952	3,908.94	0.00	0.00	0.00	0.00
1953	3,602.23	0.00	0.00	0.00	0.00
1954	11,418.24	0.00	0.00	0.00	0.00
1955	19,947.42	0.00	0.00	0.00	0.00
1956	20,003.34	0.00	0.00	0.00	0.00

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1957	22,421.95	0.00	0.00	0.00	0.00
1958	19,544.01	0.00	0.00	0.00	0.00
1959	18,752.19	0.00	0.00	0.00	0.00
1960	20,961.73	0.00	0.00	0.00	0.00
1961	27,128.79	0.00	0.00	0.00	0.00
1962	11,637.27	0.00	0.00	0.00	0.00
1963	32,845.53	0.00	0.00	0.00	0.00
1964	21,402.85	0.00	0.00	0.00	0.00
1965	27,626.11	0.00	0.00	0.00	0.00
1966	24,453.49	30.00	815.07	0.50	407.54
1967	43,709.23	30.00	1,456.90	0.86	1,249.37
1968	44,853.36	30.00	1,495.03	1.31	1,952.48
1969	39,512.25	30.00	1,317.00	1.76	2,323.67
1970	38,656.58	30.00	1,288.48	2.22	2,860.66
1971	90,842.89	30.00	3,027.93	2.66	8,069.20
1972	56,153.58	30.00	1,871.69	3.10	5,802.06
1973	32,809.47	30.00	1,093.59	3.52	3,854.64
1974	19,892.25	30.00	663.04	3.94	2,611.85
1975	13,974.71	30.00	465.80	4.35	2,025.18
1976	727.87	30.00	24.26	4.75	115.26
1977	512.94	30.00	17.10	5.15	88.03
1978	9,948.78	30.00	331.61	5.55	1,838.98
1979	30,613.30	30.00	1,020.39	5.94	6,062.36
1980	52,490.10	30.00	1,749.58	6.34	11,085.18
1981	65,051.65	30.00	2,168.27	6.73	14,597.73
1982	91,881.22	30.00	3,062.54	7.13	21,838.96
1983	64,446.82	30.00	2,148.11	7.53	16,178.99

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1984	27,107.59	30.00	903.54	7.94	7,170.88
1985	35,899.10	30.00	1,196.57	8.35	9,985.81
1986	71,014.63	30.00	2,367.03	8.76	20,731.83
1987	15,194.77	30.00	506.47	9.18	4,647.99
1988	46,291.22	30.00	1,542.96	9.60	14,814.95
1989	59,514.75	30.00	1,983.72	10.03	19,900.53
1990	45,154.47	30.00	1,505.07	10.47	15,756.05
1991	80,583.44	30.00	2,685.97	10.91	29,309.43
1992	66,946.86	30.00	2,231.44	11.36	25,354.65
1993	91,945.85	30.00	3,064.70	11.82	36,224.60
1994	126,848.10	30.00	4,228.04	12.28	51,940.61
1995	101,987.12	30.00	3,399.39	12.76	43,367.19
1996	89,525.49	30.00	2,984.02	13.24	39,500.59
1997	27,696.65	30.00	923.17	13.73	12,670.55
1999	362.58	30.00	12.09	14.72	177.94
2000	99,650.62	30.00	3,321.51	15.23	50,602.62
2001	3,108.75	30.00	103.62	15.75	1,632.39
2002	164,009.81	30.00	5,466.70	16.28	88,996.60
2003	345,660.47	30.00	11,521.40	16.81	193,710.28
2004	2,323.37	30.00	77.44	17.35	1,343.92
2005	51,261.80	30.00	1,708.64	17.90	30,586.84
2006	116,382.08	30.00	3,879.20	18.46	71,591.33
2007	150,019.53	30.00	5,000.38	19.02	95,085.78
2008	195,863.32	30.00	6,528.43	19.58	127,837.80
2009	131,113.58	30.00	4,370.22	20.15	88,073.34
2010	198,945.51	30.00	6,631.16	20.73	137,462.48
2011	161,543.96	30.00	5,384.51	21.31	114,747.65

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2012	141,244.93	30.00	4,707.91	21.90	103,082.48
2013	274,753.00	30.00	9,157.94	22.48	205,910.19
2014	135,911.12	30.00	4,530.13	23.08	104,536.95
2015	302,323.76	30.00	10,076.92	23.67	238,522.52
2016	496,416.99	30.00	16,546.35	24.27	401,530.67
2017	485,936.28	30.00	16,197.01	24.87	402,751.66
2018	492,061.81	30.00	16,401.18	25.47	417,682.68
2019	116,180.08	30.00	3,872.46	26.07	100,954.73
2020	934,118.63	30.00	31,135.62	26.68	830,554.39
2021	44,866.18	30.00	1,495.46	27.28	40,801.06
2022	368,857.02	30.00	12,294.58	27.89	342,946.21
2023	1,024,805.05	30.00	34,158.34	28.51	973,766.77
2024	207,587.42	30.00	6,919.21	29.12	201,511.92
2025	986,401.44	30.00	32,878.29	29.72	977,034.69
<i>Total</i>	9,513,777.69	18.63	307,915.21	22.01	6,777,773.69

Composite Average Remaining Life ... 22.01 Years

***Columbia Gas of Pennsylvania
Gas Division***

387.00 Other Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 32

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1941	38.38	0.00	0.00	0.00	0.00
1942	67.31	0.00	0.00	0.00	0.00
1950	90.19	0.00	0.00	0.00	0.00
1955	4,288.05	0.00	0.00	0.00	0.00
1957	14,374.70	0.00	0.00	0.00	0.00
1959	188.29	0.00	0.00	0.00	0.00
1962	7,626.48	32.00	238.32	0.50	119.16
1967	445.13	32.00	13.91	1.98	27.56
1972	7,910.24	32.00	247.19	3.47	856.54
1981	13,548.93	32.00	423.39	6.48	2,742.95
1985	14,556.64	32.00	454.88	8.02	3,649.16
1992	2,228.63	32.00	69.64	11.08	771.44
2010	68,488.09	32.00	2,140.18	21.27	45,513.78
2015	2,847.08	32.00	88.97	24.61	2,189.16
<i>Total</i>	136,698.14	18.29	3,676.47	15.20	55,869.74

Composite Average Remaining Life ... 15.20 Years

***Columbia Gas of Pennsylvania
Gas Division***

387.40 Other Equipment - Communication

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 25

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1973	917.13	0.00	0.00	0.00	0.00
1974	11,561.27	0.00	0.00	0.00	0.00
1975	3,189.09	0.00	0.00	0.00	0.00
1976	6,308.81	25.00	252.35	0.50	126.17
1980	1,144.78	25.00	45.79	1.62	73.98
1983	10,695.21	25.00	427.80	2.31	990.29
1984	4,730.23	25.00	189.20	2.54	481.52
1985	27,353.09	25.00	1,094.09	2.79	3,049.84
1986	61,596.14	25.00	2,463.78	3.04	7,496.82
1987	40,005.58	25.00	1,600.18	3.31	5,295.62
1989	3,425.59	25.00	137.02	3.87	530.39
1990	37,952.71	25.00	1,518.07	4.16	6,322.12
1991	31,594.95	25.00	1,263.76	4.47	5,645.72
1992	6,510.50	25.00	260.41	4.78	1,244.91
1993	1,718.09	25.00	68.72	5.11	350.86
1994	4,082.11	25.00	163.28	5.44	888.94
2000	47,842.64	25.00	1,913.65	7.85	15,016.35
2001	142,467.12	25.00	5,698.52	8.32	47,399.34
2003	2,326.24	25.00	93.05	9.32	867.44
2004	89,547.93	25.00	3,581.82	9.86	35,302.93
2005	219,536.12	25.00	8,781.20	10.41	91,411.56
2006	13,325.90	25.00	533.02	10.98	5,854.39
2007	9,937.59	25.00	397.49	11.58	4,601.38
2008	0.11	25.00	0.00	12.19	0.05
2009	5,832.45	25.00	233.29	12.82	2,989.83
2010	108,042.35	25.00	4,321.57	13.46	58,175.10
2011	42,386.12	25.00	1,695.40	14.12	23,944.79

***Columbia Gas of Pennsylvania
Gas Division***

387.40 Other Equipment - Communication

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 25

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2012	86,817.14	25.00	3,472.59	14.80	51,396.21
2013	479,315.49	25.00	19,172.08	15.49	297,015.96
2014	1,524,487.08	25.00	60,977.76	16.20	987,668.78
2015	689,927.53	25.00	27,596.32	16.91	466,789.85
2016	691,594.66	25.00	27,663.01	17.64	488,098.05
2017	1,709,491.37	25.00	68,377.72	18.38	1,257,117.33
2018	1,951,023.64	25.00	78,038.74	19.14	1,493,319.26
2019	710,001.20	25.00	28,399.25	19.90	565,033.93
2020	1,079,074.68	25.00	43,161.77	20.67	891,986.91
2021	567,278.96	25.00	22,690.52	21.45	486,613.67
2022	2,162,220.17	25.00	86,486.37	22.23	1,922,994.71
2023	2,929,738.01	25.00	117,186.21	23.03	2,699,149.00
2024	3,297,522.65	25.00	131,897.18	23.84	3,144,509.81
<i>Total</i>	18,812,522.43	23.13	751,852.98	20.04	15,069,753.83

Composite Average Remaining Life ... 20.04 Years

***Columbia Gas of Pennsylvania
Gas Division***

387.50 Other Equipment - GPS

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of November 30, 2025
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 10

Survivor Curve: S3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2014	1,942,103.70	10.00	194,210.38	1.54	298,662.20
2015	112,834.83	10.00	11,283.48	1.85	20,895.85
2016	33,669.32	10.00	3,366.93	2.23	7,521.38
2017	34,335.00	10.00	3,433.50	2.70	9,271.52
2018	78,429.10	10.00	7,842.91	3.27	25,629.62
<i>Total</i>	2,201,371.95	10.00	220,137.21	1.64	361,980.57

Composite Average Remaining Life ... 1.64 Years

***Columbia Gas of Pennsylvania
Gas Division***

374.40 Land and Land Rights

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 75

Survivor Curve: R2.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1957	2,767.16	75.00	36.90	20.62	760.78
1961	727.85	75.00	9.70	22.80	221.26
1962	285.72	75.00	3.81	23.37	89.03
1963	5,043.35	75.00	67.24	23.95	1,610.43
1964	3,306.05	75.00	44.08	24.54	1,081.86
1965	1,021.21	75.00	13.62	25.14	342.35
1966	2,144.60	75.00	28.59	25.75	736.38
1967	10,361.13	75.00	138.15	26.38	3,643.71
1968	1,819.23	75.00	24.26	27.00	655.02
1969	11,177.24	75.00	149.03	27.64	4,119.37
1970	7,420.79	75.00	98.94	28.29	2,799.23
1971	19,103.36	75.00	254.71	28.95	7,372.97
1972	10,817.52	75.00	144.23	29.61	4,270.66
1973	5,124.44	75.00	68.33	30.28	2,069.20
1974	15,605.71	75.00	208.08	30.96	6,442.93
1975	23,801.80	75.00	317.36	31.65	10,044.84
1976	23,027.24	75.00	307.03	32.35	9,932.41
1977	51,544.24	75.00	687.26	33.05	22,715.98
1978	20,185.59	75.00	269.14	33.76	9,087.02
1979	34,936.18	75.00	465.82	34.48	16,063.01
1980	21,993.38	75.00	293.24	35.21	10,324.74
1981	38,431.43	75.00	512.42	35.94	18,416.29
1982	60,373.24	75.00	804.98	36.68	29,527.65
1983	38,767.60	75.00	516.90	37.43	19,346.07
1984	43,364.01	75.00	578.19	38.18	22,074.42
1985	64,078.24	75.00	854.38	38.94	33,269.45
1986	38,707.41	75.00	516.10	39.71	20,491.88

***Columbia Gas of Pennsylvania
Gas Division***

374.40 Land and Land Rights

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 75

Survivor Curve: R2.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1987	62,222.25	75.00	829.63	40.48	33,580.49
1988	96,437.57	75.00	1,285.83	41.26	53,049.36
1989	128,110.70	75.00	1,708.14	42.04	71,811.83
1990	82,197.45	75.00	1,095.96	42.83	46,940.84
1991	48,189.90	75.00	642.53	43.63	28,033.02
1992	13,213.09	75.00	176.17	44.43	7,827.63
1993	42,506.38	75.00	566.75	45.24	25,639.01
1994	34,714.33	75.00	462.86	46.05	21,316.58
1995	18,973.52	75.00	252.98	46.87	11,858.08
1996	45,356.05	75.00	604.75	47.70	28,845.19
1997	37,210.42	75.00	496.14	48.53	24,077.70
1998	9,051.35	75.00	120.68	49.37	5,957.69
1999	5,955.97	75.00	79.41	50.21	3,987.02
2000	14,059.84	75.00	187.46	51.05	9,570.84
2001	13,480.74	75.00	179.74	51.91	9,329.61
2002	2,996.93	75.00	39.96	52.76	2,108.28
2003	43,263.11	75.00	576.84	53.62	30,932.26
2004	44,817.51	75.00	597.57	54.49	32,560.93
2005	25,385.54	75.00	338.47	55.36	18,737.62
2006	32,575.59	75.00	434.34	56.24	24,425.43
2007	66,507.36	75.00	886.76	57.11	50,647.47
2008	16,348.49	75.00	217.98	58.00	12,642.44
2009	132,587.86	75.00	1,767.84	58.89	104,103.52
2010	80,048.67	75.00	1,067.31	59.78	63,803.54
2011	76,443.84	75.00	1,019.25	60.68	61,843.17
2012	207,047.90	75.00	2,760.64	61.58	169,989.88
2013	198,586.64	75.00	2,647.82	62.48	165,435.79

***Columbia Gas of Pennsylvania
Gas Division***

374.40 Land and Land Rights

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 75

Survivor Curve: R2.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2014	75,152.66	75.00	1,002.03	63.39	63,516.02
2015	135,304.50	75.00	1,804.06	64.30	115,999.42
2016	171,476.00	75.00	2,286.34	65.21	149,100.58
2017	344,317.02	75.00	4,590.89	66.13	303,600.02
2018	192,515.53	75.00	2,566.87	67.05	172,116.53
2019	230,906.50	75.00	3,078.75	67.98	209,284.72
2020	232,087.10	75.00	3,094.49	68.90	213,223.14
2021	2,652,541.63	75.00	35,367.18	69.84	2,469,873.95
2022	651,378.39	75.00	8,685.03	70.77	614,623.95
2023	1,796,368.08	75.00	23,951.54	71.70	1,717,413.45
2024	2,090,347.33	75.00	27,871.26	72.64	2,024,648.96
2025	296,145.34	75.00	3,948.60	73.58	290,553.01
2026	361,796.59	75.00	4,823.95	74.53	359,514.52
<i>Total</i>	11,364,561.39	75.00	151,527.29	66.52	10,080,032.43

Composite Average Remaining Life ... 66.52 Years

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1883	866.25	0.00	0.00	0.00	0.00
1884	2,319.40	0.00	0.00	0.00	0.00
1885	952.00	0.00	0.00	0.00	0.00
1886	9,401.15	0.00	0.00	0.00	0.00
1887	4,690.00	0.00	0.00	0.00	0.00
1888	6,579.75	80.00	82.25	0.50	41.12
1889	6,551.18	80.00	81.89	0.91	74.66
1890	1,679.50	80.00	20.99	1.39	29.16
1891	8,350.23	80.00	104.38	1.25	130.47
1892	1,354.95	80.00	16.94	1.38	23.29
1893	650.85	80.00	8.14	1.55	12.61
1894	1,616.78	80.00	20.21	1.63	32.93
1895	1,133.20	80.00	14.17	1.67	23.61
1896	4,260.56	80.00	53.26	1.79	95.17
1897	2,267.65	80.00	28.35	1.91	54.12
1898	1,633.73	80.00	20.42	2.03	41.44
1899	934.25	80.00	11.68	2.05	23.99
1900	8,185.42	80.00	102.32	2.18	222.82
1901	15,227.76	80.00	190.35	2.30	438.42
1902	7,330.74	80.00	91.63	2.43	222.27
1903	15,446.32	80.00	193.08	2.47	476.66
1904	8,443.31	80.00	105.54	2.60	273.94
1905	13,211.32	80.00	165.14	2.72	449.99
1906	5,826.89	80.00	72.84	2.86	207.98
1907	4,318.72	80.00	53.98	2.92	157.46
1908	5,084.82	80.00	63.56	3.05	193.78
1909	5,578.23	80.00	69.73	3.18	222.06

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1910	944.58	80.00	11.81	3.32	39.24
1911	1,805.52	80.00	22.57	3.40	76.82
1912	1,590.08	80.00	19.88	3.54	70.42
1913	4,199.64	80.00	52.50	3.69	193.58
1914	6,522.34	80.00	81.53	3.84	312.72
1915	9,299.36	80.00	116.24	3.94	457.51
1916	2,131.53	80.00	26.64	4.09	108.86
1917	2,947.27	80.00	36.84	4.24	156.24
1918	969.85	80.00	12.12	4.40	53.35
1919	713.16	80.00	8.91	4.52	40.31
1920	1,116.43	80.00	13.96	4.69	65.38
1921	2,386.50	80.00	29.83	4.85	144.81
1922	5,478.84	80.00	68.49	5.03	344.41
1923	5,748.64	80.00	71.86	5.17	371.74
1924	2,962.36	80.00	37.03	5.35	198.21
1925	8,085.67	80.00	101.07	5.54	559.83
1926	3,690.49	80.00	46.13	5.73	264.40
1927	3,441.21	80.00	43.02	5.90	253.86
1928	3,616.30	80.00	45.20	6.10	275.81
1929	9,736.71	80.00	121.71	6.31	767.85
1930	3,705.73	80.00	46.32	6.52	302.18
1931	4,695.61	80.00	58.70	6.72	394.62
1932	2,031.20	80.00	25.39	6.95	176.41
1933	2,540.95	80.00	31.76	7.18	228.09
1934	4,020.82	80.00	50.26	7.42	373.07
1935	866.62	80.00	10.83	7.66	82.95
1936	4,994.63	80.00	62.43	7.91	493.98

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1937	3,607.79	80.00	45.10	8.18	368.77
1938	1,245.49	80.00	15.57	8.45	131.58
1939	956.06	80.00	11.95	8.73	104.28
1940	13,850.45	80.00	173.13	9.02	1,561.25
1941	4,887.61	80.00	61.10	9.32	569.46
1942	8,169.68	80.00	102.12	9.64	983.94
1943	1,693.42	80.00	21.17	9.96	210.74
1944	978.40	80.00	12.23	10.29	125.88
1945	1,004.81	80.00	12.56	10.64	133.66
1946	344.00	80.00	4.30	11.00	47.32
1947	142.29	80.00	1.78	11.38	20.24
1948	3,080.71	80.00	38.51	11.77	453.18
1949	16,198.32	80.00	202.48	12.17	2,464.62
1950	20,911.66	80.00	261.40	12.59	3,291.18
1951	11,956.42	80.00	149.46	13.03	1,947.16
1952	8,038.39	80.00	100.48	13.48	1,354.44
1953	5,949.87	80.00	74.37	13.95	1,037.31
1954	21,585.01	80.00	269.81	14.43	3,893.81
1955	32,149.56	80.00	401.87	14.94	6,003.89
1956	51,702.96	80.00	646.29	15.46	9,992.68
1957	19,916.61	80.00	248.96	16.00	3,983.68
1958	63,499.25	80.00	793.74	16.56	13,143.98
1959	28,371.09	80.00	354.64	17.15	6,080.50
1960	26,305.63	80.00	328.82	17.74	5,834.91
1961	15,768.03	80.00	197.10	18.36	3,619.47
1962	18,087.78	80.00	226.10	19.00	4,296.22
1963	27,374.57	80.00	342.18	19.67	6,730.57

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1964	40,027.79	80.00	500.35	20.35	10,182.35
1965	17,574.04	80.00	219.68	21.05	4,624.41
1966	18,597.25	80.00	232.47	21.77	5,061.04
1967	96,910.77	80.00	1,211.38	22.52	27,281.08
1968	82,637.79	80.00	1,032.97	23.28	24,050.11
1969	46,057.56	80.00	575.72	24.06	13,853.42
1970	45,097.36	80.00	563.72	24.86	14,014.71
1971	54,600.87	80.00	682.51	25.69	17,531.14
1972	80,822.88	80.00	1,010.29	26.52	26,794.99
1973	31,060.02	80.00	388.25	27.37	10,628.02
1974	42,716.26	80.00	533.95	28.24	15,079.63
1975	53,203.52	80.00	665.04	29.13	19,372.96
1976	46,796.87	80.00	584.96	30.03	17,565.18
1977	50,016.13	80.00	625.20	30.94	19,342.52
1978	27,600.77	80.00	345.01	31.86	10,991.91
1979	28,400.77	80.00	355.01	32.80	11,643.22
1980	24,054.08	80.00	300.68	33.74	10,144.89
1981	55,235.53	80.00	690.44	34.69	23,952.99
1982	47,534.94	80.00	594.19	35.65	21,183.74
1983	27,148.25	80.00	339.35	36.62	12,427.40
1984	30,306.87	80.00	378.84	37.59	14,241.87
1985	72,105.59	80.00	901.32	38.57	34,765.39
1986	17,533.91	80.00	219.17	39.55	8,669.17
1987	27,416.83	80.00	342.71	40.54	13,893.86
1988	11,339.22	80.00	141.74	41.53	5,886.51
1989	70,129.19	80.00	876.61	42.52	37,275.29
1990	44,760.66	80.00	559.51	43.52	24,347.23

***Columbia Gas of Pennsylvania
Gas Division***

374.50 Rights of Way

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 80

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1991	35,224.46	80.00	440.31	44.51	19,598.53
1992	54,141.31	80.00	676.77	45.51	30,798.08
1993	58,993.43	80.00	737.42	46.51	34,293.73
1994	184,531.84	80.00	2,306.65	47.50	109,573.50
1995	584,928.49	80.00	7,311.61	48.50	354,629.55
1996	126,940.88	80.00	1,586.76	49.50	78,546.95
1997	68,030.65	80.00	850.38	50.50	42,945.09
1998	40,132.45	80.00	501.66	51.50	25,835.51
2000	15,568.19	80.00	194.60	53.50	10,411.26
2001	39,714.12	80.00	496.43	54.50	27,055.29
2002	181,571.19	80.00	2,269.64	55.50	125,965.11
2003	1,938.28	80.00	24.23	56.50	1,368.91
<i>Total</i>	3,233,313.87	76.67	40,188.57	34.95	1,404,465.88

Composite Average Remaining Life ... 34.95 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1936	683.87	60.00	11.40	12.79	145.78
1938	423.68	60.00	7.06	13.58	95.92
1939	3,054.79	60.00	50.91	13.98	711.88
1940	433.98	60.00	7.23	14.38	104.02
1941	726.87	60.00	12.11	14.78	179.10
1942	96.36	60.00	1.61	15.19	24.39
1943	153.44	60.00	2.56	15.59	39.87
1945	553.19	60.00	9.22	16.41	151.26
1946	894.45	60.00	14.91	16.82	250.69
1947	2,030.59	60.00	33.84	17.23	583.13
1948	5,951.70	60.00	99.19	17.65	1,750.39
1949	1,031.56	60.00	17.19	18.06	310.57
1950	4,521.04	60.00	75.35	18.49	1,392.89
1951	6,998.12	60.00	116.63	18.91	2,205.53
1952	14,125.22	60.00	235.42	19.34	4,552.20
1953	20,128.75	60.00	335.47	19.77	6,631.31
1954	11,396.30	60.00	189.93	20.20	3,836.71
1955	11,120.56	60.00	185.34	20.64	3,824.75
1956	20,325.80	60.00	338.76	21.08	7,139.71
1957	25,533.14	60.00	425.54	21.52	9,157.37
1958	29,356.38	60.00	489.26	21.97	10,747.02
1959	19,590.74	60.00	326.51	22.42	7,318.80
1960	23,397.39	60.00	389.95	22.87	8,917.79
1961	32,886.02	60.00	548.09	23.33	12,784.91
1962	30,139.82	60.00	502.32	23.79	11,948.76
1963	18,666.82	60.00	311.11	24.25	7,544.80
1964	37,995.24	60.00	633.24	24.72	15,653.56

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1965	26,181.50	60.00	436.35	25.19	10,992.41
1966	25,650.07	60.00	427.49	25.67	10,972.57
1967	17,541.17	60.00	292.35	26.15	7,644.01
1968	8,026.10	60.00	133.77	26.63	3,562.25
1969	14,774.19	60.00	246.23	27.12	6,677.19
1970	4,779.47	60.00	79.66	27.61	2,199.22
1971	19,640.01	60.00	327.33	28.10	9,198.97
1972	9,695.77	60.00	161.59	28.60	4,621.98
1973	12,031.15	60.00	200.52	29.11	5,836.11
1974	4,317.14	60.00	71.95	29.61	2,130.63
1975	16,144.60	60.00	269.07	30.12	8,105.09
1976	21,617.51	60.00	360.29	30.64	11,038.06
1977	13,825.29	60.00	230.42	31.15	7,178.52
1978	20,203.15	60.00	336.71	31.68	10,665.98
1979	28,577.03	60.00	476.27	32.20	15,337.33
1980	11,920.57	60.00	198.67	32.73	6,502.97
1981	26,706.14	60.00	445.09	33.26	14,805.92
1982	33,238.07	60.00	553.96	33.80	18,724.63
1983	11,342.52	60.00	189.04	34.34	6,491.76
1984	14,065.75	60.00	234.42	34.89	8,177.91
1985	12,381.67	60.00	206.36	35.43	7,311.72
1986	25,568.70	60.00	426.14	35.98	15,333.58
1987	3,172.97	60.00	52.88	36.54	1,932.09
1988	16,025.52	60.00	267.09	37.09	9,907.06
1989	14,046.88	60.00	234.11	37.65	8,814.75
1990	8,056.83	60.00	134.28	38.22	5,131.49
1991	15,078.37	60.00	251.30	38.78	9,745.81

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1992	126.34	60.00	2.11	39.35	82.86
1993	20,774.38	60.00	346.23	39.92	13,821.88
1995	13,269.24	60.00	221.15	41.07	9,082.67
1996	11,544.40	60.00	192.40	41.65	8,013.42
1997	8,549.59	60.00	142.49	42.23	6,017.38
1998	58,293.06	60.00	971.53	42.81	41,594.14
1999	2,493.93	60.00	41.56	43.40	1,803.80
2000	19,879.14	60.00	331.31	43.98	14,572.53
2001	26,045.66	60.00	434.09	44.57	19,348.10
2002	14,413.14	60.00	240.21	45.16	10,848.65
2003	61,353.12	60.00	1,022.53	45.75	46,784.97
2004	24,545.70	60.00	409.09	46.35	18,959.95
2005	47,521.43	60.00	792.01	46.94	37,177.61
2006	53,787.48	60.00	896.44	47.54	42,613.66
2007	92,697.33	60.00	1,544.93	48.13	74,361.33
2008	339,759.21	60.00	5,662.55	48.73	275,938.88
2009	92,689.00	60.00	1,544.79	49.33	76,203.40
2010	137,251.08	60.00	2,287.48	49.93	114,210.59
2011	195,922.60	60.00	3,265.32	50.53	164,995.40
2012	224,755.65	60.00	3,745.86	51.13	191,532.08
2013	217,045.64	60.00	3,617.36	51.73	187,141.40
2014	334,590.29	60.00	5,576.40	52.34	291,861.41
2015	863,330.79	60.00	14,388.58	52.94	761,791.43
2016	380,630.47	60.00	6,343.72	53.55	339,711.42
2017	352,067.76	60.00	5,867.69	54.16	317,784.58
2018	162,528.34	60.00	2,708.76	54.77	148,352.34
2019	658,164.88	60.00	10,969.21	55.38	607,449.76

***Columbia Gas of Pennsylvania
Gas Division***

375.34 Structures - Measuring and Regulating

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 60

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2020	285,335.07	60.00	4,755.50	55.99	266,259.34
2021	245,620.70	60.00	4,093.60	56.60	231,710.85
2022	293,456.10	60.00	4,890.84	57.22	279,843.33
2023	433,565.09	60.00	7,225.95	57.83	417,902.41
2024	608,591.37	60.00	10,143.00	58.45	592,870.33
2025	866,985.07	60.00	14,449.48	59.07	853,525.14
2026	910,111.63	60.00	15,168.25	59.69	905,396.68
<i>Total</i>	8,814,518.64	60.00	146,905.91	52.53	7,716,606.81

Composite Average Remaining Life ... 52.53 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.60 Structures - Industrial M&R

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1928	87.15	55.00	1.58	3.94	6.24
1930	127.57	55.00	2.32	4.53	10.51
1931	263.40	55.00	4.79	4.83	23.15
1934	783.68	55.00	14.25	5.73	81.57
1935	147.25	55.00	2.68	6.03	16.14
1936	21.46	55.00	0.39	6.34	2.47
1937	618.76	55.00	11.25	6.65	74.82
1938	1,433.03	55.00	26.05	6.96	181.43
1940	440.04	55.00	8.00	7.60	60.83
1942	1,018.37	55.00	18.52	8.26	153.01
1944	2,850.41	55.00	51.82	8.94	463.14
1946	377.07	55.00	6.86	9.63	66.01
1947	568.77	55.00	10.34	9.98	103.23
1948	482.71	55.00	8.78	10.34	90.74
1950	1,857.60	55.00	33.77	11.07	373.76
1951	3,131.90	55.00	56.94	11.44	651.29
1952	3,450.55	55.00	62.74	11.81	741.14
1953	4,259.74	55.00	77.45	12.20	944.50
1955	4,904.63	55.00	89.17	12.97	1,156.67
1956	2,507.83	55.00	45.60	13.37	609.47
1957	14,375.38	55.00	261.36	13.77	3,598.38
1958	1,667.93	55.00	30.33	14.17	429.83
1959	5,902.55	55.00	107.32	14.59	1,565.24
1960	1,345.00	55.00	24.45	15.00	366.85
1961	1,954.81	55.00	35.54	15.42	548.18
1963	3,416.99	55.00	62.13	16.28	1,011.69
1967	1,614.49	55.00	29.35	18.07	530.54

***Columbia Gas of Pennsylvania
Gas Division***

375.60 Structures - Industrial M&R

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1970	2,450.11	55.00	44.55	19.48	867.64
1971	7,721.50	55.00	140.39	19.96	2,801.76
1972	1.00	55.00	0.02	20.44	0.37
1980	3,885.67	55.00	70.65	24.56	1,734.83
1988	11,897.69	55.00	216.32	29.08	6,289.44
<i>Total</i>	85,565.04	55.00	1,555.69	16.43	25,554.88

Composite Average Remaining Life ... 16.43 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.71 Distribution Systems - Company Stations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 90

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1928	539.04	90.00	5.99	25.15	150.63
1931	4,005.57	90.00	44.51	26.44	1,176.59
1933	401.96	90.00	4.47	27.32	122.03
1934	778.19	90.00	8.65	27.78	240.16
1937	77.17	90.00	0.86	29.17	25.01
1939	1,201.91	90.00	13.35	30.12	402.29
1948	244.11	90.00	2.71	34.72	94.16
1949	338.10	90.00	3.76	35.26	132.44
1950	56.50	90.00	0.63	35.80	22.47
1951	94.17	90.00	1.05	36.35	38.03
1955	5,011.58	90.00	55.68	38.61	2,149.76
1957	18,804.17	90.00	208.93	39.77	8,308.62
1958	45,295.26	90.00	503.28	40.35	20,309.59
1959	665.84	90.00	7.40	40.95	302.94
1960	720.61	90.00	8.01	41.55	332.65
1962	275.80	90.00	3.06	42.76	131.03
1963	16,296.83	90.00	181.07	43.37	7,853.36
1964	81,335.93	90.00	903.72	43.99	39,756.83
1965	6,256.39	90.00	69.51	44.62	3,101.46
1968	462.64	90.00	5.14	46.51	239.11
1969	117.03	90.00	1.30	47.16	61.32
1971	1,426.78	90.00	15.85	48.46	768.16
1973	1,166.63	90.00	12.96	49.77	645.20
1976	1,998.47	90.00	22.21	51.78	1,149.82
1978	3,472.31	90.00	38.58	53.14	2,050.22
1979	85,249.40	90.00	947.21	53.83	50,984.67
1981	593,681.70	90.00	6,596.40	55.21	364,179.82

***Columbia Gas of Pennsylvania
Gas Division***

375.71 Distribution Systems - Company Stations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 90

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1982	1,111.41	90.00	12.35	55.91	690.41
1983	5,480.40	90.00	60.89	56.61	3,447.11
1984	4,760.67	90.00	52.90	57.31	3,031.69
1985	20,862.34	90.00	231.80	58.02	13,449.72
1986	14,531.65	90.00	161.46	58.73	9,483.32
1987	198,785.72	90.00	2,208.71	59.45	131,306.69
1988	10,177.82	90.00	113.09	60.17	6,804.15
1991	1,625.41	90.00	18.06	62.35	1,125.96
1993	27,303.35	90.00	303.37	63.81	19,358.50
1995	202,894.25	90.00	2,254.36	65.29	147,187.94
1996	54,924.25	90.00	610.26	66.03	40,298.08
1997	59,116.96	90.00	656.85	66.78	43,864.50
1998	292,879.46	90.00	3,254.19	67.53	219,752.87
1999	6,939.23	90.00	77.10	68.28	5,264.60
2000	6,596.38	90.00	73.29	69.04	5,059.94
2001	38,452.52	90.00	427.25	69.80	29,819.74
2005	152,784.63	90.00	1,697.59	72.85	123,672.25
2006	126,751.26	90.00	1,408.33	73.62	103,684.75
2007	8,637.28	90.00	95.97	74.40	7,139.65
2008	7,810.00	90.00	86.78	75.17	6,523.14
2009	41,747.68	90.00	463.86	75.95	35,230.87
2010	147,736.99	90.00	1,641.51	76.73	125,957.91
2011	33,989.54	90.00	377.66	77.52	29,274.94
2012	781,914.65	90.00	8,687.86	78.30	680,290.77
2013	165,318.56	90.00	1,836.86	79.09	145,281.95
2014	30,907.80	90.00	343.42	79.88	27,433.65
2015	1,432,975.31	90.00	15,921.80	80.68	1,284,549.39

***Columbia Gas of Pennsylvania
Gas Division***

375.71 Distribution Systems - Company Stations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 90

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2016	1,332,537.84	90.00	14,805.84	81.48	1,206,312.60
2017	220,104.62	90.00	2,445.58	82.27	201,210.02
2018	2,397,766.58	90.00	26,641.61	83.08	2,213,345.65
2019	7,748,293.91	90.00	86,091.36	83.88	7,221,630.02
2020	52,049.67	90.00	578.32	84.69	48,978.66
2021	22,830,754.88	90.00	253,672.72	85.50	21,689,142.95
2022	307,977.36	90.00	3,421.94	86.31	295,357.39
2023	6,434,577.19	90.00	71,494.64	87.13	6,229,168.73
2024	303,625.27	90.00	3,373.58	87.95	296,690.32
2025	198,219.84	90.00	2,202.42	88.77	195,498.26
2026	223,467.31	90.00	2,482.95	89.59	222,441.12
<i>Total</i>	46,796,364.08	90.00	519,954.81	83.80	43,573,488.59

Composite Average Remaining Life ... 83.80 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.72 Portable Substations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 38

Survivor Curve: S1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1953	2,600.92	38.00	68.45	0.74	50.81
1954	2,263.57	38.00	59.57	0.99	59.12
1955	7,045.40	38.00	185.41	1.23	227.53
1956	294.53	38.00	7.75	1.49	11.54
1961	5,869.31	38.00	154.46	2.73	421.87
1966	2,114.98	38.00	55.66	3.99	222.16
1969	1,259.56	38.00	33.15	4.76	157.90
1971	106,649.53	38.00	2,806.57	5.29	14,856.59
1972	9,337.50	38.00	245.72	5.56	1,366.93
1975	5,381.53	38.00	141.62	6.40	906.69
1976	6,723.83	38.00	176.94	6.69	1,183.61
1984	43,036.41	38.00	1,132.54	9.24	10,465.65
1985	3,259.62	38.00	85.78	9.60	823.14
1987	14,383.92	38.00	378.52	10.34	3,912.54
1989	3,973.21	38.00	104.56	11.12	1,162.57
1990	32,260.00	38.00	848.95	11.53	9,786.14
1993	8,113.24	38.00	213.51	12.83	2,738.93
1994	15,147.02	38.00	398.61	13.29	5,296.79
1995	27,857.47	38.00	733.09	13.76	10,090.16
1996	2,392.16	38.00	62.95	14.25	897.33
1997	1,337.50	38.00	35.20	14.76	519.49
1998	56,879.39	38.00	1,496.83	15.28	22,874.35
1999	27,416.01	38.00	721.47	15.82	11,414.47
2000	192,645.29	38.00	5,069.61	16.38	83,021.98
2001	10,788.71	38.00	283.91	16.95	4,812.67
2004	9,680.31	38.00	254.75	18.79	4,785.78
2007	18,396.12	38.00	484.11	20.80	10,069.63

***Columbia Gas of Pennsylvania
Gas Division***

375.72 Portable Substations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 38

Survivor Curve: S1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2008	208,679.85	38.00	5,491.58	21.51	118,132.49
2010	21,628.69	38.00	569.18	23.00	13,091.33
2011	45,764.94	38.00	1,204.34	23.77	28,632.92
2012	5,855.06	38.00	154.08	24.57	3,785.98
2013	612,757.25	38.00	16,125.19	25.39	409,360.66
2014	116,167.32	38.00	3,057.03	26.22	80,167.59
2015	309,088.24	38.00	8,133.90	27.08	220,269.97
2016	431,798.65	38.00	11,363.12	27.95	317,647.31
2017	62,675.61	38.00	1,649.36	28.85	47,580.53
2018	211,266.41	38.00	5,559.64	29.76	165,444.96
2019	547,609.83	38.00	14,410.79	30.68	442,173.42
2020	169,096.94	38.00	4,449.92	31.62	140,728.35
2021	124,256.14	38.00	3,269.90	32.58	106,531.66
2022	485,748.21	38.00	12,782.85	33.55	428,809.51
2023	837,170.74	38.00	22,030.81	34.52	760,572.95
2024	98,255.59	38.00	2,585.67	35.51	91,814.13
2025	158,611.56	38.00	4,173.99	36.50	152,359.76
2026	178,814.09	38.00	4,705.63	37.50	176,461.93
<i>Total</i>	5,242,352.16	38.00	137,956.64	28.31	3,905,701.82

Composite Average Remaining Life ... 28.31 Years

***Columbia Gas of Pennsylvania
Gas Division***

375.80 Communication

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2001	16,515.16	45.00	367.00	21.77	7,988.64
<i>Total</i>	16,515.16	45.00	367.00	21.77	7,988.64

Composite Average Remaining Life ... 21.77 Years

***Columbia Gas of Pennsylvania
Gas Division***

376.01 Mains - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1957	46,415.28	65.00	714.07	21.74	15,521.11
1958	805,230.51	65.00	12,387.93	22.20	275,036.53
1959	1,062,479.73	65.00	16,345.54	22.67	370,590.79
1960	1,507,353.28	65.00	23,189.62	23.15	536,801.61
1961	1,807,144.23	65.00	27,801.70	23.63	656,920.83
1962	1,731,547.66	65.00	26,638.70	24.12	642,400.43
1963	2,300,097.02	65.00	35,385.45	24.61	870,694.90
1964	2,383,805.43	65.00	36,673.25	25.10	920,612.70
1965	2,006,451.04	65.00	30,867.90	25.60	790,347.97
1966	2,877,741.63	65.00	44,272.12	26.11	1,156,034.99
1967	2,753,148.42	65.00	42,355.34	26.62	1,127,651.34
1968	2,212,956.10	65.00	34,044.84	27.14	924,053.12
1969	1,635,379.65	65.00	25,159.22	27.67	696,048.25
1970	822,171.08	65.00	12,648.55	28.19	356,611.16
1971	1,983,537.74	65.00	30,515.40	28.73	876,652.64
1972	741,533.83	65.00	11,408.00	29.27	333,877.23
1973	508,419.58	65.00	7,821.69	29.81	233,181.88
1974	1,103.89	65.00	16.98	30.36	515.62
1975	688.53	65.00	10.59	30.92	327.50
1976	221.64	65.00	3.41	31.48	107.33
1977	1,759.77	65.00	27.07	32.04	867.54
1978	152,665.47	65.00	2,348.66	32.61	76,601.02
1979	14,971.17	65.00	230.32	33.19	7,644.92
1980	185,002.40	65.00	2,846.14	33.77	96,122.79
1981	41.06	65.00	0.63	34.36	21.71
1983	1,262.95	65.00	19.43	35.55	690.73
1984	188.37	65.00	2.90	36.15	104.77

***Columbia Gas of Pennsylvania
Gas Division***

376.01 Mains - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1985	32.93	65.00	0.51	36.76	18.62
1986	29.43	65.00	0.45	37.37	16.92
1988	0.10	65.00	0.00	38.61	0.06
1989	26.58	65.00	0.41	39.23	16.04
1990	11,086.86	65.00	170.56	39.86	6,799.34
1992	43,019.05	65.00	661.82	41.14	27,224.74
1997	3,868.40	65.00	59.51	44.39	2,641.48
1998	640.58	65.00	9.85	45.04	443.91
2008	76.32	65.00	1.17	51.80	60.82
2011	27,708.39	65.00	426.27	53.87	22,965.14
<i>Total</i>	27,629,806.10	65.00	425,066.01	25.94	11,026,228.46

Composite Average Remaining Life ... 25.94 Years

***Columbia Gas of Pennsylvania
Gas Division***

376.02 Mains - Other

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1952	115,525.24	65.00	1,777.28	19.48	34,626.08
1954	24,792.84	65.00	381.42	20.37	7,769.24
1955	94,438.18	65.00	1,452.87	20.82	30,248.89
1956	63,838.96	65.00	982.12	21.28	20,895.41
1957	82,628.92	65.00	1,271.19	21.74	27,630.82
1958	74,689.51	65.00	1,149.05	22.20	25,511.13
1959	77,715.39	65.00	1,195.60	22.67	27,106.97
1960	55,219.51	65.00	849.52	23.15	19,664.88
1961	14,921.15	65.00	229.55	23.63	5,424.04
1962	66,748.59	65.00	1,026.88	24.12	24,763.58
1963	96,359.35	65.00	1,482.42	24.61	36,476.55
1964	152,885.68	65.00	2,352.04	25.10	59,043.62
1965	51,924.38	65.00	798.82	25.60	20,453.19
1966	95,924.19	65.00	1,475.73	26.11	38,534.29
1967	44,040.40	65.00	677.53	26.62	18,038.34
1968	246,658.00	65.00	3,794.67	27.14	102,995.76
1969	522,857.14	65.00	8,043.81	27.67	222,537.80
1970	536,754.87	65.00	8,257.61	28.19	232,813.80
1971	1,148,939.93	65.00	17,675.67	28.73	507,790.30
1972	871,106.16	65.00	13,401.38	29.27	392,217.45
1973	1,907,626.00	65.00	29,347.54	29.81	874,914.81
1974	2,412,937.75	65.00	37,121.43	30.36	1,127,063.85
1975	2,272,794.52	65.00	34,965.42	30.92	1,081,048.85
1976	1,979,637.18	65.00	30,455.39	31.48	958,661.58
1977	3,933,145.84	65.00	60,508.81	32.04	1,938,971.93
1978	4,189,278.10	65.00	64,449.23	32.61	2,102,001.07
1979	5,131,680.74	65.00	78,947.46	33.19	2,620,454.14

Columbia Gas of Pennsylvania

Gas Division

376.02 Mains - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2026

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1980	6,702,945.06	65.00	103,120.31	33.77	3,482,688.90
1981	7,325,937.68	65.00	112,704.63	34.36	3,872,652.88
1982	7,072,543.04	65.00	108,806.33	34.95	3,803,162.44
1983	6,147,852.01	65.00	94,580.57	35.55	3,362,347.82
1984	6,963,285.61	65.00	107,125.47	36.15	3,872,865.74
1985	6,404,873.51	65.00	98,534.68	36.76	3,622,026.66
1986	7,375,278.12	65.00	113,463.70	37.37	4,240,274.54
1987	7,358,599.12	65.00	113,207.11	37.99	4,300,384.32
1988	8,509,862.44	65.00	130,918.52	38.61	5,054,575.40
1989	7,578,581.84	65.00	116,591.39	39.23	4,574,256.12
1990	6,145,657.29	65.00	94,546.81	39.86	3,769,001.73
1991	6,161,900.18	65.00	94,796.70	40.50	3,838,989.87
1992	6,839,425.77	65.00	105,219.97	41.14	4,328,351.28
1993	7,518,662.43	65.00	115,669.57	41.78	4,832,384.67
1994	9,548,325.69	65.00	146,894.58	42.42	6,231,939.36
1995	9,397,383.61	65.00	144,572.44	43.07	6,227,422.85
1996	9,859,272.68	65.00	151,678.29	43.73	6,632,559.40
1997	11,807,755.21	65.00	181,654.38	44.39	8,062,753.18
1998	10,433,296.99	65.00	160,509.27	45.04	7,230,116.75
1999	9,029,688.81	65.00	138,915.70	45.71	6,349,655.87
2000	8,958,373.59	65.00	137,818.56	46.37	6,391,273.82
2001	10,299,500.58	65.00	158,450.90	47.04	7,454,220.09
2002	6,961,836.71	65.00	107,103.18	47.72	5,110,512.30
2003	10,220,775.12	65.00	157,239.76	48.39	7,608,992.85
2004	15,651,170.50	65.00	240,782.75	49.07	11,814,617.89
2005	20,985,555.60	65.00	322,848.68	49.75	16,061,005.77
2006	9,678,231.95	65.00	148,893.10	50.43	7,508,532.92

Columbia Gas of Pennsylvania

Gas Division

376.02 Mains - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2026

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 65

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2007	35,107,683.38	65.00	540,108.13	51.11	27,607,060.13
2008	55,065,038.24	65.00	847,138.64	51.80	43,882,387.88
2009	33,475,613.62	65.00	514,999.84	52.49	27,031,945.83
2010	43,955,926.73	65.00	676,232.42	53.18	35,962,543.56
2011	80,410,898.03	65.00	1,237,067.67	53.87	66,645,778.83
2012	87,794,831.20	65.00	1,350,664.52	54.57	73,706,585.43
2013	114,618,044.47	65.00	1,763,321.65	55.27	97,456,937.30
2014	122,610,076.41	65.00	1,886,273.69	55.97	105,576,625.20
2015	117,610,964.50	65.00	1,809,365.71	56.67	102,545,372.76
2016	163,573,934.12	65.00	2,516,475.13	57.38	144,401,844.81
2017	179,815,297.76	65.00	2,766,337.61	58.09	160,702,330.09
2018	154,855,438.34	65.00	2,382,346.93	58.81	140,096,264.25
2019	228,255,023.84	65.00	3,511,550.26	59.52	209,012,849.34
2020	226,370,260.50	65.00	3,482,554.44	60.24	209,795,435.55
2021	205,724,908.00	65.00	3,164,939.56	60.96	192,950,207.14
2022	269,455,652.58	65.00	4,145,394.27	61.69	255,732,010.04
2023	314,740,551.24	65.00	4,842,072.02	62.42	302,244,657.51
2024	260,498,441.24	65.00	4,007,593.59	63.15	253,091,623.34
2025	271,486,749.74	65.00	4,176,641.33	63.89	266,845,480.89
2026	296,854,522.73	65.00	4,566,907.49	64.63	295,156,808.77
<i>Total</i>	3,529,481,496.33	65.00	54,298,702.68	58.61	3,182,639,972.44

Composite Average Remaining Life ... 58.61 Years

***Columbia Gas of Pennsylvania
Gas Division***

378.00 M&R Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1985	4,399.58	45.00	97.77	21.14	2,066.88
1986	27,703.14	45.00	615.61	21.64	13,322.52
1987	43,833.75	45.00	974.06	22.15	21,571.83
1988	124,987.74	45.00	2,777.43	22.66	62,927.19
1989	97,546.99	45.00	2,167.65	23.17	50,230.32
1990	93,807.74	45.00	2,084.56	23.69	49,389.94
1991	117,434.98	45.00	2,609.59	24.22	63,201.00
1992	47,860.48	45.00	1,063.54	24.75	26,321.52
1993	92,752.43	45.00	2,061.11	25.28	52,114.78
1994	172,463.16	45.00	3,832.41	25.82	98,971.48
1995	51,281.12	45.00	1,139.55	26.37	30,049.32
1996	285,923.30	45.00	6,353.68	26.92	171,031.60
1997	44,196.35	45.00	982.11	27.47	26,980.52
1998	18,733.99	45.00	416.30	28.03	11,668.95
1999	412,302.36	45.00	9,162.02	28.59	261,959.79
2000	787,304.85	45.00	17,495.18	29.16	510,115.18
2001	170,715.69	45.00	3,793.58	29.73	112,770.37
2002	204,527.16	45.00	4,544.92	30.30	137,710.68
2003	339,877.28	45.00	7,552.62	30.88	233,194.60
2004	261,286.13	45.00	5,806.20	31.46	182,634.62
2005	104,009.26	45.00	2,311.25	32.04	74,045.79
2006	449,884.76	45.00	9,997.16	32.62	326,123.95
2007	450,533.27	45.00	10,011.57	33.21	332,476.86
2008	1,201,368.02	45.00	26,696.33	33.80	902,299.10
2009	411,776.81	45.00	9,150.34	34.39	314,680.17
2010	1,357,759.59	45.00	30,171.60	34.98	1,055,498.73
2011	2,000,155.38	45.00	44,446.67	35.58	1,581,343.80

***Columbia Gas of Pennsylvania
Gas Division***

378.00 M&R Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2012	687,363.95	45.00	15,274.33	36.17	552,548.49
2013	3,039,593.58	45.00	67,544.66	36.77	2,483,812.22
2014	10,138,001.01	45.00	225,282.68	37.37	8,419,299.90
2015	8,981,710.02	45.00	199,588.04	37.97	7,578,912.75
2016	8,847,764.59	45.00	196,611.56	38.58	7,584,351.79
2017	16,655,317.31	45.00	370,107.93	39.18	14,500,461.82
2018	16,729,081.15	45.00	371,747.08	39.78	14,789,682.73
2019	21,023,905.88	45.00	467,184.99	40.39	18,870,121.63
2020	18,216,722.19	45.00	404,804.86	41.00	16,597,030.88
2021	9,146,734.37	45.00	203,255.14	41.61	8,457,547.21
2022	10,143,032.76	45.00	225,394.50	42.22	9,516,760.09
2023	8,126,911.18	45.00	180,593.03	42.84	7,736,004.32
2024	13,707,119.72	45.00	304,594.24	43.45	13,235,386.85
2025	25,012,708.35	45.00	555,822.60	44.07	24,495,540.91
2026	18,122,073.60	45.00	402,701.61	44.69	17,996,980.24
<i>Total</i>	197,952,464.97	45.00	4,398,822.06	40.81	179,519,143.30

Composite Average Remaining Life ... 40.81 Years

***Columbia Gas of Pennsylvania
Gas Division***

379.10 M&R Equipment - City Gate

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 35

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1976	591.42	35.00	16.90	4.04	68.28
1983	26,406.23	35.00	754.46	5.95	4,488.27
1984	1,074.83	35.00	30.71	6.25	192.04
1987	6,793.84	35.00	194.11	7.23	1,402.56
1988	15,907.49	35.00	454.50	7.57	3,440.83
1989	20,307.27	35.00	580.21	7.93	4,599.53
1996	48,076.94	35.00	1,373.63	10.81	14,851.82
<i>Total</i>	119,158.02	35.00	3,404.52	8.53	29,043.33

Composite Average Remaining Life ... 8.53 Years

***Columbia Gas of Pennsylvania
Gas Division***

380.01 Services - Bare Steel

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1950	8,168.48	45.00	181.52	6.15	1,116.89
1951	41,994.15	45.00	933.18	6.56	6,122.63
1952	56,556.80	45.00	1,256.78	6.97	8,754.01
1953	57,705.06	45.00	1,282.30	7.36	9,443.49
1954	95,410.21	45.00	2,120.17	7.76	16,459.69
<i>Total</i>	259,834.70	45.00	5,773.94	7.26	41,896.71

Composite Average Remaining Life ... 7.26 Years

Columbia Gas of Pennsylvania

Gas Division

380.02 Services - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2026

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1955	205,624.57	45.00	4,569.31	8.16	37,289.07
1956	241,839.29	45.00	5,374.06	8.56	45,986.86
1957	223,845.71	45.00	4,974.21	8.95	44,527.51
1958	311,512.31	45.00	6,922.30	9.35	64,705.66
1959	405,069.87	45.00	9,001.30	9.74	87,706.61
1960	305,071.61	45.00	6,779.18	10.14	68,748.50
1961	389,355.34	45.00	8,652.10	10.54	91,191.73
1962	423,414.25	45.00	9,408.95	10.94	102,925.40
1963	589,682.19	45.00	13,103.69	11.34	148,614.41
1964	601,458.59	45.00	13,365.38	11.75	156,991.44
1965	594,518.96	45.00	13,211.17	12.15	160,561.87
1966	726,430.03	45.00	16,142.44	12.56	202,800.54
1967	842,171.53	45.00	18,714.41	12.98	242,847.49
1968	913,642.27	45.00	20,302.60	13.39	271,917.08
1969	646,310.31	45.00	14,362.05	13.81	198,390.36
1970	303,217.47	45.00	6,737.98	14.24	95,932.38
1971	383,296.20	45.00	8,517.46	14.67	124,911.35
1972	379,229.55	45.00	8,427.09	15.10	127,227.34
1973	291,710.39	45.00	6,482.27	15.53	100,694.12
1974	70,071.41	45.00	1,557.10	15.97	24,873.86
1975	108,458.64	45.00	2,410.13	16.42	39,573.76
1976	262,060.42	45.00	5,823.40	16.87	98,239.06
1977	1,436,746.97	45.00	31,926.83	17.32	553,110.63
1978	1,023,416.35	45.00	22,741.96	17.78	404,437.14
1979	1,274,308.63	45.00	28,317.19	18.25	516,733.18
1980	1,824,051.63	45.00	40,533.36	18.72	758,691.37
1981	2,121,841.15	45.00	47,150.72	19.19	904,921.57

Columbia Gas of Pennsylvania

Gas Division

380.02 Services - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2026

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1982	1,753,222.59	45.00	38,959.42	19.67	766,392.16
1983	1,782,682.42	45.00	39,614.07	20.16	798,463.90
1984	2,246,646.37	45.00	49,924.09	20.65	1,030,743.11
1985	2,676,656.46	45.00	59,479.61	21.14	1,257,467.70
1986	3,023,616.76	45.00	67,189.63	21.64	1,454,065.68
1987	3,692,326.69	45.00	82,049.44	22.15	1,817,098.79
1988	4,492,987.45	45.00	99,841.41	22.66	2,262,070.39
1989	4,319,565.92	45.00	95,987.70	23.17	2,224,294.12
1990	4,475,409.12	45.00	99,450.79	23.69	2,356,310.91
1991	4,202,652.94	45.00	93,389.71	24.22	2,261,778.11
1992	4,893,818.53	45.00	108,748.52	24.75	2,691,421.85
1993	5,159,154.73	45.00	114,644.71	25.28	2,898,772.57
1994	6,223,892.03	45.00	138,304.89	25.82	3,571,706.74
1995	5,442,401.89	45.00	120,938.92	26.37	3,189,096.74
1996	5,263,752.19	45.00	116,969.04	26.92	3,148,634.51
1997	5,506,720.45	45.00	122,368.18	27.47	3,361,684.68
1998	6,050,752.61	45.00	134,457.45	28.03	3,768,867.22
1999	6,439,088.61	45.00	143,086.90	28.59	4,091,129.32
2000	6,647,084.91	45.00	147,708.91	29.16	4,306,818.23
2001	6,520,643.68	45.00	144,899.19	29.73	4,307,368.40
2002	5,532,560.00	45.00	122,942.38	30.30	3,725,141.41
2003	5,364,766.97	45.00	119,213.75	30.88	3,680,842.32
2004	7,799,589.64	45.00	173,319.42	31.46	5,451,782.40
2005	8,230,273.67	45.00	182,889.91	32.04	5,859,258.50
2006	8,046,300.89	45.00	178,801.74	32.62	5,832,808.02
2007	11,586,093.04	45.00	257,461.62	33.21	8,550,107.45
2008	13,574,100.94	45.00	301,638.35	33.80	10,194,960.14

Columbia Gas of Pennsylvania

Gas Division

380.02 Services - Other

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2026

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 45

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2009	12,400,088.69	45.00	275,549.91	34.39	9,476,157.77
2010	14,655,260.85	45.00	325,663.46	34.98	11,392,745.31
2011	21,790,692.22	45.00	484,224.22	35.58	17,227,949.54
2012	27,643,013.84	45.00	614,272.21	36.17	22,221,278.36
2013	32,906,846.45	45.00	731,243.04	36.77	26,889,919.70
2014	34,545,943.08	45.00	767,666.40	37.37	28,689,349.58
2015	39,660,855.11	45.00	881,327.97	37.97	33,466,473.53
2016	30,717,528.81	45.00	682,592.88	38.58	26,331,232.29
2017	48,377,988.25	45.00	1,075,036.69	39.18	42,118,871.61
2018	47,197,355.10	45.00	1,048,801.12	39.78	41,725,776.88
2019	58,656,716.94	45.00	1,303,446.56	40.39	52,647,656.87
2020	59,439,551.79	45.00	1,320,842.41	41.00	54,154,642.44
2021	63,951,822.05	45.00	1,421,112.31	41.61	59,133,186.99
2022	63,858,442.91	45.00	1,419,037.28	42.22	59,915,559.31
2023	69,524,565.01	45.00	1,544,947.62	42.84	66,180,412.61
2024	61,690,675.99	45.00	1,370,866.01	43.45	59,567,580.84
2025	74,497,140.89	45.00	1,655,446.25	44.07	72,956,824.05
2026	83,234,028.42	45.00	1,849,593.94	44.69	82,659,479.13
<i>Total</i>	1,012,593,633.54	45.00	22,501,458.67	38.54	867,288,732.43

Composite Average Remaining Life ... 38.54 Years

***Columbia Gas of Pennsylvania
Gas Division
381.00 Meters***

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1956	933.23	44.00	21.21	4.88	103.57
1957	2,306.78	44.00	52.43	5.18	271.78
1958	26,124.84	44.00	593.75	5.49	3,258.61
1959	22,876.74	44.00	519.93	5.79	3,010.88
1960	35,509.54	44.00	807.03	6.10	4,923.28
1961	27,609.09	44.00	627.48	6.41	4,024.29
1962	14,005.61	44.00	318.31	6.73	2,142.17
1963	34,996.41	44.00	795.37	7.05	5,604.09
1964	106,999.25	44.00	2,431.80	7.37	17,918.97
1965	102,151.45	44.00	2,321.62	7.70	17,865.24
1966	96,227.13	44.00	2,186.98	8.02	17,546.82
1967	58,969.17	44.00	1,340.21	8.36	11,199.97
1968	6,445.13	44.00	146.48	8.69	1,273.60
1969	10,829.82	44.00	246.13	9.04	2,224.22
1970	4,568.96	44.00	103.84	9.38	974.14
1971	211,827.52	44.00	4,814.26	9.73	46,849.82
1972	179,657.18	44.00	4,083.12	10.09	41,184.15
1973	115,738.06	44.00	2,630.41	10.45	27,477.80
1974	146,757.46	44.00	3,335.40	10.81	36,053.84
1975	161,114.22	44.00	3,661.69	11.18	40,933.64
1976	62,655.63	44.00	1,423.99	11.55	16,452.27
1977	144,959.95	44.00	3,294.54	11.93	39,316.35
1978	132,728.49	44.00	3,016.56	12.32	37,160.01
1979	264,895.91	44.00	6,020.36	12.71	76,519.64
1980	488,035.64	44.00	11,091.72	13.11	145,385.99
1981	518,982.05	44.00	11,795.05	13.51	159,363.81
1982	322,561.29	44.00	7,330.94	13.92	102,055.75

***Columbia Gas of Pennsylvania
Gas Division
381.00 Meters***

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 44

Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1983	243,626.40	44.00	5,536.96	14.34	79,389.53
1984	335,983.35	44.00	7,635.98	14.76	112,721.52
1985	468,867.09	44.00	10,656.07	15.19	161,898.75
1986	477,435.39	44.00	10,850.80	15.63	169,616.23
1987	478,279.80	44.00	10,869.99	16.08	174,767.43
1988	554,538.13	44.00	12,603.14	16.53	208,364.59
1989	623,188.81	44.00	14,163.38	17.00	240,716.07
1990	337,382.43	44.00	7,667.78	17.47	133,934.63
1991	435,151.68	44.00	9,889.81	17.95	177,498.80
1992	648,768.14	44.00	14,744.73	18.44	271,868.82
1993	789,940.65	44.00	17,953.19	18.94	340,001.19
1994	307,108.74	44.00	6,979.74	19.45	135,742.08
1995	7,696.07	44.00	174.91	19.97	3,492.64
1996	1,589,386.74	44.00	36,122.42	20.50	740,533.20
1997	544,186.11	44.00	12,367.86	21.04	260,261.05
1998	859,486.29	44.00	19,533.78	21.60	421,882.00
1999	913,500.94	44.00	20,761.38	22.16	460,150.45
2001	241,543.48	44.00	5,489.62	23.34	128,111.50
2002	1,059,003.96	44.00	24,068.27	23.94	576,258.36
2003	766,608.36	44.00	17,422.92	24.56	427,978.79
2004	680,387.65	44.00	15,463.35	25.20	389,657.61
2005	332,876.89	44.00	7,565.38	25.85	195,551.39
2006	481,513.48	44.00	10,943.49	26.51	290,142.58
2007	988,225.22	44.00	22,459.66	27.20	610,809.17
2008	1,021,156.43	44.00	23,208.10	27.89	647,352.81
2009	1,324,138.68	44.00	30,094.06	28.61	860,919.18
2010	1,060,594.02	44.00	24,104.41	29.34	707,247.50

***Columbia Gas of Pennsylvania
Gas Division
381.00 Meters***

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 44 Survivor Curve: S1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2011	999,552.01	44.00	22,717.09	30.09	683,577.88
2012	1,290,230.90	44.00	29,323.43	30.86	904,882.26
2013	919,863.96	44.00	20,906.00	31.64	661,562.95
2014	1,093,302.92	44.00	24,847.79	32.45	806,352.18
2015	2,456,805.28	44.00	55,836.48	33.28	1,858,009.61
2016	1,227,945.29	44.00	27,907.84	34.12	952,185.53
2017	1,205,000.28	44.00	27,386.37	34.98	957,994.37
2018	1,060,093.79	44.00	24,093.04	35.86	864,070.90
2019	1,443,843.53	44.00	32,814.62	36.76	1,206,385.65
2020	1,972,609.71	44.00	44,832.03	37.68	1,689,324.17
2021	1,691,390.91	44.00	38,440.70	38.62	1,484,417.44
2022	1,934,869.46	44.00	43,974.30	39.57	1,740,014.01
2023	2,109,643.43	44.00	47,946.44	40.53	1,943,498.21
2024	2,152,606.74	44.00	48,922.88	41.51	2,030,956.88
2025	7,744,386.63	44.00	176,008.77	42.50	7,481,002.45
2026	9,490,796.62	44.00	215,699.90	43.50	9,382,989.70
<i>Total</i>	59,663,982.94	44.00	1,355,999.47	32.77	44,435,186.74

Composite Average Remaining Life ... 32.77 Years

***Columbia Gas of Pennsylvania
Gas Division***

381.10 Meters - AMR

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 20

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2000	275,628.74	20.00	13,781.40	2.94	40,535.30
2001	261,390.73	20.00	13,069.50	3.22	42,100.38
2003	489.27	20.00	24.46	3.83	93.71
2004	103,288.67	20.00	5,164.42	4.16	21,494.40
2005	162,901.40	20.00	8,145.05	4.51	36,746.49
2007	104,596.80	20.00	5,229.83	5.28	27,605.89
2008	474,844.02	20.00	23,742.13	5.70	135,320.43
2009	413,176.20	20.00	20,658.75	6.15	127,044.94
2010	812,709.29	20.00	40,635.35	6.63	269,411.52
2011	11,129,962.32	20.00	556,496.56	7.15	3,976,399.24
2012	8,654,153.89	20.00	432,706.48	7.70	3,330,055.76
2013	350,787.04	20.00	17,539.30	8.29	145,356.60
2014	305,258.88	20.00	15,262.90	8.92	136,126.33
2015	370,938.99	20.00	18,546.90	9.60	177,977.53
2016	391,585.88	20.00	19,579.24	10.32	201,985.94
2017	188,822.48	20.00	9,441.10	11.08	104,651.55
2018	496,376.28	20.00	24,818.74	11.90	295,242.62
2019	124,586.81	20.00	6,229.32	12.75	79,439.47
2020	81,905.27	20.00	4,095.25	13.65	55,886.79
2021	377,449.38	20.00	18,872.42	14.58	275,090.93
2022	390,626.31	20.00	19,531.26	15.53	303,395.35
2023	368,384.60	20.00	18,419.18	16.51	304,138.58
2024	175,513.30	20.00	8,775.64	17.50	153,597.71
2025	1,366,813.88	20.00	68,340.50	18.50	1,264,323.55
2026	1,674,862.47	20.00	83,742.89	19.50	1,632,990.83

***Columbia Gas of Pennsylvania
Gas Division***

381.10 Meters - AMR

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 20

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
<i>Total</i>	29,057,052.90	20.00	1,452,848.58	9.04	13,137,011.84

Composite Average Remaining Life ... 9.04 Years

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1938	1,563.83	55.00	28.43	1.09	31.06
1939	2,465.59	55.00	44.83	1.32	59.17
1940	2,999.60	55.00	54.54	1.56	84.87
1941	5,217.26	55.00	94.86	1.80	170.57
1942	4,454.55	55.00	80.99	2.06	166.82
1943	2,217.30	55.00	40.31	2.29	92.48
1944	2,400.36	55.00	43.64	2.54	110.79
1945	3,366.31	55.00	61.21	2.79	170.72
1946	8,519.92	55.00	154.91	3.04	471.52
1947	12,867.75	55.00	233.96	3.31	775.19
1948	16,830.98	55.00	306.02	3.56	1,090.15
1949	22,284.91	55.00	405.18	3.81	1,545.71
1950	26,484.34	55.00	481.53	4.07	1,959.63
1951	23,542.75	55.00	428.05	4.33	1,851.63
1952	24,938.17	55.00	453.42	4.58	2,078.14
1953	30,281.18	55.00	550.57	4.85	2,669.92
1954	28,834.45	55.00	524.26	5.11	2,676.53
1955	36,646.87	55.00	666.31	5.37	3,575.10
1956	39,126.31	55.00	711.39	5.63	4,005.65
1957	36,341.53	55.00	660.75	5.90	3,899.68
1958	39,049.90	55.00	710.00	6.19	4,391.60
1959	57,764.78	55.00	1,050.27	6.47	6,792.79
1960	42,489.30	55.00	772.53	6.76	5,222.37
1961	37,134.83	55.00	675.18	7.06	4,769.08
1962	53,560.08	55.00	973.82	7.38	7,185.44
1963	57,507.15	55.00	1,045.58	7.71	8,057.74
1964	103,942.20	55.00	1,889.86	8.05	15,211.16

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1965	138,990.14	55.00	2,527.09	8.40	21,235.66
1966	129,719.37	55.00	2,358.53	8.77	20,691.26
1967	118,963.95	55.00	2,162.98	9.16	19,809.65
1968	155,585.84	55.00	2,828.83	9.56	27,044.39
1969	148,152.81	55.00	2,693.69	9.98	26,876.42
1970	136,527.45	55.00	2,482.32	10.41	25,848.15
1971	119,865.11	55.00	2,179.36	10.87	23,680.00
1972	75,754.34	55.00	1,377.35	11.34	15,612.96
1973	70,769.81	55.00	1,286.72	11.82	15,212.56
1974	12,077.72	55.00	219.59	12.33	2,706.97
1975	20,889.64	55.00	379.81	12.85	4,879.27
1976	39,062.39	55.00	710.23	13.39	9,507.05
1977	36,761.34	55.00	668.39	13.94	9,318.65
1978	37,467.59	55.00	681.23	14.51	9,887.52
1979	91,951.28	55.00	1,671.84	15.10	25,248.77
1980	192,979.23	55.00	3,508.71	15.70	55,098.05
1981	272,962.76	55.00	4,962.96	16.32	81,011.20
1982	224,813.95	55.00	4,087.53	16.96	69,314.76
1983	257,359.93	55.00	4,679.27	17.61	82,383.91
1984	321,275.74	55.00	5,841.38	18.27	106,711.69
1985	330,020.39	55.00	6,000.37	18.94	113,667.92
1986	399,441.77	55.00	7,262.58	19.63	142,560.26
1987	453,201.66	55.00	8,240.03	20.33	167,526.52
1988	550,160.08	55.00	10,002.91	21.04	210,501.07
1989	653,156.36	55.00	11,875.57	21.77	258,514.30
1990	693,369.75	55.00	12,606.72	22.50	283,705.16
1991	633,710.13	55.00	11,522.00	23.25	267,870.19

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1992	709,668.96	55.00	12,903.07	24.01	309,758.83
1993	611,754.45	55.00	11,122.80	24.77	275,565.02
1994	715,929.51	55.00	13,016.90	25.55	332,619.35
1995	637,705.39	55.00	11,594.64	26.34	305,411.38
1996	732,302.32	55.00	13,314.58	27.14	361,332.92
1997	707,879.72	55.00	12,870.54	27.94	359,646.71
1998	611,767.58	55.00	11,123.04	28.76	319,900.65
1999	516,100.74	55.00	9,383.65	29.59	277,623.52
2000	1,110,865.22	55.00	20,197.54	30.42	614,417.16
2001	1,019,414.02	55.00	18,534.79	31.26	579,462.98
2002	995,564.42	55.00	18,101.17	32.11	581,292.21
2003	1,094,496.18	55.00	19,899.92	32.97	656,182.51
2004	1,065,912.63	55.00	19,380.22	33.84	655,880.14
2005	748,974.16	55.00	13,617.71	34.72	472,796.31
2006	210,671.46	55.00	3,830.39	35.60	136,374.65
2007	2,935,373.81	55.00	53,370.42	36.49	1,947,747.24
2008	1,394,957.58	55.00	25,362.86	37.39	948,383.82
2009	1,735,603.60	55.00	31,556.42	38.30	1,208,576.27
2010	1,423,472.33	55.00	25,881.31	39.21	1,014,853.85
2011	1,536,719.37	55.00	27,940.34	40.13	1,121,279.37
2012	1,660,053.48	55.00	30,182.78	41.06	1,239,205.25
2013	1,019,138.37	55.00	18,529.78	41.99	778,011.88
2014	1,228,383.99	55.00	22,334.25	42.92	958,687.54
2015	1,323,967.18	55.00	24,072.12	43.87	1,055,978.38
2016	1,382,824.89	55.00	25,142.26	44.81	1,126,750.19
2017	1,938,278.19	55.00	35,241.41	45.77	1,612,908.59
2018	1,444,043.47	55.00	26,255.33	46.72	1,226,761.81

***Columbia Gas of Pennsylvania
Gas Division***

382.00 Meter Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 55

Survivor Curve: R3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2019	1,085,468.07	55.00	19,735.78	47.68	941,097.07
2020	789,505.68	55.00	14,354.64	48.65	698,354.30
2021	1,292,946.31	55.00	23,508.11	49.62	1,166,445.46
2022	1,834,853.96	55.00	33,360.97	50.59	1,687,764.11
2023	2,635,433.01	55.00	47,916.95	51.57	2,470,893.17
2024	6,973,277.32	55.00	126,786.82	52.54	6,661,855.33
2025	2,792,228.58	55.00	50,767.78	53.52	2,717,321.85
2026	3,130,275.24	55.00	56,914.08	54.51	3,102,252.91
<i>Total</i>	58,083,633.92	55.00	1,056,065.74	39.86	42,098,932.54

Composite Average Remaining Life ... 39.86 Years

***Columbia Gas of Pennsylvania
Gas Division***

383.00 House Regulators

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 50

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1957	16.43	50.00	0.33	6.44	2.12
1958	292.19	50.00	5.84	6.70	39.15
1960	90.80	50.00	1.82	7.24	13.15
1961	511.02	50.00	10.22	7.52	76.84
1962	2,322.27	50.00	46.45	7.80	362.36
1963	6,975.24	50.00	139.50	8.09	1,128.73
1964	10,302.33	50.00	206.05	8.39	1,727.90
1965	13,370.46	50.00	267.41	8.69	2,323.01
1966	34,518.50	50.00	690.37	8.99	6,209.57
1967	27,947.16	50.00	558.94	9.31	5,202.98
1968	37,643.73	50.00	752.87	9.63	7,249.80
1969	35,240.11	50.00	704.80	9.96	7,018.08
1970	38,927.50	50.00	778.55	10.29	8,013.56
1971	33,426.83	50.00	668.54	10.64	7,110.59
1972	19,641.69	50.00	392.83	10.99	4,316.13
1973	17,587.53	50.00	351.75	11.35	3,991.18
1974	1,384.47	50.00	27.69	11.71	324.37
1975	1,224.96	50.00	24.50	12.09	296.24
1976	1,994.24	50.00	39.88	12.48	497.69
1977	1,889.96	50.00	37.80	12.87	486.64
1978	3,025.95	50.00	60.52	13.28	803.72
1979	7,830.37	50.00	156.61	13.70	2,145.08
1980	12,215.92	50.00	244.32	14.12	3,450.93
1981	20,227.64	50.00	404.55	14.56	5,891.71
1982	22,923.00	50.00	458.46	15.01	6,883.31
1983	26,566.81	50.00	531.34	15.48	8,223.25
1984	27,759.40	50.00	555.19	15.95	8,856.16

***Columbia Gas of Pennsylvania
Gas Division***

383.00 House Regulators

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 50

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1985	26,836.23	50.00	536.72	16.44	8,823.60
1986	41,731.25	50.00	834.63	16.94	14,139.54
1987	51,659.47	50.00	1,033.19	17.46	18,035.89
1988	69,930.96	50.00	1,398.62	17.99	25,155.78
1989	78,205.54	50.00	1,564.11	18.53	28,983.78
1990	78,997.66	50.00	1,579.95	19.09	30,161.38
1991	68,068.13	50.00	1,361.36	19.67	26,771.43
1992	76,361.83	50.00	1,527.24	20.26	30,936.18
1993	55,641.26	50.00	1,112.83	20.86	23,217.82
1994	66,553.69	50.00	1,331.07	21.49	28,602.35
1995	75,220.34	50.00	1,504.41	22.13	33,291.95
1996	79,858.82	50.00	1,597.18	22.79	36,397.28
1997	93,752.52	50.00	1,875.05	23.47	43,998.30
1998	33,295.12	50.00	665.90	24.16	16,088.00
1999	18,389.71	50.00	367.79	24.87	9,147.93
2000	173,268.74	50.00	3,465.38	25.60	88,725.30
2001	67,472.21	50.00	1,349.44	26.35	35,561.44
2002	367,591.92	50.00	7,351.84	27.12	199,383.71
2003	532,154.26	50.00	10,643.09	27.91	297,006.51
2004	877,483.98	50.00	17,549.68	28.71	503,849.40
2005	703,716.82	50.00	14,074.34	29.53	415,636.06
2006	418,331.86	50.00	8,366.64	30.37	254,098.71
2007	841,682.17	50.00	16,833.64	31.23	525,653.75
2008	546,168.41	50.00	10,923.37	32.10	350,625.19
2009	776,375.22	50.00	15,527.51	32.99	512,199.05
2010	616,816.02	50.00	12,336.32	33.89	418,070.28
2011	691,805.66	50.00	13,836.11	34.81	481,582.68

***Columbia Gas of Pennsylvania
Gas Division***

383.00 House Regulators

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 50

Survivor Curve: S2

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2012	682,050.33	50.00	13,641.01	35.74	487,476.06
2013	504,735.73	50.00	10,094.72	36.68	370,253.23
2014	639,591.52	50.00	12,791.83	37.63	481,364.84
2015	540,776.78	50.00	10,815.54	38.59	417,404.44
2016	543,858.76	50.00	10,877.18	39.56	430,343.70
2017	687,149.54	50.00	13,742.99	40.54	557,169.11
2018	753,694.20	50.00	15,073.89	41.53	625,961.86
2019	936,959.95	50.00	18,739.20	42.52	796,703.43
2020	997,531.43	50.00	19,950.63	43.51	868,016.69
2021	978,058.71	50.00	19,561.18	44.50	870,549.54
2022	1,022,336.25	50.00	20,446.73	45.50	930,359.11
2023	1,392,708.95	50.00	27,854.18	46.50	1,295,233.90
2024	1,386,159.08	50.00	27,723.18	47.50	1,316,854.30
2025	1,474,959.78	50.00	29,499.20	48.50	1,430,711.24
2026	1,774,120.61	50.00	35,482.41	49.50	1,756,379.40
<i>Total</i>	22,247,917.93	50.00	444,958.39	38.62	17,183,568.40

Composite Average Remaining Life ... 38.62 Years

***Columbia Gas of Pennsylvania
Gas Division***

384.00 House Regulator Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 40

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1975	25,136.35	40.00	628.41	2.66	1,670.73
1976	13,359.25	40.00	333.98	2.83	944.75
1978	1,285.12	40.00	32.13	3.22	103.39
1979	41,233.65	40.00	1,030.84	3.44	3,542.32
1980	77,405.45	40.00	1,935.14	3.66	7,082.58
1981	102,627.19	40.00	2,565.68	3.91	10,024.34
1982	110,720.57	40.00	2,768.01	4.17	11,529.21
1983	93,709.68	40.00	2,342.74	4.45	10,418.75
1984	99,554.67	40.00	2,488.87	4.75	11,812.60
1985	116,311.27	40.00	2,907.78	5.07	14,743.84
1986	124,986.80	40.00	3,124.67	5.42	16,928.68
1987	160,370.98	40.00	4,009.27	5.79	23,223.56
1988	174,969.75	40.00	4,374.24	6.20	27,104.47
1989	145,091.42	40.00	3,627.29	6.63	24,050.22
1990	142,066.09	40.00	3,551.65	7.10	25,215.25
1991	135,027.17	40.00	3,375.68	7.60	25,660.98
1992	131,960.12	40.00	3,299.00	8.14	26,868.20
1993	112,200.44	40.00	2,805.01	8.72	24,466.46
1994	183,909.08	40.00	4,597.73	9.34	42,964.03
1995	147,443.92	40.00	3,686.10	10.00	36,874.67
1996	122,280.82	40.00	3,057.02	10.71	32,734.94
1997	182,227.94	40.00	4,555.70	11.45	52,157.60
1998	181,131.20	40.00	4,528.28	12.23	55,393.81
1999	139,852.05	40.00	3,496.30	13.05	45,627.17
2000	194,705.19	40.00	4,867.63	13.91	67,685.06
2001	229,155.22	40.00	5,728.88	14.79	84,717.89
2002	154,763.70	40.00	3,869.09	15.70	60,745.48

***Columbia Gas of Pennsylvania
Gas Division***

384.00 House Regulator Installations

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 40

Survivor Curve: S4

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2003	133,892.44	40.00	3,347.31	16.63	55,675.99
2025	31,349.02	40.00	783.73	38.50	30,173.43
2026	38,271.84	40.00	956.80	39.50	37,793.44
<i>Total</i>	3,546,998.39	40.00	88,674.97	9.79	867,933.85

Composite Average Remaining Life ... 9.79 Years

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1943	643.38	0.00	0.00	0.00	0.00
1944	474.25	0.00	0.00	0.00	0.00
1945	291.06	0.00	0.00	0.00	0.00
1946	41.99	0.00	0.00	0.00	0.00
1947	445.66	0.00	0.00	0.00	0.00
1948	761.93	0.00	0.00	0.00	0.00
1950	1,307.40	0.00	0.00	0.00	0.00
1951	2,197.57	0.00	0.00	0.00	0.00
1952	3,445.79	0.00	0.00	0.00	0.00
1953	3,205.71	0.00	0.00	0.00	0.00
1954	10,241.09	0.00	0.00	0.00	0.00
1955	18,014.45	0.00	0.00	0.00	0.00
1956	18,174.97	0.00	0.00	0.00	0.00
1957	20,479.54	0.00	0.00	0.00	0.00
1958	17,938.50	0.00	0.00	0.00	0.00
1959	17,286.58	0.00	0.00	0.00	0.00
1960	19,400.72	0.00	0.00	0.00	0.00
1961	25,202.41	0.00	0.00	0.00	0.00
1962	10,847.09	0.00	0.00	0.00	0.00
1963	30,713.81	0.00	0.00	0.00	0.00
1964	20,073.11	0.00	0.00	0.00	0.00
1965	25,981.32	0.00	0.00	0.00	0.00
1966	23,058.27	0.00	0.00	0.00	0.00
1967	41,315.78	30.00	1,377.12	0.50	688.56
1968	42,496.32	30.00	1,416.47	0.82	1,166.85
1969	37,518.45	30.00	1,250.55	1.27	1,588.64
1970	36,782.07	30.00	1,226.00	1.73	2,117.06

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1971	86,609.95	30.00	2,886.84	2.18	6,301.43
1972	53,637.48	30.00	1,787.82	2.63	4,701.67
1973	31,395.60	30.00	1,046.46	3.06	3,206.50
1974	19,067.61	30.00	635.55	3.49	2,217.81
1975	13,417.17	30.00	447.21	3.91	1,746.90
1976	699.92	30.00	23.33	4.31	100.64
1977	493.98	30.00	16.47	4.72	77.67
1978	9,594.60	30.00	319.80	5.12	1,636.38
1979	29,563.55	30.00	985.40	5.51	5,432.04
1980	50,756.43	30.00	1,691.79	5.91	9,995.19
1981	62,981.33	30.00	2,099.26	6.30	13,232.95
1982	89,063.21	30.00	2,968.61	6.70	19,887.45
1983	62,541.96	30.00	2,084.62	7.10	14,795.63
1984	26,335.05	30.00	877.79	7.50	6,582.17
1985	34,912.86	30.00	1,163.70	7.90	9,196.15
1986	69,133.03	30.00	2,304.31	8.31	19,151.13
1987	14,806.38	30.00	493.52	8.72	4,305.54
1988	45,150.00	30.00	1,504.92	9.14	13,758.24
1989	58,098.46	30.00	1,936.51	9.57	18,524.74
1990	44,117.44	30.00	1,470.50	10.00	14,698.97
1991	78,796.54	30.00	2,626.41	10.43	27,398.77
1992	65,512.62	30.00	2,183.64	10.87	23,746.74
1993	90,043.73	30.00	3,001.30	11.32	33,988.41
1994	124,310.93	30.00	4,143.47	11.78	48,816.73
1995	100,014.85	30.00	3,333.65	12.25	40,823.32
1996	87,851.03	30.00	2,928.21	12.72	37,239.60
1997	27,195.12	30.00	906.45	13.20	11,962.60

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1999	356.42	30.00	11.88	14.18	168.45
2000	98,009.72	30.00	3,266.81	14.68	47,962.76
2001	3,059.11	30.00	101.96	15.19	1,549.06
2002	161,466.55	30.00	5,381.93	15.71	84,549.71
2003	340,455.13	30.00	11,347.89	16.24	184,241.23
2004	2,289.35	30.00	76.31	16.77	1,279.56
2005	50,531.41	30.00	1,684.29	17.31	29,152.28
2006	114,768.10	30.00	3,825.40	17.86	68,304.54
2007	147,991.43	30.00	4,932.78	18.41	90,807.32
2008	193,281.15	30.00	6,442.36	18.97	122,202.02
2009	129,426.43	30.00	4,313.98	19.53	84,271.09
2010	196,444.06	30.00	6,547.78	20.11	131,645.76
2011	159,559.12	30.00	5,318.35	20.68	109,990.56
2012	139,546.86	30.00	4,651.31	21.26	98,897.08
2013	271,520.03	30.00	9,050.18	21.85	197,717.59
2014	134,345.40	30.00	4,477.94	22.43	100,462.43
2015	298,912.06	30.00	9,963.20	23.03	229,418.46
2016	490,931.99	30.00	16,363.51	23.62	386,517.19
2017	480,676.94	30.00	16,021.70	24.22	387,998.71
2018	486,845.13	30.00	16,227.29	24.82	402,694.69
2019	114,974.00	30.00	3,832.26	25.42	97,402.88
2020	924,617.68	30.00	30,818.92	26.02	801,890.09
2021	44,419.27	30.00	1,480.56	26.62	39,419.81
2022	365,257.86	30.00	12,174.60	27.23	331,546.63
2023	1,015,007.21	30.00	33,831.74	27.84	941,975.76
2024	205,643.88	30.00	6,854.43	28.46	195,051.49
2025	1,164,330.14	30.00	38,808.91	29.07	1,128,260.23

***Columbia Gas of Pennsylvania
Gas Division***

385.00 Industrial M&R Station Equipment

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 30

Survivor Curve: R0.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2026	1,211,153.15	30.00	40,369.59	29.69	1,198,611.42
<i>Total</i>	10,750,259.63	21.59	349,315.54	22.60	7,893,075.29

Composite Average Remaining Life ... 22.60 Years

***Columbia Gas of Pennsylvania
Gas Division***

387.00 Other Equipment - General

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 32

Survivor Curve: R1

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1941	38.38	0.00	0.00	0.00	0.00
1942	67.31	0.00	0.00	0.00	0.00
1950	90.19	0.00	0.00	0.00	0.00
1955	4,288.05	0.00	0.00	0.00	0.00
1957	14,374.70	0.00	0.00	0.00	0.00
1959	188.29	0.00	0.00	0.00	0.00
1962	7,626.48	0.00	0.00	0.00	0.00
1967	445.13	32.00	13.91	1.64	22.83
1972	7,910.24	32.00	247.19	3.14	775.67
1981	13,548.93	32.00	423.39	6.08	2,575.51
1985	14,556.64	32.00	454.88	7.59	3,452.92
1992	2,228.63	32.00	69.64	10.57	736.31
2010	68,488.09	32.00	2,140.17	20.56	44,009.72
2015	2,847.08	32.00	88.97	23.87	2,123.74
<i>Total</i>	136,698.14	16.00	3,438.15	15.62	53,696.70

Composite Average Remaining Life ... 15.62 Years

***Columbia Gas of Pennsylvania
Gas Division***

387.40 Other Equipment - Communication

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 25

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
1973	917.13	0.00	0.00	0.00	0.00
1974	11,561.27	0.00	0.00	0.00	0.00
1975	3,189.09	0.00	0.00	0.00	0.00
1976	6,308.81	0.00	0.00	0.00	0.00
1980	1,144.78	25.00	45.79	1.29	59.18
1983	10,695.21	25.00	427.79	2.08	888.39
1984	4,730.23	25.00	189.20	2.30	434.83
1985	27,353.09	25.00	1,094.09	2.53	2,765.14
1986	61,596.14	25.00	2,463.77	2.77	6,821.61
1987	40,005.58	25.00	1,600.17	3.02	4,837.19
1989	3,425.59	25.00	137.02	3.56	488.34
1990	37,952.71	25.00	1,518.06	3.85	5,842.04
1991	31,594.95	25.00	1,263.76	4.14	5,233.54
1992	6,510.50	25.00	260.41	4.44	1,157.06
1993	1,718.09	25.00	68.72	4.76	326.80
1994	4,082.11	25.00	163.28	5.08	829.35
2000	47,842.64	25.00	1,913.64	7.36	14,087.79
2001	142,467.12	25.00	5,698.50	7.81	44,504.38
2003	2,326.24	25.00	93.05	8.77	815.93
2004	89,547.93	25.00	3,581.80	9.28	33,239.58
2005	219,536.12	25.00	8,781.16	9.81	86,159.87
2006	13,325.90	25.00	533.02	10.36	5,524.18
2007	9,937.59	25.00	397.49	10.94	4,346.87
2008	0.11	25.00	0.00	11.53	0.05
2009	5,832.45	25.00	233.29	12.14	2,831.27
2010	108,042.35	25.00	4,321.56	12.76	55,158.29
2011	42,386.12	25.00	1,695.39	13.41	22,731.49

***Columbia Gas of Pennsylvania
Gas Division***

387.40 Other Equipment - Communication

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 25

Survivor Curve: R1.5

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2012	86,817.14	25.00	3,472.57	14.07	48,853.27
2013	479,315.49	25.00	19,172.00	14.74	282,675.32
2014	1,524,487.08	25.00	60,977.53	15.43	941,158.98
2015	689,927.53	25.00	27,596.22	16.14	445,360.88
2016	691,594.66	25.00	27,662.90	16.86	466,262.42
2017	1,709,491.37	25.00	68,377.46	17.58	1,202,327.06
2018	1,951,023.64	25.00	78,038.44	18.32	1,429,915.70
2019	710,001.20	25.00	28,399.14	19.07	541,659.06
2020	1,079,074.68	25.00	43,161.60	19.83	856,012.57
2021	567,278.96	25.00	22,690.43	20.60	467,467.51
2022	2,162,220.17	25.00	86,486.03	21.38	1,849,132.85
2023	2,929,738.01	25.00	117,185.76	22.17	2,597,877.85
2024	3,297,522.65	25.00	131,896.67	22.97	3,029,195.53
<i>Total</i>	18,812,522.43	22.50	751,597.71	19.24	14,456,982.16

Composite Average Remaining Life ... 19.24 Years

***Columbia Gas of Pennsylvania
Gas Division***

387.50 Other Equipment - GPS

***Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2026
Based Upon Broad Group/Remaining Life Procedure and Technique***

Average Service Life: 10

Survivor Curve: S3

<i>Year</i>	<i>Original Cost</i>	<i>Avg. Service Life</i>	<i>Avg. Annual Accrual</i>	<i>Avg. Remaining Life</i>	<i>Future Annual Accruals</i>
<i>(1)</i>	<i>(2)</i>	<i>(3)</i>	<i>(4)</i>	<i>(5)</i>	<i>(6)</i>
2014	1,942,103.70	10.00	194,210.39	1.26	244,291.23
2015	112,834.83	10.00	11,283.48	1.51	17,083.64
2016	33,669.32	10.00	3,366.93	1.82	6,138.34
2017	34,335.00	10.00	3,433.50	2.20	7,549.82
2018	78,429.10	10.00	7,842.91	2.66	20,843.32
<i>Total</i>	2,201,371.95	10.00	220,137.21	1.34	295,906.35

Composite Average Remaining Life ... 1.34 Years

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

Columbia Gas of Pennsylvania, Inc.

:
:
:
:
:
:
:

Docket No. R-2025-3053499

VERIFICATION

I, David J. Garrett, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 3, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

DATED: June 18, 2025

Signature: /s/ David J. Garrett
David J. Garrett

Address: 101 Park Avenue, Suite 1125
Oklahoma, OK 73120

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

**Pennsylvania Public Utility Commission :
v. : Docket No. R-2025-3053499
Columbia Gas of Pennsylvania :**

SURREBUTTAL TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF OF

THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

July 31, 2025

1 **I. Introduction**

2 **Q. State your name and occupation.**

3 A. My name is David J. Garrett. I am a consultant specializing in public utility regulation. I
4 am the managing member of Resolve Utility Consulting PLLC.

5 **Q. Have you previously filed testimony in this proceeding?**

6 A. Yes. I filed direct testimony in OCA Statement 2 on June 18, 2025, on behalf of the
7 Pennsylvania Office of Consumer Advocate (“OCA”). A summary of my qualifications is
8 included in my direct testimony.

9 **Q. What is the purpose of your surrebuttal testimony?**

10 A. My surrebuttal testimony responds to the rebuttal testimony of Columbia Gas of
11 Pennsylvania (“Columbia” or the “Company”) witnesses Vincent Rea and Mark Kempic
12 regarding rate of return issues. I also address the rebuttal testimony of Columbia witness
13 John Spanos regarding depreciation issues.

14 **Q. Did the Company’s rebuttal testimony cause you to change any of your positions or**
15 **recommendations discussed in your direct testimony?**

16 A. No. Additionally, to the extent I do not specifically address a statement made in the
17 company’s rebuttal testimony filed in this case, it should not constitute my agreement with
18 such testimony.

19 **Q. Are you sponsoring any exhibits to your surrebuttal testimony?**

20 A. No.

II. Rate of Return

Q. Please summarize your surrebuttal testimony directed to the rebuttal testimony of Mr. Rea.

A. In my surrebuttal testimony to Mr. Rea, I will address the assertions made in his rebuttal testimony regarding the impact of my authorized return on equity (“ROE”) recommendation, federal monetary policy, the Discounted Cash Flow (“DCF”) Model, the Capital Asset Pricing Model (“CAPM”), capital structure, and other issues. I will also briefly address Mr. Kempic’s testimony regarding the management performance premium.

A. Impact of ROE Recommendation

Q. Please summarize Mr. Rea’s testimony regarding the impact of your ROE recommendation.

A. Mr. Rea claims that my proposed ROE of 8.9% is far removed from national averages, and that adopting my proposed ROE would disincentivize utility investment in Pennsylvania because it would be no longer “fully supportive” of utilities.¹

Q. Do you agree with Mr. Rea’s rebuttal testimony on this issue?

A. No. First, Mr. Rea has provided no evidence to support his claims. I am not aware of any utility in U.S. history that has not been able to attract sufficient capital to provide service as a result of an authorized ROE that was lower than the national average. According to Mr. Rea’s logic, the regulatory jurisdiction that currently has the lowest ROE should not be able to issue debt or equity because investors would prefer to invest in any other jurisdiction. This is obviously not the case. Utility ROE witnesses such as Mr. Rea in this

¹ Rebuttal Testimony of Vincent Rea. p. 2.

1 case, often present similar narratives suggesting that regulators who authorize the highest
2 ROEs are somehow winning a race to be the most “supportive” of their utilities. It is not
3 the Commission’s duty to be supportive of the Company any more or less than it is to
4 customers. The authorized ROE I recommend in this case is not high or low; rather it is
5 simply fair, as it is based on an objective analysis of the Company’s market-based cost of
6 equity. Furthermore, neither the *Hope* nor *Bluefield* standards dictate that an authorized
7 ROE must conform to a national average. To the extent regulators simply rely on a national
8 average of authorized ROEs, it would mean that the authorized ROEs themselves have
9 little basis in market indicators, and the purpose of conducting financial modeling to
10 analyze specific utilities would be negated. If the Commission were to adopt an 8.9%
11 ROE, it would not affect the Company’s ability to attract capital or its duty to provide safe
12 and reliable service.

13 **B. Federal Reserve Monetary Policy**

14 **Q. Please summarize Mr. Rea’s testimony regarding the Federal Reserve’s monetary**
15 **policy and its impact to the cost of equity.**

16 A. Mr. Rea projects an upward trend in interest rates and concludes that my CAPM understates
17 the Company’s cost of equity relative to bond yields and interest rates at the time of
18 Columbia’s 2024 rate case.²

19 **Q. Do you agree with Mr. Rea on these issues?**

20 A. No. There are several problems with Mr. Rea’s arguments on these issues. First, Mr. Rea
21 cannot predict whether interest rates and Treasury bond yields will increase or decrease. I

² Rebuttal Testimony of Vincent Rea. pp. 23-27.

1 have never seen a utility ROE witness, including Mr. Rea in many prior cases, state a
2 prediction of future market indicators that would have a decreasing effect on the utility's
3 cost of equity in the present. After nearly a decade of observing these one-sided predictions
4 in every case without exception, I find it difficult to believe Mr. Rea's predictions are
5 purely objective and unbiased. Furthermore, Mr. Rea is primarily focusing on one factor
6 that can affect cost of equity. In reality, all aspects would need to be considered when
7 attempting to project how future market indicators could impact the cost of equity of any
8 particular company. For example, even if interest rates do increase, the equity risk
9 premium might also decrease, which would have a decreasing effect on cost of equity. In
10 addition, the average beta of the proxy group could also decrease, which is a trend I have
11 observed for both gas and electric utilities recently. Furthermore, the benefit of periodic
12 rate cases is that relevant market trends can be incorporated into the latest analysis used to
13 determine the authorized ROE at that time.

14 Finally, Mr. Rea's reference to market indicators during the 2024 rate case ignores the
15 reality that authorized ROEs around the country did not consistently fall with interest rates
16 during the period of historically low interest rates. If they had, average authorized ROEs
17 around the country would have likely been closer to 8%. Now that interest rates increased
18 over the past few years, a common tactic of utility ROE witnesses, including Mr. Rea in
19 this case, is to use the utility's prior case as a launching point for higher ROEs, when in
20 reality the authorized ROE never fell as far as they should have as interest rates decreased.
21 In other words, if Mr. Rea's logic had been consistently followed over the past 10 years,
22 Columbia's authorized ROEs would likely have been much lower including its authorized
23 ROE in the 2024 case had it been litigated. Regardless, my application of the CAPM in

1 this case is consistent with how I have always applied it, which is not to base the results on
2 a prior regulatory proceeding, but rather to use current market indicators to develop an
3 objective estimate of the cost of equity.

4 **C. DCF Analysis**

5 **Q. Please summarize Mr. Rea's criticisms of your DCF Model.**

6 A. Mr. Rea criticizes both variations of my DCF Model: the sustainable growth variation and
7 the analyst growth variation.

8 **Q. Do you agree with Mr. Rea's criticisms regarding your applications of the DCF**
9 **Models?**

10 A. No. At the outset, it is worth noting a few things about the results of my DCF Models.
11 First, the results of the sustainable growth and analyst growth variation were fairly similar,
12 at 7.3% and 7.5%, respectively. This means that Value Line analysts project annual
13 dividend growth for the proxy companies at an annual rate not much higher than projected
14 GDP growth, which is about 3.7% over the long-run. Thus, despite Mr. Rea's numerous
15 criticisms of the sustainable growth variation, Value Line's own analysts do not project a
16 much higher growth rate for the companies in the proxy group. Furthermore, regardless of
17 our disagreements regarding the theory behind the sustainable growth DCF Model, the
18 authorized ROE I propose in this case is much higher than the result of this particular
19 model. Second, regarding the analyst growth variation, Mr. Rea criticizes the fact that I
20 considered dividend growth rather than earnings growth. It is important to reiterate that in
21 the DCF Model, the "cash" that is being discounted is the dividends paid to investors.
22 While it is true that dividends are paid from earnings, and earnings growth can be an
23 indicator to consider when assessing the growth rate input in the DCF Model, the ultimate

1 form of “cash flow” in the discounted cash flow model, is dividends. In that regard, it is
2 perfectly appropriate and reasonable to consider dividend growth when conducting the
3 DCF Model. If I were to agree with Mr. Rea on anything in his rebuttal testimony, it is
4 that these DCF results likely understate Columbia’s cost of equity in the current market
5 environment. Accordingly, my ROE recommendation for the Company is much higher
6 than these results.

7 **D. CAPM Analysis**

8 **Q. Please summarize Mr. Rea’s criticisms of your CAPM analysis.**

9 A. Mr. Rea primarily disagrees with my equity risk premium (“ERP”) input (which he refers
10 to as the market risk premium) and the various sources I incorporated into my ERP
11 analysis.³

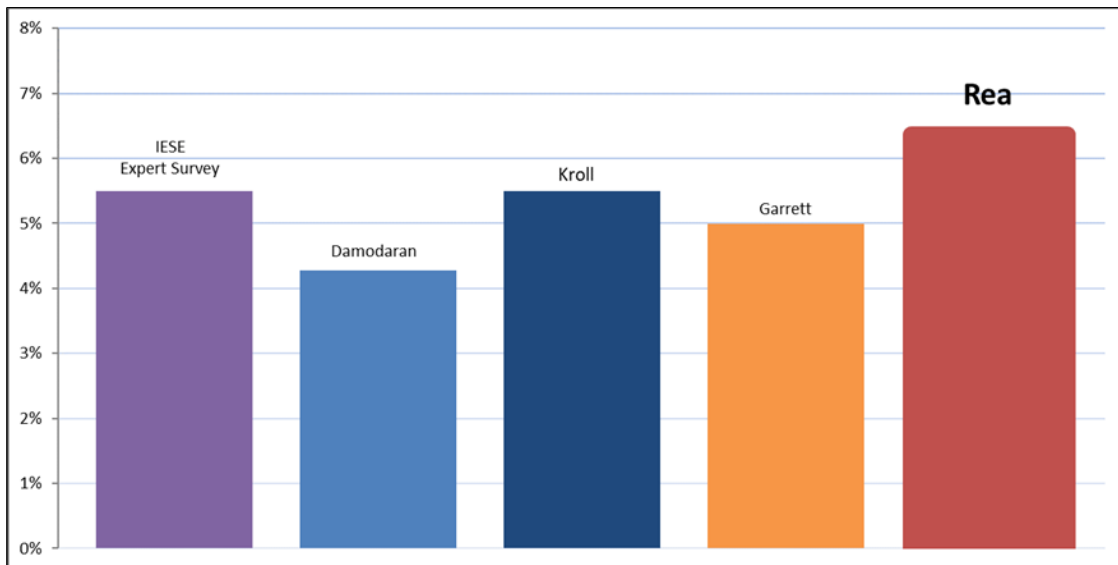
12 **Q. Please briefly reiterate the sources you considered for the ERP estimate.**

13 A. The ERP is an important figure for financial and market analysts in all industries, not just
14 utility regulation. Thus, many analysts, managers, investors, and academics are constantly
15 studying and are concerned with obtaining a reliable and accurate estimate of this important
16 number, which can be used in a variety of financial analyses, including the CAPM. All
17 else held constant, a higher ERP will result in a higher indicated cost of equity and apply
18 upward pressure on the authorized ROE. I considered three reliable and objective sources
19 to include in my overall ERP estimate, including the result of the IESE Business School
20 survey of experts, the estimate published by Kroll (formerly Duff & Phelps), and the

³ *Id.* at pp. 58-63.

1 estimate published by one of the world's leading experts on the issue, Dr. Aswath
2 Damodaran. I also conducted and presented my own ERP estimate, the result of which is
3 similar to those from the other sources. The figure below contrasts the ERP estimates from
4 these sources with the ERP estimated by Mr. Rea.⁴

5 **Figure 1:**
6 **Equity Risk Premium Comparison**



7 When compared with other independent sources for the ERP (as well as my estimate),
8 which do not have a wide variance, Mr. Rea's ERP estimate is clearly not within the range
9 of reasonableness. Mr. Rea's claim that investors do not rely on expert survey ERPs as
10 well as the other sources shown in this graph is unfounded. I would argue that investors
11 are more likely to rely on these types of sources for the ERP than Mr. Rea's personal ERP
12 estimate. Effectively, Mr. Rea is suggesting the Commission should adopt his ERP

⁴ See also Exhibit DJG-10.

1 estimate over the opinions of thousands of unbiased experts, Kroll (a global financial
2 advisory firm), and one of the world's leading experts on the ERP.

3 **E. Capital Structure**

4 **Q. Please summarize Mr. Rea's criticisms of your capital structure adjustment.**

5 A. Mr. Rea disagrees with my capital structure recommendation, and claims that the proper
6 comparison should be to the subsidiary holding companies of the proxy group, rather than
7 the parent companies.⁵ He refers to my capital structure adjustment as a "double leverage
8 adjustment that would penalize the Company."⁶

9 **Q. What is your response to Mr. Rea's rebuttal testimony on this issue?**

10 A. Mr. Rea's rebuttal testimony issue ignores the primary reasoning behind my capital
11 structure adjustment. It is imperative to consider the capital proxy holding companies
12 themselves (rather than their subsidiaries) in the adjusted CAPM analysis (i.e., the Hamada
13 Model) because those are the companies from which the other inputs to the cost of equity
14 models were obtained. We used the betas, stock prices, dividends, growth rates, and other
15 factors applicable to the proxy companies themselves, not their subsidiaries. The idea of
16 ignoring the capital structures of that same proxy group in favor of a different group of
17 companies would amount to cherry picking analytical metrics (in favor of a higher rate of
18 return). Compared to the proxy group, Columbia has less financial risk due to its projected
19 capital structure which has a higher equity component than the average of the proxy group
20 – a fact that should be reflected in either a lower cost of equity estimate, or as I propose,

⁵ Rebuttal Testimony of Vincent Rea, pp. 91-98.

⁶ Id. at p. 3, lines 17-18.

1 an imputed capital structure for ratemaking purposes. Despite Mr. Rea's claims, my capital
2 structure adjustment, while perhaps a type of "double leverage" adjustment, would not
3 "penalize" the Company. Rather, it would simply promote fair rates and reduce the excess
4 transfer of wealth from customers to shareholders that would otherwise occur if the
5 Company's capital structure is adopted. The current debt ratio of Columbia's parent
6 company, NiSource Inc. is about 54%. Since the "equity" on Columbia's balance sheet is
7 essentially comprised of NiSource's capital structure mix, this means NiSource is
8 effectively earning a high equity return on its low cost debt. The fact that many other
9 utilities around the country take advantage of this double leverage scheme is not surprising;
10 however, it is ultimately unfair for ratepayers to the extent the Commission does not make
11 a capital structure adjustment.

12 **F. Other Issues**

13 **Q. Are there other issues raised in Mr. Rea's rebuttal testimony to which you would like**
14 **to respond?**

15 **A.** Yes. Mr. Rea maintains his support for the management performance premium. He also
16 criticizes the fact that I do not make the same leverage adjustment that he does. Finally,
17 he continues to support the inclusion of a flotation cost adjustments.

1 **Q. Please summarize Mr. Rea's and Mr. Kempic's rebuttal testimony regarding the**
2 **management performance premium.**

3 A. Mr. Rea asserts that I failed to demonstrate that Columbia is not entitled to a management
4 performance premium. Mr. Kempic argues that the management performance premium
5 "helps the Company attract the capital"⁷ needed for investment and asset replacement.

6 **Q. What is your response to these witnesses on this issue?**

7 A. I disagree with both witnesses. I provided several arguments in my direct testimony why
8 Columbia is not entitled to a management performance premium. Essentially, Columbia's
9 authorized ROE should be based on its market-based cost of equity. The concept of the
10 cost of equity, and the models used to estimate cost of equity, do not even contemplate the
11 concept that prudent management performance would have an increasing effect on the cost
12 of equity. In fact, in the competitive market environment, if good managerial performance
13 were to have any impact of the cost of equity, it would be a *decreasing* effect. This is
14 because, all else held constant, good management reduces risk, and thus reduces the cost
15 of equity. Furthermore, adding such a premium to the authorized ROE runs the risk of
16 being at odds with *Hope* and *Bluefield* standards. These standards say that the authorized
17 ROE should be commensurate with the risk of the utility. Premiums for good managerial
18 performance do not comport with these standards because they are not driven by risk; and
19 moreover, if they were tied to risk, it would result in an ROE discount, as discussed above.
20 Furthermore, I am not aware of any other utility who has received such a premium.
21 Customers already compensate management, and they should not be forced to pay an

⁷ Rebuttal Testimony of Mark Kempic, p. 19, line 12.

1 additional premium to shareholders (beyond an above-market ROE) for managerial
2 performance. Regarding Mr. Kempic's argument, a 25-basis point premium will not have
3 an impact on the Company's ability to "attract capital." As discussed above, the vast
4 majority of U.S. utilities who do not specifically receive such a premium are clearly cable
5 of attracting sufficient capital for their capital investment projects.

6 **Q. Please summarize Mr. Rea's rebuttal testimony regarding the leverage adjustment.**

7 A. Mr. Rea continues to assert that a leverage adjustment should be applied to the cost of
8 equity modeling results to increase the cost of equity indications.

9 **Q. What is your response to Mr. Rea's rebuttal testimony on this issue?**

10 A. As discussed in my direct testimony, any adjustment to reconcile the fact that Columbia
11 has less debt (and thus less financial risk) than the proxy group average, should result in a
12 downward adjustment to the ROE. I demonstrated this with my Hamada model presented
13 in my direct testimony. Mr. Rea's attempt to *increase* Columbia ROE due to debt is an
14 adjustment in the wrong direction. Alternatively, as I propose, the Commission can make
15 a capital structure adjustment that aligns Columbia's capital structure with the proxy group
16 average.

17 **Q. Please summarize Mr. Rea's rebuttal testimony regarding flotation costs.**

18 A. Mr. Rea continues to assert that a flotation cost adjustment should be applied to the cost of
19 equity modeling results to increase the cost of equity indications.

20 **Q. What is your response to Mr. Rea's rebuttal testimony on this issue?**

21 A. As discussed in my direct testimony, Mr. Rea's flotation cost adjustment should be rejected
22 for several reasons. First, if Columbia has experienced any type of costs associated with
23 the issuance of new shares by NiSource during the FPFTY, then those expenses should

1 have been included in the Company's expense schedules. It should not result in a
2 permanent upward adjustment to the authorized ROE. Similar to Mr. Rea's management
3 performance premium, I am not aware of any commission who specifically authorizes
4 flotation cost premiums.

5 **III. Depreciation**

6 **Q. Please summarize Mr. Spanos's criticisms regarding your use of the ALG procedure.**

7 A. Mr. Spanos maintains that the ELG procedure should be used in this case. He argues that
8 the ELG procedure is more equitable not only for future customers, but also for current
9 customers.⁸ Mr. Spanos also claims that the annual updates to its depreciation studies
10 addresses concerns I raised about proper application of ELG depreciation rates.

11 **Q. What is your response to Mr. Spanos's testimony on this issue.**

12 A. In reading Mr. Spanos's testimony, one could get the impression that Mr. Spanos himself
13 does not also use the ALG in most of the depreciation studies that he conducts. However,
14 based on my experience, Mr. Spanos utilizes the ALG method in the vast majority of
15 depreciation studies I have reviewed that have been sponsored by him and Gannett
16 Fleming. This fact alone should negate any of Mr. Spanos's statements or inferences in
17 his rebuttal testimony suggesting the ALG procedure might not be fair, accurate, or
18 reasonable. In other words, his claim in this case that the ELG procedure is "more
19 equitable"⁹ would necessarily mean that he is using a *less* equitable procedure in his

⁸ Rebuttal Testimony of John Spanos, p. 15, line 9.

⁹ Id. at p. 4, line 12.

1 depreciation studies in other jurisdictions. In reality, the ALG procedure that Mr. Spanos
2 uses a majority of the time is very fair and reasonable (assuming reasonable estimates are
3 made for other depreciation parameters). Furthermore, I do not believe the financial well
4 being of future customers is the primary motivation for the Company's proposal to use the
5 ELG method. Mr. Spanos does not represent either present or future customers in this case,
6 and he exclusively represents utility companies as I understand. Also, in Mr. Spanos's
7 rebuttal testimony, I did not see him rebut the fact that compared with the ALG procedure,
8 the ELG procedure will result in higher depreciation rates for current customers. Likewise,
9 the ELG procedure will result in higher cash flows for Columbia relative to the ALG
10 procedure.

11 **Q. Did Mr. Spanos rebut the fact that current customers would pay more for the**
12 **Company's assets relative to future customers under the ELG procedure?**

13 A. No. This point is undisputable and is proven mathematically in both Mr. Spanos's
14 testimony and my testimony. Under the ELG procedure proposed by Mr. Spanos (in this
15 jurisdiction), current customers would effectively be subsidizing future customers by
16 paying a larger proportionate share of what is essentially the same asset base. This was
17 demonstrated in an example presented in my direct testimony. In that example, there were
18 two units being depreciated – one with an original cost of \$4,000 and a 4-year life and the
19 second with an original cost of \$6,000 and an 8-year life. Thus, the average life of this
20 group is 6.4 years. Under the ALG procedure, the depreciation rate is 15.625% per year
21 ($1/6.4 = 15.625\%$). Under the ELG procedure, however, there are higher rates and accrual
22 amounts during the earlier years. In reality, Columbia has numerous units of property that
23 are depreciated on a group basis in each account. Under the ELG procedure, customers

1 rates (not just depreciation rates), would need to be adjusted every year in order for the
2 ELG procedure to produce accurate depreciation rates. Since that is not practical, the vast
3 majority of jurisdictions have adopted the ALG procedure.

4 **Q. Mr. Spanos claims that the ALG method will result in higher rates over time and**
5 **results in intergenerational inequity. What is your response to these arguments?**

6 A. I do not agree with Mr. Spanos's narrative on these issues. Again, Mr. Spanos is attempting
7 to position himself as a representative not only for customers, but very specifically for
8 future customers. In reality, the Company's proposal to use the ELG method results in
9 higher cash flow for the Company in the present, which is likely the primary motivation
10 for the Company's proposal to use the ELG method. From my point of view, it is the ELG
11 method, not the ALG method, that results in intergenerational inequity for customers. To
12 say otherwise would mean that the vast majority of regulatory jurisdictions (using the ALG
13 method) are authorizing inequitable depreciation rates, and have been doing so for decades,
14 which cannot be accurate.

15 **Q. Mr. Spanos claims that you made an error by using the incorrect reserve balances in**
16 **calculating your proposed rates under the ELG method. What is your response?**

17 A. To calculate my proposed depreciation rates, I used the reserve balances that were
18 presented in Mr. Spanos's exhibits. If Mr. Spanos is suggesting different reserve balances
19 should be used, he did not present those balances to be considered. The primary issue
20 before the Commission is whether the ALG or ELG method should be used, which has an
21 impact of approximately \$45 million to depreciation expense as of the 2026 depreciation
22 study. The use of different estimated reserve balances, as Mr. Spanos is suggesting, should
23 not have a material impact to the overall result. If it does, the Company can present what

1 it believes are the correct balances to use for calculating ALG rates so the parties can review
2 it (though it did not take the opportunity to do so in rebuttal testimony).

3 **Q. Does this conclude your surrebuttal testimony?**

4 A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission

v.

Columbia Gas of Pennsylvania, Inc.

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:
:

Docket No. R-2025-3053499

VERIFICATION

I, David J. Garrett, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 3SR, are true and correct to the best of my knowledge, information, and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 (relating to unsworn falsification to authorities).

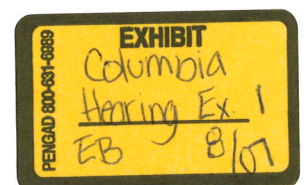
DATED: July 31, 2025

Signature: /s/ David J. Garrett
David J. Garrett

Address: 101 Park Avenue, Suite 1125
Oklahoma, OK 73120

COLUMBIA

HEARING EXHIBIT 1



Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2025 RATE CASE PROCEEDING

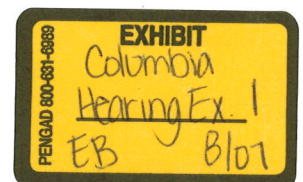
Docket No. R-2025-3053499
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. I & E RE-011-D:

Reference Columbia Volume 10, Statement No. 18, p. 7 concerning the FTY/FPFTY total employee count of 715 each year. Provide the following:

- A. Monthly total number of full-time employees by category (clerical labor, exempt labor, manual-non-union, and manual union) and monthly total labor cost for the fiscal years ended November 30, 2022, November 30, 2023, November 30, 2024, and the actual monthly amounts for the current period from December 1, 2024, through March 31, 2025.
- B. Total number of employees' retirement/resignation/ termination/transfer (normal vacancies) by employee category (clerical labor, exempt labor, manual-non-union, and manual union) anticipated by month in the FTY and FPFTY.
- C. Number of budgeted, filled, and vacant positions due to normal vacancies by month for the fiscal years ended November 30, 2022, November 30, 2023, November 30, 2024, and for the current period from December 1, 2024, through March 31, 2025.
- D. Number of new employees hired, hiring dates, and their payroll details (with employee names redacted) for fiscal years ended November 30, 2022, November 30, 2023, November 30, 2024, and for the current period from December 1, 2024, through March 31, 2025.
- E. Describe the procedures and approximate time frame involved in filling a vacant position (starting from vacancy date, hiring review process, approval by the upper management, and new employee start date/vacancy filling date).



- F. Names of labor contractors, type of service, and amount paid/incurred during the HTY 2024 that are included in labor expense.

Response:

- A. Please see I&E RE-011-D Attachment A for the requested information. Please note, the labor costs in Attachment A represent gross payroll expenses, excluding intercompany activity.
- B. The FTY and FPFTY labor budget assumes the same level of actual headcount as the end of the HTY as no incremental positions were included in the budget. When vacancies occur, the Company uses overtime or outside resources to complete the work plan.
- C. Please see I&E RE-011-D Attachment B for vacant positions by month. I&E RE-011-D CONFIDENTIAL Attachment C provides recently filled (hired) positions and I&E RE-011-D Attachment A provides total active employees by month. Information for budgeted normal vacancies is addressed in the response to Part B above.
- D. Please see CONFIDENTIAL I&E RE-011-D Attachment C for the requested information.
- E. Please see I&E RE-011-D Attachment D for the requested process information. Note, the timeline for filling vacancies can vary between approximately 8 weeks to 16 weeks depending on the timing of the vacancies, the number of applicants and other variables.
- F. Labor Contractor costs are not included in Labor expense but rather are recorded as an Outside Service expense. Please refer to the response to SDR-GAS-RR-052 for additional information for Outside Services.

Columbia Gas of Pennsylvania
Employee Headcounts by Employee Category, By Month
Total Gross Labor (Normal, Premium, and Overtime) By Month

	TME 11/30/2022	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
Total Clerical Labor		89	88	86	88	83	86	88	90	92	93	93	93	
Total Exempt Labor		176	177	178	173	175	180	184	181	180	182	182	182	
Total Manual - Non-Union		18	18	18	18	18	18	18	18	19	18	17	17	
Total Manual - Union		491	491	489	488	481	474	468	480	480	480	479	478	
Total Employees		774	774	771	767	757	758	758	769	771	773	771	770	
Gross Payroll, Excluding Intercompany		6,880,857	5,859,110	5,699,319	6,819,213	6,937,812	6,251,976	6,119,992	6,467,842	6,501,276	6,619,016	6,758,728	6,791,895	77,707,035
	TME 11/30/2023	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
Total Clerical Labor		93	93	93	92	91	89	88	87	86	90	89	90	
Total Exempt Labor		180	177	178	178	175	176	176	177	174	174	175	178	
Total Manual - Non-Union		17	17	17	17	18	18	18	18	18	18	18	18	
Total Manual - Union		473	469	468	462	462	460	458	458	452	448	447	442	
Total Employees		763	756	756	749	746	743	740	740	730	730	729	728	
Gross Payroll, Excluding Intercompany		8,088,415	6,546,713	6,439,234	6,774,256	6,154,468	6,776,949	7,288,401	6,902,887	6,230,620	7,069,634	7,181,654	7,016,855	82,470,085
	TME 11/30/2024	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
Total Clerical Labor		85	85	82	81	82	82	82	84	85	85	85	85	
Total Exempt Labor		177	181	181	177	174	174	174	174	174	176	174	173	
Total Manual - Non-Union		18	17	20	20	19	18	18	19	19	20	20	20	
Total Manual - Union		442	440	436	433	445	441	439	435	435	443	443	437	
Total Employees		722	723	719	711	720	715	713	712	713	724	722	715	
Gross Payroll, Excluding Intercompany		8,369,735	6,696,079	6,843,755	6,773,614	6,568,105	7,497,316	7,168,275	5,979,526	7,755,521	8,385,903	7,450,123	7,227,514	86,715,465
	2024/2025 Actuals	Dec	Jan	Feb	Mar									
Total Clerical Labor		85	84	84	82									
Total Exempt Labor		172	172	170	172									
Total Manual - Non-Union		20	20	20	20									
Total Manual - Union		435	432	424	436									
Total Employees		712	708	698	710									
Gross Payroll, Excluding Intercompany		7,448,794	7,156,849	6,768,982	6,975,045									

I&E-RE-011-D
Attachment B
Page 1 of 1

Date	# of Vacancies
12/31/2021	60
1/31/2022	53
2/28/2022	51
3/31/2022	60
4/30/2022	68
5/31/2022	62
6/30/2022	61
7/31/2022	53
8/31/2022	59
9/30/2022	53
10/31/2022	54
11/30/2022	56
12/31/2022	56
1/31/2023	61
2/28/2023	61
3/31/2023	63
4/30/2023	60
5/31/2023	61
6/30/2023	62
7/31/2023	63
8/31/2023	66
9/30/2023	72
10/31/2023	62
11/30/2023	63

12/31/2023	71
1/31/2024	74
2/29/2024	82
3/31/2024	69
4/30/2024	57
5/31/2024	57
6/30/2024	60
7/31/2024	62
8/31/2024	61
9/30/2024	53
10/31/2024	59
11/30/2024	72
12/31/2024	73
1/31/2025	79
2/28/2025	90
3/31/2025	87

	TME 11/30/2022	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	
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9/30/2022	53
10/31/2022	54
11/30/2022	56
12/31/2022	56
1/31/2023	61
2/28/2023	61
3/31/2023	63
4/30/2023	60
5/31/2023	61
6/30/2023	62
7/31/2023	63
8/31/2023	66
9/30/2023	72
10/31/2023	62
11/30/2023	63

12/31/2023	71
1/31/2024	74
2/29/2024	82
3/31/2024	69
4/30/2024	57
5/31/2024	57
6/30/2024	60
7/31/2024	62
8/31/2024	61
9/30/2024	53
10/31/2024	59
11/30/2024	72
12/31/2024	73
1/31/2025	79
2/28/2025	90
3/31/2025	87