Pennsylvania Public Utility Commission, v. Columbia Gas of Pennsylvania, Inc.	Docket No.: R-2024-3046519
Call-In Telephonic Evidentiary Hearing	

Pages 234 - 332

Judge's Chambers

Piatt Place

301 5th Avenue

Suite 220

Pittsburgh, PA

Thursday, August 1, 2024

Commencing at 10:08 a.m.

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Hearing Date: August 1, 2024

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COLUMBIA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MARK KEMPIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

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I. INTRODUCTION

Q. Please state your name and business address.

A. Mark Kempic, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as its President and Chief Operating Officer.

Q. What are your responsibilities as Columbia's President?

A. I am the corporate officer responsible for the leadership of Columbia and its various departments, including Field Operations, Measurement & Regulation, Rates and Regulatory Policy, Governmental and Public Affairs, and Large Customer and Community Relations.

Q. What is your educational and professional background?

A. I hold an Associate Engineering Degree in Solar Heating and Cooling Technology from the Pennsylvania State University, a Bachelor of Science Degree in Computer Science from the University of Pittsburgh and a Juris Doctor from the Capital University Law School in Columbus, Ohio. I held various positions within Columbia and its parent company from 1979 through 1992 including emergency service dispatcher, engineering technician, information systems analyst, gas supply and corporate planning analyst. From 1992 through 1994, I worked at a law firm where I represented the interests of industrial customers in utility regulatory proceedings

before the Public Utilities Commission of Ohio, and from 1994 until my return to Columbia, I worked as in-house state regulatory counsel for an electric company in Cleveland, Ohio. After rejoining Columbia in 1998, I served as an attorney and was subsequently promoted to senior attorney and then assistant general counsel. In October of 2009, I was named Director of Rates and Regulatory Policy for Columbia. I served as President from 2012 until 2017, at which time I accepted a position as the Chief Transformation Officer for NiSource Inc. ("NiSource"). In the fall of 2018, I relocated to Massachusetts at first in a temporary capacity, and then I was named President and Chief Operating Officer of Columbia Gas of Massachusetts, a position I held until August of 2020. I resumed my role as President of Columbia Gas of Pennsylvania in September of 2020.

Q. Have you ever testified before a regulatory Commission?

A. Yes, I have testified before both the Pennsylvania Public Utility Commission ("Commission") as well as the Maryland Public Service Commission. Previously, I testified in Columbia's numerous base rate cases before the Commission at Docket Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748, R-2014-2406274, R-2015-2468o56, R-2016-2529660, R-2021-3024296, and R-2022-3031211.

Q. Please describe the scope of your testimony in this proceeding.

A. Through my testimony, I will provide the Commission with an overview of this base rate filing, and discuss the objectives that Columbia seeks to accomplish in this proceeding. I will also discuss the Company's performance during 2023 and at the

outset of 2024, and address Columbia's performance quality in compliance with Section 523 of the Public Utility Code.

Finally, I will introduce Columbia's other witnesses who provide detailed testimony and supporting documentation for all revenues, expenses and rate base elements included in the Fully Projected Future Test Year ("FPFTY") in this base rate filing.

Q. Please describe briefly the corporate history of Columbia and its relationship with its parent company, NiSource.

A. Columbia was incorporated on June 23, 1960 as a wholly-owned subsidiary of the Columbia Gas System, Inc., under the Act of May 29, 1885, P.L. 29 of the Commonwealth of Pennsylvania and commenced service as Columbia Gas of Pennsylvania, Inc., on January 1, 1962, when it acquired the Pennsylvania retail business of The Manufacturers Light and Heat Company, which was at that time another wholly-owned subsidiary of The Columbia Gas System, Inc. In 1998, the Columbia Gas System, Inc. became the Columbia Energy Group ("CEG"). In turn, CEG merged with NiSource in 2000, at which time Columbia became one of ten (10) natural gas distribution companies in the NiSource corporate family as it existed at that time. Columbia is engaged in the business of delivering natural gas service to approximately 445,000 residential, commercial, and industrial customers pursuant to certificates of public convenience and necessity issued by the Commission. Columbia has its principal office in Canonsburg, Pennsylvania, and

provides natural gas distribution service in portions of 26 counties in Pennsylvania, primarily in the western half of the state, as well as parts of Northwest, Southern and Central Pennsylvania.

NiSource, headquartered in Merrillville, Indiana, is an energy holding company whose subsidiaries provide natural gas and electricity distribution services to approximately 3.8 million customers. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource Inc. on April 14, 1999. In connection with the acquisition of CEG on November 1, 2000, NiSource became a Delaware corporation registered under the Public Utility Holding Company Act of 1935, which has since been replaced by the Public Utility Holding Company Act of 2005.

NiSource is subject to the jurisdiction of the Securities and Exchange Commission and is traded on the New York Stock Exchange with the symbol "NI". The NiSource gas distribution companies are: Northern Indiana Public Service Company ("NIPSCO"), Columbia Gas of Kentucky, Columbia Gas of Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and Columbia Gas of Virginia.

II. CASE OBJECTIVES

Q. Please summarize Columbia's major objectives in this proceeding.

A. Consistent with prior cases, the primary driver for this filing is Columbia's ongoing significant investment to enhance its distribution system through the replacement

of pipe and related appurtenances that are reaching the end of their useful lives. Columbia seeks Commission approval to increase its base rates to recover the revenue requirement associated with the capital Columbia has invested, and will continue to invest, in its facilities as part of its continued focus to prioritize spend to address identified risks on our system, including our accelerated pipeline replacement program, as well as Columbia's ongoing operations and maintenance expenditures. Approval of the Company's request is necessary for Columbia to continue to provide safe and reliable natural gas service at the lowest reasonable price to its customers, while providing the Company with a reasonable opportunity to recover its costs and to earn a fair rate of return. Further, approval of this request will demonstrate to the investment community that the Commission continues to support the need for intensified focus on pipeline safety matters as well as the need for reasonable and predictable earnings. My testimony will outline, at a high level, the objectives of Columbia's filing. Details and documentation supporting each of the objectives will be provided by Company witnesses that I will introduce later in my testimony.

a. <u>Proposed Rate Increase</u>

Q. Will you please explain Columbia's main objective by filing this case?

A. Columbia seeks recovery of, and an opportunity to earn a return on, the capital investments being made in its distribution system which are necessary to provide safe and reliable natural gas distribution service to its customers. In light of the

substantial capital investment Columbia has made and the large capital investments that will be made through the end of 2025, Columbia is filing this base rate case using the Fully Projected Future Test Year ("FPFTY") as authorized under 66 Pa. C.S. § 315 in order to provide itself with a reasonable opportunity to recover its investment in its distribution system and its operation and maintenance ("O&M") expenditures.

Q. Why is Columbia filing a base rate case when the Distribution System Improvement Charge ("DSIC") is available?

A. Columbia's revenue deficiency is driven by the large capital investment that it continues to make in modernizing its distribution system. Columbia's last rate case was filed two years ago and since January 2023, Columbia has added $424 million in capital and retired $39 million resulting in net addition of $385 million. Columbia exceeded the level of investments that it had forecasted and included in the last rate case. While Columbia continually assesses whether and when it should file a DSIC, due to the scale of Columbia's investments in replacement pipe, a DSIC alone is not enough to address the revenue deficiency as Columbia's requested overall distribution (i.e., exclusive of gas costs) revenue increase in this proceeding exceeds the current 5% cap for a DSIC surcharge. I would note that in 2016, Columbia requested Commission approval to increase the cap on DSIC surcharges to 10%, but the requested waiver was denied.

Q. What is Columbia's proposed rate increase in the case and what are some of the primary drivers for the increase?

A. Based on the rates established in Columbia's last base rate case and Columbia's existing and planned capital and O&M programs, Columbia will experience a revenue deficiency of approximately $124.1 million, as detailed and supported in testimony of Company witness Komenda (Columbia Statement No. 4). This revenue deficiency is driven primarily by substantial capital investments Columbia has made, and continues to make, in its system. As detailed in Company witness Brumley's testimony (Columbia Statement No. 7), since Columbia started its accelerated pipeline replacement program in 2007, Columbia has replaced 7,434,696 feet (over 1,408 miles) of cast iron and bare steel, as well as 1,447,960 feet (over 274 miles) of pre-1971 ineffectively coated steel pipe and 751,401 feet (over 142 miles) of pre-1982 plastic.

Q. Has Columbia considered the impact of a rate increase on customers?

A. The Company realizes that rate increases will always have an impact on customers; however, considering the large, ongoing and growing capital program, which is necessary to retire and replace aging infrastructure, a rate increase is unavoidable. Columbia estimates that the total bill of an average residential customer using 70 therms per month will increase by $18.76 per month. However, even with this increase, the average customer's bill will be 24% less than the average customer's bill was 20 years ago after you adjust for inflation. While you cannot put a price on

the improvements in safety and reliability which we have brought about by our investments over the last 15 years, it is good to know that we have made those improvements and kept the customer's cost reasonable and less than inflation. In addition to the safety and reliability benefits provided by the Company's large scale pipeline replacement program, the Company believes that maintaining and growing its infrastructure modernization program provides the ancillary benefit of energizing the local economies through the wages paid to the skilled labor necessary to complete the work. This economic boost is especially important in many of the rural and economically disadvantaged communities in which Columbia provides service. In addition, through these efforts, we are reducing methane emissions from our main and service lines.

b. <u>Other Objectives</u>

Q. Does Columbia have other objectives in this case?

A. Yes. Additional objectives in this proceeding are as follows:

Establishment of a Revenue Normalization Adjustment ("RNA") Mechanism: Columbia proposes to implement an RNA to be used in conjunction with its Weather Normalization Adjustment ("WNA"). Through this proceeding, the Company proposes to establish a benchmark revenue level, regardless of changes in customers' actual usage levels. Excess collections above the benchmark revenue level would be refunded to customers and amounts below

the benchmark level would be recouped by the Company. Company witness Johnson will discuss the proposed RNA further in Columbia Statement No. 6.

Removal of the 3% Dead Band in the Company's WNA: The Company is seeking to remove the 3% dead band from the WNA. Because of the 3% dead band, a portion of revenue variation due to weather continues to be unaddressed. Thus, the goal of the WNA, to improve customer bill and revenue stability, is not fully realized. Eliminating the 3% dead band would cause all billing adjustments related to weather to occur through the WNA in real time and would limit adjustments passing through the RNA. Company witness Johnson will discuss the proposed WNA further in Columbia Statement No. 6.

Municipal Levelization Charge ("MLC"): The Company is seeking the authority to charge customers in certain municipalities an MLC to reflect the impact of excessive costs incurred by Columbia in those municipalities. Specifically, if approved, the MLC will recover costs associated with ordinances and permit requirements, which increase the costs of the Company's infrastructure replacement projects and thereby reduce the amount of aging infrastructure that Columbia can replace, from customers residing in these municipalities. Despite significant efforts to negotiate for reduction of fees and, at times, lawsuits filed when negotiations are not successful, certain municipalities continue to maintain and enforce requirements with significant cost impacts overall to the Company's infrastructure replacement projects. The MLC is revenue neutral to Columbia as

designed. It is intended to more appropriately allocate the costs incurred to customers in municipalities that benefit from the onerous restoration and permitting requirements while providing a corresponding credit to customers within municipalities that have municipal ordinances with minimal impact on project costs. Further discussion on this topic can be found later in my testimony, while the calculation of the MLC can be found in Company witness Paloney's testimony at Columbia Statement No. 9.

Purchase of Hydrogen: The Company is seeking recovery of the purchase of hydrogen for its Hydrogen Blending Skid at Columbia's training center in Monaca, Pennsylvania. The goal of installing the blending skid is to advance hydrogen technology and demonstrate that blending hydrogen with natural gas can contribute to a reduction in carbon emissions. Company witness Paloney further addresses this in Columbia Statement No. 9, and Company witness Komenda makes an O&M adjustment for the purchase of hydrogen in Columbia Statement No. 4.

Q. Does the Company have any other ongoing initiatives?

A. Yes. The Company has accelerated its efforts to maximize efficiencies, improve process discipline, reduce risk and reduce costs across the enterprise over the long-term to gain sustainable capability enhancements and cost efficiency improvements that reflect NiSource's commitment to safety, risk mitigation and customer service.

Specifically, in 2023, NiSource bolstered its continuous improvement and cost savings efforts by establishing a dedicated team, primarily consisting of field employees, that was tasked with looking at our largest cost drivers as an organization and working with subject matter experts and leadership to find opportunities to improve efficiencies, lean out processes, and reduce cost. The team found considerable opportunities across NiSource companies, including Columbia.

In addition, as further described by Company witness Skinner at Columbia Statement No. 16, over the next five years, NiSource plans to replace outdated legacy IT systems with integrated, secure, and reliable systems that will benefit both customers and employees. The first step in this transformation is implementation of the Work and Asset Management ("WAM") program to facilitate the planning, scheduling, dispatch, and execution of the work on and management of utility assets. Costs related to WAM in this case relate to costs expected to be incurred to complete the WAM component of the IT transformation plan for 2025.

Q. Please provide a brief overview of the WAM component of the planned 5-year IT transformation plan.

A. The term "WAM program" refers to the development and system-wide deployment of new, integrated work and asset management IT systems to replace existing programs that are at or nearing the end of their useful lives, are not fully integrated, and are at risk of failure. The WAM program consists of three major components:

(1) the "Work Management Initiative," which will substantially improve the Company's work and asset planning and management processes; (2) the "Mobile Workforce Initiative," which will support integrated planning of work in the field, scheduling, and work route planning; and (3) the "Mobile Mapping Initiative," which will provide mapping technology and functionality and allow front-line employees to view and capture more robust details about the Company's infrastructure when and where the work happens. Company Witness Skinner discusses each of these three technologies. Mr. Skinner also explains how the three technologies will work together as one integrated unit to help bring NiSource into the digital age of utility services by giving front-line employees easy-to-use applications. Company Witness McCaul will discuss the operation impact of replacement of the Company's existing work management system in Columbia Statement No. 14.

c. <u>Future Infrastructure Replacement</u>

Q. What are the Company's future plans for infrastructure replacement?

A. The Company intends to continue replacement of prone to fail pipe at an accelerated pace in order to retire its remaining aging infrastructures soon as possible. As Columbia's infrastructure replacement program has been operating for almost 17 years, substantial progress has been made on replacing bare steel and all of the prior cast iron has been removed from the system. However, the Company

will expand its investments beyond bare steel replacement, as warranted, due to other risks identified on our system. The Company's focus on risk identification and mitigation was validated with the Commission's April 20, 2023 approval of Columbia's Third Long Term Infrastructure and Improvement Plan ("LTIIP") for the years of 2023 to 2027. Specifically, in that proceeding the Commission approved Columbia's plan to continue its focus on replacing remaining bare steel, but to also expand its focus to include pre-1982 plastic (including "Adyl-A") and pre-1971 ineffectively coated steel pipe as discussed in the LTIIP at Docket P-2022-3037388. The prioritization of spend to address identified risks is and will continue to be the Company's focus.

Columbia recognizes that gas distribution systems have been constructed over scores of decades with virtually unlimited types and generations of pipes, components, valves, fittings, etc., and that means Columbia will continue to endorse and enhance its Safety Management System ("SMS") and its Distribution Integrity Management Program ("DIMP") to identify emergent risks that need to be considered and addressed. To that end, Columbia may identify additional risks that warrant "priority" replacement as employees raise issues through Columbia's SMS Corrective Action Program and through the detailed analyses of the distribution system risks in its DIMP. While it is essential to address aging infrastructure and respond appropriately to emergent risks, that work does not come without a cost. Figure 1 below is an excerpt from the Company's response to Standard Data

Request GAS-ROR-014. I note that Columbia's ability to increase its capital investment and maintain these accelerated levels of investment is a direct result of Act 11's impact on reducing the regulatory lag that was formerly associated with utility ratemaking in Pennsylvania.

Figure 1

Capital Expenditures Net Reimbursements

Class	2024	2025	2026	2027	2028
Growth	$42,722	$45,239	$44,618	$45,990	$55,839
Betterment	$12,697	$22,184	$23,165	$7,238	$10,110
Public Improvement	$8,000	$7,000	$7,500	$7,500	$7,500
Replacement	$330,116	$308,648	$365,866	$379,909	$385,740
Support Services	$4,181	$4,648	$10,040	$4,554	$4,111
Total Net Capital	**$397,715**	**$387,718**	**$451,189**	**$445,191**	**$463,301**

Q. What are the drivers for Columbia to continue investment in replacing aging infrastructure?

A. As shown in Figure 2 below, in terms of miles, Columbia's distribution system is the third largest in Pennsylvania.

Figure 2

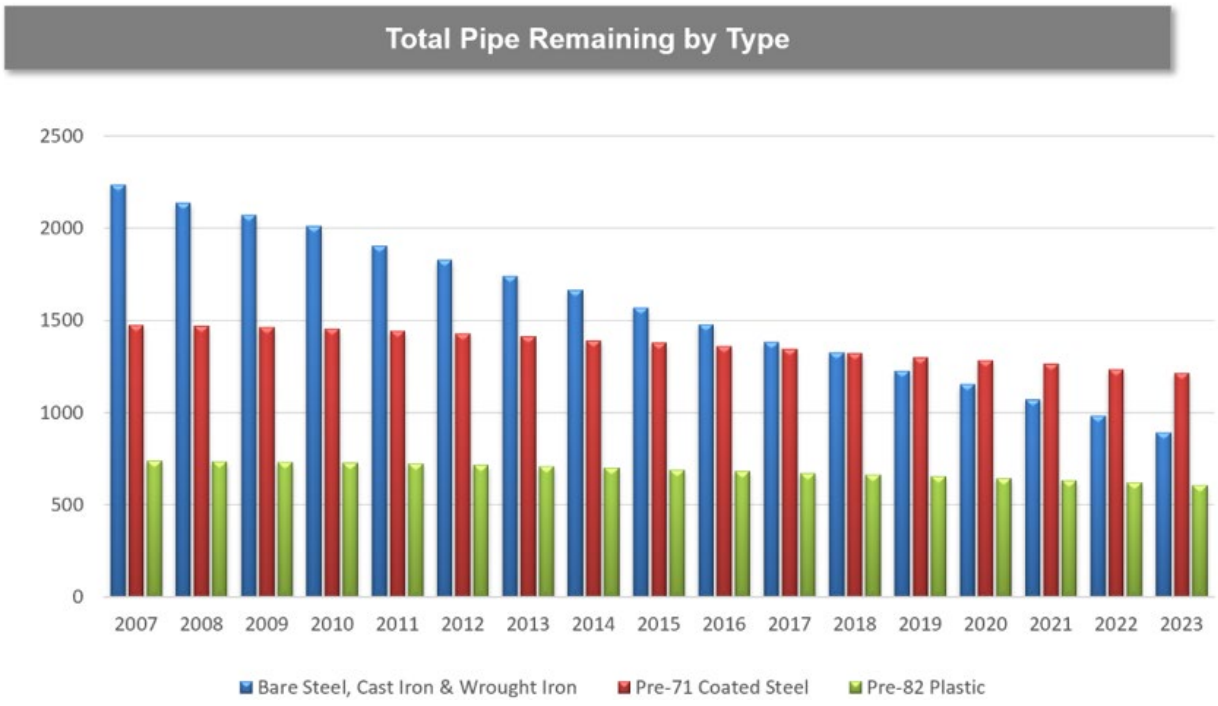
Pennsylvania LDCs – Pipeline Mileage

NGDC	Miles of Pipe (2022)
Columbia Gas	7,727.40
PGW	3,043.35
PECO	7,228.90
UGI	12,315.00
Peoples	13,096.59
National Fuel	4,845.07

The size of the Company's capital investment program is largely driven by the amount of pipe that needs to be maintained and ultimately replaced rather than the number of customers. Approximately 11% of Columbia's total inventory of pipe is either bare steel or wrought iron, approximately 7% is pre-1982 plastic, and approximately 15% is pre-1971 coated pipe. Both pre-1982 plastic and pre-1971 coated pipe are reaching the end of their useful lives and because Columbia has focused primarily on replacing bare steel and cast-iron pipe over the last fifteen years, the inventories of pre-1982 plastic and pre-1971 coated steel have not been substantially reduced. As explained more fully in Columbia's LTIIP, in the past when the latter two types of pipe have bordered cast iron or bare steel, the Company included them in the replacement project in order to reduce that risk, rather than leaving them in the ground and designing and executing a separate replacement project. Because Columbia's strategy under prior LTIIPs, however, was to focus on replacing cast iron and bare steel, as shown in Figure 3 below, the inventories of pre-1982 plastic and pre-1971 coated steel have not been substantially reduced.

Figure 3

Columbia Gas Remaining Pipeline Inventories



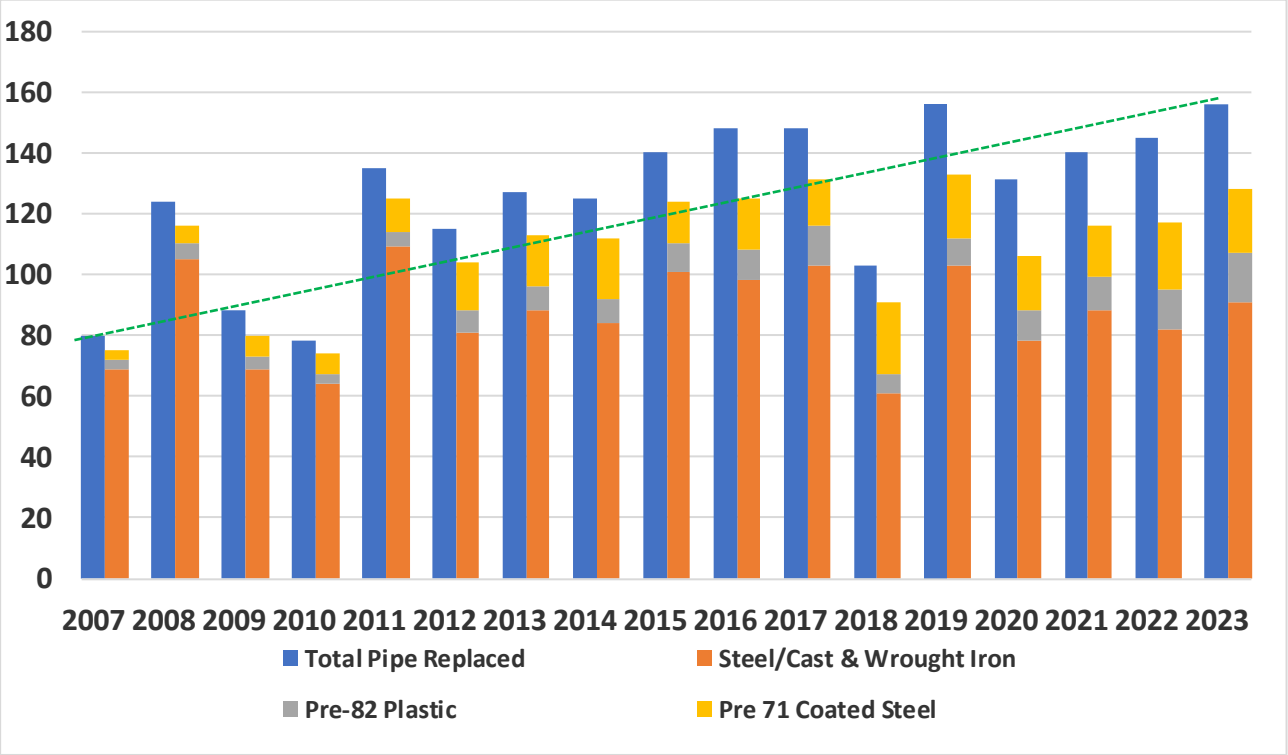
Under Columbia's Commission-approved third LTIIP, it is now time to focus on replacing these types of pipes even if they are not adjacent to a bare steel replacement project to reduce the risk associated with these pipe inventories. It makes sense to do it now before the pipe fails, and while gas prices remain relatively low in Pennsylvania. Therefore, in addition to reducing risk by replacing this pipe now, the customer's total gas bill will continue to be affordable.

Q. What is the Company's history of retired bare steel and cast-iron pipe?

A. See Figure 4 below for the Company's history of infrastructure replacement compared to total pipe replaced since 2007, which was the first year the Company

began replacing pipe at an accelerated rate.

Figure 4



Q. Discuss the Company's infrastructure replacement program levels over the past few years.

A. As Figure 4 above indicates, following a decrease in 2020, the Company resumed its normal performance levels by replacing 83 miles of bare steel, cast iron and wrought iron in 2021. In 2022 the Company replaced 82 miles of bare steel, cast iron and wrought iron, then in 2023 the Company replaced 91 miles of bare steel and wrought iron, 16 miles of pre-1982 plastic and 21 miles of pre-1971 coated steel, for a total of 128 miles of pipe that needed to be replaced.

d. <u>Municipal Levelization Charge</u>

Q: What are the biggest challenges related to enhancing the infrastructure replacement program?

A: Columbia's capital program is robust and, as stated above, the Company's large capital investments are driven by the number of miles of pipe and the related distribution system facilities that must be replaced to ensure safety and reliability rather than the number of customers served. Because Columbia does not have as large a customer base as other utilities to help absorb the costs of facility replacement, Columbia is laser- focused on finding ways to reduce costs associated with pipeline replacement. Columbia's goal is to maximize every single capital dollar to replace as many miles of its aging infrastructure as possible rather than spending those dollars on complying with municipal ordinances that require restoration of municipal roadways not only above and beyond the areas that were disturbed, but above and beyond what PennDOT requires on state highways.

At the time Columbia began to accelerate pipeline replacement in 2008, it cost approximately $81.25 per foot to replace pipe. As of the end of 2023, that cost has increased to $289 per foot. Some of the drivers for the increases are inflation, increases in the costs of labor, materials and supplies, which are expected and consistent with increases across the board in our economy. However, one major driver of the cost increase is due to sharp increases in municipal costs, mainly in permit fees and restoration requirements mandated by local ordinances. To be

clear, Columbia's objective is to always restore disturbed property to as good as condition as it was before the pipeline replacement project began; however, the ordinances in many of the municipalities we serve have restoration requirements that far exceed restoring the area disturbed. Further, they far exceed the restoration requirements that PennDOT enforces for state highways, which receive much more traffic than many municipal roadways.

Q. Do the permitting and restoration fees really cost that much more than what Columbia would pay under PennDOT's requirements?

A: Yes, these cost differentials are material. For example, for two proposed pipeline projects in one Pennsylvania township, Columbia calculated the permitting and restoration costs demanded by the township compared to what would be required under PennDOT requirements. Under PennDOT requirements, the permit fees for these projects would be $2,510; however, under the township's ordinance, permitting and engineering fees would be $143,740. In other words, the township's costs are 57 times the cost of PennDOT's requirements.

Another example involves the mill and overlay requirements of many municipalities. Under the PennDOT requirements, found in 67 Pa Code Section 459.8, disturbed roadways must be restored by milling and overlaying the traffic lane in which an opening or openings were made by using paving at 1.5 inches thick. If four or more openings were made that cross the street within 100 linear feet, the utility must overlay the entire disturbed area, which is commonly called "curb to

curb" restoration. Some municipal ordinances require curb to curb paving and 3.5" or even 4" overlay paving thickness in virtually all circumstances. These requirements to pave far beyond the area disturbed by gas pipeline construction and in thicknesses that are far greater than what is required on a state highway unnecessarily increase costs for utility customers across the state. These are essentially municipal paving costs that are more appropriately borne by the citizens of the municipality demanding the additional paving rather than utility rate payers.

A third example is a borough that requires curb to curb paving *plus* paving 25 feet on both sides of a street cut. Columbia likewise compared the costs under the PennDOT requirements to what the cost would be under the borough's ordinance. If the PennDOT permitting and restoration requirements would be applied, Columbia's customers would be responsible for $260,000 in paving and restoration costs. However, under the borough's demands, customers are ultimately responsible for paying $470,000 for permitting and restoration – nearly double the cost.

Q: Why does Columbia continue to pay these costs?

A: Columbia serves 450 municipalities in its service territory, each of which has its own municipal fee ordinance structure and permitting methodologies. When Columbia proposes a pipeline project, it applies for the necessary permits and is told what the fees will be. Columbia reviews these fees for reasonableness, and in cases where the fees do not appear to be reasonable and/or related to the cost of

administering the permit, Columbia begins negotiations with the municipality. I have been advised by counsel that under Pennsylvania law, such municipal permit fees are supposed to be limited to the costs associated with reviewing and administering permits. As interpreted by Pennsylvania courts, local municipalities are not permitted to use such fees as a source of revenue. Nonetheless, many municipalities recognize that these negotiations can take months, and they recognize that when a pipeline is leaking, time is of the essence and Columbia needs to move quickly – and therefore, they are often unwilling to negotiate.

Q. Could Columbia simply sue the municipalities if they are attempting to use permitting fees as a source of revenue?

A. We are engaged in such a lawsuit now, and it is well known that it can take quite some time for lawsuits to reach a conclusion. Further, even without initiating litigation, it has been our experience that each municipality tries to maintain that its fees are administrative in nature rather than a prohibited source of revenue, which extends and delays negotiations (and thereby delays pipeline replacement projects). It would be cost prohibitive and take years to sue each municipality that demands permitting or restoration costs in excess of reasonable standards.

Q. Are you saying that Columbia's paving and restoration costs are not reasonable and prudent?

A. Absolutely not. When Columbia is unable to negotiate with a municipality to reduce permit fees or limit restoration requirements to the area disturbed by gas pipeline

construction, the costs incurred are in compliance with municipal ordinances and are therefore, prudent and reasonable. I am simply saying that Columbia has been doing - and will continue to do - everything reasonably possible to negotiate the permitting and restoration costs downward. We want to lower those costs even further because we want to use all available capital to replace aging infrastructure rather than using it to pave roadways beyond the area in which the roadway was disturbed by the pipeline replacement project.

Q. What is your proposed solution?

A. Columbia proposes to implement a revenue neutral Municipal Levelization Charge for customers in two of the municipalities that have ordinances requiring permitting and restoration costs far above what other municipalities require and far above the statewide PennDOT requirements. At the same time Columbia proposes to apply a credit to customers in those municipalities that have permitting structures and restoration standards that allow for restoration back to existing condition. This experimental charge will foster fairness because customers living in municipalities which do not require costly permitting, and restoration will no longer need to pay for permitting and restoration costs that benefit only those customers in the municipalities that require it.

Q. Would this Municipal Levelization Charge be applicable to every municipality?

A. At present, Columbia proposes to implement the charge for customers in two municipalities whose paving ordinances exceed PennDOT requirements, while customers in two municipalities that allow for restoration back to existing conditions will receive a credit on their bills. All charges and credits are designed to be revenue neutral to Columbia. Columbia plans to gain experience with administering the revenue neutral charge/credit for these four municipalities before determining whether to propose expanding the charge to other municipalities. Regardless of the number of municipalities, Columbia plans to implement it in a revenue neutral manner.

Q. Are there any other solutions Columbia has considered?

A. Yes. Another solution would be for the Commission or the General Assembly to adopt statewide utility restoration standards. An example of standards enacted by a regulatory agency can be found in Exhibit MK-2, which is a copy of a 1999 order from the Massachusetts Department of Telecommunications and Energy (now known as the Department of Public Utilities), wherein it issued statewide utility restoration standards in response municipal complaints about restoration and the Massachusetts Supreme Judicial Court's decision that invalidated municipal ordinances. The Massachusetts Department of Telecommunications and Energy relied on its general supervisory power over utilities with reference to safety and convenience of the public and found that a single statewide street restoration standard was in the public interest and conducive to the fundamental State policy of

ensuring uniform and efficient utility service to the public. While adopting a statewide standard would be more complicated and time consuming than adopting the Municipal Levelization Charge, adopting such a statewide restoration standard for utilities in Pennsylvania could result in substantial savings for utility customers across the entire Commonwealth. It has been my experience that this statewide standard provided the state of Massachusetts' underground utilities with more predictable and lower permitting and restoration costs, which directly benefit customers in the form of lower bills. In addition, it also optimizes public safety by preserving precious capital dollars and directs those dollars to replacement pipe instead of paving roadways beyond the area disturbed by pipeline replacement. In addition, I understand that Pennsylvania House Bill 1655 was introduced in September 2023 which would require all utilities to retore to the PennDot requirements. If this bill were enacted, it would provide the appropriate consistency, predictability and fairness we believe is needed. But legislative efforts can take years to accomplish and we would like to resolve the problem as soon as possible to further optimize capital to replacing pipe instead of paving roadways that were not directly impacted by our replacement projects.

e. <u>Other Enhancements to Infrastructure Replacement Efforts</u>

Q. As your replacement program has progressed, how is Columbia enhancing its approach to infrastructure replacement?

A. Through our own experiences beginning in 2007 when we began to accelerate infrastructure replacement, and through the experiences learned from other Columbia companies across the NiSource footprint, the Company is expanding the focus of risk reduction beyond the replacement of aging infrastructure.

Q. How has the Company expanded risk identification?

A. The Company has established SMS pursuant to American Petroleum Institute Recommended Practice (or "RP") 1173. RP-1173 provides guidance to pipeline operators for developing and maintaining a pipeline safety management system and is intended to augment existing practices while not duplicating any other requirements. The Asset & Risk Management ("A&RM") group evaluates asset health, asset life cycle, asset risks and mitigation efforts to reduce top risk drivers. Examples include:

- Risk associated with bridge/water crossings are unique from other buried main line and service line facilities. These risks include external corrosion, vehicular damage, location of pipeline, general condition of the bridge, bridge collapse, soil erosion of the stream banks and impact from debris in the waterway. With the large number of bridges in Pennsylvania, the A&RM team conducted a separate review of the conditions of the bridges, which resulted in the re-routing of a pipeline that was attached to a bridge with deteriorating conditions. Columbia continues to assess bridge

crossings with greater focus on the condition of the bridge itself rather than a targeted focus on the Company's facilities.

- Evaluation of the prudency of accelerating and prioritizing regulator station replacement vs. modernization to proactively reduce risk of failure and comply with future PHMSA regulations. Many regulator stations have been in service for decades and are approaching their end of useful life. Columbia's pipeline modernization program addresses things like the removal of low-pressure systems (which increases the layers of protection) or the modification of regulator stations to provide intermediate or medium pressure. Some low-pressure stations will be eliminated entirely based on a safety and efficiency evaluations.
- In Line Inspection ("ILI"): ILI of transmission pipelines, where viable, is an advanced inspection technique that is in use across the industry and is largely successful in susceptibility identification along the entire pipeline extents. The use of ILI over the extent of a transmission pipeline to identify threat conditions allows for proactive mitigation of targeted segments for replacement versus less effective system wide mitigation activities. Columbia is focused on advancing ILI as the most effective and complete assessment method to identify threats in a proactive manner with the overall vision to prevent failures across its transmission pipeline effectively, efficiently, and completely. ILI is the only efficient tool

available to address all known, inspectable threats to a pipeline, as required by the Regulation Identification Number 2 ("RIN 2") rulemaking. PHMSA passed RIN2 of the Mega Rule in August of 2022, and added language in 49 CFR Section 192.917 requiring companies to address all threats, no longer allowing manufacturing or seam threats to be active, but stable where pressure test records are unavailable.

Q. Can you provide an example of how SMS has impacted the Company's infrastructure replacement program?

A. Yes. In addition to the 91 miles of bare steel and wrought iron pipe replaced in 2023, the Company replaced an additional 37 miles of first-generation plastic pipe installed prior to 1982 and pre-1971 coated steel. As Company witnesses McCaul and Brumley discuss in their testimonies, at Columbia Statements 14 and 7, respectively, first generation plastic pipe, typically installed between 1970 and 1981 in most distribution systems, is more brittle than today's material composition of plastic pipe and has demonstrated itself to be prone to stress propagation cracking under some circumstances. Likewise, pre-1971 coated steel pipe needs to be prioritized for replacement, as federal standards requiring operators to cathodically protect and maintain all new steel piping installations were not adopted until 1971. Beginning in the 1950s and into the 1960s, coated steel pipe was installed in gas distribution systems as a means of fending off corrosion. However, in those early years the industry lacked standards for cathodic

protection and coating material was not as effective as today's materials, and hence, pre-1971 coated steel pipe has been identified for accelerated replacement. As we move forward, and these facilities continue to age, the Company now includes these facilities in its prioritization of assets to be replaced in accordance with its approved 2023-2027 LTIIP.

Q. How does SMS benefit Columbia's customers?

A. SMS enhances Columbia's risk prioritization and modeling, and strengthens and formalizes our continuous improvement processes, which helps us provide the safest possible service at the best cost to the customer. These enhancements will continue to improve the integration of all pipeline safety initiatives across the Company's organization. Through SMS we are increasing our rigor, and continuously learning and improving so we can identify risks and take actions to keep our employees, contractors, customers and communities safe. SMS uses the following building blocks: (1) culture – as all employees and contractors are empowered to report risks; (2) process safety – layers of protection for safe work with a focus on enhanced consistent standards and processes; and (3) asset management – accountability to effectively evaluate, prioritize, and mitigate identified risks.

III. REVENUE REQUIREMENT

Q. How did Columbia determine the revenue requirement for this case?

A. As described in the testimony of Company witness Komenda (Columbia Statement No. 4), Columbia reviewed its costs to serve its customers using a FPFTY ending December 31, 2025, pro forma and adjusted for known and measurable changes. Columbia then compared the costs determined for the FPFTY to the revenues at present rates calculated for the FPFTY. This analysis produced a revenue deficiency, from which Columbia calculated the corresponding revenue requirement that Columbia will require to make up this deficiency, including a fair rate of return on the investment devoted to serving the public.

Q. Why is the proposed rate increase necessary to address the revenue deficiency?

A. Columbia's current rates do not provide the opportunity for the Company to recover its costs to serve its customers, including a fair rate of return on the capital invested to provide distribution service to the public in the FPFTY. The proposed rates have been developed to address this deficiency.

Q. Without the increase requested in this case, what rate of return will Columbia experience?

A. Without the increase requested, Columbia's overall rate of return will drop to 6.13% in the FPFTY as shown on Exhibit 102, Schedule 3, Page 3.

Q. What overall rate of return and return on equity does Columbia propose in this case?

A. Columbia proposes an overall rate of return of 8.71%. Company witness Moul (Columbia Statement No. 8) demonstrates that Columbia should be granted an opportunity to earn a 11.75% rate of return on common equity.

IV. MANAGEMENT EFFECTIVENESS

Q. Is the Company seeking a rate of return adjustment for management effectiveness in this proceeding?

A. Yes. The Company, and its employees, continue to perform at a high level to the benefit to our customers and the communities we serve. As such, the Company has directed its rate of return consultant, Mr. Moul, to include 25 basis points in the recommended rate of return on common equity. Columbia continues to maintain high levels of customer service, both in back-office operations and in field operations. I will discuss each item individually. Field operations and customer service will be discussed in the operations section of my testimony.

Q. How has Columbia performed relative to its peers from a Management Audit perspective?

A. In addition to Columbia's aggressive pipeline replacement program detailed in the testimony of Company witness Brumley at Columbia Statement No. 7, which demonstrates the effectiveness of Columbia's management and its concern for safety and excellence in customer service, Columbia has analyzed the most recent Management and Operations Audit reports from the Commission's website for Columbia, Peoples Natural Gas Company, Philadelphia Gas Works, UGI, National

Fuel Gas and PECO. The data appears as Exhibit MK-1, which is attached to my testimony. Initially, I observe that the Commission's auditors employ a ranking category system that ranges from "Meets Expected Performance Level" to "Major Improvement Necessary" and they assign one of those ranking categories to various aspects of a utility company's management performance. Columbia evaluated the number of rankings categories for each gas distribution company mentioned and determined the number of times the Commission's auditors assigned each of the various ranking categories to a gas distribution company. They are set forth in Figure 5, below.

Figure 5
Summary of Most Recent
Commission Management and Operations Audit Results

Standard	CPA	Peoples*	PGW	UGI	NFG	PECO
Meets Expected Performance	36%	27%	0%	0%	55%	55%
Minor Improvement Necessary	45%	27%	60%	55%	45%	27%
Moderate Improvement Necessary	18%	36%	30%	36%	0%	18%
Significant Improvement Necessary	0%	0%	10%	9%	0%	0%
Major Improvement Necessary	0%	9%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%

* Peoples represents Peoples Natural Gas, the former Equitable Gas and Peoples TWP

As Figure 5 illustrates, Columbia achieved the "Meets Expected Performance Level" ranking category in 36% of the categories evaluated by the auditors, with two peers, NFG and PECO, scoring higher than Columbia. Also, Columbia was one of four gas companies that did not receive any ranking of either "Significant" or "Major"

Improvement Necessary. With regards to this metric, Columbia ranked slightly better than the industry average.

Q. Please provide evidence concerning the performance of Columbia's management in providing quality service to its customers.

A. In October of 2023, the Commission issued its Annual Utility Consumer Report and Evaluation ("UCARE") for 2022. The overall information contained in the Activities report illustrates the most recent information available on how well utilities handle consumer complaints.

Q. What were the results of the 2022 UCARE report?

A. The report focuses on three main categories: Consumer Complaints, Payment Arrangement Requests ("PAR") and Compliance with Commission regulations. As shown in Figure 6, below, Columbia's 2022 performance, as reflected in the UCARE report with regards to the five major natural gas companies, is among the best in most categories across the Pennsylvania gas utility industry. In the measure of Residential Consumer Complaints, Columbia had the second to lowest consumer complaint rate of 0.41 per 1,000 residential customers in Pennsylvania. Columbia's consumer complaint rate was also better than the average complaint rate of 0.86 of the five major natural gas companies. It further shows that Columbia had the lowest Justified Consumer Complaints at a rate of 0.0 justified consumer complaints, which is as good as you can get and which is far lower than the 0.12 average justified consumer complaint rate for all of Pennsylvania's gas utilities. Finally, Table 6

shows that when you look at the percent of justified consumer complaints, Columbia has the lowest percentage of justified consumer complaints at 6/10th of one percent compared to the industry high of 20.7%. I attribute this result to the hard work of our dedicated field employees for doing the right thing and treating our customers fairly and with the respect they deserve.

Figure 6

**2022 Residential Consumer Complaint Rates,
Justified Consumer Complaint Rates, and Percent of Justified Consumer Complaints
Major Natural Gas Distribution Companies**

Utility	Consumer Complaint Rate	Justified Consumer Complaint Rate	Percent of Justified Consumer Complaints
Columbia	0.41	0.00	0.6%
NFG	0.34	0.04	12.1%
Peoples	0.58	0.02	3.8%
PGW	2.25	0.47*	20.7%*
UGI Gas	0.73	0.07	9.3%
Average	**0.86**	**0.12**	**13.7%**

* Based on a probability sample of complaints.

Per Figure 7 below, Columbia's Justified Consumer Complaint Rate per 1,000 residential customers is at 0.01, from 2019-2022. Columbia's Justified Consumer Complaint Rate is better than the natural gas utility average rate of 0.12. I am especially proud of these numbers in light of the substantial disruption that our pipeline replacement can have on customers and their communities. Nobody likes to have their streets, sidewalks and lawns dug up; however, our team provides

quality work and respectful interactions with customers, and this is reflected in the low complaint rate. As a result, our customers are satisfied even though we caused them and their communities disruption from our construction activities.

Figure 7

2019-22 Justified Residential Consumer Complaint Numbers/Rates
Major Natural Gas Distribution Companies

Utility	2019		2020		2021		2022	
	Number**	Rate***	Number**	Rate***	Number**	Rate***	Number**	Rate***
Columbia	4	0.01	3	0.01	7	0.02	1	0.00
NFG	10	0.05	6	0.03	5	0.03	8	0.04
Peoples+	3	0.01	5	0.01	12	0.02	13	0.02
Peoples-Equitable+	9	0.04	n/a	n/a	n/a	n/a	n/a	n/a
PGW	77*	0.16*	70	0.14	150*	0.31*	227*	0.47*
UGI Gas++	33	0.09	18	0.03	40	0.07	42	0.07
UGI North++	25	0.16	n/a	n/a	n/a	n/a	n/a	n/a
Total	**161**		**102**		**214**		**291**	
Average of Rates		**0.07**		**0.04**		**0.09**		**0.12**

As shown in Figure 8 below, Columbia's Payment Arrangement Request ("PAR") rate was 1.35 in 2022 and the Justified PAR rate was 0.04. The percent of justified PARs was 3.1%, which is lower than the industry average of 8.9%, as shown in Figure 8 below.

Figure 8

Commission Infraction Rates*
Major Natural Gas Distribution Companies

Utility	2019	2020	2021	2022
Columbia	0.00	0.00	0.03	0.02
NFG	0.07	0.06	0.16	0.10
Peoples+	0.01	0.01	0.06	0.02
Peoples-Equitable+	0.03	n/a	n/a	n/a
PGW	0.18	0.28	0.47	0.83
UGI Gas++	0.14	0.04	0.13	0.18
UGI North++	0.25	n/a	n/a	n/a

In the measure of Commission Infractions, Columbia had an infraction rate per 1,000 residential customers of 0.02 in 2022, which is the lowest and ties with Peoples Gas as the best of five major natural gas companies. Figure 9, below, is illustrative.

Figure 9

2022 Residential Payment Arrangement Request (PAR) Rates,
Justified PAR Rates, and Percent of Justified PARs
Major Natural Gas Distribution Companies

Utility	PAR Rate	Justified PAR Rate	Percent of Justified PARs
Columbia	1.35	0.04	3.1%
NFG	1.79	0.07	3.7%
Peoples	1.71	0.03*	1.5%*
PGW	8.21	1.43*	17.5%*
UGI Gas	5.49	0.14*	2.5%*
Average	**3.71**	**0.34**	**8.9%**

* Based on a probability sample of complaints

Q. Can you provide an overview of Columbia's 2023 Quality of Service Performance Report?

A. Yes, Columbia's "Quality of Service Performance Report," which was filed on January 31, 2024, has five general categories: Call Center Performance, Residential and Small Commercial Billing, Meter Reading, Dispute Reporting, and Customer Satisfaction. Columbia's performance for each of these categories is explained below.

a. **Call Center Performance**:

Columbia reports three separate measures of telephone access: 1) average busy out rate; 2) call abandonment rate, and 3) percent of calls answered within 30 seconds.

Columbia's call volume for 2023 was 455,273, a 11.3% decrease from the 513,374 calls taken in 2022. Calls answered within 30 seconds remained relatively flat at 72.93% in 2023, in comparison to 73.62% in 2022. The overall abandonment rate also remained relatively flat at 6.93% in 2023, in comparison to 7.46% in 2022. The Busy-Out Rate remains at 0%, which is consistent performance year over year. Columbia remains focused on maintaining service levels of 80% for calls answered within 30-seconds, increased customer service representative retention, employee engagement and development. Columbia's busy out rate metric cannot be improved upon; however, I was not satisfied with the call center's performance in the areas of calls answered within 30 seconds and the call abandonment rate. So I had a team

created in 2023 to identify what could be done to improve performance on those metrics. The team developed and implemented the following actions in 2023 to improve customer satisfaction, call center performance, and employee engagement:

- Introduced a mentorship program for new Customer Service Representatives ("CSRs") during training for continuous development. One of the drivers of a lower than desired average speed of answer is the training and knowledge level of the CSRs to answer the customers' concerns quickly and accurately. The mentorship program will help train CSRs to be better equipped to answer customer concerns quickly and accurately and thereby free them up to answer other calls more quickly;
- Implemented a New Hire Employee Engagement and Recognition program to improve retention during and after training. In evaluating the reasons the average speed of answer and the call abandonment rate metrics were less than desired, the team noticed that CSRs were not staying in their jobs. That resulted in less than full staffing, which meant that new CSRs had to be hired and trained to replace the ones who left. During the time the trained CSRs left and the replacement CSRs were hired and trained, customers had to wait longer to have their calls answered because there were fewer (and less experienced) CSRs to answer the phones. The new Engagement and Recognition program is intended to

retain the trained employees so that we will have a full team of skilled employees to answer customer questions quickly and accurately;

- Bilingual CSR Recruitment efforts continue, along with creating written processes in Spanish for continuous development of our Bilingual CSRs;
- Developed CSR Empathy Training to improve customer satisfaction;
- Delivered a series of leadership and professional development training for our front-line leaders to enhance skills, knowledge, and abilities to become more effective leaders; and
- Created Real-Time Analyst positions to manage performance in real-time focused on meeting service levels and average speed of answer metrics.

In addition, during 2023, more than 50 website enhancements were completed, which included a navigation refresh for both desktop and mobile responsive menus to more easily guide customers to the functions they want to use on the website. The changes simplified the ability to manage bank accounts and make payments, increased ease of use to manage multiple accounts, validated email addresses to ensure accurate communications, created a digital CHOICE® provider experience online making it easier to view and manage CHOICE® supplier information, as well as other online changes to improve the

user experience of customers with a disability. The Company has processed 34,503 start, stop & move orders online for customers from April 14, 2021 through December 31, 2023.

The Columbia Customer Care Center is now 100% remote, thereby expanding the pool of potential employees through a wider recruitment area. Recruitment efforts continued through NiSource job postings, various social media platforms, and virtual networking events to attract talent. The Company also continued to focus on retention of current care center employees and added a Customer Care Engagement Lead that developed and implemented employee engagement programs and activities. As a result of being fully remote, Columbia continued virtual screening, testing, and interviewing as a part of our recruitment practices, which provides for greater flexibility for the Company, and for candidates. Recruiting continues within 80 miles of the Company's Smithfield Pennsylvania and York Pennsylvania operating areas, with the goal of bolstering the local economy in our service territory.

In 2022, Columbia implemented its new Chatbot capability to its customers. It offers a simple way for customers to interact with the Company online. Customers can quickly learn their account balance, payment status, look up an account number, or get help with a forgotten password. The Chatbot can also acts as a guide for customers, who can either select a button (like Billing, Payments, Outage, & Emergency) or type in a specific request to receive a link that brings them

to the information for which they are looking. Columbia completed 38,426 chat sessions in 2023.

In addition, CSRs have handled 3,964 live chats. Live chat is available Tuesday through Friday (4 hours per day). Columbia will continue to explore increasing the hours and live chat CSRs based on overall business and staffing needs.

Columbia has 47 CSRs. Of those CSRs, 34 support the Universal Service program, with all working remotely as At-Home-CSRs. We continue to advance our diversity with our continued recruitment expansion strategy by recruiting bilingual CSRs to assist our growing customer base of Spanish speaking customers to improve customer service and reduce the average handle time when compared to utilizing our language interpreter services. This has improved customer and employee experience. In 2024, Columbia's Customer Care Center's focus will be achieving a combined 80% service level for calls answered in 30 seconds, increasing retention, and talent development for all employees.

b. <u>Residential and Small Commercial Billing Data</u>

For the twelfth consecutive year, Columbia did not have any deferred billings for its residential or small commercial customers. A strong emphasis on reducing occurrences of deferred bills by Columbia's Billing Exceptions Group continues to aid in this success, and this group continues to exhibit a strong effort on the prompt

follow up of billing abnormalities.

Columbia printed and mailed approximately 3.3 million bills to customers in 2023. In addition, approximately 2.1 million paperless bills were issued to customers. Approximately 3.6 million electronic payments were posted to customer accounts, accounting for 75.43% of total payments being posted on accounts.

c. **Meter Reading:**

In 2023, Columbia read over 5.4 million meters, with 99.90% of meters read on the scheduled meter reading date. Columbia experienced a decrease in the average number of meters not read monthly. In 2022, 11 meters were not read monthly, compared to an average of 10 meters not read monthly in 2023. These numbers are more reflective of the company's pre-COVID meter reading stats since customer are providing more access to their homes for these inside basement meters. Also, the number of inside meters has decreased since 2021 due to the Company's ongoing initiatives to relocate the inside meters to an outside location. In addition, the Company has been making telephone calls, sending letters, and making blind field visits to gain access to these inside basement meters. In 2023, the average number of meters not read pursuant 52 Pa. Code Section 56.12 (4)(iii) was 2 meters, which is the same as in 2022.

Normally, meter reads are picked up through Columbia's Mobile Collecting Device located in the vehicle. If any reads are not able to be transmitted or received by the Mobile Collecting Device when driving by customer locations, the meter

reader may walk up to the location and often times obtain the meter read by way of the handheld device, which can occur if the meter is located inside the home as well. If the Meter Reader has access to a meter, a visual read can also be obtained.

d. <u>Customer Satisfaction:</u>

Q. Are there metrics that Columbia utilizes to gauge customer satisfaction and the Company's effectiveness in providing quality customer service?

A. Columbia uses a variety of methods to gather customer feedback. In addition to performing a thorough review and analysis of the Commission's UCARE, the Quality of Service Performance Report and the Universal Service and Collections Report, Columbia uses three outside contractors to perform surveys to determine the effectiveness of satisfaction reported by its customers. Those contractors are J.D. Power, The MSR Group ("MSR") and Metrix Matrix. Columbia participates in the J.D. Power Gas Residential Customer syndicated survey, utilizes the MSR group to conduct a post-transaction satisfaction study and participates in the Metrix Matrix study mandated by the Commission. Columbia also relies on an online residential customer panel to help the Company incorporate customer feedback into improving the customer experience.

Q. Can you share the results of these surveys?

A. Based on the results of the MSR survey, Columbia provided high quality service to its customers in 2023. In 2023, Columbia's "First Contact Resolution" rate was 85.50%. This statistic indicates the success our call center CCC has had in satisfying

customers the first time they contact the Company. Figure 10 below, gives more detail on the service results Columbia achieved in this area in 2023.

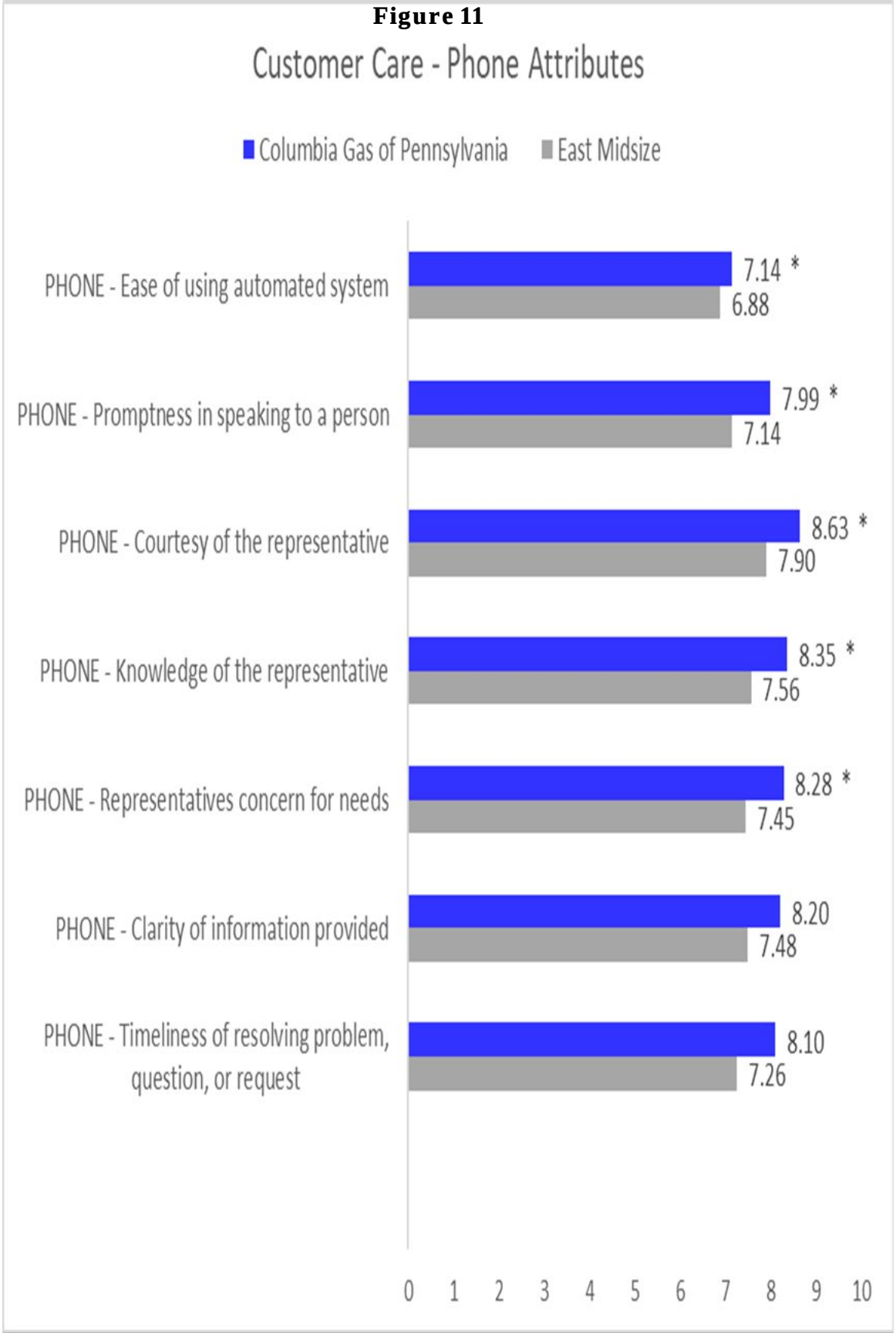
Figure 10

Phone Rep Performance	
	YE 2023
Overall satisfaction	87.80%
Put on hold after speaking with a rep	19.20%
Rep explained reason for hold	88.10%
Being courteous and professional	91.90%
Treated as a respected customer	90.40%
Showing concern for the situation	86.00%
Displaying knowledge in job	85.40%
Adequately answering questions	85.40%
How well rep listened to customer	89.70%
Having authority to make decisions	84.50%
Working quickly and efficiently	84.70%
Clarity of speech, speed, tone, and volume	91.30%
First contact resolution	85.50%

CPA Automated Phone Service	
	YE 2023
Overall satisfaction	67.80%
Ease of getting directly to information	66.10%
Ease of getting connected to live representative	63.80%
Number of steps required to complete the transaction	87.60%
IVR first contact resolution	68.70%

In addition to the MSR Survey, the Company's JD Power phone satisfaction score was 818, which ranks first place in the East Midsize segment of peer gas utilities for this category. Telephone satisfaction is based on the attributes in Figure 11 below.

Figure 11


Customer Care - Phone Attributes
Columbia Gas of Pennsylvania
East Midsize
PHONE - Ease of using automated system
7.14 *
6.88
PHONE - Promptness in speaking to a person
7.99 *
7.14
PHONE - Courtesy of the representative
8.63 *
7.90
PHONE - Knowledge of the representative
8.35 *
7.56
PHONE - Representatives concern for needs
8.28 *
7.45
PHONE - Clarity of information provided
8.20
7.48
PHONE - Timeliness of resolving problem, question, or request
8.10
7.26
0 1 2 3 4 5 6 7 8 9 10

Q. How well did Columbia perform on field service ratings?

A. As reflected in Figure 12 below, MSR results for Columbia's Field Service Representatives easily met the Company's 90%+ satisfaction threshold goal. The following chart demonstrates that customers are satisfied with the level of service provided by Columbia employees working at their home or on their property.

Figure 12

CPA Field Visit Scheduling	
	YE 2023
Willing to accommodate needs	94.50%
Told when work would take place	94.40%
Arrived on time	96.50%
Total time to resolve	95.10%
CPA Field Work Crew Performance Ratings	
	YE 2023
Overall satisfaction with performance	97.10%
Courteous and professional	98.80%
Displayed skill and knowledge	97.90%
Explained work being performed	97.40%
Adequately answered questions	97.70%
Aware of service performed	91.60%
Worked quickly and efficiently	97.70%
Being respectful of your property	98.20%
Left work property as found before work began	100.00%
Work crew identified themselves	98.50%
Completed work on the first visit	91.60%

Q. How did Columbia perform in the 2023 J.D. Power Residential Customer Satisfaction Survey?

A. Columbia achieved an overall Customer Satisfaction Index ("CSI") score of 749 in the annual J.D. Power Gas Residential survey, ending in third place for the mid-sized Eastern natural gas utilities. The Company outperformed the mid-sized Eastern utility average of 722 by 27 points.

In addition, Columbia scored above the mid-sized eastern utility averages in all seven categories and as stated above, had the top number one mid-sized eastern ranking in the Customer Care phone categories.

Q. What has been Columbia's success with implementing Chapter 14 Regulations?

A. Over the past 19 years, Columbia has been successful in implementing the Commission's Chapter 14 regulations, which provide the necessary tools to reduce residential customer delinquency and write-offs. Based on data filed annually pursuant to the Commission's regulations at Section 56.231, Columbia has reduced its gross residential write-off ratio from 4.07% in 2005 to 1.91% in 2022. It also reduced its net write-off for the same period from 2.79% to 1.24%.

Q. Can you identify any data that contributes to Columbia's success in assisting its low-income customers?

A. Based on information contained in the 2022 Universal Service Program and Collections Performance Report, Columbia had the 2nd most affordable Customer Assistance Program ("CAP") in the Commonwealth at $57.00, and the lowest of the gas industry. Columbia's average CAP bill is $12 per month lower than the

statewide average CAP bill for all gas utilities. Columbia's CAP provides the 2nd highest annual CAP credit of all Pennsylvania gas utilities, $353 more than the gas industry average. Further, Columbia's CAP default rates are significantly lower, in each poverty level, than the industry average. Columbia's administrative costs are also lower than the gas industry average as a percentage of total spend. Columbia has developed an extensive outreach strategy to increase awareness of available resources and programs. Columbia's grass roots efforts are highlighted in each of its Universal Service advisory group meetings. As demonstrated by the Universal Service and Collections Report, the Company has seen an increase in the percentage of CAP customers in the lowest income category year over year.

Q. Can you describe any process improvements that Columbia has made to better serve its customers?

A. Columbia has a continued focus on providing a simple and seamless experience for customers and will continue its focus to work across all business lines to further strengthen and enhance relationships with its customers by proactively resolving their concerns and making it easier to conduct business with us. Examples of enhancements to improve customer interaction in 2023 includes:

- In 2023, Columbia initiated a new data-drive engagement strategy that utilizes analytical models to meet our customers' expectations around service and value. The initiative enables us to connect with customers to provide them with possible payment solutions before problems arise or assist in

arrears rehabilitation if the customer becomes delinquent. Communication includes payment programs such as auto pay, budget billing, payment reminders, energy assistance and payment plans. Since January 2023, we have seen a 10% increase in residential customers paying their bills in full every month.

- Our "Columbia Gas Mobile App", launched in August 2021, provided our customers another digital channel of choice to perform self-service transactions. The mobile app serves all of NiSource's Columbia states, including Pennsylvania. In 2023, we completed 17 enhancements to the app, including adding new shortcut tiles on the login screen to more easily guide customers to functions like Make a Payment, Register an Account and Start/Stop/Move, making it easier for customers to do business with us. We also added two call-in payment plan options on the Mobile App for Columbia customers, allowing them to enroll in payment plans via their digital channel of choice (web or mobile app). In 2023, more than 300,000 transactions were completed by Columbia customers in the app. The Columbia App has a rating of 4.8 out of 5 in the App Store (iOS) and 4.5 out of 5 in Google Play (Android).
- In 2023, Columbia customers completed 38,426 sessions within our chatbots, where customers can quickly learn their account balance, check payment status, look up an account number, get help with a forgotten password, or get a copy of

their current bill (with a new self-service function added in October 2023). In addition, CSRs have handled 3,964 live chats during 2023.

- The digital transaction self-service adoption rate for 2023 across all digital channels (excluding payments) resulted in 50% of transactions being completed through self-service options—Web, Mobile App, IVR, and Chatbots. Our Columbia mobile app has had more than 546,000 downloads since it launched in August 2021, and we have recorded more than 266,000 Start, Stop & Move transactions through the Service Request Module since it went live in April 2021. These self-service options are providing customers with a quick and easy way to service their Columbia account - on their own time schedules - without necessitating a call to the call center. The 11% drop in calls between 2022 and 2023 is reflective of customers migrating to these self-service digital options for many of the more routine questions and changes to their accounts, while customers with more involved and complicated questions and account changes continue to call the call center.
- For web findability, we implemented multiple enhancements to make finding content easier, such as a megamenu to show additional page options in the main menu, a new home page banner to promote programs, a search bar, and a redesigned mobile responsive view. These changes also included changes for accessibility such as increasing contrast ratios for customers with visual impairments and other Americans with Disabilities Act work.

- For web self-service, we added a multitude of new functionality over the last two years, such as a wallet to the web "My Account" portal, so users can view and manage multiple bank accounts at one time, including the ability to delete bank accounts they are no longer using without having to add a new one. We also increased the usability for the account nickname functions, so users can manage and edit their account nicknames, which was a customer satisfaction detractor previously. Customers can now view 24 months of bill history in the web portal regardless of their paperless billing status. Previously, only customers enrolled in paperless billing could view their 24-month billing history online. New functionality included a real-time Experian email validation to ensure customers entering their new email addresses when registering and editing an email address on file is typed correctly and a valid email address to receive email communications and alerts. Users can also now self-serve deleting their "My Account" email login for security purposes. Implementation of an updated IVR system that enables the customer to interact with the system conversationally was delivered in March 2022.

Q. Besides customer service initiatives, is Columbia making any efforts to improve customer, employee, and system safety?

A. Yes**,** the Company works to continuously improve and add layers of protection to our existing safety practices and build on the success of previous efforts. This includes enhancements to processes, training, tools, and support, all of which are

designed to improve safety and eliminate high-consequence events. These efforts include:

- Quality Management and Oversight: The Quality Management organization is responsible for systematically reviewing Gas and Electric Operations actions, documentation, and processes to provide adequate proof and confidence that work was completed, and tools/equipment were used in a safe and compliant manner, per Company standards and state regulations. Grounded in a risk-based strategy, the organization provides oversight of critical tasks performed by our employees and contractors; executes field and records audits to validate the quality of our work; and provides data on outcomes and trends to interested stakeholders, linking findings and corrective actions based on the riskiest work performed in the organization.
- "Process Safety Review": Continuation of incorporating process safety principles into daily work. This is a continuation of work started in 2021 where process safety reviews for selected critical processes were performed in order to verify the ability to "fail safely" and/or whether Columbia needs to add additional layers of protection for worker safety and pipeline safety. This is work that will continue for new and existing assets to ensure improvements are made to processes and procedures to

have strong prevention and mitigation barriers for events that could cause loss of containment or safety consequences, and which may also represent opportunities for continuous improvement in process safety.

- "Incidents & Near Miss Reporting": Columbia has implemented an event reporting tool to support event identification, event trending, causal evaluation, corrective action, and sharing of lessons learned to strengthen our abilities to be a learning organization through consistent rigorous processes.

In addition to the processes work, the Company is providing additional support to employees and leaders to further promote safe behavior and improve overall performance. Examples of this support include:

- Job and Worksite Support (JAWS): Digital tools, resources, and short-form content that offers instant assistance to improve employee job performance.
- Energy Recognition Program: Employees receive training on energy-based hazard recognition and the use of the Energy Wheel to increase the ability to identify hazards. The Energy Wheel is a simple tool that helps enhance a pre-job brief by highlighting what energy sources are present on jobsites.
- "Safety Technology": pilots and deployments that focus on employee safety through wearable safety devices that detect/communicate hazards and incidents, virtual reality technology that will help enhance the employee

training offerings, work zone safety technology to improve employee and community safety through advanced automated flagging advancement, customer/community safety looking at next generation safety endpoints/meters and asset safety through advanced locking mechanisms at our gas regulator stations.

Our goal is to eliminate high-consequence events by providing clear processes, training and support to our employees, so they have the knowledge, skill and confidence to perform these events flawlessly and repeatedly.

Q. How does Columbia support the communities it serves?

A. Columbia is dedicated to investing in the communities it serves, and to helping enhance quality of life for our customers, as well as our employees. It is important to ensure that individuals and families within the communities we serve have what they need to thrive.

Each year, the NiSource Charitable Foundation[1] has a mission to help create strong and sustainable communities where our employees and customers live and work. Columbia, in addition to the NiSource Charitable Foundation, donated more than $613,991 in 2023 to 120 non-profit organizations throughout the 26-county and 450 community service area where we deliver natural gas. Donations supported

[1] Donations are made through the NiSource Charitable Foundation. Charitable contributions are not funded by customers though utility service rates. Charitable contributions are primarily funded by shareholders as a core part of the Company's commitment to support the communities and customers it serves.

basic needs and safety; STEM and energy education; diversity, equity, and inclusion; environmental stewardship; and economic and workforce development efforts in the communities we serve. We also partner with community leaders and state, regional, and local economic development organizations to attract new businesses and support the expansion of existing businesses, while helping to create more jobs across the area.

Contributions made to the community by Columbia, its employees and the NiSource Charitable Foundation in 2023 include the following:

- American Red Cross: The NiSource Charitable Foundation and Columbia provided over $50,000 to the American Red Cross to support home safety programs in Pennsylvania in addition to our employees organizing blood drives and donating locally.
- Food Insecurity: Due to the rise of inflation in our economy, Columbia donated $60,000 to local and regional food banks and organizations that work to address the needs of those in local communities. In addition, employees volunteered to help with distributing food with the Greater Pittsburgh Food Bank and Fayette County Community Action Agency.
- United Way Campaign: Through the annual United Way campaign, employees from Pennsylvania and Maryland pledged over $119,833 of their personal income to local United Way chapters in support of education, financial stability, and community health. In addition to direct

employee donations, six United Way organizations received approximately $23,700 in donations from the NiSource Charitable Foundation and Columbia.

- Energy Innovation Center: The NiSource Charitable Foundation and Columbia made a $50,000 contribution and partnered with the Energy Innovation Center, whose mission is to engage community leaders to support minority-focused, post-secondary workforce development training and education, and to develop and demonstrate technology to support the emerging clean and sustainable energy market.
- Dollar Energy Fund: Through donations and sponsorships, Columbia provided $200,000 in support to the non-profit Dollar Energy Fund providing utility assistance to income-eligible families experiencing hardship.
- Dollars for Doers Program: In addition to our Company's charitable contributions, we partnered with our Pennsylvania employees to support the organizations, which they are passionate about. More than $97,000 of the funding provided by the NiSource Charitable Foundation was given in recognition of employee volunteerism through the Dollars for Doers program in 2023. This program encourages employees to make a difference in our communities by matching their volunteer hours with a

financial contribution to the Section 501(c)(3) non-profit organizations, to which they gave their time.

- Employee Volunteerism: Employees also participated in various volunteer projects in partnership with Company initiatives. Our employees assisted children to select new winter outerwear at three personal shopping trips in Western PA in Allegheny County, Beaver County, and Fayette County through the Salvation Army and Project Bundle Up. In addition, employees volunteered to help with a community clean-up and a tree planting with Allegheny Parks Foundation and fundraised for a March of Dimes military baby shower for families in need.
- Customer Safety: The safety of our customers is paramount. In order to enhance customer safety in targeted communities, over $5,000 in NiSource Charitable Foundation donations were allocated to local first responders for the purchase and give away of combination carbon monoxide and smoke detectors for four communities in our service area.

V. INTRODUCTION OF WITNESSES

Q. Please introduce Columbia's witnesses and describe their testimony.

A. Columbia presents the following witnesses:

- Company witness Michael Girata is Manager of Demand Forecasting for NiSource Corporate Services Company ("NCSC"), providing demand forecasting services for Columbia. In Columbia Statement No. 2, he explains how residential

and commercial sales volumes are normalized for weather. The results of the normalization procedure are contained in Company witness Battig's testimony (Columbia Statement No. 3) and Exhibit 3, Schedule 4. Company witness Girata also explains the projection of the future test year and fully projected future test year customer and load growth.

- Company witness May Battig is a Lead Regulatory Analyst for NCSC. In Columbia Statement No. 3, Company witness Battig supports the Company's requested increase in base rates by providing detailed information on the Company's pro forma operating revenues for the historical test year, the future test year ending November 30, 2024, and for the twelve months ending December 31, 2025 (FPFTY).
- Company witness Brittany Komenda is a Lead Regulatory Analyst for NCSC. In Columbia Statement No. 4, Company witness Komenda presents Columbia's cost of service and quantifies the revenue deficiency based on operating costs and revenues, as adjusted. Company witness Komenda supports Columbia's cost of service O&M expenses.
- Company witness John J. Spanos is the President of Gannett Fleming Valuation and Rate Consultants, LLC. In Columbia Statement No. 5, Company witness Spanos supports the depreciation study Gannett Fleming prepared for Columbia's gas plant.

- Company witness Kevin Johnson is a Lead Regulatory Analyst for NCSC. In Company Statement No. 6, he testifies about Columbia's allocated cost of service studies. Company witness Johnson will also address the Company's RNA proposal, the removal of the WNA deadband, revenue allocation and rate design.
- Company witness Ray Brumley is the Director of Construction Services for Columbia. In Columbia Statement No. 7, Company witness Brumley will discuss Columbia's ongoing replacement activities and provide testimony in support of Columbia's plant additions through the FPFTY.
- Company witness Paul Moul is Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. In Columbia Statement No. 8, Company witness Moul presents detailed testimony and documentation and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Commission should recognize in this case. His recommendation is supported by detailed financial data and an in-depth explanation of the application of the various financial models upon which he relies.
- Company witness Nicole Paloney is the Director of Rates and Regulatory Affairs for Columbia. In Columbia Statement No. 9, Company witness Paloney provides testimony in support of the budgeted O&M expenses for Columbia for the Fully Projected Future Test Year that are included in Columbia witness

Komenda's cost of service analysis for the Company. In addition, she addresses Bill Ready Billing and provides support for the proposed Municipal Levelization Charge.

- Company witness Jennifer Harding is the Vice President of Tax for NCSC. In Columbia Statement No. 10, Company witness Harding supports Columbia's income tax and other tax expense included in the cost of service. She provides detail about both federal and state income tax recovery, and reduction of rate base for deferred income taxes.
- Company witness Julie Covert is a Lead Regulatory Analyst for NCSC. In Columbia Statement No. 11, she provides detail and support about the methods and assumptions used to develop the Historic Test Year, Future Test Year and the Fully Projected Future Test Year rate base as presented in Exhibits 8 and 108.
- Company witness Ribeka Danhires is Manager of Rates for Columbia. In Columbia Statement No. 12, Company witness Danhires explains and supports the tariff changes that the Company seeks to make in this proceeding.
- Company Witness Theodore Love is a Partner in the Green Energy Economics Group. In Columbia Statement 13, Company Witness Love will support the Company's Residential Energy Efficiency program, as well as discuss the benefits of energy efficiency to customers.

- Company witness Brian McCaul is the Vice President and General Manager for Columbia. In Columbia Statement No. 14, Company witness McCaul provides an overview of Columbia's distribution system, Columbia's historic operating performance, the initiatives taken to improve its overall safety and compliance efforts and the metrics that are used to track performance and progress, and the planned system enhancements to Columbia's operations. In addition, he provides information regarding Columbia's Distribution Integrity Management Program ("DIMP"), the strategic O&M activities that it has undertaken to improve its system, and the additional O&M activities that Columbia is planning to undertake beginning in 2023.
- Company witness Nicholas Bly is the Manager of Accounting for NCSC. In Columbia Statement No. 15, Company witness Bly provides testimony in support of the budgeted O&M expenses for NCSC for the FPFTY that are included in Columbia witness Komenda's cost of service analysis.
- Company Witness Gregory Skinner, Vice President of IT Utilities Systems for NCSC, describes in Statement No. 16 NiSource's IT transformation plan and schedule, which includes the WAM program, and discusses in greater detail why implementation of the IT transformation plan and the WAM program are necessary.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to the two exhibits attached to this testimony, I am sponsoring Exhibit No. 13, Schedule 3, which cross references the standard filing requirements with the corresponding Exhibits and Schedules in this filing for both the historic and future test years. I am also supporting Exhibit 113, Schedule 1, which documents tariff changes resulting from the requested increase.

Q. Does this conclude your direct testimony?

A. Yes.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Exhibit I – 1
Columbia Gas of Pennsylvania, Inc.
Management and Operations Audit
Functional Area Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure		X			
Corporate Governance		X			
Affiliated Interests and Cost Allocations			X		
Financial Management		X			
Gas Operations	X				
Customer Service			X		
Purchasing and Materials Management	X				
Emergency Preparedness	X				
Human Resources		X			
Fleet Management		X			
Information Technology	X				

D. Benefits

Where possible, the auditors estimated the potential savings expected from implementing the recommendations made in this report. The audit report contains potential cost savings of $272,000 to $332,000, annually. We tried to identify, whenever practical, the potential savings, net of the projected costs, for implementation. Some of these savings could be an actual reduction in costs, avoided costs, or increased revenues; whereas, others would result in better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore, actual benefits from effective implementation of the recommendations are subject to uncertainty and could be higher or lower than the estimate. An overall summary of the annual and one-time costs savings quantified in the audit report are shown in Exhibit I – 2 on the next page.

Exhibit I – 2
Columbia Gas of Pennsylvania, Inc.
Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Implement various strategies to reduce arrearage levels such as increasing CAP enrollment and effective calculation of internal arrearage data to appropriately monitor and manage arrearage performance. (VIII – 2)	$92,000	
Complete an analysis of the third-party retention application to evaluate program efficacy in reducing CSR turnover rates by December 31, 2020. (VIII – 5)	$180,000 - $240,000	
Total	**$272,000 - $332,000**	**-**

For most of the recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist nor was not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

CPA will have options to implement the recommendations and, as a result, the auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Recommendation Summary

Chapters III through XIII provide conclusions, findings, and recommendations for each functional area reviewed in-depth during this audit. Exhibit I – 3 summarizes the recommendations with the following priority assessments for implementation:

- INITIATION – Estimated time frame for how quickly CPA should be able to initiate its implementation efforts given CPA's resources and general operating environment. The time necessary to complete implementation will vary depending on the nature of the recommendation, the scope of the efforts necessary, and resources available to implement the recommendation.

COLUMBIA GAS OF PENNSYLVANIA, INC.

- BENEFITS – Net quantifiable benefits are provided, where they could be estimated, as discussed in Section D – Benefits. Our estimated overall level of benefit rankings is not solely based on quantifiable dollars but considers the auditors' assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of CPA and/or the services it provides.

  - HIGH BENEFIT – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

  - MEDIUM BENEFIT – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

  - LOW BENEFIT – Implementation of the recommendation is likely to result in service improvements, improvements in management practices and performance, and/or enhanced cost controls.

Exhibit I–1
Aqua Pennsylvania, Inc.
The Peoples Companies
Functional Area Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Aqua Pennsylvania, Inc.					
Executive Management and Organizational Structure			X		
Corporate Governance		X			
Affiliated Interests and Cost Allocations			X		
Financial Management		X			
Water Operations			X		
Emergency Preparedness			X		
Materials Management		X			
Customer Service		X			
Information Technology	X				
Fleet Management		X			
Human Resources and Diversity	X				
The Peoples Companies					
Executive Management and Organizational Structure	X				
Corporate Governance			X		
Affiliated Interests and Cost Allocations					X
Financial Management			X		
Gas Operations			X		
Emergency Preparedness	X				
Materials Management		X			
Customer Service		X			
Information Technology	X				
Fleet Management		X			
Human Resources and Diversity			X		

D. Benefits

Wherever possible, the audit staff estimated the potential savings expected from implementing the recommendations made in this report. The audit report details potential savings of approximately $417,000 annually with $339,000 and $78,000 attributed to Aqua PA and the Peoples Companies, respectively. We tried to identify, whenever practical, the potential savings, net of the projected costs, for implementation. Some of these savings could be an actual reduction in costs, avoided costs, or increased revenues; whereas, others would result in better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore, actual benefits from effective implementation of the recommendations are subject to uncertainty and

could be higher or lower than the estimate. An overall summary of the annual and one-time costs savings quantified in the audit report are shown in Exhibit I-2, below.

Exhibit I–2
Aqua Pennsylvania, Inc. & The Peoples Companies
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Aqua PA		
Document all lease agreements between Aqua PA and its affiliates and submit them to the Commission for approval. (V-2)	$150,000	-
Focus efforts on reducing NRW at the Roaring Creek system. (VII-5)	$189,000	-
Aqua PA Subtotal	$339,000	-
Peoples Companies		
Benchmark with similar utilities to set separate net collection goals for primary and secondary collection agencies at the Peoples Companies and measure each collection agency to the respective collection goal. (XI-4)	PNGC: $51,000 PGC: $27,000	-
Peoples Companies Subtotal	$78,000	-
Total for All Companies	**$417,000**	**-**

For most recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist nor was not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

Aqua PA and/or the Peoples Companies will have options to implement the recommendations and, as a result, the audit staff have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Current Events

On March 6, 2020, the Governor of Pennsylvania, Tom Wolf, declared a disaster emergency due to the COVID-19 pandemic. This and other state government actions ordered all but essential businesses and their operations closed for the safety of the general public. Although fixed utility operations such as water treatment and gas distribution were considered essential, most of the back-office functions such as corporate management, accounting and government relations were deemed nonessential. Most Pennsylvania utilities closed their business offices and allowed their employees to work remotely. The Pennsylvania Public Utility Commission also closed the main office and allowed employees, including those of the Audit Bureau, to perform their functions remotely. All nonessential travel and in-person meetings were prohibited.

As such, the COVID-19 crisis affected the approach and timeline of the audit. For example, some interviews and data request responses were delayed or modified. In all cases, the audit staff worked with Aqua PA and the Peoples Companies to acquire information needed to issue the findings and recommendations contained within this report. Although some aspects of fieldwork were modified and/or unfeasible, we worked to minimize the impact to the conclusions presented within the report. We believe that our procedures sufficiently mitigate the audit risk associated with altering our standard practices. However, conclusions presented within this report may change if additional information is made available. Furthermore, it is important to note that although COVID-19 affected the companies' operations; this report does not, nor was it intended to reflect any modified operations.

F. Recommendation Summary

Chapters III through XIV provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

- INITIATION TIME FRAME – Estimated time frame on how quickly the Company should be able to initiate its implementation efforts given the Company's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation and the scope of the efforts necessary and resources available to effectively implement the recommendation.

- BENEFITS – Net quantifiable benefits have been provided where they could be estimated as discussed in Section D - Benefits. Our overall rankings are not solely based on quantifiable dollars but rather our assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of the Company and/or the services it provides.

- HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

- MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

- LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

Exhibit I-1
UGI Utilities, Inc.
Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure		X			
Corporate Governance		X			
Affiliated Interests and Cost Allocations			X		
Financial Management		X			
Gas Operations			X		
Electric Operations		X			
Emergency Preparedness				X	
Materials Management			X		
Information Technology		X			
Customer Service			X		
Fleet Management		X			
Human Resources / Diversity		X			

D. Benefits

Where possible, the auditors quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. The audit report contains identifiable potential quantifiable cost savings of $336,090 to $713,019 in annual savings and $3,360,900 to $7,130,196 in one-time savings from effective implementation of the recommendations. We identify, whenever it is reasonably practical, the potential savings net of the projected costs for implementation. Some of these savings could be considered an actual reduction in costs, avoided costs or increased revenues; whereas others would result from better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore, the actual benefits from effective implementation of the recommendations are subject to some degree of uncertainty and could be higher or lower than the amounts estimated by the auditors. An overall summary of the annual and one-time cost savings quantified in the audit report are shown in Exhibit I-2.

Exhibit I-2
UGI Utilities, Inc.
Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
X-1. Improve company-wide inventory turnover and exclude emergency stock from inventory turnover calculations.	$336,090 - $713,019	$3,360,900 - $7,130,196

For most of the recommendations, it is not possible or practical to estimate quantitative benefits as they are of a qualitative nature or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a specific function but cannot be easily quantified.

UGI Utilities will have options to implement the recommendations and so the auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted to the reader that the cost of implementing certain recommendations could be significant.

E. Recommendation Summary

Chapters III through XIV detail the findings, conclusions and recommendations for each function or area reviewed in-depth during this audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

- INITIATION TIME FRAME – Estimated time frame for how quickly UGI Utilities should be able to initiate its implementation efforts, given UGI Utilities' resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation, the scope of the efforts necessary, and resources available to effectively implement the recommendation.

- BENEFITS – Net quantifiable benefits have been provided, where they could be estimated, as discussed in Section D - Benefits. Our estimated overall level of benefits rankings is not solely based on quantifiable dollars, but the auditor's assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of UGI Utilities, and/or the services it provides. In addition, the ratings weight the avoidance of future adverse conditions based upon the potential severity of the adverse condition. In this form, high consequence conditions could

garner a higher benefit rating than conditions occurring frequently but with a lower impact.

- HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, avoidance of substantial consequences, and/or significant cost savings.

- MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, avoidance of unfavorable but manageable consequences, and/or meaningful cost savings.

- LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

Exhibit I – 1
National Fuel Gas Distribution Corporation
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure		x			
Corporate Governance		x			
Affiliated Interests and Cost Allocations	x				
Financial Management	x				
Gas Operations	x				
Customer Service		x			
Purchasing and Materials Management	x				
Emergency Preparedness	x				
Human Resources		x			
Fleet Management		x			
Information Technology	x				

D. Benefits

Where possible, the auditors try to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. However, for most of the recommendations, it is not possible or practical to estimate quantitative benefits as their benefits are of a qualitative nature or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist or was not fully functional. Similarly, changes in work flow or implementation of good business practices could result in improved effectiveness and efficiency of a specific function but cannot be easily quantified.

NFGDC will have options to implement the recommendations and so the auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted to the reader that the cost of implementing certain recommendations could be significant.

E. Recommendation Summary

Chapters III through XIII detail the findings, conclusions and recommendations for each function or area reviewed in-depth during this focused audit. Exhibit I-2 summarizes the recommendations with the following priority assessments for implementation:

- INITIATION TIME FRAME – Estimated time frame for how quickly NFGDC should be able to initiate its implementation efforts, given NFGDC's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation, the scope of the efforts necessary, and resources available to effectively implement the recommendation.

- BENEFITS – Net quantifiable benefits have been provided, where they could be estimated, as discussed in Section D - Benefits. Our estimated overall level of benefits rankings is not solely based on quantifiable dollars, but the auditor's assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of NFGDC, and/or the services it provides.

    - HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

    - MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

    - LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

Exhibit I-1
Philadelphia Gas Works
Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Corporate Governance			X		
Executive Management and Organizational Structure		X			
Financial Management		X			
Gas Operations			X		
Emergency Preparedness				X	
Materials Management		X			
Customer Service			X		
Information Technology		X			
Fleet Management		X			
Human Resources and Diversity		X			

D. Benefits

Where possible, the audit staff attempt to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. However, for most recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist or were not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

The company will have options to implement the recommendations and, as a result, the PUC auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Current Events

On March 6, 2020, the Governor of Pennsylvania, Tom Wolf, declared a disaster emergency due to the COVID-19 pandemic. This and other state government actions ordered all but essential businesses and their operations closed for the safety of the general public. Although fixed utility operation such as gas distribution was considered

essential, most of the back-office functions such as corporate management, accounting and government relations were deemed nonessential. Most Pennsylvania utilities closed their business offices and allowed their employees to work remotely. The Pennsylvania Public Utility Commission also closed the main office and allowed employees, including those of the Audit Bureau, to perform their functions remotely. All nonessential travel and in-person meetings were prohibited.

As such, the COVID-19 crisis affected the operation and data contained within this audit. In addition, where needed the approach and timeline of the audit was changed to accommodate lingering COVID-19 implications. For example, some interviews and data request responses were delayed or modified. In all cases, the audit staff worked with PGW to acquire information needed to issue the findings and recommendations contained within this report. We believe that our procedures sufficiently mitigate the audit risk associated with altering our standard practices to address COVID-19's impact to the company or our audit. However, conclusions presented within this report may change if additional information is made available.

F. Recommendation Summary

Chapters III through XII provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

- INITIATION TIME FRAME – Estimated time frame on how quickly the company should be able to initiate its implementation efforts given the company's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation and the scope of the efforts necessary and resources available to effectively implement the recommendation.

- BENEFITS – Net quantifiable benefits have been provided where they could be estimated as discussed in Section D - Benefits. Our overall rankings are not solely based on quantifiable dollars but rather our assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of the company and/or the services it provides.

    - HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

    - MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

- LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

Exhibit I-1
PECO Energy Company
Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure	X				
Corporate Governance	X				
Affiliated Interests and Cost Allocations			X		
Financial Management	X				
Electric Operations			X		
Gas Operations			X		
Emergency Preparedness		X			
Materials Management	X				
Customer Service		X			
Information Technology	X				
Fleet Management	X				
Human Resources and Diversity		X			

D. Benefits

Where possible, the audit staff attempts to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. The audit report contains identifiable potential quantifiable cost savings of approximately $15 million in annual savings and $13,581,327 in one-time savings from effective implementation of the recommendations. We try to identify, whenever it is reasonably practical, the potential savings net of the projected costs for implementation. Some of these savings could be considered an actual reduction in costs, avoided costs or increased revenues, whereas others would result from better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore, the actual benefits from effective implementation of the recommendations are subject to some degree of uncertainty and could be higher or lower than the amounts estimated by the audit staff. An overall summary of the annual and one-time cost savings quantified in the audit report are shown in Exhibit I-2.

Exhibit I-2
PECO Energy Company
Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Submit a detailed proposal to the Commission for the appropriate crediting of ratepayers due to PECO's corrected billings for the use of PECO's fiber network. (V-1)	-	$13,581,327
Reduce Electric operations staff overtime to 15% overtime hours per normal hours worked or less. (VI-1)	Up to $15,000,000	-
Reduce Gas Operations staff overtime to 15% overtime hours per normal hours worked or less. (VII-3)	(a subset of $15,000,000 in VI-1)	-
Totals	$15,000,000	$13,581,327

For most recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist or were not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

The company will have options to implement the recommendations and, as a result, the PUC auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Current Events

On March 6, 2020, the Governor of Pennsylvania, Tom Wolf, declared a disaster emergency due to the COVID-19 pandemic. This and other state government actions ordered all but essential businesses and their operations closed for the safety of the general public. Although fixed utility operations such as electric distribution and gas distribution were considered essential, most of the back-office functions such as corporate management, accounting and government relations were deemed nonessential. Most Pennsylvania utilities closed their business offices and allowed their employees to work remotely. The Pennsylvania Public Utility Commission also closed the main office and allowed employees, including those of the Audit Bureau, to perform their functions remotely. All nonessential travel and in-person meetings were prohibited.

As such, the COVID-19 crisis affected the approach and timeline of the audit. For example, some interviews and data request responses were delayed or modified. In all cases, the audit staff worked with PECO Energy Company to acquire information needed to issue the findings and recommendations contained within this report. Although some aspects of fieldwork were modified and/or unfeasible, we worked to minimize the impact to the conclusions presented within the report. We believe that our procedures sufficiently mitigate the audit risk associated with altering our standard practices. However, conclusions presented within this report may change if additional information is made available. Furthermore, it is important to note that although COVID-19 affected the companies' operations; this report does not, nor was it intended to evaluate modifications to operations.

F. Recommendation Summary

Chapters III through XV provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

- INITIATION TIME FRAME – Estimated time frame on how quickly the company should be able to initiate its implementation efforts given the company's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation and the scope of the efforts necessary and resources available to effectively implement the recommendation.

- BENEFITS – Net quantifiable benefits have been provided where they could be estimated as discussed in Section D - Benefits. Our overall rankings are not solely based on quantifiable dollars but rather our assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of the company and/or the services it provides.

    - HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.

    - MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

    - LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

August 26, 1999

D.T.E. 98-22

Investigation by the Department of Telecommunications and Energy upon its own motion, pursuant to G.L. chapters 164, 165 and 166A commencing a review of standards employed by public utility operators when restoring municipal street surfaces after performing excavations.

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ATTACHMENT: Standards to Be Employed by Public Utility Operators When Restoring any of the Streets, Lanes and Highways in Municipalities

- PROCEDURAL HISTORY

On February 13, 1998, the Department of Telecommunications and Energy ("Department"), pursuant to G.L. chapters 164, 165 and 166A, issued to all utility companies under its jurisdiction a Notice of Compliance Review. The notice requested that each utility provide the Department, by March 13, 1998, with a copy of its standards[(1)] or procedures for excavation and resurfacing openings in public ways, as well as a copy of internal written statements or policies designed to insure that managers and crews are aware of, and held accountable to, standards and procedures for street excavation and repair. Thirty-two operators responded to the notice.[(2)]

On May 1, 1998, the Department invited each municipality to comment on the companies' responses and on the performance of individual public utility operators under the Department's jurisdiction. The Department received 125 responses from municipalities. A number of municipalities expressed concern with the utilities' failure to adequately restore roads by (1) irregular pavement cutting; (2) poor placement and compaction of backfill material; (3) poor preparation of the excavation and adjacent pavement to receive the patch material; (4) poor placement and compaction of patch material; (5) failure to seal joints;

(6) ineffective field control; and (7) slow response when called back to correct repair failures. Other municipalities expressed a need for consistency in the guidelines for repair and maintenance of trenches and utility cuts.

After considering the responses of the utilities and the municipalities to the Department's notices, the Department formed a technical committee ("Committee") to formulate reasonable operator standards and procedures for utilities to follow for street excavation and repair.[(3)] The Department conducted technical conferences with the Committee on July 23 and August 12, 1998.

On November 20, 1998, the Committee filed with the Department a document entitled "Restoration of Municipal Streets" that proposed street restoration standards. The Committee's proposal was based upon the Commonwealth of Massachusetts Department of Public Works Standard Specifications for Highways and Bridges, 1988 Edition ("Massachusetts Highway Standards") and permit requirements.[(4)] Any entity that excavates or works in a State road must follow applicable Massachusetts Highway Department ("MHD") standards and permit requirements.[(5)] On November 24, 1998, the Department conducted a third technical conference to discuss the Committee's proposed standards.

Based upon the Committee's proposed standards, the Department developed its own document, "Standards to Be Employed by Public Utility Operators When Restoring any of the Streets, Lanes and Highways in Municipalities" ("Standards"). On May 11, 1999, after notice duly issued, the Department conducted a public hearing and accepted written comments on the Standards until May 18, 1999.[(6)]

Comments on the Standards were submitted by New England Telephone and Telegraph Company, d/b/a Bell Atlantic ("Bell Atlantic"); Berkshire Gas Company ("Berkshire"); the City of Boston ("Boston"); Boston Edison Company ("BECo"); Boston Gas Company ("Boston Gas"); Bowker Consulting ("Bowker"); the City of Brockton ("Brockton"); the City of Cambridge ("Cambridge"); Colonial Gas Company ("Colonial"); Commonwealth Gas Company ("ComGas"); Senator James Jajuga (Third Essex District); Massachusetts Concrete & Aggregate Producers Association, Inc. ("MCAPA"); Massachusetts Electric Company and Nantucket Electric Company ("MECo/Nantucket"); Massachusetts Highway Association ("MHA"); Massachusetts Municipal Association ("MMA"); the City of Medford ("Medford"); New England Gas Association ("NEGA"); RCN-BECo Com LLC ("RCN-BECo Com"); the City of Somerville ("Somerville"); the Southeastern Regional Services Group ("SERSG")[(7)]; Representative Joseph C. Sullivan (5th Norfolk District); and the Town of Wellesley ("Wellesley").

II. DEPARTMENT AUTHORITY TO CONDUCT THIS INVESTIGATION

Pursuant to G.L. c. 25, § 4, and G.L. c. 164, § 76, the Department, on its own motion, commenced this investigation into the quality of service of utilities to their customers and the general public, as it relates to the restoration of public ways following utility excavations. The Department is responding to complaints by municipalities that utilities

were not meeting their responsibility to properly restore street surfaces in the public way after excavations. We are also responding to the Supreme Judicial Court ("SJC") decisions that invalidated municipal ordinances related to utility street-opening permits because those ordinances were inconsistent with and pre-empted by G.L. c. 164. Boston Gas Company v. City of Newton, 425 Mass. 697 (1997) ("Newton") Boston Gas Company v. City of Somerville, 420 Mass. 702 (1995) ("Somerville").[(8)]

The Department has "general supervision of all gas and electric companies and shall make all necessary examination and inquiries and keep itself informed as to ... the manner in which [gas and electric companies] are conducted with reference to the safety and convenience of the public, and as to their compliance with the provisions of law and the orders, directions and requirements of the Department." G.L. c. 164, § 76; see also, G.L. c. 165, § 4 (Department general supervisory authority over water companies); G.L. c. 159, § 16 (Department authority to regulate and supervise activities of telephone utilities). The Department possesses "broad investigative authority over electric utilities and may properly inquire into ... the efficiency of [a regulated utility's] operations and the productivity of all its employees, both management and non-management." Boston Edison Company v. Department of Public Utilities, 375 Mass. 1, 43, 44 (1978). The Department has conducted several investigations into the quality of service of regulated utility companies. See Rules and Practices Relating to Telephone Service to Residential Customers of New England Telephone Company, D.P.U. 18448 (1977); Western Massachusetts Electric Company, D.P.U. 95-86 (1995) (review of WMECo emergency plans and procedures); Eastern Edison Company, D.P.U. 85-232 (1986) (Department orders Eastern Edison to revise its storm emergency plan); Investigation by the Department Regarding Hurricane Bob, D.P.U. 91-228 (1992) (investigation of emergency plans and restoration of service of all jurisdictional electric utility companies in Massachusetts).

III. DISCUSSION AND ANALYSIS

A. Purpose of the Standards

The Standards in this Order are intended to ensure that all utilities under the Department's jurisdiction adopt, as part of their operating procedures, a recognized, uniform standard and associated procedures for backfill, compaction and resurfacing public ways. The Standards are consistent with and conductive to the fundamental State policy of ensuring uniform and efficient utility services to the public. See Somerville, 420 Mass. 702, 706 (1995). The SJC has found that G.L. c. 164, § 70 imposes an affirmative obligation on a utility to restore all streets, lanes, and highways to the condition they were in prior to being opened and to inspect excavation sites after the necessary repairs have been made.[(9)] See Newton, 425 Mass. 697, 699-701 (1997); Somerville, 420 Mass. 702, 705 (1995); see also, G.L. c. 166A, § 5(g). Further, the SJC has held that G.L. c. 164, § 70 does not require a utility to maintain the street after the excavation site has been repaired.

Newton, 425 Mass. 697, 700 (1997); Seltzer v. Amesbury & Salisbury Gas Co., 188 Mass. 242, 244 (1905).

The Department has reviewed the individual utility street restoration plans submitted in response to our February 13, 1998 Notice of Compliance Review. We find that those utility plans vary considerably in detail and substance. In light of this finding, and in response to the request by municipalities for a consistent standard based upon generally acceptable street restoration methods, we conclude that a single standard would be in the public interest.

The Department appreciates the time and thought of the Committee in proposing draft standards to the Department. With the understanding that the Committee's work represents an agreement among diverse interests in this proceeding, the Department, in formulating our Standards, retained as much of the Committee's proposal as was practicable. In reviewing the Committee's proposal, the Department considered the reasonableness of each element of the Committee's proposal and all the documentation submitted in the record of this proceeding. The Department also reviewed each term of the Committee's proposal to determine whether the provisions are consistent with applicable law, Department precedent, and the public interest. See Berkshire Gas Company, D.P.U. 96-92, at 8 (1996); Boston Gas Company, D.P.U 96-50, at 7 (Phase I) (1996); Massachusetts Electric Company, D.P.U. 96-59, at 7 (1996).

The Department received a substantial number of comments and recommendations on the proposed Standards. We have considered all of these comments and the entire record in this proceeding and, where appropriate, revised the Standards. In the next section, we will discuss the modifications made to the Standards that the Department first proposed for public comment on April 16, 1999. The final Standards are attached to this Order.

B. Section-By-Section Analysis of Revisions to the Standards

1. Section One - Purpose and Scope

We added one sentence to § 1.2 of the proposed Standards that states "[n]othing in these Standards is intended to prevent a utility and a municipality from mutually agreeing to exceptions to these Standards." Section 1.2 of the Standards now reads:

Nothing in these standards may be construed to restrict the Constitutional or statutory authority of cities or towns ("Municipalities") with respect to public ways. Nothing in these standards is intended to prevent a Utility and a Municipality from mutually agreeing to exceptions to these standards.

Some commenters stated that the Standards needed specific language for those communities that maintain their own contracts for permanent pavers for the repair of

utility excavations (MMA Comments at 1; Cambridge Comments at 1; Tr. at 17-18). The proposed Standards were silent on the status of a mutual agreement between a utility and municipality regarding, among other things, the use of a city-retained contractor for excavation repairs. Such mutual agreements are an option available to utilities because they allow utilities and municipalities to (1) reconcile issues not specifically addressed or contemplated by the Standards and (2) forge cost-effective arrangements that may be mutually beneficial. The reasonableness and allowance of any such agreement would be a question in a ratemaking proceeding

We added the words "ordinance or" to § 1.3 to make it clear that this section includes all laws enacted by towns and cities and to be consistent with the language in G.L. c. 43B,

§ 13 (Exercise of Powers and Functions by Municipalities). Therefore, § 1.3 of the Standards now reads:

Nothing in these standards is intended to be inconsistent with any ordinance or by-law and the constitution and laws of the Commonwealth.

We note that the intent of § 1.3 is to ensure that these Standards do not "impinge on the right of cities and towns to regulate their streets" (see Boston Comments at 1). These Standards regulate only those utilities under our jurisdiction.[(10)] As for a by-law or ordinance that may differ from these Standards, we note that one of the purposes of §§ 1.2 and 1.3 of the Standards is to recognize that the Standards cannot, as a matter of law, pre-empt any ordinance or by-law that is consistent with State laws.

[A]ny city or town may, by the adoption, amendment, or repeal of local ordinances or by-laws, exercise any power or function which the general court has power to confer upon it, which is not inconsistent with the constitution or law enacted by the general court . . .

Art. 89, § 6 of the Amendments to the Massachusetts Constitution. See also, G.L. c. 43B,

§ 13. Whether a particular ordinance or by-law is consistent with any State law is a question for the courts to decide. See Newton, 425 Mass. 697, 699 (1997); Somerville, 420 Mass. 702, 704 (1995).

The Department added a new Section 1.4 to the Standards.

Nothing in these standards is intended to create a contractor relationship between a Municipality and the Utilities regulated by the DTE.

Commenters stated that this provision is necessary to make it clear that the municipality/utility relationship is not expanded beyond the grantor/grantee relationship that pertains to street opening permits (ComGas Comments at 7-8; MMA Comments at 9; Tr. at 30-31). This language is based upon language contained in the Massachusetts Highway Standards and was language in the original document proposed by the Committee. Upon consideration of the comments and the entire record in this proceeding, we have modified § 1.4 of the Standards as noted.[(11)]

2. Section Two - Definitions

We added "Cold Patch" to the definitions which is defined as, "bituminous concrete made with slow curing asphalts and used primarily as a temporary patching material when hot mix plants are closed." We added the definition to avoid ambiguity concerning the term (see Wellesley Comments at 1).

We have revised our definition of the term "Controlled Density Fill" ("CDF") by adding the sentence, "[h]igh air (25% plus) may be used instead of fly ash with an adjustment in sand content." This change was made in response to one commenter's concern that CDF containing fly ash is corrosive to metallic pipe (Boston Gas Comments at 3). Another commenter noted that it is important to use CDF meeting MHD specifications and this revision of the definition meets MHD specifications (MHA Comments at 5). We agree and have revised the definition to reflect MHD specifications.

We revised the definition of "Infrared Process" to read "a recycling procedure whereby an infrared heater plasticizes the surface of an asphalt pavement, preparatory to the introduction of additional compatible paving materials uniformly re-worked and compacted to achieve a density and profile consistent and thoroughly integrated with the adjacent pavement." We agree with the comments that this is a more accurate description of the process involved and revised the definition accordingly (MHA Comments at 1; MMA Comments at 5).

We revised the definition of "Massachusetts Highway Standards" to read "the Commonwealth of Massachusetts Department of Public Works Standard Specifications For Highways and Bridges, 1988 Edition." The Committee had based its proposed standards upon the 1988 Edition (MHA Comments at 2; MMA Comments at 6; Boston Gas Comments at 2).

We revised the definition of "Newly Paved Road" to read "a road whose re-paving is less than five years old." The proposed definition included only those roads reconstructed with both a binder and top course. However, we agree with commenters that a roadway overlaid with 1.5 inches of Class I bituminous concrete was intended to be protected for a period of five years (MHA comments at 2; MMA comments at 6).

3. Section Three - Permit Requirements

We revised the first paragraph in § 3.0 to now read:

3.0 Permit Requirements

Each Municipality may incorporate in its permit procedures the portions of these standards that shall apply to Utility excavations within its jurisdiction. A permit may be issued with the stipulation that it may be modified or revoked with just cause at any time at the discretion of the Municipality without rendering the Municipality liable in any way. It is recognized that each Municipality shall have the authority to inspect work in progress and the Utility shall correct any deficiencies identified during said inspections. The following are the requirements that a Municipality may require of a Utility when granting Permits.

We deleted the word "minimum" from (1) the title of section 3.0 and (2) the final sentence of the paragraph following the title. We also added the following language to the second sentence to read, "[a] permit may be issued with the stipulation that it may be modified or revoked with just cause at any time at the discretion of the Municipality without rendering the Municipality liable in any way."

Several Commenters objected to the word "minimum" as too restrictive to utilities and not expressly stated in the standards proposed by the Committee (Boston Gas Comments

at 2-3; Tr. at 22-24). Other Commenters requested that we add language to allow municipalities to revoke permits for due cause (MHA Comments at 3; MMA Comments at 8). Upon consideration of these comments and review of the Standards, we agree with the suggested edits and modified § 3.0.[(12)]

We added to § 3.3, "in accordance with G.L. c. 82, § 40." Section 3.3 now reads:

The Utility shall notify Dig Safe, in accordance with G.L. c. 82, § 40, at least 72 hours prior to the start of work for the purpose of identifying the location of underground utilities.

One Commenter suggested including the term "Dig Safe" by adding a provision that a Utility provide notice in accordance with Dig Safe requirements (ComGas Comments at 3-4). See G.L. c. 82, § 40; 220 C.M.R. §§ 99.00 et seq. Our revised wording reminds utilities that they must comply with the statutory requirements of Dig Safe.

We added "(except for emergency repair work)" to § 3.5. Section 3.5 now reads:

A copy of the Permit must be on the job site at all times for inspection (except for emergency repair work). Failure to have the permit available could result in suspension of the rights granted by the Permit.

We added language excepting emergency repair work from this requirement since a permit may not be obtainable before commencing emergency work (see ComGas Comments at 4).

One commenter expressed concern about the liability and indemnification provision in § 3.9 (Bell Atlantic Comments at 1-2). The Commenter stated that the provision is overbroad and could potentially expose utilities to large and uncertain levels of liability, and may have an adverse impact on rates (id. at 2).[(13)]

We note that any person injured because of an excavation in a public street may be able to recover damages on the ground that the excavation constituted a nuisance, without any such express liability or indemnification language. See Bern v. Boston Consolidated Gas Company, 310 Mass 651 (1942); see also G.L. c. 164, § 70. In addition, a utility is liable for the negligent acts and omissions[(14)] of its agents that are not directly connected to the utility services it provides. See Lebowitz Jewelers v New England Telephone and Telegraph Company, 24 Mass. App. Ct. 268, 278, n. 9 (1987), citing McNicholas v. New England Telephone and Telegraph Company, 196 Mass. 138 (1907) (telephone company liable where child injured when a telephone linesman installing a line negligently dropped a insulator cover); Hoxie v New England Telephone and Telegraph Company, 287 Mass. 121 (1934) (telephone company liable where bicyclist killed by negligent operation of telephone company's motor vehicle). Accordingly, in light of the decisions mentioned above, we conclude that § 3.9 is not necessary and deleted it.

4. Section Four - Work Standards

We revised Section 4.1 to read, "All work shall be in compliance with the Massachusetts Highway Standards as it pertains to utility street excavations and repairs unless modified by these standards." This change was necessary to be consistent with the definition of Massachusetts Highway Standards.

5. Section Five - Safety

We revised a portion of Section 5.5 to correct a typographical error to now correctly read, "Manual on Uniform Traffic Control Devices (MUTCD)."

6. Section Six - Protection of Adjoining Facilities

We revised § 6.13 to read, "These standards do not cover the installation of any utility poles." Commenters noted that utility pole installation does not require a permit (Bell Atlantic Comments at 2; BECo Comments at 4). In light of these comments, and upon consideration of the language proposed by the Committee, we revised this section accordingly.

7. Section Eight - Backfill and Compaction

The Department revised § 8.4 to read, "CDF shall be utilized for those excavations where compaction cannot be readily accomplished with normal compaction methods (i.e. vacuum holes, utility clusters)." Commenters stated that the wording in Section 8.4 deviated from the original language agreed to by the Committee (MECo/ Nantucket Comments at 2; ComGas Comments at 6-7). We agree that the original wording could lead to disagreement about how this standard would be applied and therefore added "vacuum holes, utility clusters."

We revised the first sentence in § 8.7.2 to read,"Suitable backfill material is free of stones larger than half the size of the compacted lift as provided for in Massachusetts Highway Standards, construction debris, trash, frozen soil and other foreign material." This revision is in response to comments requesting clarification that the largest stone in a lift not exceed half the size of the compacted lift (MHA Comments at 6-7; MMA Comments at 13).

We revised § 8.12.8 to read, "All maintenance work shall be compacted in 6" lifts." In response to comments, we deleted the words "prior to compaction" because this wording was extraneous and did not add to the meaning of this section (MHA Comments at 7; MMA Comments at 14).

8. Section Nine - Pavement Restoration

We revised § 9.4 to read, "All non-emergency pavement excavations shall be repaired with same day permanent patches unless specifically exempted in the permit." One commenter stated that same day paving was very much the exception (RCN-BECo-Com Comments at 5). However, the record indicates that the Committee's consensus is that the installation of same day patching is the preferred method by both utilities and municipalities. Other commenters also requested to modify this Section to reflect the original wording submitted by the Committee to the Department (ComGas Comments at 7; MHA Comments at 7; MMA Comments at 14). Upon consideration of the comments and review of the record in this proceeding we have modified this section accordingly.[(15)]

We revised the last sentence of § 9.8 to read, "All pavement courses shall be thoroughly compacted prior to placement of subsequent courses" to correct a typographical error. Some commenters noted that the language referring to"Proctor" density in the Department's proposed Standards does not pertain to compaction of pavement (Boston Gas Comments at 5; Bowker Comments at 2; MHA Comments at 7; MMA Comments at 15).

We have revised § 9.11 by deleting § 9.11.c, "[w]ork performed when it is not feasible to place a permanent patch." Some commenters noted a conflict with § 9.4 (Boston Gas Comments at 5; ComGas Comments at 5; NEGA Comments at 2). Other commenters noted that the proposed wording in § 9.11.c was vague and might be subject to future disagreements between municipalities and utilities about the circumstances in which it

would be infeasible to place a permanent patch (MHA Comments at 8; MMA Comments at 15). We agree and revised the language of § 9.11 accordingly by deletion.

We deleted § 9.14 which read, "Bituminous concrete shall not be installed between November 15th and April 15th except as allowed by the Municipality." A number of commenters recommended that § 9.14 be deleted stating that bituminous concrete is generally available year round (Boston Gas Comments at 4; Comgas Comments at 5; BECo Comments

at 6; NEGA Comments at 2 MHA Comments at 8; MMA Comments at 16). Some commenters noted a conflict between the timing provisions of § 9.14 and those of §§ 9.11b and 9.15 (ComGas Comments at 5; NEGA Comments at 2). Upon consideration of these comments, we deleted § 9.14.[(16)]

We revised the second sentence of the proposed Standards at § 9.15, now renumbered § 9.14, to read, "Temporary patches made between December 1 and March 30 shall be removed and replaced with a permanent patch as outlined above within five (5) working days." One commenter recommended a 60 day period in which to replace temporary patches made during the winter (BECo Comments at 6). Other commenters suggested using the original wording submitted by the Committee (MHA Comments at 8; MMA Comments at 16). Since bituminous concrete is available year round, this change encourages a permanent patch be made in a reasonable amount of time. A utility and municipality can agree to more specific terms as an exception, if circumstances warrant. Thus, we revised the language accordingly.

We revised proposed Standards at § 9.16, now renumbered § 9.15, by deleting the second sentence that concerns inspection of temporary patches until a permanent patch is made. The Standard at § 9.15 now reads, "[t]he Utility shall be responsible to maintain temporary patches in a safe condition for all types of travel until a permanent pavement repair has been made." We agree with the commenters that suggested deleting the second sentence because (1) temporary patches would be replaced within five working days and (2) utilities are responsible to maintain temporary patches (see NEGA Comments at 2; MHA Comments at 9; MMA Comments at 16-17). Thus, the requirement for inspection of temporary patches would be unnecessary.

C. Other Issues

1. Fees

Some commenters have requested that the Department address fees in its Standards (MHA Comments at 10). As noted, the SJC has ruled invalid those portions of an ordinance charging inspection and maintenance fees for street opening permits. Newton, 425 Mass.

at 697, 699. However, the SJC noted that G.L. c. 164, § 70 requires a utility to procure a permit before excavating, and the court noted that a fee to reimburse a city for its costs in

processing permit applications is valid. Id. at 699, 706. In addition, the SJC found that utilities have a duty to inspect excavation sites after a repair is made. Id. at 699-701. Municipalities, and not the Department, have authority to assess charges related to the costs of providing municipal services as long as those charges are consistent with state law as construed by the Court. See Art. 89, § 6 of the Amendments to the Massachusetts Constitution; G.L. c. 43B, § 13.

2. Accountability

The Department has reviewed the utility street restoration plans filed pursuant to its February 13, 1998 Notice of Compliance Review. We find that many plans lacked detailed information concerning internal written statements or policies designed to insure that managers and crews are aware of, and held accountable to, standards and procedures for street excavation and repair. Thus, the Department directs each utility company under its jurisdiction to file, within sixty days of this Order, adequate documentation ensuring that the utility has incorporated in its procedures the following: (1) a backfill/resurfacing training program for the company's street crew members and managers, including periodic refresher training; (2) a schedule for periodic inspection by the company of past excavations over a one-or two-year frost cycle; (3) review of the work performed at each excavation site by crews and managers themselves (including a crew manager reporting and accountability provision for correction of failures to apply or to satisfy the Standards); and (4) a system for corrective action in the case of indivvidual excavations and in order to identify and correct patterns of substandard performance, i.e. where managers or crews exhibit a continued uncorrected or systematic failure to comply with or meet the Standards.

3. Periodic Review of These Standards

MHA and MMA have suggested that there be a yearly process to (1) consider the effectiveness of the Standards; (2) review the information submitted pursuant to §§ 11.1 - 11.4 of the Standards; and (3) make recommendations to the DTE for any amendments to the Standards (MHA Comments at 9; Tr. at 40-41). We agree that a such review of the Standards is necessary and in the public interest. The appropriate interval for such review remains to be ascertained. We authorize the Director of the Gas Pipeline Engineering and Safety Division to establish a committee to meet and propose changes to the Standards, if necessary.

IV. ORDER

Accordingly, after due notice, hearing, and consideration, it is

ORDERED: That the Standards To Be Employed by Public Utility Operators When Restoring any of the Streets, Lanes and Highways in Municipalities, attached hereto, be and hereby are adopted by the Commission, effective thirty (30) days from the date of this Order; and it is

FURTHER ORDERED: That not later than sixty (60) days after the effective date of these Standards, all utility companies under the jurisdiction of the Department of Telecommunications and Energy incorporate said Standards into their operating procedures, unless otherwise ordered by the Commission; and it is

FURTHER ORDERED: That all utility companies under the jurisdiction of the Department of Telecommunications and Energy make diligent efforts to inform municipalities

of the Standards attached to this Order; and it is

FURTHER ORDERED: That all utility companies under the jurisdiction of the Department of Telecommunications and Energy follow all other directives in this Order.

By Order of the Department,

Janet Gail Besser, Chair

James Connelly, Commissioner

Paul B. Vasington, Commissioner

W. Robert Keating, Commissioner

1. A standard is "[a] type, model, or combination of elements accepted as correct or perfect." Blacks Law Dictionary 1404 (6th ed. 1990).

2. The respondents included: gas local distribution companies; electric companies; cable television companies; telephone companies; private water companies; municipal gas/electric departments; interstate gas pipeline companies; and the Massachusetts Bay Transportation Authority.

3. The Department invited two representatives from the gas industry and one representative from each of the following groups to participate on the Committee: electric companies; water companies; cable companies; telephone companies; the New England Gas Association; Massachusetts Municipal Association; Massachusetts Highway Department; and the Southeastern Regional Services Group. In addition, the Department invited one municipal representative from each of the seven Massachusetts Highway Association districts to participate on the Committee.

4. The Department, pursuant to 220 C.M.R. § 1.10(3), hereby incorporates the Massachusetts Highway Standards into the record of this proceeding.

5. MHD was formerly known as the Massachusetts Department of Public Works.

6. The Department granted the City of Boston and Massachusetts Municipal Association extensions to file comments on May 28 and June 3, 1999 respectively.

7. SERSG represents 17 municipalities in southeastern Massachusetts.

8. In Newton, the SJC struck down a city ordinance that required utilities to pay maintenance and inspection fees as a prerequisite to opening a public way on the grounds that the ordinance was inconsistent with and pre-empted by G.L. c. 164. Newton, 425 Mass. 697, 700, 701 (1997). In Somerville, the SJC struck down as inconsistent with state law a municipal ordinance that required a utility to hire particular contractors, selected by the city, to provide patching, paving, and repair services at specified rates. In addition, the ordinance required the utility to pay certain fees, use certain materials and paving techniques to repair the streets, and mandated that the utility's responsibility for the excavation continue for three years beyond the final infrared treatment. Somerville, 420 Mass. 702, 703, 705.

9. G.L. c. 164, § 70 reads in pertinent part that:

[a] gas company may, with the written consent of the aldermen or the selectmen, dig up and open the ground in any of the streets, lanes and highways of a town .... It shall put all such streets, lanes and highways in as good repair as they were in when opened; and upon failure to do so within a reasonable time, shall be guilty of a nuisance. See also, G.L. c. 166A § 5(g) (cable companies to restore opened streets to "as good condition as before entry").

10. We note that the definition of "Utility" in the Standards is based upon the language in G.L. c. 25, § 3.

11. Since we added § 1.4, the numbering for the other standards in the Purpose and Scope section has been adjusted accordingly.

12. We again note that utilities and municipalities can mutually agree to any exceptions to these Standards, and these Standards can not pre-empt any ordinance or by-law that is otherwise consistent with State laws (Standards at § 1.02). Further, a utility that fails to comply with these Standards can have its permit revoked until such utility meets the Standards and any other legally applicable municipal requirements (Standards at § 3.0).

13. Several courts have held that there are sound public policy reasons for shielding utility companies from certain damage claims because such limitation allows a utility to set its rates at a reasonable level. See Lebowitz Jewelers v New England Telephone and Telegraph Company, 24 Mass. App. Ct. 268, 273 (1987) (regulation of telephone company precluded finding of liability against telephone company for negligent act which allowed burglars to neutralize signal to police, allowing theft). Limitation of liability is an inherent part of a tariffed rate. See Western Union Telephone Company v. Esteve Gros. & Co., 256 U.S. 566, 572 (1921).

14. We also note that some utilities have terms in their tariff exempting the company from liability from interruption in service unless caused by the utility's own "negligent acts or omissions." Western Massachusetts Electric Company, D.P.U. 95-86, at 55 (1995). Tariffed utility service is not a contract relationship, Boston Edison Company,

390 Mass. 772, 777 (1984), and claims sounding in tort (e.g., "negligent acts or omissions") lie within the jurisdiction of the courts, not the Department.

D.P.U. 95-86, at 55 (1995).

15. In situations where permanent patches may not be possible, the utility and municipality can agree to exceptions (Standards at § 1.2).

16. Since we deleted § 9.14, all succeeding sections will be renumbered accordingly.

COLUMBIA STATEMENT NO. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
MARK KEMPIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

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I. INTRODUCTION

Q. Please state your name and business address.

A. Mark Kempic, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as its President and Chief Operating Officer.

Q. Have you previously filed testimony in this matter?

A. Yes. I previously submitted Columbia Statement No. 1.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony served in this proceeding by the Office of Consumer Advocate ("OCA") witnesses Dismukes, Andrews, Mierzwa, Colton and DeMarco; Office of Small Business Advocate ("OSBA") witness Ewen, and Pennsylvania State University ("PSU") witness Crist.

II. OCA WITNESS DAVID E. DISMUKES

Q. **What is your response to OCA witness Dismukes' testimony** from pages 8 through 20 of his direct testimony concerning regulatory lag?

A. First, witness Dismukes asserts that Columbia is seeking an RNA and a redesign of the WNA in order to reduce regulatory lag[1], but that is simply not the case. In my testimony, I clearly state that the goal of the WNA is to improve "customer bill and

[1] OCA Statement 1, Direct Testimony of David E. Dismukes, PH.D, Page 8, Line 6.

revenue stability", but I never mentioned regulatory lag because the WNA is not a tool to reduce regulatory lag. Rather, it is a tool to provide stability to customer bills and to the company's revenues. In fact, I only mentioned "regulatory lag" one time in my direct testimony and that is on page 14 where I mention that "Columbia's ability to increase its capital investment and maintain these accelerated levels of investment is a direct result of Act 11's impact on reducing the regulatory lag that was formerly associated with utility ratemaking in Pennsylvania". While it is important to shorten regulatory lag to the greatest degree possible when a utility the size of Columbia invests substantial capital in replacing as much of its aging infrastructure as Columbia does each year, that is not the reason Columbia is seeking the RNA or initially sought the changes to the WNA[2]. Instead, Columbia is seeking to implement the RNA to more closely align its rates with the drivers of its costs so as to send a more appropriate price signal to customers.

Q. Please explain why **Columbia's** rates are not sending the most appropriate price signals to customers?

A. As I stated in my direct testimony, the primary driver for this filing is Columbia's ongoing significant investment to enhance its distribution system through the replacement of pipe and related appurtenances that are reaching the end of their useful lives. It is important to recognize that a gas utility's delivery service costs

[2] Please see Company witness Johnson's rebuttal testimony, Company Statement 6-R in which the Company withdraws its requested changes to the WNA.

(i.e. non-gas costs) are fixed costs that do not vary with throughput. A gas utility designs and installs a distribution system that is capable of meeting its customers' design day requirements at the time of initial installation. These facilities include the city gate, mains and pressure regulating facilities, services, and meters all designed to meet the design day requirements of the gas utility's customers. Placing these facilities in service permits the gas utility to serve the changes in load due to extreme weather (the design day peak load) or the prevailing economic conditions. Once facilities are installed to serve customers, the costs associated with these facilities are by their nature fixed and do not vary as a function of the volume of gas consumed by customers. In other words, when Columbia invests a million dollars to replace a pipe (for instance), that cost exists regardless of how much gas is delivered through that pipe; however, under the volumetric rates embraced in Pennsylvania, customers pay for the use of that pipe based on the vagaries of the weather, not based on cost causation. Customers are not seeing an accurate price signal for the cost of replacement pipe, because they pay more when it is cold and less when it is warm – even though the cost of the pipe installation is fixed. This inappropriate price signal is magnified for utilities like Columbia whose primary cost drivers are the replacement of aging infrastructure since those are all fixed costs. The replacement of large amounts of bare steel main, pre-71 inadequately coated steel, and first-generation plastic (as explained in Columbia's Long Term Infrastructure Improvement Plan approved by the Commission in Docket Number

P-2022-3037388) requires significant new investment in rate base that is unrelated to demand growth. Rather, this investment is necessary to provide safe, reliable gas service to existing customers. Allocation of these costs to customers in a manner which recognizes that the fixed costs do not vary with consumption - such as the RNA or a WNA - is a more appropriate price signal to customers because it reflects the reality that the costs are fixed and do not vary with throughput.

Q. Do you have any other response to witness D**ismukes' discussion about** regulatory lag?

A. Yes, while I agree with some of his extensive testimony about regulatory lag and I disagree with a lot of it, I will not at this time rebut every point with which I disagree as I find the entire section to be misplaced and largely irrelevant to Columbia's rate request. Having said that, I do specifically disagree with his assertion that "inflation challenges do not represent a solid rational for its proposed weakening of regulatory lag[3]". First, I disagree with his apparent assertion that inflationary pressures are behind Columbia's effort to implement an RNA and to initially seek to make changes to the WNA (if that is in fact what he is arguing with reference to "proposed weakening of regulatory lag"). As explained above and in my direct testimony, Columbia's pipeline replacement program is the primary driver of our rate increase, and costs associate with that effort are magnified due to the inflationary pressures on the costs of pipe, paving, materials, supplies, labor,

[3] Witness Dismukes, at 17, line 2.

borrowing funds to invest in replacing pipe., etc. So, while inflationary pressures add to the Company's existing costs, the RNA makes sense even without inflationary pressures due to the magnitude of the Company's capital investment. To put it another way, Columbia is requesting the RNA for the purpose of sending more stable and better price signals to customers independent of inflationary pressures, to stabilize revenues for the Company and to better align its large fixed investments with the recovery mechanism.

Second, I firmly disagree that citing the inflation that we are all experiencing is in any way inappropriate for consideration in determining future expenses in this rate case[4]. While witness Dismukes argues that inflation was much worse in the 1970s, that does not change the reality that we have an obligation to establish rates which are as reflective of actual costs as is humanly possible. While witness Dismukes attempts to minimize the impact of the highest inflation rates in forty years and suggests that we do not need to consider the impact of inflation when establishing rates, he does not provide an alternative. The Company's position is that we need to provide evidence reflecting of the most realistic costs that we will incur in providing service to our customers during the Fully Projected Future Test Year (FPFTY), and that includes consideration of the impact of inflation. We have done just that in our rate case application.

[4] Witness Dismukes, at 17, line 5.

Third, witness Dismukes references the energy crisis of the early to md-1970s and the inflationary pressures of that time and, after admitting that the results of the studies of inflation on utility regulation were mixed, he sides with one study that concludes that there were no significant financial impediments or opportunities created by regulatory lag in any of these periods.[5] But regulatory policy and laws in many states - including Pennsylvania - stand in stark contradiction to his claim that inflationary pressures did not pose financial impediments at that time. In fact, the inflationary pressure in the price of the natural gas commodity during the energy crisis of the 1970s was behind Act 74 of 1984[6] which created a sliding scale of rates to permit gas companies to recover escalating gas costs outside of a (then) traditional base rate case through a new mechanism under Section 1307(f) of Title 66. That law recognized that sending proper price signals to customers was important and Section 1307(f) therefore removed one of the largest variable costs from a gas company's base rates and segregated it into a purchased gas cost recovery rate. I continue to believe that it is important to send proper price signals to customers and that is why Columbia believes its RNA proposal should be adopted and its current WNA should continue.

[5] Witness Dismukes, at 18, line 5.

[6] https://www.legis.state.pa.us/CFDOCS/Legis/PN/Public/btCheck.cfm?txtType=PDF&sessYr=1983&sessInd=0&billBody=H&billTyp=B&billNbr=0132&pn=2871

III. OCA WITNESS BRIAN C. ANDREWS

Q. Turning now to OCA witness Andrews' testimony in which he proposes to change depreciation from Equal Life Group to Average Life Group, do you agree with that recommendation?

A. No, while Company witness Spanos (Columbia Statement No. 5-R) provides rebuttal testimony concerning the technical flaws with the OCA's proposal, I'd like to provide the following explanation about *impact* of the proposal on the Company's business and its ability to continue improving the safety and reliability of service to our customers. As witness Spanos explains, witness Andrews' radical proposal to decrease depreciation expense by $43,880,000[7] by departing from the Equal Life Group procedure that Columbia has employed since 1984 would result in higher rate base and higher overall costs to customers over time.

In addition to the flaws in witness Andrews' recommendation that Columbia witness Spanos has addressed, it is important to recognize that the Company uses this deprecation expense every year as a funding source for its accelerated pipeline replacement program as outlined in the Long-Term Infrastructure and Improvement Plan ("LTIIP") approved by the Commission[8]. If the Company were no longer able to use this depreciation expense to fund its LTIIP projects, it would need to go to the market to obtain this amount in order to continue replacing pipe.

[7] OCA Statement 4, Direct Testimony of Brian C. Andrews at 3.

[8] Docket No. P-2022-3037388 and approved by the Commission on April 20, 2023

Instead of funding the capital program through the depreciation expense sourced from the customer revenue without finance charges, the funding would need to come from the market and it would come with an added cost of return on the investment to the investors – which would be especially high with today's interest rates – and which would ultimately increase costs to customers. This is because Mr. Andrews' proposal will increase rate base, as further explained by Mr. Spanos. As an alternative to going to the market for these funds which carries a premium in the form of the return, the Company's only other option would be to substantially cut back on the amount of capital invested in its accelerated pipeline replacement program. However, a $43 million annual reduction would severely elongate the time necessary to replace the remaining bare steel, pre-71 inadequately coated steel, and first-generation plastic pipe and would be inconsistent with the LTIIP that Columbia outlined and presented to the Commission for approval. Such a change would increase risk to customers and communities over the current plan outlined in the LTIIP, and it would threaten safety and reliability, which is not something that the Company desires to do.

IV. OCA WITNESS JEROME D. MIERZWA

Q. **Do you have a response to OCA witness Mierzwa's testimony recommending disapproval of Columbia's proposed Municipal** Levelization Charge **("MLC")**?

A. Yes, witness Mierzwa argues that the MLC should be rejected because it is "experimental" and he has "not seen an MLC or similar mechanism being charged anywhere else in the county by any public utility."[9] Columbia admits that the MLC is experimental, but neither that nor the fact that the OCA witness has not seen it is grounds for disapproval of the mechanism. The Commission has approved experimental programs for Columbia and for other Pennsylvania utilities in the past for the purpose of testing and proving theories. For instance, the Commission approved a pilot "Energy Assurance Program" for Columbia in 1990 at the request of OCA witness Colton, in order to:

> test empirically some of the claims made by Roger Colton for an EAP. Hopefully the results of the pilot program will prove Mr. Colton's thesis that EAP will enable more customers to avoid termination and collection actions, while also reducing the uncollectible expense that can be anticipated if existing approaches remain unchanged. In any event, if these hopes for EAP are not realized, testing it in a pilot will limit any costs incurred.[10]

Likewise, in 1997 the Commission approved a voluntary pilot capacity release program for Columbia which was "available only to residential and small, priority one, commercial customers located within Washington County via marketers who wish to participate in the program."[11] In a separate Statement approving the pilot program, Commissioner Hanger noted: "These proposals give all involved,

[9] OCA Statement No. 5, Direct Testimony of Jerome D. Mierzwa at 29.
[10] *Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania*, R-891468,Order Adopted December 19, 1991, Order Entered January 24, 1992.
[11] *Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania*, R-00963688, Order Adopted and Entered August 8, 1996.

including this Commission, an opportunity to consider many important issues ... These are just a few of the issues that interest me. Again, I congratulate Columbia for making these important proposals."[12]

Similar to the Energy Assurance Program, (which is the ancestor to Columbia's current Customer Assistance Program) and the voluntary capacity release program in Washington County PA (which precedes Pennsylvania's Natural Gas Choice and Competition Act of 1999), Columbia's proposed MLC will provide the Commission, the statutory intervenors, and Columbia with valuable information concerning the impact of communicating the cost of restoration to customers. Columbia believes that the MLC can help to spur municipalities to accept reasonable PennDot permitting and restoration standards when customers living in those municipalities - along with the municipal leaders - are made aware of the financial impact those municipal ordinances are having on their gas utility bills.

Q. **What is your response to witness Mierzwa's assertion that the MLC should not be approved because it represents less than 1% difference in the cost of serving customers?**

A. Witness Mierzwa incorrectly believes that the proposed MLC is intended to account for all differences in costs to serve all different municipalities. He further posits that a 1% difference (as per his calculation) should be ignored. However, the MLC is not intended to address all differences in costs between municipalities; it is

[12] *Id.* Statement of Commissioner John Hanger.

intended to address *one* major cost category that is *uniquely* driving increases in rates to customers across all municipalities: i.e., those municipalities that demand restoration which far exceeds the PennDot standards. By bringing visibility of these costs through transparent bills to customers residing in those municipalities, both customers and municipal leaders will better understand the true cost impact of oppressive restoration standards. Without visibility into this cost, all of Columbia's customers across its twenty-six county service territory are paying for road restoration that only benefits a small portion of Columbia's customer base.

Next, witness Mierzwa's focus on the 1% differential in rates (which he calculated) misses the point. Rather than looking at the differential in rates, one needs to look at the vast differential in paving costs between municipalities and calculate the potential for more pipeline replacement at the same cost (or lower costs with the same amount of pipeline replacement) if municipalities were to adopt the PennDot standards for restoration. As shown in Company witness Paloney's Exhibit NP-1, the City of Pittsburgh's paving requirements are 328% more expensive than the PennDot standard for 2023. This is not a one-time occurrence. In 2022, the City of Pittsburgh's paving requirement was 309% more expensive than the PennDot standard. Over these two years, Columbia was forced to spend $1,271,306 of its capital program to pave above and beyond the standards that are perfectly fine for every state highway in Pennsylvania - instead of using those funds to invest in replacing nearly another *mile* of aging pipe.

This is especially concerning with the amount of pipe that the Columbia operates in municipalities having restoration standards which exceed the PennDot standards. As shown in Columbia's response to OCA interrogatory Set 4-029 attached to my testimony as Exhibit MK-1-R-1, Columbia operates approximately 1,246,331 feet of pipe in Pittsburgh and Perryopolis. Of those totals, approximately 161,600 feet and 10,700 feet of priority pipe will need to be replaced in Pittsburgh and Perryopolis, respectively. Columbia's customers will ultimately bear the brunt of that incremental expense in restoration costs above and beyond what would have been the cost necessary to restore the streets and roadways to the standard acceptable to the Commonwealth of Pennsylvania, thus foregoing additional main line to be replaced elsewhere.

Q. Do you agree with witness Mierzwa's assertion that the MLC should not be approved because the MLC does not recognize differences in the costs associated with serving different customer classes?

A. No. The MLC does not need to consider any differences in costs to serve different customer classes because the MLC is limited to the incremental permitting and restoration requirements which exceed the PennDot standards and which are entirely independent of the costs of serving different customer classes. From a rate design perspective, different rates are driven by the differences in costs to serve different types of customers. Traditionally, the differences in costs to serve customers relates to things like meter size, volume of gas consumed, service line

size, etc. But in the situation of the MLC, no such differences exist because permitting and restoration costs are determined by the municipality without regard to any of those criteria and all customers benefit from the restoration equally. That is why Columbia recommended applying the same MLC to all customer classes.

V. OCA WITNESS ROGER COLTON

Q. OCA witness **Colton cites the fact that Columbia's CAP payment rate is** less than other utilities as a sign of non-superior management performance. Do you agree?

A. No. Witness Colton fails to recognize that this is directly impacted by the number of CAP bills that are paid by a LIHEAP grant. The CAP payment rate is a calculation of the total CAP bills issued divided by the total number of bills *paid by* a CAP customer. In this metric, the Company does not consider a LIHEAP grant as paid by the customer and therefore does not count it as a bill paid by the customer. However, the Company still counts the bill as issued even if the Company has LIHEAP funds to cover the bill. Due to Columbia's lowest asked-to-pay amount, it follows logically that Columbia's CAP customers have less bills to pay than other utility programs because the LIHEAP grant pays a higher percentage of their bills.

Q. Witness **Colton states that Columbia only enrolls a "fraction" of its** estimated low-income population. He cites this metric as an example of management problems. Do you agree?

A. No. Witness Colton cites the estimated low-income count when suggesting management problems even when the Company has explained that census data can only reach to a county level in a service territory that is shared by two gas companies. In addition, census data does not take into consideration the use of other fuel types including electric, oil, coal, propane or wood. This leads to erroneous numbers and should not be used to suggest management problems. It should be noted, Columbia's enrollment percentage of confirmed low-income customers is above the average of other Pennsylvania gas utilities who define confirmed low-income in the same way, thereby suggesting superior management of our enrollment.

Q. Witness **Colton states that Columbia's collection performance is poor as** evidenced by the high number of termination notices compared to the disconnects that are worked. Do you agree?

A. No. The Company is required or encouraged to follow many procedures that impact this metric. For example, the Company stops collections if a customer calls and requests a payment plan, agrees to apply for CAP, asks for a medical certification or applies for other assistance programs such as LIHEAP or CRISIS. In addition, the Company sends out termination notices beginning in February for an April 1 termination date or later so a customer can apply for CRISIS. That customer could get two notices before April 1 with no additional action. The Commission encourages swift termination activity on CAP accounts to help keep

balances reasonable. Therefore, in some cases, customers pay every other month and receive a notice every month, because they are always behind, but are never disconnected. All of these efforts, which are designed to motivate customers to pay or take action, inflate the termination to disconnect ratio. One could suggest that the disconnect notices are working as intended and customers are acting to stop the termination, which is the desired outcome.

VI. OCA WITNESS NICOLAS A. DEMARCO

Q. **Can you please respond to OCA witness DeMarco's testimony at page 14, where he recommends that the Company should address whether it has made or not made a ratemaking claim to recover the $1,527,500 in administrative penalties that it was required to pay at Dockets: M-2021-3005572, M-2022-3012079, and C-2023-1 3040925**

A. The Company has not made any claims to recover the civil penalties totaling $1,527,500 as the settlement agreements approved by the Commission specifically prohibit recovery of those penalties.

Q. **Can you please respond to OCA witness DeMarco's testimony at page 16 where he recommends that the Company address in its testimony whether the expenses and capital costs that were previously incurred by the Company related to the events were covered by insurance or shareholder funds?**

A. As explained in the Company's response to OCA Set 20-002, attached as Exhibit

MK-1-R-2, there are two basic categories of costs generally associated with incidents, including: third party claims, and O&M and capital costs associated with repair of infrastructure, if any is needed.

Regarding third party claims, in the cases referenced by witness DeMarco, only Docket No. M-2022-3012079 (North Franklin Incident) involved property damage claims by third parties. For third-party claim costs, Columbia is responsible for the deductible portion of its insurance policy in the amount of $25,000. Above that amount, claims are paid and ultimately reimbursed by the insurance carriers, and the deductible expense is included in the Company's 5-year average of Injuries and Damages which has historically been included in the Company's expense claim as a cost of doing business. Further testimony regarding treatment of the deductible expense is provided in the rebuttal of Columbia Witness Komenda.

Regarding O&M and capital costs associated with repair of infrastructure:

- Docket No. M-2022-3012079 (North Franklin Incident) involved no such costs so no costs were included in any rate case.
- Docket No. C-2023-3040925 (Maiden Street Line Damage) involved damage to the Company's existing facilities during a Columbia main replacement project in May of 2020 and required capital expenditures to repair. In its response to OCA Set 24-004, attached as Exhibit MK-1-R-3, Columbia clarified its response to OCA 20-002(a) to indicate that the Company's costs to repair the Maiden Street line damage were charged to O&M and that, as

such, the costs were not included in the FPFTY in Columbia's 2021 rate case, or any other rate case.

- Docket No. M-2021-3005572 involved the Rimersburg and Fayetteville Overpressure Incidents that occurred in 2018. Subsequent to the incidents, Columbia Gas filed rate cases in 2020 (Docket No. R-2020-3018835), 2021 (Docket No. R-2021-3024296), and 2022 (Docket No. R-2022-3031211). In Columbia's 2022 rate case (Docket No. R-2022-3031211), which concluded with a final order issued on December 8, 2022, OCA served discovery that sought information from Columbia Gas regarding overpressure events, including the date and location, corrective action taken, expenses and/or capital costs incurred for such events, and whether customer equipment was damaged. The Company's response to that discovery included the requested information regarding the 2018 events at issue in Docket No. M-2021-3005572. No party in that rate case, nor in any of the three rate cases listed above, submitted testimony that challenged Columbia Gas's recovery of costs associated with either event.

Furthermore, as Columbia has explained in its response to OCA Set 24-003, attached as Exhibit MK-1-R-4, the cost to replace the main that was involved in the Rimersburg overpressurization incident were not related to the overpressurization because the replacement of those facilities had been planned for operational purposes. The Revised Settlement Agreement in

Docket No. M-2021-3005572 noted that the section of pipeline in Rimersburg that was overpressurized and that was taken out of service and replaced was not due to the overpressure event but, rather, due to the age and condition of the facilities. Moreover, Columbia Attachment 1 to the Revised Settlement Agreement (provided as Attachment B to the response to OCA 24-003) provided details about the compromised facilities related to the Fayetteville overpressure event that were replaced. While replacement of those facilities had not been scheduled as of the date of the overpressure event, from the vintages and material type of the facilities it is evident that they would have been scheduled for replacement as part of Columbia's Long Term Infrastructure Improvement Plan even if the overpressure event had not occurred.

Q. **Do you agree with OCA witness DeMarco's recommendation that any ongoing or recurring costs in rate base and expenses associated with incidents should not be included in rates?**

A. I disagree because those costs were reasonably and prudently incurred to improve the gas distribution system. Upon advice of counsel, I note that the Commission promulgated a Policy Statement at 52 Pa. Code §69.1201 that sets forth factors to be considered when evaluating whether a proposed settlement for violation is reasonable. One of those factors is the amount of the civil penalty necessary to deter future violations as well as past Commission decisions in similar situations.

In other words, under the Commission's policy statement, the civil penalty – when viewed in the context of the overall settlement which typically includes remedial actions – is intended to be the regulatory construct that deters the undesired behavior. It is important to note that the policy statement does not contain any provision disallowing recovery of remedial costs. In addition, none of the settlements referenced by witness DeMarco contain language disallowing the recovery of costs associated with remediation. Nor do any of the orders approving those settlements disallow the recovery of such costs, despite comments submitted by OCA in Docket No. M-2021-3005572 which advocated that Columbia should bear the costs involved in the repair and replacement of the overpressurized systems. In fact, in its Opinion and Order approving the Revised Settlement Agreement in that case, the Commission observed that

> Columbia Gas has provided the details of the facilities replaced in the Rimersburg system as a result of age and condition and those in the Fayetteville system that resulted from the overpressure incident. The Parties acknowledge that Columbia Gas is not prohibited from recovery of costs of these facilities in rate base.[13]

By contrast, Columbia was previously involved in a case in which O&M and capital costs associated with remedial actions were specifically required to be incurred and specifically prohibited from being recovered in its rates:

> Respondent shall pay a civil settlement amount of $100,000 minus those costs incurred during the first eighteen months after approval of this

[13] *Pennsylvania Public Utility Commission, Bureau of Investigation and Enforcement v. Columbia Gas of Pennsylvania, Inc.*, Docket No. M-2021-3005572, August 24, 2023 Opinion and Order at 29

> Settlement Agreement associated with Columbia's construction of a gas safety training facility and Columbia's provision of Operator Qualification gas safety training as specified in Paragraphs 1 and 3 of the Appendix to this Settlement Agreement
>
> Respondent agrees not to seek recovery of costs associated with this gas safety training facility in any rate proceeding. As noted, the Parties agree that Respondent may count expenditures incurred during the initial eighteen (18) months for constructing the training facility towards the civil penalty imposed on Respondent under the Settlement Agreement.[14]

Columbia included the costs associated with the repair of the overpressurized systems that were the subject of Docket No. M-2021-3005572 in its rates because it negotiated the settlement agreements with the understanding that the civil penalty and the act of taking the remedial actions contained in the settlement agreements was the fine to be paid. Prohibition of recovery of such costs now, after the settlement agreement were negotiated and approved by the Commission, would unfairly change the intent of the settlement agreements after the fact.

VII. OCA WITNESS GREG R. MEYER

Q. **OCA Witness Greg R. Meyer proposes to reduce Columbia's FPFTY budget capital additions by $41 million. Would you please address that recommendation?**

A. Mr. Meyer's recommendation should be rejected for several reasons. First, as Columbia Witness Spanos observed in his rebuttal testimony (Columbia Statement 5-R), Mr. Meyer's comparison of actual capital additions to budgeted capital

[14] *Pennsylvania Public Utility Commission, Law Bureau Prosecutory Staff v. Columbia Gas of Pennsylvania, Inc.*, Docket No. M-00051886, Order Entered October 4, 2005.

additions associated with Columbia's past five rate cases shows that Columbia's additions are more closely aligning with the budgeted projections over time during the sequence of rate cases Mr. Meyer provides in his testimony. Second, slow construction progress is common for Columbia during the winter months due to inclement weather conditions which hamper construction progress. In the first quarter of 2024, due to weather conditions the Company was unable to field its full complement of active projects on eleven days from January through March of 2024. It is common for Columbia to make up for a first quarter construction lag during the remainder of the year, which is shown by the quarter-by-quarter breakdown of the Company's project costs in Exhibit MK-1-R-4 attached to my rebuttal testimony. Third, the first quarter of 2024 was atypical for Columbia in that the Company engaged in more project start-ups than usual during that quarter, whereas usually first quarter construction activity is largely comprised of carry-over work from the prior year. Project start-up work involves complex one-call tickets (14 days), notifications to permitting parties, environment start-up compliance, locates, and pre-construction meetings to name a few. These activities must be completed as part of the project, but they are precursor activities to "shovel in the ground" work that moves the project along. Once the start-up work is completed, project work can then proceed at a quicker pace. Fourth, the budgeting for Columbia's capital additions includes costs for property restoration such as asphalt paving. That work cannot be completed during the winter months because the

asphalt plants do not operate in the winter. So, while the projects that were part of the Company's first quarter budgeted capital additions included amounts to be spent on restoration activity, the actual spend would typically occur during the second and third quarters.

VIII. OSBA WITNESS MARK D. EWEN

Q. What is your response to Office of Small Business Advocate witness **Ewen's testimony where he "disagrees with Columbia that accelerating** pipeline replacements on the basis of current commodity prices **represents a reasonable strategy"**[15]?

A. My response is that his testimony is a total misrepresentation of Columbia's strategy. Columbia's pipeline replacement strategy, as outlined in its third Long Term Infrastructure Improvement Plan filed with the Commission in Docket No. P-22-3037388 and Approved by the Commission on April 20, 2023 is as follows:

> The Third LTIIP will continue the repair, improvement and replacement of aging and at-risk infrastructure at an accelerated pace. Columbia's schedule for planned repairs, improvements and replacements of aging and at-risk infrastructure will be driven by the needs of the distribution system, in accordance with the basic tenets of system engineering and planning. As Columbia's infrastructure replacement program continues to mature, the Company remains focused on replacing prone to fail pipe at an accelerated pace in order to retire its remaining bare steel, wrought iron, pre-1971 coated steel and first-generation plastic facilities. Replacements are determined based on the condition and age of the pipe, geographical proximity,

[15] OSBA Statement No. 1, Direct Testimony of Mark D. Ewen at Page 2, Line 8.

> leak history, the capacity needs of the area, and expected growth in system demand requirements.[16]

As per the approved strategy explained in the LTIIP, Columbia is pursuing its pipeline replacements based on the needs of the distribution system in accordance with the basic tenants of system engineering and planning. Columbia would need to continue replacing pipe based on the needs of the distribution system regardless of the price of natural gas commodity.

Q. Do you agree that natural gas prices have been volatile in recent years as witness Ewen testifies?

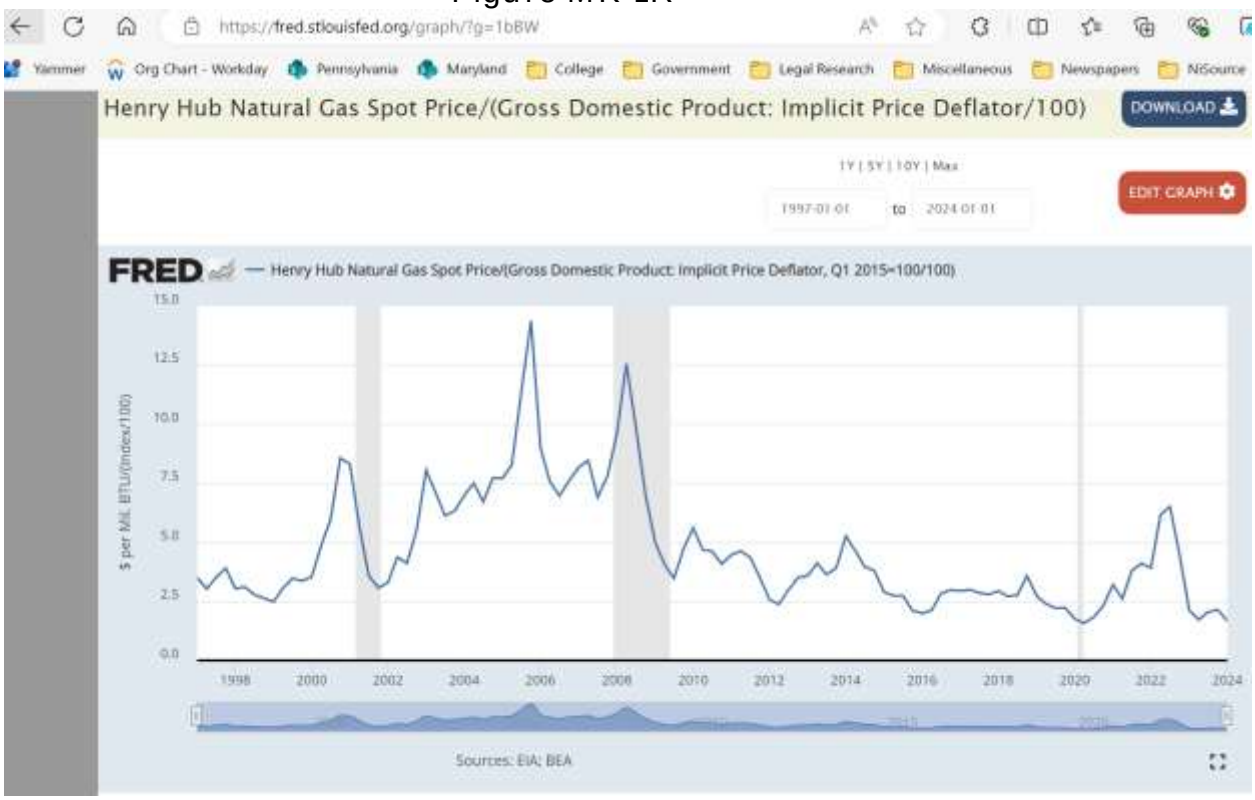
A. While I agree that the global pandemic had temporarily introduced some volatility into the gas commodity market during 2021 and 2022, it is important to recognize that: 1) prices during the worst quarter of the pandemic ($6.49 per MMBTU) were not as high as the prices experienced in the mid-2000s (which reached a high of $14.36 in 2005 and which averaged higher than $6.50 for much of the decade); 2) by end of the first quarter of 2023, Henry Hub Spot Prices were down to pre-pandemic levels; 3) as show in Figure MK-1R below, there is a noticeable and continuing downward trendline in the commodity price since the Marcellus wells began coming on line in 2008 and 2009, and continuing through today. Incidentally, the Henry Hub spot price fell to record lows in February of 2024[17].

---

[16] *Petition of Columbia Gas of Pennsylvania, Inc. for Approval of its Third Long-Term Infrastructure Improvement Plan*, Docket No. P-2022-3037388, Petition at Paragraph 20.

[17] Henry Hub daily natural gas spot price fell to record lows in February - U.S. Energy

Figure MK-1R



So while lower gas commodity prices do not drive the strategy, the fact that commodity prices are lower helps the customer's total gas bills to be affordable, which reduces the impact to the customer while providing the customer with the benefits of a safer, more modern, and reliable distribution network at a reasonable cost.

Information Administration (EIA);
https://www.eia.gov/todayinenergy/detail.php?id=61484

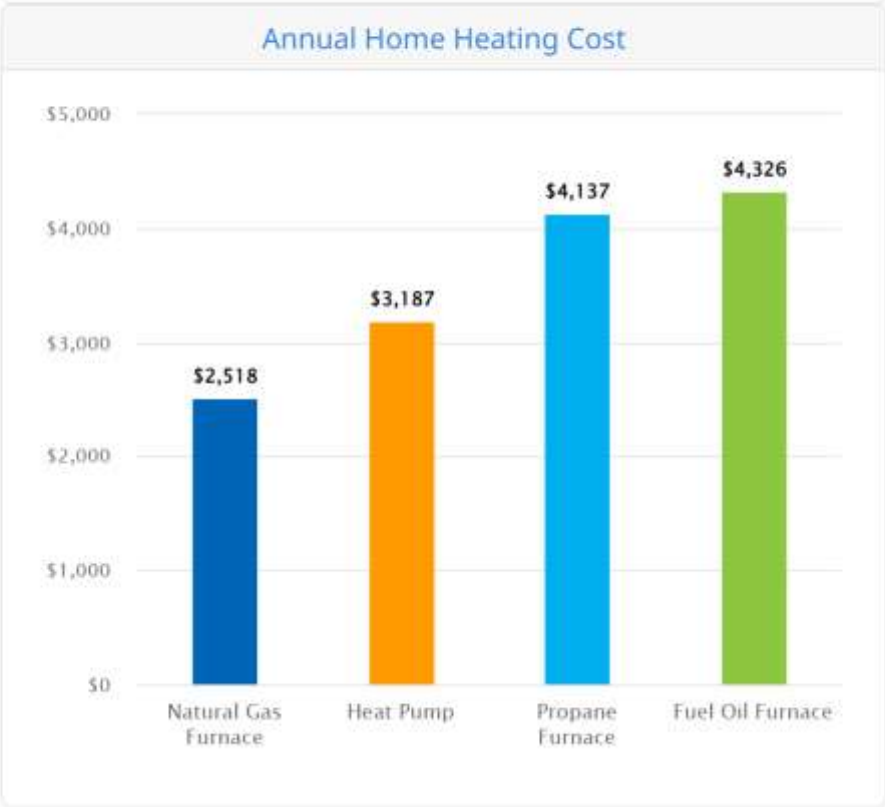
Q. **Do you agree with witness Ewen's assessment that Columbia will not be able to recover this investment in its replacement pipe because of "the Company's declining distribution cost competitiveness**?

A. Absolutely not. In an effort to provide transparent cost information to customers and the public in general, Columbia added a tool to its website[18] to enable customers to compare the cost of heating their homes using various types of fuels such as natural gas, electric heat pumps, propane and fuel oil. As shown in Figure MK-2R, based on current prices for the Pittsburgh region, even an old 80% efficient gas furnace would cost a customer less to operate than a standard heat pump and far less than propane or fuel oil. Even with the full rate increase, Columbia's service will remain the most economical choice.

[18] https://www.columbiagaspa.com/services/add-or-convert-to-gas/calculate-your-savings

Figure MK-2R

Columbia Gas of Pennsylvania
A NiSource Company



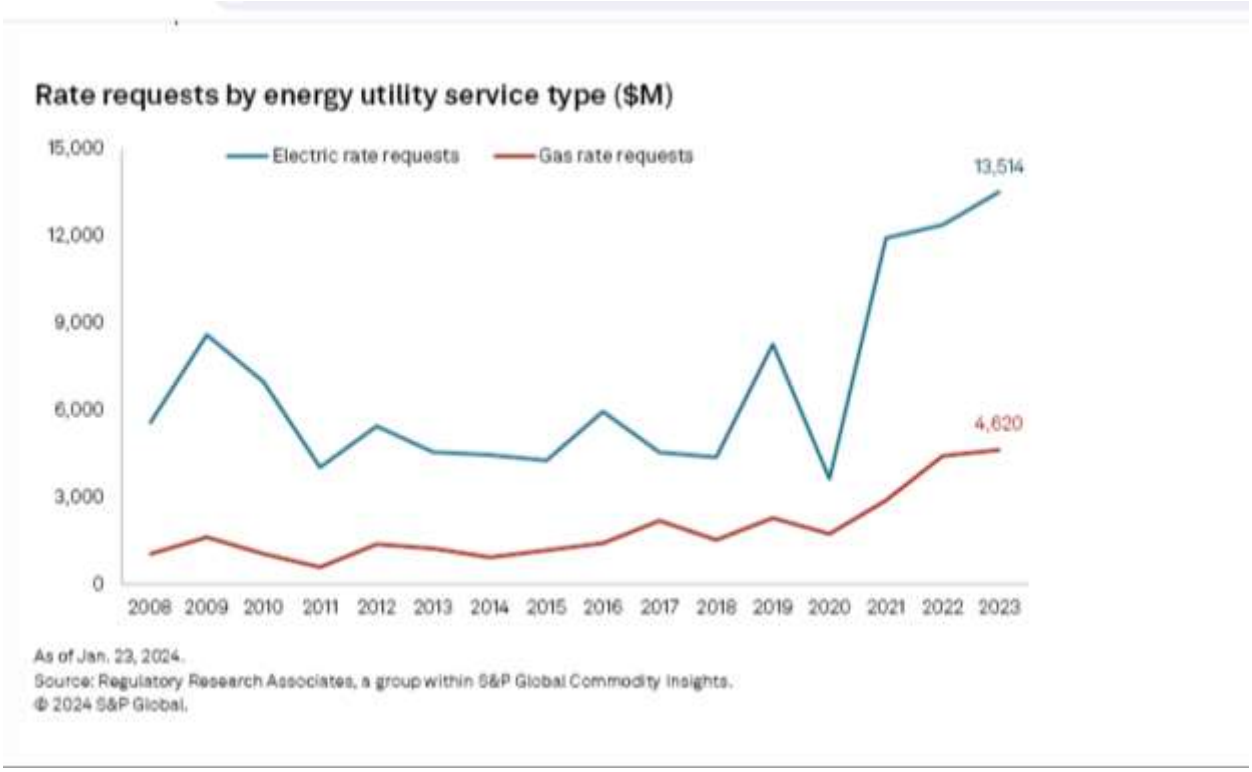
With regard to future rates for heating and the competitiveness of gas compared to heat pumps and mini-splits, witness Ewen apparently contemplates that only Columbia will increase rates and that electric utilities, propane and fuel oil companies and other energy suppliers will remain the same. That is simply not the case. There are many active rate cases before the Pennsylvania Public Utility

Commission at present and, according to a February 2024 report by S&P Global[19], the number of rate increase requests for utilities set a record in 2023 for the third straight year as a large number of utilities are seeking rate relief reflecting the utilities' significant capital expenditures. Simply put, Columbia is not alone.

Moreover, as shown in Figure MK-3R below electric utility rate requests far exceed those of gas utilities. While nobody likes any costs to increase, Columbia's costs are increasing in order to implement the LTIIP approved by the Commission to replace aging distribution infrastructure necessitated by the demands of the distribution system. And while Columbia may have started its infrastructure replacement program earlier than other utilities, it is not unique in its need for rate relief due to capital investment for infrastructure replacement. Frankly, I am pleased that Columbia has replaced so much of its infrastructure before the pandemic using "pre-inflationary" dollars because it would cost more to replace that infrastructure now than it cost Columbia to replace it in the past. This is a financial benefit to customers in addition to the improved safety and reliability that the customers have experienced since the beginning of Columbia's accelerated pipeline replacement program.

[19] https://www.spglobal.com/marketintelligence/en/news-insights/research/rate-requests-by-us-energy-utilities-set-record-in-2023-for-3rd-straight-year#:~:text=Number%20of%20cases,filed%2C%20the%20most%20since%201983.

Figure MK-3R



Q. What is your response to witness Ewen's conclusion that he does not believe that the Company has demonstrated its overall capital spending plan is prudent and that the Commission should require Columbia to demonstrate that it has a long-term viable business as part of its next LTIIP filing?

A. His recommendation is redundant and unnecessary. On December 28, 2022, Columbia filed its Petition for Approval of its Third Long-Term Infrastructure

Improvement Plan with the Commission[20]. In that LTIIP, Columbia provided detailed information about its capital spend and the amount of infrastructure replaced during the period before the Company accelerated its replacement program, through the period covered by LTIIP I, and the period covered by LTIIP II and its plans for the capital to be invested and the infrastructure to be replaced in the period of LTIIP III, which covers the years 2023 – 2027. LTIIP III contains a detailed analysis of the process Columbia adopted to optimize risk reduction, including Columbia's Safety Management System ("SMS") and its Distribution Integrity Management Program ("DIMP"). The Company provided a detailed analysis of the risks associated with first generation plastic pipe and pre-1971 ineffectively coated steel, inline pipe inspection, etc. The Company provided detailed footages of both mains, services, and meters to be replaced as well as the expected costs associated with each of the five years addressed by LTIIP III. The costs and the benefits associated with LTIIP III have already been subject to a public regulatory proceeding in advance of the Commission's approval of the LTIIP, so the costs should not be a surprise to any stakeholder. In addition, each rate case provides the Commission with the opportunity to perform a prudence review, so no separate *ex post* prudence review needs to be adopted. Finally, as explained above, while Columbia's rates have gone up to replace infrastructure, other utilities' rates are also going up to replace their infrastructure. Fortunately, Columbia has

[20] Docket No. P-2022-3037388.

replaced a substantial amount of its infrastructure when costs were lower than they are today; however, electric utilities will likely need to make future investments in their infrastructure at costs that are higher than when Columbia did much of its work.

Also, upon advice of counsel, I know of no such legal obligation for the Company to demonstrate that its overall capital spending plan is prudent and that it has a long-term viable business as part of its next LTIIP filing. Throughout my decades in the gas industry, I have experienced the energy crisis, the moratorium on new gas connections, the gas supply bubble, high gas prices, open access, Choice®, massive changes brought about by the Marcellus Shale, and many other issues, each of which was believed to substantially impact the viability of the natural gas industry. One thing I have learned from my experience is that the gas industry is extremely resilient and has weathered those storms and is a necessary component of our energy future. In addition to the fact that no obligation exists to conduct such an analysis, I do not see the practical need to perform such an analysis.

Finally, contrary to witness Ewen's assertions about the viability of gas compared to heat pumps and mini-split systems, I believe that natural gas has a very competitive future.

Q. Do you have any final observations concerning the testimony of witness Ewen?

A. Yes, his testimony contains a number of broad and general statements regarding the prudency of Columbia's ongoing commitment to replace aging infrastructure due to "increased regulation of CO2 emissions", and "societal and political concerns" regarding fossil fuels. On the basis of these general statements, he concludes that the Commission should direct Columbia, "to demonstrate that it has long-term viable business as part of its next LTIIP filing."

Q. Does witness Ewen provide support for these statements?

A. No, he does not. In fact, he does not cite to any specific laws or regulations in support of his contentions. Moreover, the Pennsylvania law authorizing the fully projected future test year also sets forth a five year review process for utility's long term infrastructure investments, so his claim of possible imprudence due to not having a plan longer than five years is not supported by the structure set forth by the General Assembly in Pennsylvania law. In addition, regardless of any political or societal concerns that may or may not develop in the future, the fact remains that natural gas distribution facilities which are reaching the end of their useful life must be replaced in order to keep customers served by those facilities safe. Moreover, if such facilities are not replaced, existing customers served by those facilities would face substantial costs to replace their gas-fired equipment. Witness Ewen also does not recommend any expense or revenue adjustments, so his recommendation should be dismissed because in addition to it being inconsistent with the spirit and intent of Pennsylvania law, it is vague.

Q. Are you aware of the Commission addressing any similar arguments?

A. Yes. I am advised by counsel that similar arguments were advanced in the 2020 base rate case filed by the Philadelphia Gas Works ("PGW") by environmental parties.[21] In that case, the Commission determined that the environmental parties failed to provide any evidence to support an affirmative position, such as a specific expense or an adjustment to revenue projections. Further, the Commission denied the environmental parties' request that PGW be required to perform studies and prepare reports based on speculative assertions, and in the absence of statutory, regulatory or other legal order or requirement to do so.

Q. Is the PGW decision instructive in this case?

A. It certainly appears so. In this case, much like the environmental parties in the PGW case, witness Ewen raises a general concern about the prudency of Columbia's capital plan as it relates to infrastructure replacement. However, he provides no evidentiary support for his concerns, advocates for no expense or revenue adjustments, yet he seeks to require that the Company justify its viability as a company in a future proceeding wholly unrelated to this case. For these reasons, witness Ewen's assertions, and requested relief, should be rejected by the Commission.

[21] *PaPUC v. Philadelphia Gas Works*, Docket No. R-2020-3017206 (November 19, 2020).

IX. Penn State University James Crist

Q. **Do you have a response to Penn State University witness Crist's testimony concerning Columbia's rates compared to inflation?**

A. Yes, witness Crist first recounts the base rate cases that Columbia has filed since 2008 and notes that before 2008 Columbia had not filed a rate increase since 1995. Nevertheless, he omitted the fact that Columbia embarked upon an accelerated pipeline replacement program in 2008 which has been consistently cited in evidence in every rate case since 2008 as the driving force behind every rate request. In addition, Columbia embarked upon this accelerated pipeline replacement program in 2008 with the full and open support of the Commission and the Pipeline Safety Division, so any implication that Columbia's rate increases are being driven by any motive other than improving the safety and reliability of our distribution service to our customers is wholly incorrect. It is also relevant to note that pipelines are a long-lived investment, with average service lives of 65 years. It should not be surprising that new investment in pipes replacing pipes 65 years or older substantially exceed the current rate of inflation.

He next attempts to disparage me personally by claiming that I am misleading people by noting that the average customers' bill is lower now than it was twenty years ago after you adjust for inflation, instead of focusing solely on the distribution component of the total bill. My statement about the total bill being lower after it is adjusted for inflation is true both in fact and in spirit. Our residential customers

care about their total out of pocket costs – the total bill – and how much of their wallet that consumes. Just as a homebuyer cares about the total cost of a house rather than offsetting increases and decreases in the costs of concrete, appliances, nails, etc., it is the total out of pocket expense that drives the economic decision. Witness Crist goes further and testifies that "Columbia should not be allow to increase its distribution rates simply because the global energy markets have declined over the recent 15-year period", incomprehensibly suggesting that there is some cause and effect between decreasing commodity rates and increasing distribution rates. He points to no evidence of any such relationship, nor any desire on Columbia's part to seek a rate increase for that reason, because no such evidence exists. Columbia's rate request is driven by its substantial investment in replacing bare steel and other aging first generation pipe which needs to be replaced in order to maintain safe and reliable service to customers. The bottom line is that when it comes to Columbia's inflation-adjusted total bill, our customers are paying a lower total bill today than they were 20 years ago, which is not true for many other household expenses. In addition, that lower bill also brings with it the benefit of substantial investments in safety and reliability improvements.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

OFFICE OF CONSUMER ADVOCATE INTERROGATORIES
Set 4

Question No. OCA 4-029:

Reference Statement No. 9, page 19, lines 11-14. Please identify the length of the distribution mains in feet currently servicing the City of Pittsburgh, the Borough of Perryopolis, Roscoe Borough, and New Sewickley Township.

Response:

Please see Table OCA 4-029 below showing the distribution mains in feet currently servicing the City of Pittsburgh, the Borough of Perryopolis, Roscoe Borough, and New Sewickley Township:

Table OCA 4-029

Location	Distribution Mains (Feet)
City of Pittsburgh	1,175,840
Borough of Perryopolis	70,491
Roscoe Borough	26,280
New Sewickley Township	249,794

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

OFFICE OF CONSUMER ADVOCATE INTERROGATORIES
Set 20

Question No. OCA 20-002:

Reference Columbia's Response to OCA Set 20, Question 1. For each settlement identified, please provide the following information:

a. Is Columbia making a claim in this base rate case for any property and/or infrastructure repair or replacement that arose from an incident underlying any of the identified settlements?

b. Identify, by category, cost, and basis, any claims that Columbia is making in this base rate case related to the repair and/or replacement of any public and private property that resulted from any incident underlying any of the identified settlements.

c. Can Columbia confirm that all costs related to settlements it entered with the Commission's Bureau of Investigation and Enforcement since its last base rate case will be covered by insurance and/or through shareholder funding? If not, identify any such costs that are included in this base rate case and provide an explanation of why Columbia is seeking to include those costs.

Response:

a. Among the matters identified in response to OCA Set 20, question 1, only Docket No. M-2022-3012079 (North Franklin Incident) involved property damage claims by third parties. For third-party claim costs, Columbia would be responsible for the deductible portion of its insurance policy in the amount of $25,000. Above that amount, claims are paid and ultimately reimbursed by the insurance carriers, and the deductible expense is included in the Company's 5-year average of Injuries and Damages.

Regarding Columbia's repair or replacement of its infrastructure, Docket No. M-2022-3012079 (North Franklin Incident) involved no such costs.

Subsequent to the overpressure events at issue that occurred in 2018 which were the subject of Docket No. M-2021-3005572 (Rimersburg and Fayetteville Overpressure Events), Columbia Gas filed rate cases in 2020 (Docket No. R-2020-3018835), 2021 (Docket No. R-2021-3024296), and 2022 (Docket No. R-2022-3031211). In the 2022 case, which concluded with a final order issued on December 8, 2022, OCA served discovery that sought information from Columbia Gas regarding overpressure events, including the date and location, corrective action taken, expenses and/or capital costs incurred for such events, and whether customer equipment was damaged. The Company's response to that discovery included the requested information regarding the 2018 events at issue in Docket No. M-2021-3005572. No party in that rate case, nor in any of the three rate cases listed above, submitted testimony that challenged Columbia Gas's recovery of costs associated with either event.

Docket No. C-2023-3040925 (Maiden Street Line Damage) involved damage to the Company's existing facilities during a Columbia main replacement project in May of 2020. Subsequent to that event, Columbia filed a rate case in 2021, as noted above. Capital expenditures associated with Columbia's repair of its facilities would have been included in that case.

b. See response to subpart a, above.

c. See response to subpart a, above. The basis for including any such costs in rate base is that they were reasonably and prudently incurred.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

OFFICE OF CONSUMER ADVOCATE INTERROGATORIES
Set 24

Question No. OCA 24-004:

Please refer to the Company's response to OCA-20-002(a). For the Maiden Street Line Damage which was the subject of Docket No. C-2023-3040925:

a. Identify the costs, by category and amount, that were previously included in rates related to the damage in the 2021 rate case.

b. For the costs identified in subpart (a), did any party raise recovery of such costs as an issue in the 2021 case that either got addressed in settlement or litigation?

c. Has the Company fully recovered the costs identified above in subpart (a)?

    i. If so, please indicate when cost recovery was completed and the amount and category of costs recovered.

    ii. If not, please indicate the costs by amount and category remaining to be recovered in existing and proposed rates.

Response:

Clarifying the response to OCA 20-002(a), Columbia's costs to repair the E. Maiden Street line damage were charged to O&M. As such, the costs were not included in the company's Fully Projected Future Test Year in the 2021 rate case, or any other rate case.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

OFFICE OF CONSUMER ADVOCATE INTERROGATORIES
Set 24

Question No. OCA 24-003:

Please refer to the Company's response to OCA-20-002(a). For the Rimersburg and Fayetteville overpressurization events which were the subject of Docket No. M-2021-3005572:

a. Provide the referred to OCA discovery questions and Company responses from the prior rate case.

b. Identify the costs, by category and amount, that were previously included in rates related to these overpressure events and identify which rate case (2020, 2021, or 2022) that these costs were included by the Company?

c. For the costs identified in subpart (b) and for the rate case identified in subpart (b), did any party raise recovery of such costs as an issue in the case that either got addressed in settlement or litigation?

d. Has the Company fully recovered the costs identified above in subpart (b)?

    i. If so, please indicate when cost recovery was completed and the amount and category of costs recovered.

    ii. If not, please indicate the costs by amount and category remaining to be recovered in existing and proposed rates.

Response:

a. Columbia's response to OCA Set 10, question 5 in Docket No. R-2022-3031211 is provided as Attachment A to this response.

b. As noted in in Attachment A to the Company's response to OCA Set 10, question 5 in Docket No. R-2022-3031211, the cost to replace the main that was involved in the Rimersburg overpressurization incident were not related to the overpressurization because the replacement of those facilities had been planned for operational purposes. The Revised Settlement Agreement in Docket No. M-2021-3005572 noted that the section of pipeline in Rimersburg that was overpressurized was taken out of service and replaced was not due to the overpressure event but, rather, due to the age and condition of the facilities.

   The Revised Settlement Agreement noted that Columbia replaced approximately 45,000 feet of compromised facilities related to the Fayetteville overpressure event. Columbia Attachment 1 to the Revised Settlement Agreement (provided as Attachment B to this response) provided details about the facilities that were installed and the facilities that were replaced. While replacement of those facilities had not been scheduled as of the date of the overpressure event, from the vintages and material type of the facilities it is evident that they would have been scheduled for replacement as part of Columbia's Long Term Infrastructure Improvement Plan even if the overpressure event had not occurred.

   Any O&M costs associated with the replacement of the Fayetteville facilities would not have been included in the Company's claim for O&M recovery as part of any fully projected future test year. The capital costs associated with the replacement was $5,842,294 and were included in the Company's rate base in 2018.

c. Columbia is not aware of a party raising an issue as described in subpart c to this data request.

d. Please refer to OCA 24-003 Attachment C for amounts remaining to be recovered.

From CPA's 2022 Captial Status Report
Net View (in 000)

Class	Actuals through March 2022	Actuals though June 2022	Actuals through September 2022	Actuals through December 2022
Growth	$8,521	$17,381	$26,992	$37,899
Betterment	$2,617	$5,681	$8,927	$14,437
Age & Condition	$50,586	$124,202	$208,431	$300,040
Public Improvement	$1,968	$3,614	$5,681	$9,909
Support Services	$191	$767	$1,485	$3,103
Shared Services Allocation	$2,623	$5,875	$8,548	$14,723
Total Net Capital (includes Shared Services)	$66,506	$157,520	$260,065	$380,111
Segment Totals (excludes Shared Services)	$63,883	$151,645	$251,516	$365,388

From CPA's 2023 Captial Status Report
Net View (in 000)

Class	Actuals through March 2023	Actuals though June 2023	Actuals through September 2023	Actuals through December 2023
Growth	$5,355	$14,201	$20,744	$30,500
Betterment	$3,280	$7,723	$12,012	$17,030
Age & Condition	$61,454	$150,894	$248,360	$338,439
Public Improvement	$3,288	$8,377	$14,543	$15,487
Support Services	$938	$2,853	$4,308	$5,727
Shared Services Allocation	$5,225	$9,507	$12,828	$27,446
Total Net Capital (includes Shared Services)	$79,539	$193,556	$312,796	$434,629
Segment Totals (excludes Shared Services)	$74,314	$184,049	$299,968	$407,184

COLUMBIA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MICHAEL E. GIRATA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

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I. Introduction

Q. Please state your name and business address.

A. My name is Michael E. Girata, and my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a subsidiary of NiSource Inc. ("NiSource") as Manager of Demand Forecasting.

Q. Please briefly describe your professional experience.

A. After starting my career in data science consulting, I joined NCSC in June 2017, working as a Sr. Business Analytics Analyst assisting with report building and predictive modeling efforts. In January 2019, I joined our GPS Program Management team as a Project Lead, focusing my efforts on program management and IT support in the form of dashboard development and automation. In February 2020, I joined the Demand Forecasting team as a Lead Analyst supporting forecast development for financial planning, regulatory filings, and peak modeling efforts for our electric business. In August 2021, I joined NCSC's Corporate Strategy & Risk group as a Project Consultant helping define NCSC's electric strategy related to generation and emerging technologies. In June 2022, I rejoined the Demand Forecasting team in my current role of Manager of Demand Forecasting. In March 2023, I was given additional responsibilities related to Revenue Planning.

Q. Please describe your educational background.

A. I graduated from Westminster College with a Bachelor's Degree in Mathematics

in December 2014.

Q. What are your responsibilities in your current position?

A. In my current position as Manager of Demand Forecasting, I am responsible for the development of short-range and long-range forecasts of customers and energy consumption for the natural gas utilities in NiSource's natural gas distribution segment, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"). I have the same responsibilities for NiSource's one combination gas-electric utility, along with peak modeling efforts for NiSource's electric segment. I am also responsible for other business-related analyses and forecasts related to Revenue Planning.

Q. Have you previously testified before this or any other regulatory agency?

A. Yes, I have testified on behalf of Columbia Gas of Maryland before the Public Service Commission of Maryland in Case No. 9701.

Q. What test years will you be addressing in this testimony?

A. I will be addressing the twelve-month period ending November 30, 2023 as the Historic Test Year ("HTY"), the twelve-month period ending November 30, 2024 as the Future Test Year ("FTY"), and the twelve-month period ending December 31, 2025 as the Fully Projected Future Test Year ("FPFTY").

Q. What is the purpose of your testimony in this proceeding?

A. I will explain how residential and commercial sales are normalized for weather. The results of the normalization process are contained in Company witness May Battig's testimony (Columbia Statement No. 3) and Exhibit 003, Schedule 04. I

will also explain the forecast methodology used to develop forecasted number of customers and usage for the FTY and the FPFTY. The results of the forecast are contained in Exhibit 010, Schedule 02.

II. Weather Normalization of Historical Test Year

Q. Please explain the weather normalization methodology.

A. At a high level, actual sales per customer are separated into base use and temperature-sensitive use per customer for each month of the HTY for the residential and commercial classes. Monthly temperature-sensitive use per customer is adjusted by the ratio of normal to actual heating degree days ("HDD") by month to derive normal temperature-sensitive use per customer by month. The monthly normal temperature-sensitive use per customer is added to the base use per customer to arrive at the normal sales per customer. This value is multiplied by the customer count by month to produce monthly normal sales. All calculations are performed on a billing month basis and use billing month sales, the average number of days in the billing cycle, and billing month HDD.

Q. What data sources do you use for your calculations?

A. I use the Company's billing records to obtain monthly customer counts and billed sales for the residential and commercial classes for the HTY. I use temperatures from DTN, a weather consulting service which aggregates National Weather Service weather stations relevant to the Company's service territory, to calculate HDD. I rely on temperature data from five weather stations due to the geographical dispersion of Columbia's customers. A weighted average HDD for

the Company is calculated by using the percent of residential customers assigned to each station as a weight for that station.

Q. How is base usage determined?

A. Base usage is the portion of usage that is not dependent on weather, i.e., not temperature-sensitive. I assume that there is no temperature sensitive usage in the summer months of July and August, therefore, all usage in July and August is base use and is not affected by the weather normalization process. In addition, the total use per customer per day (Total Use/Customer/Day) for July and August is all base use. If total use per customer per day in September is less than July or August, then I also assume September has no temperature sensitive usage (i.e., September is also assumed to be a base use-only month and not affected by the weather normalization process). The base use per customer per day used to weather normalize the remaining months of the HTY is calculated by averaging the two lowest observed use per customer per day values from the months of July through September.

Q. How are monthly sales in the remaining months weather normalized?

A. The base use per customer per day is multiplied by the number of days ((base use/customer/day)*days in billing cycle) to produce monthly base use per customer. Temperature-sensitive use per customer equals the total use per customer minus the base use per customer. The temperature-sensitive use per customer is normalized for weather by multiplying it by a ratio of normal HDD to actual HDD. Normal use per customer is calculated by adding the base use per customer to the normal temperature-sensitive use per customer. Total monthly

normalized usage is generated by multiplying monthly normal use per customer by the monthly customer count. This calculation for the HTY is prepared separately for residential and commercial customers and the results are presented in Exhibit 010, Schedule 08.

Q. Has the methodology for normalizing weather changed from Columbia's last rate filing?

A. No, the methodology has not changed since Columbia's last rate filing. However, the historical average HDD have been updated to include the most recent 20-year history (i.e., 20 years ended December 31, 2023). The previous base rate case filing defined normal weather as the 20-year average ending in 2021. In all other respects, the weather normalization process is the same.

Q. Why is Columbia using a 20-year average HDD in the weather normalization process?

A. The Company continues to use the 20-year average HDD in the weather normalization process because it is consistent with the Company's approach since 2008. In addition, an analysis of weather data demonstrates that a rolling 20-year average is a superior predictor of one-year-ahead HDD and five-year ahead HDD than the 30-year average HDD, and the 20-year average HDD is a more dynamic measure than the 30-year average HDD, as discussed in more detail below.

Q. Please explain your analysis that demonstrates that the 20-year average HDD is a better predictor of one-year-ahead and five-year ahead HDD than the 30-year average HDD.

A. Table 1, below, compares the actual HDD experienced each year from 1986 through 2023 with the historical average HDD calculated using either the prior 20-years or the prior 30-years. The absolute error is calculated as the absolute value of the difference between the actual HDD and either the 20-year or 30-year average. Table 1 demonstrates that the 20-year average HDD has a lower absolute error than the 30-year average HDD in 63% of the most recent 38 years. Table 1 also illustrates that the 20-year average HDD has a lower mean absolute error when predicting the one-year-ahead HDD, as compared to the 30-year average HDD when considering the most recent 38-year period.

In Table 2, the 20-year and 30-year average HDD are used to predict annual HDD for each five-year period for the five years ended 1990 through the five years ended 2023. As measured by the smallest difference over the five-year period, the 20-year average HDD outperforms the 30-year average HDD in 100% or 34 out of the 34 periods. When considering the most recent ten periods, the 20-year average HDD outperforms the 30-year average HDD in 100% or all of the ten periods.

Table 1
Weather Averages as Predictors
Moving Averages used to Predict Following Year
Columbia Gas of Pennsylvania

	Annual Heating Degree Days			Absolute Error		Better 1-year predictor	
	Actual	20-yr Average	30-yr Average	20-yr Average	30-yr Average	20-yr Average	30-yr Average
1985		5885	5891				
1986	5470	5859	5886	415	421	x	
1987	5457	5838	5884	402	429	x	
1988	6011	5830	5875	173	127		x
1989	6020	5829	5888	190	145		x
1990	4760	5774	5843	1069	1128	x	
1991	5006	5741	5812	768	837	x	
1992	5605	5725	5792	136	207	x	
1993	5600	5740	5770	125	192	x	
1994	5601	5749	5768	139	169	x	
1995	5652	5754	5763	97	116	x	
1996	5891	5737	5760	137	128		x
1997	5716	5720	5754	21	44	x	
1998	4612	5642	5702	1108	1142	x	
1999	5230	5605	5675	412	472	x	
2000	5657	5574	5669	52	18		x
2001	5204	5525	5653	370	465	x	
2002	5363	5504	5634	162	290	x	
2003	5836	5501	5652	332	202		x
2004	5436	5484	5652	65	216	x	
2005	5626	5488	5655	142	26		x
2006	5023	5465	5614	465	632	x	
2007	5417	5463	5594	48	197	x	
2008	5621	5444	5575	158	27		x
2009	5549	5420	5561	105	26		x
2010	5500	5457	5535	80	61		x
2011	5253	5470	5504	204	282	x	
2012	4769	5428	5471	701	735	x	
2013	5549	5425	5459	121	78		x
2014	5950	5443	5465	525	491		x
2015	5337	5427	5457	106	128	x	
2016	4992	5382	5441	435	465	x	
2017	4850	5339	5421	532	591	x	
2018	5532	5385	5405	193	111		x
2019	5245	5385	5379	140	160	x	
2020	4961	5351	5386	424	418		x
2021	4923	5337	5383	428	463	x	
2022	5411	5339	5377	74	28		x
2023	4451	5270	5339	888	926	x	
				Mean Absolute Error		Frequency of Lowest Absolute Error	
			1986-2023	314	331	24	14
						Relative Frequency of Lowest Absolute Error	
					1986-2023	63%	37%

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Table 2

Weather Averages as Predictors

Moving Averages used to Predict the Following Five Years

Columbia Gas of Pennsylvania

	Annual Heating Degree Days			Five Year Sum of Errors		Better 5-year predictor	
	Actual	20-yr Average	30-yr Average	20-yr Average	30-yr Average	20-yr Average	30-yr Average
1985		5885	5891				
1986	5470	5859	5886				
1987	5457	5838	5884				
1988	6011	5830	5875				
1989	6020	5829	5888				
1990	4760	5774	5843	-1707	-1736	x	
1991	5006	5741	5812	-2043	-2176	x	
1992	5605	5725	5792	-1788	-2016	x	
1993	5600	5740	5770	-2161	-2386	x	
1994	5601	5749	5768	-2572	-2867	x	
1995	5652	5754	5763	-1408	-1751	x	
1996	5891	5737	5760	-356	-710	x	
1997	5716	5720	5754	-164	-502	x	
1998	4612	5642	5702	-1228	-1377	x	
1999	5230	5605	5675	-1643	-1741	x	
2000	5657	5574	5669	-1665	-1708	x	
2001	5204	5525	5653	-2264	-2380	x	
2002	5363	5504	5634	-2536	-2704	x	
2003	5836	5501	5652	-921	-1222	x	
2004	5436	5484	5652	-529	-878	x	
2005	5626	5488	5655	-406	-878	x	
2006	5023	5465	5614	-340	-980	x	
2007	5417	5463	5594	-184	-832	x	
2008	5621	5444	5575	-383	-1138	x	
2009	5549	5420	5561	-186	-1026	x	
2010	5500	5457	5535	-328	-1166	x	
2011	5253	5470	5504	13	-732	x	
2012	4769	5428	5471	-625	-1277	x	
2013	5549	5425	5459	-599	-1256	x	
2014	5950	5443	5465	-80	-784	x	
2015	5337	5427	5457	-428	-818	x	
2016	4992	5382	5441	-751	-923	x	
2017	4850	5339	5421	-461	-675	x	
2018	5532	5385	5405	-465	-633	x	
2019	5245	5385	5379	-1258	-1368	x	
2020	4961	5351	5386	-1555	-1707	x	
2021	4923	5337	5383	-1399	-1696	x	
2022	5411	5339	5377	-621	-1034	x	
2023	4451	5270	5339	-1933	-2035	x	

	Mean Absolute Error		Frequency of Lowest Error	
1990-2023	-1028	-1386	34	0
2014-2023	-895	-1167	10	0

Relative Frequency of Lowest Error		
1990-2023	100%	0%
2014-2023	100%	0%

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Q. Please explain your analysis that demonstrates that the 20-year average HDD is more dynamic than the 30-year average HDD.

A. Table 3 demonstrates that the average annual change for the 20-year average HDD is 0.4%, while the average annual change for the 30-year average is 0.3% HDD. The 20-year normal HDD is a more dynamic measure that is better able to react more quickly to weather changes because it replaces 5% of the data each year rather than the 3% that is replaced with the 30-year average.

Table 3

Weather Averages
Annual Change in Averages 1986-2023
Absolute Values
Columbia Gas of Pennsylvania

	20-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	6.9%
Maximum	1.4%	0.9%	20.9%

III. Demand Forecast Methodology for Future Test Year and Fully Projected Future Test Year

A. Demand Forecast Methodology Overview

Q. Please explain the methodology employed for developing the forecasted number of customers and volume for the FTY and FPFTY.

A. Total residential and total commercial customers and volume for both the FTY and FPFTY are forecasted using econometric models. Total industrial volume for both the FTY and FPFTY are forecasted based on knowledge gained through relationships with large industrial customers. Total residential, total commercial, and total industrial forecasts are subsequently split into sales, choice, and GTS customers and volumes, as appropriate, using historical data.

Q. What data sources do you use to develop the econometric models for the residential and commercial classes?

A. I use the Company's billing records through November 2023 to obtain historical monthly customer counts and billed usage for the residential and commercial customer classes. Historical billed usage is divided by historical customer counts to produce monthly historical use per customer data for residential and commercial customers. The historical customer counts and use per customer are used as the dependent variables in the residential customer, residential use per customer, commercial customer, and commercial use per customer econometric models.

Several sources are used to obtain data for the independent variables included in the econometric models. Historical and forecast gas price data is sourced from the U.S. Energy Information Administration ("EIA"). Historical and forecast average efficiency data is provided by Itron Inc., a national utility consulting firm. Historical and forecast values for economic and demographic variables (e.g., number of households and gross county product) and deflator data are from IHS Global Insight, Inc., a data consultant. Historical weather data (HDD) is provided by DTN, a weather consulting service, and the same 20-year average HDD described in the weather normalization process above is used as the weather during forecast period.

B. <u>Residential Forecast</u>

Q. Please describe the residential customer forecast methodology.

A. The residential customer forecast is developed using a monthly econometric model

that incorporates the number of households and monthly variables for shaping.

Q. Please describe the residential use per customer forecast methodology.

A. The residential use per customer forecast is developed using a monthly econometric model that incorporates weather in the form of HDD, energy intensity, and monthly variables for additional shaping.

Q. How is the forecast of monthly residential volume determined?

A. Monthly residential customer counts are multiplied by monthly residential use per customer to produce monthly residential volume.

Q. How are the total residential customers and usage split into residential sales and residential CHOICE?

A. Residential CHOICE customer counts are based on extrapolating the recent declining trend in residential CHOICE customers. Residential sales customer counts are determined by subtracting residential CHOICE customer count from the total residential customer count.

Use per customer for residential CHOICE customers has been higher than use per customer for residential sales customers in recent years. Forecasted use per customer for residential CHOICE customers is determined by applying the historical monthly ratio of residential CHOICE use per customer to total residential use per customer. Forecasted residential CHOICE usage is determined by multiplying residential CHOICE customers by residential CHOICE use per customer. Residential sales usage is determined by subtracting residential CHOICE usage from the total residential usage.

Q. Is the impact of the Company's residential energy efficiency program incorporated into the residential demand forecast?

A. Columbia had a new energy efficiency program go into effect in August 2023. Since a full year of history of DSM savings are not yet available, adjustments were made to the historical data to reflect what total demand would look like had the program not been implemented. The usage per customer forecast was built on this adjusted data.

The resulting forecast was a view of residential usage per customer with no energy efficiency program impacts. This usage per customer forecast was multiplied by the customer count forecast to create the total volumetric forecast. Finally, projected savings from the energy efficiency program were applied to the volumetric forecast to create the final volumetric forecast for the residential customer class.

C. <u>Commercial Forecast</u>

Q. Please describe the commercial customer forecast methodology.

A. The commercial customer forecast is developed using a monthly econometric model that incorporates real gross county product and monthly variables for shaping.

Q. Please describe the commercial use per customer forecast methodology.

A. The commercial use per customer forecast is developed using a monthly econometric model that incorporates weather in the form of HDD, and monthly variables for additional shaping.

Q. How is the forecast of monthly commercial volume determined?

A. Monthly commercial customer counts are multiplied by monthly commercial use per customer to produce monthly commercial volume.

Q. How are the total commercial customers and volumes split into commercial sales, commercial CHOICE, and commercial GTS?

A. Commercial GTS and commercial CHOICE customers are forecasted to remain at recent historical customer levels. Commercial sales customers are the customers remaining when commercial GTS and commercial CHOICE customers are subtracted from the total commercial customer forecast. Total commercial usage is allocated to sales, GTS and CHOICE based proportions experienced in the most recent 12-months.

D. <u>Industrial Forecast</u>

Q. Please describe the industrial forecast methodology.

A. The industrial forecast is provided by the Large Customer Relations group by incorporating information generated through individual customer interviews. Since the Large Customer Relations group covers over 90% of the total industrial volumes, it is assumed that the remaining industrial volume grows at the same rate as those forecasted by the Large Customer Relations group.

Q. How is the total industrial usage split into industrial sales and industrial GTS?

A. Total industrial usage is allocated to sales and GTS based upon monthly proportions experienced in the most recent 24-months.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 2-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
MICHAEL E. GIRATA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

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II. Residential Usage Per Customer 1

I. Introduction

Q. Please state your name and business address.

A. My name is Michael E. Girata, and my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony submitted in this proceeding by Office of Consumer Advocate ("OCA") Witness Greg R. Meyer regarding residential usage per customer.

II. Residential Usage Per Customer

Q. Do you agree with Witness Meyer's portrayal of the Historic Level of Residential Usage Per Customer in Table GRM-7?

A. No. The annual residential usage per customer shown in Table GRM-7 is the actual, non-weather normalized usage per customer. This usage per customer was provided in Columbia Gas of Pennsylvania's ("Columbia") response to Question No. GAS-RR-011, included in Attachment C. Showing weather normalized usage per customer will provide a more accurate indicator of usage trends over time by removing abnormal weather impacts from history.

I have prepared Table MEG-1 which compares the historical non-weather normalized usage per customer from Table GRM-7 against weather normalized usage per customer over the same period. The weather normalized usage per customer shown in this table was provided in response to a discovery request from the OCA (OCA Set 12, Question 15, Attachment A, Part 2).

Table MEG-1

Historical Usage Per Customer (Dth)

Year	Non-Weather Normalized	Weather Normalized
2018	94.45	87.25
2019	86.34	85.08
2020	78.57	83.19
2021	82.50	83.62
2022	83.33	83.02
2023	74.70	81.78
2018 - 2022 Average	85.04	84.43
2018 - 2023 Average	83.32	83.99

Q. Do you agree with Witness Meyer's recommendation of using an average residential usage per customer of 85.04 Dth to annualize residential revenues?

A. No. A residential usage per customer of 85.04 Dth is overstated when removing the impact of abnormal weather events in history. A residential usage per customer of 85.04 Dth has not been seen since 2019.

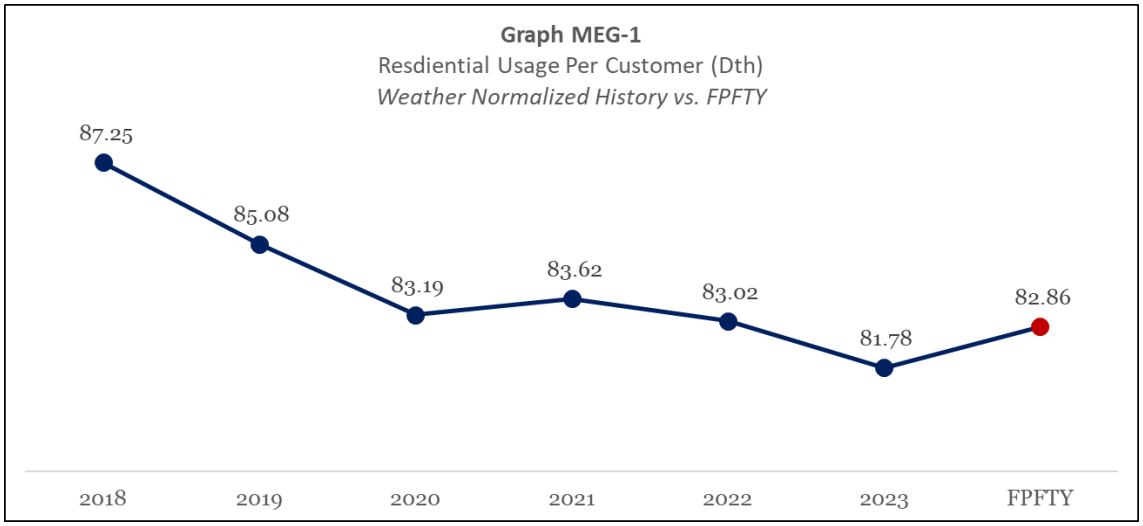
Q. Does taking a simple average of historical residential usage per customer accurately estimate the expected usage per customer in future years?

A. No. As shown in Table MEG-1, weather normalized residential usage per customer has seen a steady annual decrease from 2018 to 2023, absent 2020 when COVID-19 moratoriums caused customers to change their normal usage patterns. Using a simple average of the last five years would not capture this decreasing trend and would produce a projection that is too high.

Q. Is Columbia's recommended residential usage per customer of 82.86 Dth appropriate when comparing to weather normalized history?

A. Yes. As provided in Exhibit No. 103, Schedule 4, Page 14, Columbia's proposed annual residential usage per customer is 82.86 Dth. OCA Witness Meyer referenced a residential usage per customer of 82.19 Dth, calculated using a different methodology. The 82.19 Dth is derived assuming constant customer count throughout the fully projected future test year ("FPFTY"), which does not account for the seasonality of residential customer counts. Furthermore, the volumes and customer count that OCA Witness Meyer used in his calculation are adjusted for new construction and attrition. These adjustments are based on partial month usage related to the residential usage per customer of 82.86 Dth. These adjustments understate true usage per a single residential customer in a given calendar year, and therefore should not be included in these estimates.

I have prepared Graph MEG-1 to visually show the historical weather normalized residential usage per customer compared to the FPFTY projection of 82.86 Dth. The projection of 82.86 Dth appropriately carries the historical trend into the FPFTY. Also, given the weather normalized results for 2023, the projection is conservative and does not project a further decrease of usage into the FPFTY.



Q. Should Columbia's residential revenues provided by Witness Battig be adjusted based on the residential usage per customer findings described in this Rebuttal?

A. No. The residential usage per customer projection of 82.86 Dth is appropriate for the FPFTY, and therefore would not lead to changes in residential revenues defined by Columbia Witness Battig.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MAY BATTIG
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

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I. Introduction

Q. Please state your name and business address.

A. My name is May Battig. My business address is 290 West Nationwide Boulevard, Columbus, Ohio, 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Lead Regulatory Analyst in the Regulatory Studies Department at NCSC.

Q. Please briefly describe your professional experience.

A. I have over 20 years of experience working in various financial planning and regulatory functions primarily supporting NiSource gas distribution companies. In May 2001, I joined NCSC as a Financial Analyst in the Financial Planning Department for Columbia Gas Distribution Companies. From 2001 – 2006, I held several positions of increasing responsibility and worked specifically on the budgets for Bay State Gas Company dba Columbia Gas of Massachusetts ("CMA") and Columbia Gas of Ohio ("COH"). In mid-2006, I accepted a position as a Senior Regulatory Analyst in NCSC's Regulatory Strategy and Support Department. I became a Lead Regulatory Analyst in 2009. In mid-2009, I returned to Financial Planning as a Lead Financial Analyst working on budgets for COH. From 2013 to present, I rejoined Regulatory Strategy and Support as a Lead Regulatory Analyst supporting various NiSource companies.

Q. Please describe your educational background.

A. I graduated from The Ohio State University in 1994 with a Bachelor of Science degree in Business Administration, majoring in Finance and Economics.

Q. What are your responsibilities in your current position?

A. My primary responsibilities as a Lead Regulatory Analyst include providing support for regulatory filings and rate cases for NiSource gas distribution companies, including, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"), Columbia Gas of Maryland, Inc., Columbia Gas of Kentucky, Inc., Columbia Gas of Virginia, Inc., and COH.

Q. Have you previously testified before this or any other regulatory agency?

A. I have submitted direct testimony for Columbia Gas of Maryland before the Public Service Commission of Maryland in Case Nos. 9417, 9447, and 9609.

Q. What was the nature of the testimony you provided in those proceedings?

A. In connection with those various rate case proceedings, I prepared and submitted testimony on Cash Working Capital ("CWC")/Lead Lag Study.

II. Purpose and Summary of Testimony

Q. Please state the purpose of your prepared direct testimony in this proceeding.

A. I am sponsoring and describing Exhibits 3 and 103 (Operating Revenues). I am also sponsoring the following exhibits:

Exhibit No.
Exhibit 003, Schedule 01 through 10, (02) (03) (04) Pages 01-05
Exhibit 010, Schedule 03, (22), Page 01
Exhibit 010, Schedule 04, (38), Page 01
Exhibit 010, Schedule 07, (03) (14), Page 01
Exhibit 012, Schedule 01, (05) Page 01
Exhibit 012, Schedule 02 (18), Pages 01-02
Exhibit 012, Schedule 03, (23) Page 01
Exhibit 012, Schedule 04, (24) (26) (30) (36), Page 01
Exhibit 012, Schedule 04, (25) Page 01
Exhibit 012, Schedule 05, (31), Page 01
Exhibit 012, Schedule 06, (11) Page 01
Exhibit 012, Schedule 07, Pages 01-02
Exhibit 012, Schedule 08, Page 01
Exhibit 016, (7), Pages 01-05
Exhibit 017, (01) (28) Pages 01-07
Exhibit 103, Schedules 01 through 7, (02) (03) (04), Pages 01-15
Exhibit 110, Schedule 03, (22), Page 01
Exhibit 110, Schedule 04, (38) (39), Page 01
Exhibit 110, Schedule 07, (03) (14), Page 01
Exhibit 112, Schedule 01 (05) Page 01
Exhibit 112, Schedule 02, (18) (23) thru (26) (30) (31) (36) (11) Pages 01-04
Exhibit 112, Schedule 03, Pages 01-03
Exhibit 112, Schedule 04, Page 01
Exhibit 116, (07), Page 01
Exhibit 117, (01) (28), Pages 01-02

Q. Are you sponsoring any additional exhibits?

A. Yes. Attached to my testimony are three additional exhibits that support the Company's revenue proposal. Each exhibit, identified below, will be addressed later in my testimony.

Exhibit No.	Description
Exhibit MLB-1	Calculation of the Merchant Function Charge
Exhibit MLB-2	Annualization of Forfeited Discounts (Account 487)
Exhibit MLB-3	Total Operating Revenues for the Twelve Months Ending December 31, 2023

III. Operating Revenues

A. Exhibit 3

Q. Please explain the process that was undertaken to produce the number of bills used to price revenue in this case.

A. The following calculations are made to determine the number of bills found in Exhibit 3, Schedule 2, for the Historic Test Year ("HTY"). Active customer counts for each month of the HTY are accumulated by rate schedule and shown in Column 1 of Exhibit 3, Schedule 2. The bills are accumulated based on which rate schedule the customer is on at the end of the HTY. Adjustments were made in Exhibit 3, Schedule 2, Column 2 to reflect discontinued or added services for Large Commercial and Industrial customers. Incremental residential and commercial customers that were added or discontinued during the HTY are shown in Column 3 and 4, respectively, for a full year impact. The corresponding backup for customer additions and attrition for the HTY can be found in Exhibit 3, Schedule 5, Pages 1 – 7. Finally, an adjustment is made to the number of bills for final billed

customers, because a Customer Charge is billed to customers who receive a final bill even though they are not included as an active customer. These customers are not classified as active in the Company's billing systems during the HTY, so the final bills must be added to active bills to price revenue in this case. Bills in Exhibit 3, Schedule 2, Column 7 are used for pricing in Exhibit 3, Schedule 1 (pro forma revenue at current rates) and Exhibit 3, Schedule 10 (pro forma revenue at proposed rates).

Q. Please explain the development of the adjusted volumes in Dekatherm ("Dth") for the HTY.

A. Physical flow volumes were summarized by rate schedule in Exhibit 3, Schedule 3 on a customer-by-customer, and month-by-month basis. The volumes, as shown in Column 1, were accumulated based on the rate schedule the customer was on at November 30, 2023. The Weather Normalization Adjustment ("WNA") in Exhibit 3, Schedule 3, Column 2 represents the change to physical flow volumes due to the use of a 20-year weather definition normalization. Adjustments were made in Exhibit 3, Schedule 3, Column 3 to reflect discontinued or added services for Large Commercial and Industrial customers. Incremental residential and commercial customers that were added or discontinued during the HTY are shown in Columns 4 and 5, respectively, for a full year impact. The corresponding support for customer additions and attrition for the HTY can be found in Exhibit 3, Schedule 5, Pages 1 – 7.

Q. Please explain why physical flow volumes were used instead of invoiced volumes as the basis for calculating operating revenues.

A. Physical flow volumes were used instead of invoiced volumes because they represent volumes that flowed during the HTY. Invoiced volumes may include adjustments made for prior billing periods that are outside of the HTY. Therefore, physical flow volumes were used to eliminate out of period adjustments.

Q. How is the 20-year weather normalization definition utilized in Exhibit 3, Schedule 4?

A. Company witness Michael Girata (Columbia Statement No. 2) provided the total normalized volumes by month for residential and commercial customers. The total normalized volumes were allocated based on the customers' actual physical flow volumes and by their class. Then they were accumulated by rate schedule by rate block, if applicable, as shown in Exhibit 3, Schedule 4, Column 2. The weather adjustment in Column 3 is calculated by subtracting actual physical flow Dth in Column 1 from the normalized Dth in Column 2. The revenue impact as shown in Column 5 is determined by multiplying the Dth in Column 3 by the current base rates in Column 4.

Q. Please explain Schedules 6 through 9 of Exhibit 3.

A. Schedules 6 and 7 eliminate certain per book amounts (off system sales revenues, unbilled revenues and unbilled gas costs) that are not relevant to a pro forma calculation of revenues and expenses. Schedules 8 and 9 show the calculated split of

per books gas cost, Gas Procurement Charge ("GPC"), Rider Universal Service Plan ("USP"), Merchant Function Charge ("MFC"), Rider Customer Choice ("CC"), and Rider Energy Efficiency ("EE") by customer class used in reconciling per books revenue to annualized revenue in Exhibit 3, Page 9.

Q. How was pro forma revenue at current rates calculated?

A. As shown in Exhibit 3, Schedule 1, adjusted test year bills from Schedule 2 are shown in Column 1 and adjusted test year Dth from Schedule 3 are shown in Column 2. Current rates are shown in Column 3. Revenue is calculated in Column 4 by multiplying the Customer Charge by number of bills and volumetric rates by volumes. An average rate per Dth is calculated in Column 5 by dividing Column 4 by Column 2. Pro forma revenue at current rates was calculated using the Purchased Gas Cost ("PGC") rate and Rider USP rate as of January 1, 2024, which is the most recent available at the time the schedules were developed. The MFC rate (please refer to Exhibit MLB–1, attached to this testimony) was updated to reflect the January 1, 2024 PGC rate and the proposed residential and non-residential uncollectible expense ratio as calculated by Company witness Komenda and shown in Exhibit No. 4, Schedule 2, Page 27, Lines 7 and 14. The State Tax Adjustment Surcharge ("STAS") is reflected at 0% on Exhibit 3, Schedule 1, the rate in effect since January 1, 2016. However, effective January 1, 2024, the STAS rate changed to -.044% and is reflected in both the FTY and FPFTY on Exhibit 103, Schedule 1.

Q. Please explain the adjustment to Forfeited Discounts (Account 487) in Exhibit 3 Page 8.

A. Exhibit MLB-2, attached to this testimony, compares Account 487 revenue to total billed revenue for the three years ending November 2021, November 2022 and November 2023, and calculates a three-year average. This three-year period was selected to match the same basis used by the Company in this rate case to determine an average net write-off rate used for annualization of uncollectible expense. As with net write-offs, Forfeited Discounts historically produce a reasonably predictable percentage of billed revenue over time. A three-year average is used to account for the percentage differences caused primarily by changes in gas cost recovery revenue.

The historic three-year average percentage of billed revenue is applied to annualized HTY revenue, resulting in annualized historic test year Forfeited Discounts shown on Exhibit MLB-2, page 1. The historic three-year average percentage of billed revenue is applied to annualized FTY revenue and annualized FPFTY revenue (Exhibit 103), resulting in annualized Forfeited Discounts revenue for those test years shown on Exhibit MLB-2, pages 2 and 3 respectively.

Q. Please explain Exhibit 3 Schedule 10.

A. This schedule calculates pro forma revenues at proposed rates for the HTY reflecting the rate design as shown on Exhibit 103, Schedule 8.

Q. Please explain Pages 6 - 8 of Exhibit 3.

A. The summary shows, by rate schedule by customer class, pro forma test year bills

(Column 1), Volumes (Dth) (Column 2), Revenue at Current Rates (Column 3), proposed adjustment (Column 4), and Revenue at Proposed Rates (Column 5). The summary serves as a comparison of revenue at current and proposed rates.

Q. Please explain the "Dth and Revenue Summary at Current Rates" on Page 9 of Exhibit 3.

A. This page summarizes revenue for the HTY by customer class and is the reconciliation of per books revenue to annualized revenue as calculated in Exhibit 3, Schedule 1. Exhibit 3, Page 9, Column 1 reflects the per books revenue as of November 30, 2023. Columns 2 through 7 show the calculated split of per books gas cost, Rider USP, GPC, MFC, CC, and EE by customer class calculated on Exhibit 3, Schedules 8 and 9. The weather normalization adjustment calculated on Exhibit 3, Schedule 4 is shown in Exhibit 3, Page 9, Column 10. Column 11 reflects pricing out the test year billing determinants (bills and volumes) at the most current base rates. Column 12 is the pro forma Delivery Service revenue at current rates calculated on Exhibit 3, Schedule 1.

Q. Please explain the "Dth and Revenue Summary at Current Rates" on Page 10 of Exhibit 3.

A. This page summarizes annualized total revenue at current rates as calculated on Exhibit 3 Schedule 1. Column 1 shows pro forma base revenue at current rates. Column 2 shows a summary of gas costs at current rates in effect as of January 1, 2024. Column 3 shows a summary of Rider USP at current rates in effect as of

January 1, 2024. Column 4 shows a summary of the Gas Procurement Charge. Column 5 shows a summary of the MFC. Columns 6 and 7 show a summary of Rider CC and EE respectively. Detailed calculations by rate schedule for Columns 1 through 7 are shown in Exhibit 3, Schedule 1. Column 8 shows total revenue at current rates.

B. Exhibit 103

Q. Please describe the projection of bills for the FTY and FPFTY.

A. Forecasted active customer counts are first determined on a total company basis by customer class by type of service (sales/CHOICE transportation/non-CHOICE transportation) by month in the Company's forecast model supported by Company witness Girata on Exhibit 10, Schedule 2. The customer counts are then spread for each month of the FTY and the FPFTY, based on the HTY experience, by rate schedule, by customer class, and by type of service for Residential and Small Commercial sales and CHOICE customers. The bills are accumulated based on which rate schedule the customer is on at the end of the HTY and the results are shown in Exhibit 103, Schedule 2, Column 1.

Adjustments resulting from Large Commercial or Industrial customers that are expected either to discontinue or to add service during the FTY and FPFTY are shown by customer in Exhibit 103, Schedule 4, Pages 16 and 18 respectively, and summarized in Exhibit 103, Schedule 2, Column 2. New construction customers who are expected to begin service during the FTY and FPFTY are shown on Exhibit

103, Schedule 4, Pages 1 and 7, respectively and summarized on Exhibit 103, Schedule 2, Column 3. Customer attrition, which is expected to occur during the FTY and FPFTY, is shown on Exhibit 103, Schedule 4, Pages 3 and 9, respectively, and summarized on Exhibit 103, Schedule 2, Column 4. Column 5 of Exhibit 103, Schedule 2, reflects the shifts between rate schedules that occurred during the test year. The Company considers the HTY final bill count to be representative of what can be expected during the FTY and FPFTY. Therefore, the HTY final bill count was added to the forecasted active bills to price revenue in this case. Final bill counts are shown in Exhibit 103, Schedule 2, Column 6. FTY adjusted number of bills in Exhibit 103, Schedule 2, Column 7 is the sum of Columns 1 through 6. Bills in Column 7 are used for pricing in Exhibit 103, Schedule 1 (pro forma revenue at current rates) and Exhibit 103, Schedule 7 (pro forma revenue at proposed rates) for both the FTY and the FPFTY.

Q. Please explain the process used to develop FTY and FPFTY Dth.

A. Forecasted adjusted Dth for both the FTY and the FPFTY are shown in Exhibit 103, Schedule 3, Column 6 and are the sum of: (a) forecasted Dth in Exhibit 103, Schedule 3, Column 1; (b) Large Commercial and Industrial adjustments in Exhibit 103, Schedule 3, Column 2; (c) new construction consumption in Exhibit 103, Schedule 3, Column 3; (d) attrition consumption in Exhibit 103, Schedule 3, Column 4; and (e) rate schedule transfers in Exhibit 103, Schedule 3, Column 5. Volumes in Exhibit 103, Schedule 3, Column 6 are used for pricing in Exhibit 103,

Schedule 1 (pro-forma revenue at current rates) and Exhibit 103, Schedule 7 (pro-forma revenue at proposed rates) for both the FTY and FPFTY.

Forecasted Dth are first determined by customer class, by type of service (sales/CHOICE transportation/non-CHOICE transportation), by month in the Company's forecast model supported by Company witness Girata in Exhibit 10, Schedule 2. These Dth are spread for each month of the FTY and FPFTY based on the HTY by rate schedule, by customer class, and by type of service for Residential Sales and CHOICE customers. The spread for Commercial and Industrial Sales and CHOICE transportation customers and all non-CHOICE transportation customers is performed down to the individual customer level. The Dth are accumulated based on which rate schedule the customer is on at the end of the HTY and shown in Column 1 of Exhibit 103, Schedule 3.

Adjusted Dth in Exhibit 103, Schedule 3, Column 6 are the sum of Columns 1 through 5 for both the FTY and FPFTY. Adjustments resulting from Large Commercial and Industrial customers either discontinuing or adding service during the FTY and FPFTY are shown by customer in Exhibit 103, Schedule 4, Pages 16 and 18, respectively, and summarized in Exhibit 103, Schedule 3, Column 2 for reasons I explained previously, with respect to customer bills. Consumption calculated for new construction customers who are expected to begin service during the FTY is shown on Exhibit 103, Schedule 4, Pages 10 and 11 and Pages 14 and 15 for the FPFTY. The Dth attributable to new customers are summarized on

Exhibit 103, Schedule 4, Page 2, Column 1 and are shown on Exhibit 103, Schedule 3, Column 3. Customer attrition, which is expected to occur during the FTY and FPFTY is calculated on Exhibit 103, Schedule 4, Pages 3 and 9, respectively, and is shown on Exhibit 103, Schedule 3, Column 4.

Q. Please explain Exhibit 103, Schedule 7.

A. This schedule calculates pro forma revenues at proposed rates for the FTY and FPFTY, respectively, reflecting the rate design as shown on Exhibit 103, Schedule 8, sponsored by Company witness Kevin Johnson.

Q. Please explain Pages 6 - 9 of Exhibit 103.

A. The summary shows, by rate schedule by customer class, pro forma test year bills (Column 1), Consumption (Dth) (Column 2), Revenue at Current Rates (Column 3), proposed adjustment (Column 4), and Revenue at Proposed Rates (Column 5). The summary serves as a comparison of revenue at current and proposed rates.

Q. Please explain the "Dth and Revenue Summary at Current Rates" on Pages 10 through 15 of Exhibit 103.

A. These pages summarize annualized total revenue at current rates as calculated on Exhibit 103, Schedule 7. Exhibit 103 includes annualized total revenue for both the FTY and FPFTY.

Q. Please summarize the drivers that make up the difference in revenue in Exhibit 103 between the FTY and the FPFTY.

A. The difference between the revenue in the FTY and the FPFTY year is driven by

changes in customer growth, attrition, changes in use per customer, expected changes in customer counts, and usage for large customers based upon a customer-by-customer review. See Company witness Girata's testimony for an explanation of the forecast models.

C. Exhibit MLB-3

Q. Please describe Exhibit MLB-3

A. Pursuant to Paragraph 33 of the Joint Settlement Agreement for R-2022-3031211, I am sponsoring Exhibit MLB-3, which provides a comparison of actual versus projected revenues for the twelve months ending December 31, 2023.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Calculation of Merchant Function Charge Utilized in Exhibit No. 3 and Exhibit No. 103
Calculated Using Gas Costs as of January 1, 2024

Line No.	Description	Reference		Rate $	
1	PGCC Rate	Exhibit 1-A, Schedule 1, Page 1, Col. 3, Line 5 (1/01/2024 Quarterly GCR Filing)		2.2053	
2	Total Commodity Cost of Gas			**2.2053**	per Dth
3	Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 27, Line 7	0.0167927		
4	Non-Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 27, Line 14	0.0046215		
5	Merchant Function Charge - Residential Sales Service	(Line 4 x Line 5)		0.0370	per Dth
6	Merchant Function Charge - Small General Sales Service	(Line 4 x Line 6)		0.0102	per Dth

[1] Per Order in Docket No. R-2012-2321748

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2023

Line No.		12 Mos November 2021	12 Mos November 2022	12 Mos November 2023	Total 3 Year Average		
1	Per Books Acct 487	$ 451,085	$ 1,599,988	$ 1,897,169	$ 3,948,242		
2	Per Books Billed Revenue	$ 652,705,000	$ 825,062,491	$ 860,472,954	$ 2,338,240,446		
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.0691%	0.1939%	0.2205%	0.1689%		
4	Historic Test Year Sales Revenue (Ex. 3, Page 10, Line 6)					$	597,747,762
5	Historic Test Year Revenue -Transportation Revenue (Ex. 3, Page 10, Line 9)					$	171,352,149
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$	769,099,911
7	3 Year Average						0.1689%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$	1,299,010
9	Historic Test Year Acct 487 (Ex. 3, Page 9)					$	1,897,169
10	Annualization Adjustment (Line 8 - Line 9)					$	(598,159)

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2024

Line No.		12 Mos November 2021	12 Mos November 2022	12 Mos November 2023	Total 3 Year Average		
1	Per Books Acct 487	$ 451,085	$ 1,599,988	$ 1,897,169	$ 3,948,242		
2	Per Books Billed Revenue	$ 652,705,000	$ 825,062,491	$ 860,472,954	$ 2,338,240,446		
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.0691%	0.1939%	0.2205%	0.1689%		
4	Future Test Year Sales Revenue (Ex. 103, Page 11, Line 5)					$	616,191,911
5	Future Test Year Transportation Revenue (Ex. 103, Page 11, Line 8)					$	169,190,114
6	Total Sales and Transportation Revenue (Line 4 + Line 5)					$	785,382,025
7	3 Year Average						0.1689%
8	Annualized Forfeited Discounts (Line 4 * Line 6)					$	1,326,510
9	Future Test Year Acct 487 (Ex. 103, Page 10)					$	1,299,010
10	Annualization Adjustment (Line 7 - Line 8)					$	27,500

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending December 31, 2025

Line No.		12 Mos November 2021	12 Mos November 2022	12 Mos November 2023	Total 3 Year Average		
1	Per Books Acct 487	$ 451,085	$ 1,599,988	$ 1,897,169	$ 3,948,242		
2	Per Books Billed Revenue	$ 652,705,000	$ 825,062,491	$ 860,472,954	$ 2,338,240,446		
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.0691%	0.1939%	0.2205%	0.1689%		
4	Fully Projected Future Test Year Sales Revenue (Ex. 103, Page 15, Line 5)					$	619,642,440
5	Fully Projected Future Test Year Transportation Revenue (Ex. 103, Page 15, Line 8)					$	165,022,859
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$	784,665,299
7	3 Year Average						0.1689%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$	1,325,300
9	Fully Projected Future Test Year Acct 487 (Ex. 103, Page 14)					$	1,326,510
10	Annualization Adjustment (Line 8 - Line 9)					$	(1,210)

Columbia Gas of Pennsylvania, Inc.
Total Operating Revenues
For the Twelve Months Ending December 31, 2023

Line No.	Description	R-2022-3031211 Twelve Months Ended 31-Dec-23 @ Proposed Rates	Twelve Months Ended 31-Dec-23 Actual	Difference
		(1) $	(2) $	(3)=(2)-(1) $
1	Operation Revenues			
2	Base Rate Revenues (Incl. Transportation)	576,398,980	526,045,872	(50,353,108)
3	Fuel Revenues	235,166,198	239,233,991	4,067,793
4	Rider USP	44,283,690	37,039,186	(7,244,504)
5	Gas Procurement Charge	453,307	403,292	(50,015)
6	Merchant Function Charge	1,581,571	1,921,948	340,377
7	Rider CC	47,098	38,870	(8,228)
8	Rider EE [1]	0	899,598	899,598
9	Total Sales and Transportation Revenue	857,930,844	805,582,758	(52,348,086)
10	Off System Sales Revenue	0	11,592,593	11,592,593
11	Late Payment Fees	966,087	1,875,194	909,107
12	Other Operating Revenues (Excl. Transportation)	108,496	2,090,175	1,981,679
13	Total Operating Revenues	859,005,427	821,140,720	(37,864,708)

(1) Rider EE was not included in Case No. R-2022-3031211 base rate revenue requirement, however it was included in settlement as submitted in Final Rate Design for Appendix B - Final.

COLUMBIA STATEMENT NO. 3-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
MAY BATTIG
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

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I. Introduction 1

II. Purpose and Summary of Testimony 1

III. Residential Usage Adjustment 1

I. Introduction

Q. Please state your name and business address.

A. My name is May Battig. My business address is 290 West Nationwide Boulevard, Columbus, Ohio, 43215.

Q. Have you previously filed testimony in this matter?

A. Yes.

II. <u>Purpose and Summary of Testimony</u>

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony served in this proceeding by the Pennsylvania Office of Consumer Advocate ("OCA") witness Greg R. Meyer concerning the adjustment to the Company's revenue deficiency for its level of residential revenues.

III. <u>Residential Usage Adjustment</u>

Q. Have you reviewed OCA witness Meyer's testimony regarding the Company's level of residential revenues and the impact it has on the revenue deficiency?

A. Yes.

Q. Please describe OCA witness Meyer's residential revenue calculation resulting in the recommendation to decrease the Company's revenue deficiency.

A. OCA witness Meyer states that the level of residential revenues proposed by the Company is understated and as shown on Table GRM-1, Page 4, Line 8 in Meyer's

testimony and Exhibit 1, Page 5 attached to Meyer's testimony, he reflects an adjustment that increases residential revenues by $12.2 million and in turn, decreases the Company's revenue deficiency by $12.2 million. To reach his conclusion regarding residential revenues, OCA witness Meyer first calculated a 5-year residential usage per customer average of 85.04 Dth based on historical data from 2018-2022 and compared it to a calculated residential usage per customer of 82.19 Dth using the Company's projected FPFTY volumes and bill information to represent the Company's proposed total residential usage per customer. Next, OCA witness Meyer derived his total residential volumes of 35,270,907 Dth by multiplying the 5-year residential historical usage per customer of 85.04 Dth by the total number of residential customers for FPFTY of 414,766 and does the same for the calculated residential usage per customer of 82.19 Dth to derive the Company's level of total residential volumes of 34,089,652 Dth. Witness Meyer's residential usage adjustment is an additional 1,181,255 Dth and is then multiplied by the rates applicable to Rate Schedule RSS - Residential Sales Service to come up with additional residential revenue of $12,217,836 as shown on OCA witness Meyer's Exhibit 1, Page 5, Line 13 and 14, resulting in a decrease to the Company's revenue deficiency by $12,217,836.

Q. Do you agree with OCA witness Meyer's $12.2 million decrease to the revenue deficiency pertaining to the Company's level of residential revenues?

No. As stated on page 22 of OCA witness Meyer's testimony, "Revenues are generally calculated by determining a normalized level of usage per customer (in Dths) for each rate class. This normalized usage is then multiplied by the normalized number of customers or bills to arrive at total usage. Total usage is then multiplied by the appropriate tariff rates for each rate class to arrive at a normalized level of revenues per class." Witness Meyer calculated a 5-year usage per customer average of 85.04 Dth based on 2018 – 2022 historical information as shown in his Table GRM-7 on Page 23 of Witness Meyer's testimony. The calculation was made using actual data, not data that has been normalized for weather. By using actual data that has not been normalized for weather, OCA witness Meyer calculated an inaccurate level of residential revenues ultimately leading to an improper $12.2 million reduction to the Company's requested revenue increase. Company witness Michael Girata's rebuttal testimony further addresses OCA witness Meyer's improper residential usage per customer calculation and has already explained in direct testimony the specific details of the normalization process taken when developing an appropriate forecasted usage and number of customers that is utilized in the Company's FPFTY.

Q. Why is it important to use weather-normalized volumes in the calculation of usage?

A. Actual usage for a single year or a short series of years can distort the projection of volumes for ratemaking purposes. I am advised by counsel that this has long been

recognized by the Commission and is why it is standard practice for gas utilities to use weather-normalized volumes in developing a projection of future usage.

Q. Are there different types of residential customers included in the FPFTY which would have different applicable rates when calculating revenues?

A. Yes, of the total 414,766 residential customers in the Company's FPFTY, which OCA accepts, there are 345,713 customers on rate schedule RSS – Residential Sales Service, 24,718 customers on rate schedule CAP – Customer Assistance Plan, and 44,335 customers on rate schedule RDS – Residential Distribution Service (CHOICE).

Q. What are the differences in rates between rate schedules RSS – Residential Sales Service, CAP – Customer Assistance Plan, and RDS – Residential Distribution Service (CHOICE) when calculating the adjustment to residential revenues?

A. While all three residential rate schedules have the same usage charge of $9.1069 per Dth, customers on Rate RSS - Residential Sales Service would also have Riders USP, CC, EE and GPC applied to their bills. For customers on Rate CAP – Customer Assistance Plan, only Rider GPC applies and for customers on Rate RDS – Residential Distribution Service (CHOICE), Riders USP, CC, and EE apply, but Rider GPC does not.

Q. Does OCA witness Meyer consider the different types of residential customers with different applicable rates when calculating the adjustment to residential revenues?

A. No. OCA witness Meyer's adjustment to usage of 1,181,255 was entirely applied to rate schedule RSS – Residential Sales Service even though his calculated 5-year usage per customer average of 85.04 Dth also included residential CAP and CHOICE information in the calculation. Therefore, by not applying some of the usage adjustment to applicable rates schedules for CAP and CHOICE, which do not include all the rates for riders on rate schedule RSS, OCA has overstated its calculated residential revenue increase. Table MLB-1R below, shows by component how OCA has calculated its $12.2 million increase in residential revenue.

TABLE MLB-1R
OCA Calculation of Residential Sales Revenue Adjustment

Rate RSS - Residential Sales Service

Distribution Charge and Riders	Usage Adjustment[1]	Rate per Dth[2]		Revenue
Usage Charge	1,181,255	$9.1069	$	10,757,569
Rider USP - Universal Service Plan	1,181,255	$1.1841	$	1,398,724
Rider CC - Customer Choice	1,181,255	$0.0010	$	1,181
Rider EE - Energy Efficiency Rider	1,181,255	$0.0398	$	47,014
Gas Procurement Charge	1,181,255	$0.0113	$	13,348
Total Residential Sales Revenue Adjustment		$10.3431	$	12,217,836

Sources:
1. OCA Meyer Testimony, Exhibit No. 1, Page 5, Line 13.
2. Exhibit 3, Schedule No. 1, Page 1.

Q. Are there any reconcilable riders on rate schedule RSS – Residential Sales Service that should be taken into consideration when OCA witness Meyer calculated his residential revenue adjustment?

A. Yes, Rider USP is a reconcilable rider that should either be removed from this adjustment or included in expense to properly offset each other.

Q. What is OCA witness Meyer's proposed revenue adjustment that would reduce the Company's requested revenue increase?

A. There is a discrepancy between what is written in OCA witness Meyer's testimony and what is reflected on Table GRM-1 and Exhibit No. 1. On page 25 of OCA witness Meyer's testimony, he writes the calculated revenue increase is approximately $4.5 million, but on Table GRM-1, Line 8 Sales Revenue reflects an adjustment of $12.2 million and Exhibit No. 1, Page 5, Line 14 reflects an adjustment of $12,217,836.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 3-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REJOINDER TESTIMONY OF
MAY BATTIG
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 30, 2024

Q. Please state your name and business address.

A. My name is May Battig. My business address is 290 West Nationwide Boulevard, Columbus, Ohio, 43215.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rejoinder testimony?

A. I will respond to the surrebuttal testimony served in this proceeding by the Pennsylvania Office of Consumer Advocate ("OCA") witness Greg R. Meyer concerning his updated sales revenue adjustment.

Q. Please describe OCA witness Meyer's updated sales revenue adjustment.

A. Mr. Meyer is proposing an updated sales revenue adjustment based on a re-calculated average usage per customer level that incorporates 2018-2023 information but excludes year 2020 due to COVID-19 impact on customers' annual usage patterns. His updated revenue adjustment also addresses the different types of residential customers with their own applicable rates and does not include the revenues from Rider USP. The impact of his revised revenue adjustment at current rates would reduce the Company's revenue deficiency by $5.3 million.

Q. What is the usage per customer used in OCA witness Meyer's revised sales revenue adjustment?

A. While Table GRM-SR-2 in Mr. Meyer's surrebuttal testimony reflects historical usage per customer information for years 2018 – 2023 with columns for both Non-Weather

Normalized and Weather Normalized, Mr. Meyer's revised revenue adjustment is calculated using the column for Non-Weather Normalized 2018 – 2023 usage per customer average without year 2020 of 84.26 Dth.

Q. Do you agree with OCA witness Meyer's 84.26 DTH usage per customer level and his approach of using a simple average of historical residential usage per customer for his sales revenue adjustment?

A. No, first, the 84.26 Dth usage per customer level used in the calculation of Mr. Meyer's revenue adjustment does not reflect a usage per customer level that is normalized for weather. As stated in my rebuttal testimony on page 3, lines 17-20, and continuing on page 4, lines 1-2, it is standard practice to use weather normalized volumes in the development of future usage projections to avoid distortion.

Second, Company witness Michael Girata explains in rebuttal testimony that the weather normalized residential usage per customer has declined steadily on an annual basis from 2018 to 2023, excluding 2020 for COVID-19 impact, as shown in Table MEG-1 on page 2. He states that by simply utilizing Mr. Meyer's average of the last five years would not incorporate this decreasing trend and would produce usage projections that are too high.

Furthermore, the Company's forecasted projections have already incorporated normalized weather using the most recent 20-year history, which in this case is the 20 years ended December 31, 2023. In his direct testimony, Company witness Girata described his normalization methodology to develop the forecasted usage and

number of customers used in the Company's FPFTY. It would be inappropriate to make an additional adjustment to the already normalized usage per customer level.

Q. Do you agree with OCA witness Meyer's updated residential revenue adjustment of $5.3 million?

A. No, although Mr. Meyer applied the appropriate rates of the different types of residential customers to his calculated volumes and has removed Rider USP revenues, the volumes that he calculated are distorted because of his use of a five-year non-weather normalized average to derive volumes. By using actual data that has not been normalized for weather and that does not recognize the ongoing trend of reduced usage per customer, OCA witness Meyer calculated an inaccurate level of residential revenues ultimately leading to an improper $5.3 million decrease to the Company's revenue deficiency.

Q. Does this complete your prepared Rejoinder Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
BRITTANY KOMENDA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

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I. Introduction

Q. Please state your name and business address.

A. My name is Brittany Komenda. My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Lead Regulatory Analyst at NCSC.

Q. Please briefly describe your professional experience.

A. I was hired with Northern Indiana Public Utility Company ("NIPSCO") in September 2014 as a Senior Regulatory Analyst. In July 2020, I was promoted to my current position of Lead Regulatory Analyst. I have experience in utility regulatory functions supporting NiSource operating companies, including, but not limited to, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company").

Q. Please describe your educational background.

A. I hold a Bachelor of Science degree in Business with a concentration in Financial Information Systems and Accounting from Indiana University Northwest.

Q. What are your responsibilities in your current position?

A. My responsibilities as a Lead Regulatory Analyst include providing revenue requirement support for base rate cases for several NiSource companies, including,

NIPSCO, Columbia and its regulated natural gas distribution affiliates in Maryland, Ohio, Virginia, and Kentucky.

Q. Have you previously testified before this or any other regulatory agency?

A. Yes, I submitted testimony to the Maryland Public Service Commission as the Cost of Service witness for Columbia Gas of Maryland, Inc. in Case Nos. 9680 and 9701.

Q. Please describe the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to present Columbia's cost of service and to quantify an existing revenue deficiency based on Twelve Months Ending December 31, 2025 operating costs and revenues, as adjusted. As part of the cost of service analysis, my testimony supports all rate making adjustments to Columbia's Cost of Service Operating and Maintenance ("O&M") expenses.

Q. Would you please provide a listing of the exhibits that you are sponsoring through your testimony?

A. Yes. For the historic test year, I am supporting Exhibit 1, Exhibit 2, and Exhibit 4. For the future test year and fully projected future test year, I am sponsoring Exhibit 101, Exhibit 102, Exhibit 104 (in coordination with Company witnesses Paloney (Columbia Statement No. 9) and Bly (Columbia Statement No. 15)), and Exhibit 414. I am also sponsoring portions of Exhibits 13 and 113. All of these exhibits were either prepared by me or under my direct supervision and control.

Q. Are you sponsoring any additional exhibits?

A. Yes. Pursuant to paragraph 33 of the approved Settlement in Docket No. R-2022-3031211, Columbia is required to provide a comparison of its actual revenue, expenses and rate base additions for the twelve months ended December 31, 2023, to the projections in the case. I am sponsoring Exhibit BJK-1, attached to my testimony, which provides a comparison of actual and projected O&M Expenses for the twelve months ended December 31, 2023.

Q. What test years will you be addressing in this testimony?

A. I will be addressing the twelve-month period ended November 30, 2023 as the "historic test year" or "HTY", the twelve month period ending November 30, 2024 as the "future test year" or "FTY", and the twelve month period ending December 31, 2025 as the "fully projected future test year" or "FPFTY".

Q. What is the basis for Columbia's claim for revenue deficiency?

A. Columbia's revenue deficiency is calculated utilizing a rate year ending December 31, 2025 for rate base, revenues and expenses, with pro forma adjustments for known and measurable changes. This approach recognizes that a utility's revenues should be sufficient to recover the reasonably and prudently incurred costs of providing safe and reliable service to its customers, including a reasonable opportunity to earn a fair rate of return on the used and useful investment that the utility has devoted to such service.

Q. Would you please summarize the results of the cost of service requirement and resulting revenue deficiency?

A. As indicated on Exhibit 102, Schedule 3, Page 5, Columbia has a revenue deficiency of $124,138,477 based upon pro forma revenue requirement for the twelve months ending December 31, 2025. Columbia's computation of the revenue deficiency reflects total rate base of $3,489,087,567. In addition, the computation of the revenue deficiency reflects known and measurable changes to both utility operating income and rate base, which are explained later in my testimony and in the testimony of other Company witnesses.

Q. How is your following testimony organized?

A. I will first address the HTY, Exhibit 2 and Exhibit 4, followed by a discussion of the FTY and FPFTY, Exhibit 102 and Exhibit 104.

II. HTY – Exhibit 2 – Statement of Income

Q. Please describe Exhibit 2, Schedule 3, Page 3.

A. This Exhibit is the statement of operating income, pro forma at present and proposed rates, for the HTY. Column 2 reflects the per book operating revenue, operating revenue deductions, income taxes and utility operating income for the Company for the twelve months ended November 30, 2023. These amounts have been adjusted to reflect pro forma operating income at HTY present rates in Column 4. Column 5 adjustments are detailed in Exhibit 2, Schedule 3, Pages 5 and 6. Column 6 shows the resulting pro forma operating revenue, expenses and income for the HTY at proposed rates.

Q. Please describe the data inputs of Exhibit 2, Schedule 3, Page 3.

A. Operating revenues are supplied by Company witness Battig (Columbia Statement No. 3) and are included on lines 1 through 12. Company witness Battig also provides the level of Gas Supply Expense and Off System Sales Expense that are included on lines 15 and 16, respectively. These two items are exactly offsetting to the level of revenue included in this case and accordingly do not impact the base rate claim in this case; rates for these items are determined in the Company's annual gas cost proceedings. I am supporting the Gas Used in Company Operations as presented on Line 17 and O&M Expense level as presented on line 18. Lines 19 and 20, Depreciation and Amortization and Net Salvage Amortized, respectively, are provided by Company witness Spanos (Columbia Statement No. 5). Taxes Other Than Income, Income Taxes, and Investment Tax Credit, lines 21, 24 and 25, respectively, have been provided by Company witness Harding (Columbia Statement No. 10), and Rate Base on line 27 has been provided by Company witness Covert (Columbia Statement No. 11). The Percentage Rate of Return at Proposed Rates on Line 28, Column 6 is provided by Company witness Moul (Columbia Statement No. 8). Each witness' testimony provides detailed support for each of these items.

Q. Please describe Exhibit 2, Schedule 3, Pages 4 through 6.

A. Page 4 shows the pro forma interest expense as calculated by multiplying the Rate Base shown in Exhibit 8, Page 3, by the weighted cost of short and long term debt shown in Exhibit 400, Schedule 1, Page 1.

Exhibit 2, Schedule 3, Page 5 shows the derivation of the Revenue Conversion Factor on lines 8 through 17. The Revenue Conversion Factor is then utilized to determine the Gross Revenue Requirement on line 7.

Page 6 shows the calculated adjustments to pro forma expenses and income taxes to achieve the requested return on Rate Base of 8.71% shown on Exhibit 400 using the HTY data.

III. HTY – Exhibit 4 - Operation & Maintenance Expenses

Q. What are Columbia's per books historic test year O&M Expenses?

A. In the HTY, Columbia recorded $228,194,643 in O&M expense exclusive of gas cost, as shown on Exhibit 4, Schedule 1, Page 2, Column 3. The O&M data is presented in a Cost Element format, which provides a breakdown by cost causation. Note, for comparative purposes, Columbia has added per book actual O&M Expenses for two years prior to the HTY in Column 1 (twelve months ended November 30, 2021) and Column 2 (twelve months ended November 30, 2022).

Q. Did you make adjustments to the actual HTY O&M to reflect a pro forma HTY O&M expense level?

A. Yes. I have prepared pro forma O&M expenses for this filing. The historic test year level of O&M expense starts with O&M Expense per books, which was then normalized and annualized to determine the pro forma level of O&M Expense as summarized on Exhibit 4, Schedule 1, Page 2, Column 5.

Q. What adjustments has Columbia made to O&M expense?

A. The Company has reflected the following ratemaking adjustments to the HTY, each of which will be explained in greater detail later on in my testimony:

a) Labor related adjustments to annualize and normalize payroll for employees as of the end of the HTY;

b) An adjustment to incentive compensation;

c) An adjustment to annualize the amortization expense of the Prepaid Pension Deferral;

d) Removal of the negative OPEB expense;

e) Adjustments to normalize Outside Services;

f) Annualization of building rents and leases;

g) Corporate insurance adjusted to latest known and measurable levels;

h) Injuries and Damages adjusted to reflect a five year average of cash payments;

i) Adjustment to remove non-recoverable employee expenses;

j) Company Memberships adjustments to latest known and measurable level less Lobbying Expense;

k) Removal of fuel used in company operations;

l) Advertising adjusted to remove non-recoverable items;

m) Adjustment to Materials and Supplies to remove Lobbying Expense;

n) Adjustment to Other O&M to remove non-recurring items;

o) Adjust Commission assessments (fees) to latest known and measurable level;

p) NCSC costs adjusted to annualize and normalize labor and incentive costs, and to remove non-recoverable and non-recurring items;

q) Adjust NCSC OPEB costs amortization level to reflect the annualized level;

r) Removal of Charitable Contributions;

s) Normalization of rate case expense;

t) Uncollectible Accounts explained and adjusted to a three year average experience;

u) Adjust COVID-19 amortization level to reflect the annualized level;

v) Adjust USP Rider expense to match revenue; and

w) Included interest on customer deposits.

A. <u>Labor</u>

Exhibit 4: *Schedule 1, Page 2, Line 1; Schedule 2, Pages 1, 2, and 3.*

Q. Please provide a brief explanation of the labor adjustments.

A. Labor costs in the historic test year were adjusted to reflect the annualized gross base or normal wages of the 728 active Columbia employees as of November 30, 2023. The difference, or annualization adjustment, was further adjusted to net O&M Expense by applying the O&M Expense experience percentage as provided on Exhibit No. 4, Schedule 2, Page 5. The annualization adjustment of $18,898 as calculated in Schedule 2, Page 1, Line 5, and a downward lobbying adjustment of $5,894 to remove labor relating to lobbying on Line 6, resulting in a total labor annualization and normalization adjustment of $13,004 is added to the actual HTY labor expense level

of $38,414,985 in Schedule 1, Page 2. Total Pro Forma HTY labor expense level is $38,427,989 as shown on Exhibit 4, Schedule 1, Page 2.

B. Incentive Compensation

Exhibit 4: *Schedule 1, Page 2, Line 2; Schedule 2, Page 4*

Q. Please provide an explanation of the HTY incentive adjustment.

A. Columbia's HTY per books incentive level of $3,370,857 was decreased by $1,174,127 to reflect the actual level of expense associated with incentive compensation paid in 2023. This adjustment removes any out of period true-ups for the prior year and adjusts the accrual made in the test year to the experienced pay out level at the claimed O&M Expense experience percentage. Detail supporting the historic test year adjustment is provided on Exhibit 4, Schedule 2, Page 4.

C. Prepaid Pension Deferral Amortization Expense

Exhibit 4: *Schedule 1, Page 2, Line 4; Schedule 2, Page 6*

Q. Please describe the ratemaking adjustment for Prepaid Pension Deferral Amortization Expense.

A. The Final Order approving the Settlement at Docket No. R-2018-2647577 permitted Columbia to recover the deferred prepaid pension O&M expense of $8,449,772 over a ten-year period starting December 16, 2018. This ratemaking entry verifies the annual amount of $844,977 for amortization expense.

D. OPEB – Other Post Employment Benefits

Exhibit 4: *Schedule 1, Page 2, Line 5; Schedule 2, Page 7*

Q. Please describe the ratemaking adjustment for OPEB.

A. As established in the Settlement of Columbia's base rate proceeding at Docket No. R-2012-2321748, Columbia will be permitted to continue to defer the difference between the annual OPEB expense calculated pursuant to FASB Accounting Standards Codification ("ASC") 715, "Compensation – Retirement Benefits" (SFAS No. 106) and the annual OPEB expense allowance in rates of $0. Therefore, this adjustment removes the credit OPEB expense of $791,873 to reflect an adjusted expense level of $0, which matches the amount recovered in revenues. It is important to note that the OPEB credit amount is an accounting calculation, and the Company did not actually receive a credit payment.

E. <u>Outside Services</u>

Exhibit 4: *Schedule 1, Page 2, Line 7; Schedule 2, Page 8 & 25*

Q. Please describe the ratemaking adjustment for Outside Services.

A. Ratemaking adjustments have been made to Outside Services to remove non-recoverable consulting costs associated with Lobbying and to move RP1162 Public Awareness costs to advertising.

F. <u>Rents and Leases</u>

Exhibit 4: *Schedule 1, Page 2, Lines 8 & 9; Schedule 2, Page 9*

Q. How were Rents and Leases adjusted for the HTY?

A. Rents and leases were first separated into a) rents and leases related to buildings, and b) other rents and leases including communications equipment and lines, office

machines and furnishings. Rents and leases attributable to contractual levels for buildings were annualized on Exhibit 4, Schedule 2, Page 9 for a total of $905,361. This amount was then reconciled with the per book test year level of $1,749,244. The resulting adjustment is a decrease of $843,883. The remaining portion of rents and leases includes communications equipment and lines, office machines, and other items. The historic test year level related to these is $505,142 and remains unchanged as seen on Exhibit 4, Schedule 1, Page 2, Line 9.

Q. Please explain the decrease in Building Leases.

A. The decrease is primarily related to the elimination of rent and CAM expense for Alpine Point Operating Center to reflect the purchase of the facility in October 2023.

G. <u>Corporate Insurance</u>

Exhibit 4: *Schedule 1, Page 2, Line 10; Schedule 2, Page 10*

Q. Please explain the Corporate Insurance adjustment for the historic test year.

A. Corporate insurance includes property insurance, workers compensation, medical stop loss premiums, and other miscellaneous premiums. Most of Columbia's policy periods are either effective January 1 through December 31, July 1 through June 30, or November 1 through October 31 of each year. Premium payments are generally made the same month as the policy effective date. The prepayment of these costs are recorded and amortized over the appropriate fiscal period. The HTY adjustment annualizes expense to the latest annual premium payments by type of coverage from

the amounts expensed during the period. Detailed calculations of these adjustments have been provided on Exhibit 4, Schedule 2, Page 10.

H. <u>Injuries and Damages</u>

Exhibit 4: *Schedule 1, Page 2, Line 11; Schedule 2, Page 11*

Q. Was an adjustment made for injury and damages?

A. Yes. The HTY expense level for injury and damages of $349,074 represents an amount including both actual experience and adjustments to an injury and damages accrual account. An upward adjustment of $32,943 was made to normalize the level of injuries and damages expense based upon a five-year average actual cash outlay experience in real dollars using a Gross Domestic Product Implicit Price Deflator ("GDPIPD"). As in previous base rate cases, a five-year average is used because it more accurately reflects the injury and damages amount actually paid. Detail supporting this adjustment is shown on Exhibit 4, Schedule 2, Page 11.

I. <u>Employee Expenses</u>

Exhibit 4: *Schedule 1, Page 2, Line 12; Schedule 2, Page 12*

Q. Was an adjustment made for employee expenses?

A. Yes. A downward adjustment was made to the HTY to remove certain employee expenses which Columbia is not seeking to include for recovery in this proceeding. Details supporting this adjustment is shown on Exhibit 4, Schedule 2, Page 12.

J. <u>Company Memberships</u>

Exhibit 4: *Schedule 1, Page 2, Line 13; Schedule 2, Page 13*

Q. Please explain the adjustments made for Company Memberships.

A. The HTY expense for Company Memberships has been adjusted for two primary items. Annualization adjustments were made for the American Gas Association dues reflective of the payments made relating to calendar year 2023, and adjustments in Column 4, totaling a net decrease of $28,195, were made to remove all costs identified as Lobbying from Company Memberships. The details of these adjustments are shown on Exhibit 4, Schedule 2, Page 13.

K. <u>Utilities and Fuel Used in Company Operations</u>

Exhibit 4: *Schedule 1, Page 2, Line 14; Schedule 2, Page 14*

Q. What does the historic test year adjustment to Utilities and Fuel used in Company Operations represent?

A. A decrease to historic test year utilities and fuel used in Company operations expense of $823,312 is made to recognize inclusion of this amount as both recovery of gas cost and gas purchase expense by Company witness Battig. Columbia includes the expenses associated with gas used in Company operations when establishing its gas cost recovery rates. The purchased gas is recorded as system supply and then reclassified from gas purchase to O&M expense. Therefore, it is necessary to remove the amount above from O&M for the purposes of calculating base rates and appropriately show this same level of expense in gas purchase expense along with an offsetting gas recovery level. The remaining historic test year level of $2,328,522 represents other utility costs, such as electric and telecommunications (internet

service, cell phones, land lines, etc.), not recovered through the Section 1307(f) process.

L. Advertising

Exhibit 4: *Schedule 1, Page 2, Line 15; Schedule 2, Page 15*

Q. Was advertising adjusted?

A. Yes. Columbia has made an adjustment to first remove the expenses associated with its advertising that do not represent a recoverable operating expense and then to add RP1162 Public Awareness advertising expenses that were inadvertently classified to Outside Services, Material & Supplies, and Other O&M. The Company has removed $131,155 of brand advertising and $905 of other small misclassified items from HTY costs and added an additional $95,296 related to RP1162 Public Awareness Advertising expenses. Please see Exhibit 4, Schedule 2, page 15 for details.

M. Materials and Supplies

Exhibit 4: *Schedule 1, Page 2, Line 17; Schedule 2, Page 16*

Q. Was material and supplies adjusted?

A. Yes. Columbia has made an adjustment to remove lobbying-related materials and supply expenses and to move RP1162 Public Awareness costs to advertising. Please see Exhibit 4, Schedule 2, page 16 for details.

N. Other O&M

Exhibit 4: *Schedule 1, Page 2, Line 18; Schedule 2, Page 17*

Q. Was other O&M adjusted?

A. Yes. Columbia has made an adjustment to HTY Other O&M Expenses to remove a credit for a non-recurring cost totaling $208,329 and to move $69,358 RP1162 Public Awareness costs to advertising. Please see Exhibit 4, Schedule 2, page 17 for details.

O. Commission, OCA and OSBA Assessments

Exhibit 4: *Schedule 1, Page 2, Line 19; Schedule 2, Page 18*

Q. Please explain the $159,189 increase to the HTY Commission, OCA and OSBA Assessment expenses.

A. The adjustment is needed to increase the HTY level of expense to the most current invoice amount for Commission, Office of Consumer Advocate and Office of Small Business Advocate assessments. The normalized test year expense amount of $2,550,124 reflects the most recent invoice amount (September 8, 2023) received as of the submission of this base rate filing.

P. NiSource Corporate Services Company ("NCSC")

Exhibit 4: *Schedule 1, page 2, Line 20; Schedule 2, pages 19-22*

Q. Please explain the structure and role of NCSC.

A. NCSC is a subsidiary of NiSource and an affiliate of Columbia within the NiSource corporate organization. NCSC was established to provide centralized services to the individual operating companies within NiSource and to coordinate the allocation and billing of charges to the NiSource operating companies for services provided by both NCSC directly and by third-party vendors. The rendering of services on a centralized basis enables the affiliates to realize benefits from economies of scale by leveraging

the use and specialized expertise of personnel and equipment across the whole enterprise. Thus, NCSC offers Columbia, as well as the other NiSource distribution companies, access to the depth and breadth of professional experience that may not otherwise be available, or that may be available from consultants at much higher costs.

Q. Is there a contract between Columbia and NCSC?

A. Yes. A copy of the Service Agreement is provided as Exhibit 4, Schedule 11, Attachment B. Other detailed information regarding NCSC is also provided as a part of Exhibit 4, Schedule 11.

Q. How are NCSC's costs billed to affiliates?

A. There are two types of billings made to affiliates, including Columbia: 1) contract billing; and 2) convenience billing. Contract billings are identified by billing pool and represent labor and expenses billed to the respective affiliate. Contract billed charges may be direct (billed directly to a single affiliate) or allocated (split between or among several affiliates), depending on the nature of the expense. Convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate is billed on a monthly basis for its proportional share of the payments made in that respective month. As the name implies, convenience billing is intended as a convenience to vendors because it eliminates the need for a separate invoice to be generated for each affiliate entity receiving the same services.

Q. How does NCSC determine charges applicable to Columbia?

A. NCSC was regulated by the Securities Exchange Commission ("SEC") under the Public Utility Holding Company Act of 1935 until February 8, 2006, when the Public Utility Holding Company Act of 2005 ("PUHCA 2005") was enacted. PUHCA 2005 transferred regulatory jurisdiction over public utility holding companies from the SEC to Federal Energy Regulatory Commission ("FERC"). Pursuant to FERC Order No. 684, issued October 19, 2006, 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. In compliance with PUHCA 2005 and FERC, NCSC accumulates costs that are applicable and billable to affiliates, including Columbia.

Q. Please describe the controls in place to ensure that an affiliate is consistently and appropriately billed.

A. NCSC allocates costs for a particular billing pool in accordance with the bases of allocation that have been previously approved by the SEC and filed annually with the FERC. A description of each of the bases of allocations are provided in the Service Agreement (See Ex. 4, Sch. 11, Att. B). NCSC currently updates the statistical data used in the approved allocation bases, at a minimum, on a semi-annual basis; and furthermore, prior to publishing the new allocation percentages, NCSC provides Columbia's leadership team the opportunity to review, discuss, and provide feedback.

Additionally, Internal Audit conducts an annual review of cost allocation procedures and makes recommendations related to contract and convenience billing processing.

Q. Has the FERC conducted an audit of NCSC, its billing system and allocation methodologies?

A. Yes. NiSource Inc., including NCSC, underwent a FERC audit, Docket No. FA11-5-000, which covered the period January 1, 2009, through December 31, 2010. The Final Audit Report was issued by the FERC on October 24, 2012. As indicated in the Final Report, the Audit Staff reviewed and tested the supporting details for NCSC's cost allocation methods. They then sampled and selected supporting documents to ensure that NCSC's billings and accounting comply within the USOA (Uniform System of Accounts). FERC did not issue any adverse comments to NCSC related to its allocation methods.

Q. Have there been any changes to the billing methods used by NCSC since this Audit?

A. No, there have not.

Q. Are you sponsoring the adjustments made on Exhibit 4, Schedule 1, Page 2 to NCSC?

A. Yes. The following adjustments have been made to NCSC charges for ratemaking purposes for the HTY and are summarized on Exhibit 4, Schedule 2, Page 19:

a) Adjustment to Incentive Compensation for actual incentive compensation paid in 2023;

b) Annualization of Labor, Payroll Taxes & Benefits; and

c) Removal of Non-recoverable Items and Non-recurring Items.

Q. Please provide a brief overview of Exhibit 4, Schedule 2, Page 19.

A. Page 19, line 1 states the gross NCSC charges in the HTY. A portion of these costs are recorded to non-O&M accounts. Line 2 details the charges transferred to balance sheet or non-utility expenses. The HTY O&M costs generated from NCSC billings is $73,587,371.

Q. Please explain the various adjustments made to the actual HTY O&M costs.

A. Continuing on Exhibit No. 4, Schedule No. 2, Page 19, Lines 4 through 16 reflect adjustments made to the actual HTY O&M expense as follows:

Line 4 – Adjusts the NCSC Incentive Compensation to the level paid in 2023 using the latest percentage of NCSC loaded labor charges to Columbia. This calculation is detailed on Page 20.

Line 5 - Annualizes NCSC labor, payroll taxes and benefits as detailed on Page 21. Net NCSC labor, payroll taxes and benefits adjustment is determined by applying the percentage of NCSC labor charged to O&M derived on Exhibit 4, Schedule 2, Page 22, Line 4.

Lines 6 – 11 – Non-Recoverable Items that were included in the HTY are removed in the pro forma HTY expense claim.

Lines 12 - 14 – Non-Recurring Items that were included in the HTY are removed in the pro forma HTY expense claim.

Q. NCSC OPEB Amortization

Exhibit 4: *Schedule 1, Page 2, Line 21; Schedule 2, Page 23*

Q. Has the HTY been adjusted to reflect the appropriate amount of NCSC OPEB amortization?

A. Yes. According to the Settlement in the Company's 2012 base rate proceeding, Docket No. R-2012-2321748, the Company is permitted to amortize the regulatory asset of $903,131 associated with the transition of NCSC from a cash to accrual basis for OPEBs, over a ten year period, or $90,313 annually. As of June 2023 the regulatory asset for NCSC OPEB Expense became fully amortized. Exhibit 4, Schedule 2, Page 23 shows that an adjustment of $52,683 is required to remove amortization expense from the HTY.

R. Charitable Contributions

Exhibit 4: *Schedule 1, Page 2, Line 22; Schedule 2, Page 24*

Q. How are charitable contributions treated as a cost of service item?

A. Charitable contributions are normally booked below the line in a non-utility account and are not a part of Columbia's claim as a cost of service item. Please see Exhibit 4, Schedule 2, page 24 for the details of removing any contributions that were inadvertently booked above the line during the HTY.

S. Rate Case Expense Normalization

Exhibit 4: *Schedule 1, Page 2, Line 23; Schedule 2, Page 25*

Q. Has the Company included a normalized level of rate case expense in its HTY Cost of Service?

A. Yes. Actual rate case expense incurred during the HTY for the Company's prior base rate case has been removed from the outside services pro forma HTY expense and are detailed in lines 1 through 2. On line 3, I have included a normalized level of rate case expense based on the proposed rate case expense normalization included in this current case as included on Exhibit 104, Schedule 2, Page 14. The Company is using a one year normalization period due to prior base rate case filing experience and the expectation of annual future base rate case filings.

T. Uncollectible Accounts Expense

(Uncollectible Accounts & Uncollectible Accounts – Unbundled Gas)

Exhibit 4: *Schedule 1, Page 2, Line 24 & 25; Schedule 2, Pages 26 – 28*

Q. Please explain Columbia's claim for recovery of uncollectible accounts expense.

A. Two major categories of uncollectible accounts have been recorded historically and have been represented in the development of cost of service support. These two categories are "normal" (or non-CAP) uncollectible accounts and Customer Assistance Program ("CAP") uncollectible accounts.

Normal uncollectible accounts expense is determined by using a three-year average write-off rate, which has been developed on Exhibit 4, Schedule 2, Page 26. The CAP uncollectible accounts expense related to the CAP shortfall has been developed and is included in Total USP Rider on Exhibit 4, Schedule 2, Page 30 for the HTY.

Q. What years are included in the calculation of the three-year average write-off experience factor for determining normalized uncollectible expense for this proceeding?

A. The Company is proposing to use the most current data from the Twelve Months Ended November 30, 2021, 2022 and 2023 to determine an uncollectible experience factor to produce normalized uncollectible expense for the HTY, FTY and FPFTY.

Q. Please explain the development of the HTY normal uncollectible accounts expense.

A. Exhibit 4, Schedule 2, Pages 26 sets forth the development of a percentage for uncollectible accounts related to normal charge-offs recovered through base rates. The write-off percentage for charge-offs related to normal customers recovered through base rates is calculated based on comparing the three year average of write-offs for normal uncollectible accounts expense to billed revenue, Columbia is using a three year average of data for the Twelve Months Ended November 30, 2021, 2022 and 2023. Several adjustments to billed revenue are necessary to develop the write-off percentage. First, account write-offs lag billed revenue by approximately 120 days, or 4 months. This lag in days includes consideration for the time between

original billing and an account being placed into final status, as well as consideration for the average time between an account being placed into final status and termination of service, which is when the account is written-off. I have used billed revenue for the twelve months ended July 31 of each year to appropriately reflect the lag (4 months) between the billing and write-off of accounts.

Additionally, I have provided on Page 27 the average write-off rate for Residential customers as well as the combined write-off rate for Commercial and Industrial customers. This information was utilized by Company witness Battig (Columbia Statement No. 3) in the development of the Merchant Function Charge.

Q. What other adjustments have been made to billed revenue?

A. Columbia's Distributive Information System ("DIS") billing system is used to bill all residential and small business accounts and, therefore, includes revenues applicable to CAP customer accounts. Exhibit 4, Schedule 2, Line 2 of Page 26, titled as, "Total DIS Billed Revenue," has been adjusted to remove the revenue associated with Columbia's CAP (Page 28), as CAP uncollectibles are accounted for separately, as explained earlier in my testimony. Exhibit 4, Schedule 2, Line 4 of Page 26 represents Adjusted DIS Billed Revenue that relates to the net write-offs as shown on Exhibit 4, Schedule 2, Line 9 of Page 26.

Q. How were the net write-offs shown on Line 9 developed?

A. The net write-offs shown on Exhibit 4, Schedule 2, Line 9 of Page 26 represent the summation of gross charge-offs and recoveries for all customers billed through DIS.

Q. How are the adjusted billed revenue and net write-off amounts used in the development of normal uncollectibles?

A. The three years of adjusted revenue is added together to generate the total revenue as shown on Line 4 and Column 4. Similarly, a three year total is developed for net write-offs. An uncollectible rate is then calculated by dividing the three year total net write-off by the three year total adjusted revenue. This rate, which is shown on Line 10, is then applied to the annualized DIS revenue as provided by Company witness Battig for the historic test year. The result is Columbia's adjusted historic test year normal uncollectibles for DIS billed customers, Line 16.

Q. Does this fully describe all adjustments made to the historic test year normal uncollectible expense?

A. Yes. While DIS is one of three billing systems used to bill revenue related to normal uncollectible write-offs, the Company had no write-offs from the other billing systems.

Q. Please summarize Columbia's proposed normal historic test year uncollectible accounts expense adjustments.

A. The historic normal uncollectible adjustments are a net increase to expense of $2,427,071 as shown on Exhibit 4, Schedule 1, Page 2, Lines 24 and 25. This amount has been developed by comparing an annualized DIS net write-offs, as described above, and comparing that to the actual uncollectible expense level recorded in Columbia's historic test year ending November 30, 2023.

U. Amortization of Deferred COVID-19 Uncollectible Expense

Exhibit 4: *Schedule 1, Page 2, Line 27; Schedule 2, Page 29*

Q. Has the HTY been adjusted to reflect the appropriate amount of COVID-19 Uncollectible Expense amortization?

A. Yes. According to the Settlement in the Company's 2022 base rate proceeding, Docket No. R-2022-3031211, the Company is permitted to amortize the regulatory asset of $2,832,363 over a four year period, or $708,091 annually. Exhibit 4, Schedule 2, Page 29 shows that a downward adjustment of $33,979 is required to reflect the appropriate amortization expense for the HTY.

V. Rider USP Costs

(Uncollectible CAP – Rider USP & Rider USP – LIURP/Energy Efficiency)

Exhibit 4: *Schedule 1, Page 2, Line 28; Schedule 2, Page 30*

Q. Are you sponsoring an adjustment for Rider USP costs as well?

A. Yes. A Rider USP adjustment has been made to the HTY as shown on Exhibit 4, Schedule 2, Page 30.

Q. Please explain the test year adjustment.

A. The adjustment is a result of the matching of expenses to revenue, as Rider USP is a fully reconciled mechanism. As calculated in Exhibit 3, Page 10, Rider USP revenues are $36,493,459 for the normalized HTY as determined by Company witness Battig. Consequently, the adjustment reflects changes that are necessary to match the expense with the revenues supported by Company witness Battig. As a result, the

Rider USP net impact to operating income is zero with the expense offsetting revenues. Therefore, Rider USP costs do not impact the base rate increase requested in this case.

W. Interest on Customer Deposits

Exhibit 4: *Schedule 1, Page 2, Line 29; Schedule 2, Page 31*

Q. Please explain the adjustment for Interest on Customer Deposits.

A. An adjustment for interest on customer deposits is necessary to recognize the expense related to interest recorded on customer deposits not included in O&M Expense on the books and records of Columbia. Customer deposits are considered a source of capital in Columbia's rate base for this case and, as such, reduce rate base. This adjustment is made to recognize the expense related to this source of capital. The adjustment reflects the 7% interest rate on customer deposits established under Chapter 14 of the Public Utility Code applied to the average customer deposit balance. No further adjustment is made to this item for either the future test year or the fully projected future test year, because the Company has made no projection of changes to the balance of customer deposits.

IV. FTY/FPFTY – Exhibit 102 – Statement of Income

Q. Is Exhibit 102 presented in the same format as Exhibit 2?

A. Yes. Exhibit 102, Schedule 3 is a Statement of Income based on HTY, FTY, FPFTY at present rates and the FPFTY at Proposed Rates. Note that Columbia has included HTY information on Exhibit 102, Schedule 3, Page 3 for comparison purposes.

Exhibit 102, Schedule 3, Page 3, as referenced earlier in my testimony when describing Exhibit 2, Schedule 3, Page 3, utilizes data that has been provided by other witnesses in this case to determine a total revenue requirement. This Exhibit begins with the per books HTY in Column 2, followed by HTY adjustments at Present Rates in Column 3 to arrive at Pro Forma HTY in Column 4. Next, in Column 5, are the FTY adjustments at present rates to arrive at Pro Forma FTY in Column 6. Column 7 provides the FPFTY adjustment needed to arrive at Pro Forma FPFTY at Present Rates in Column 8. Adjustments in Column 9 are then made to determine the FPFTY at proposed rates in Column 10. Column 9 shows the revenue requirement of $124,138,477 necessary to achieve a reasonable opportunity to earn a fair rate of return. The various exhibits in support of the adjustments at present and proposed rates are identified in Column 1.

Q. Please explain Exhibit 102, Schedule 3, Page 4.

A. This page calculates the synchronized interest expense based upon the FTY rate base multiplied by the weighted cost of debt in Lines 1 through 4, and similarly based on the FPFTY year rate base in Lines 5 through 8.

Q. Please explain Page 5 and 6 of Exhibit 102, Schedule 3.

A. Page 5 of Exhibit 102, Schedule 3 presents the calculation of the gross required revenue increase of $124,138,477 on Line 7 using the revenue conversion factor, applied to the Net Required Operating Income on Line 5. The revenue conversion factor calculation on Lines 8 through 17 accounts for additional normal uncollectible

expense associated with the gross required revenue increase, as well as income taxes. The State Income Tax rate of 7.99% is adjusted to reflect the effective tax rate of 6.85% for the FPFTY as discussed in Witness Harding's Testimony. The Federal Income Tax rate is applied at 21% to arrive at Adjusted Operating Income as a percent of Total Operating Revenues. Page 6 determines the Net Required Operating Income by starting with Columbia's requested increase in revenues as calculated on Page 5 of Exhibit 102, Schedule 3. Line 2 displays the additional Late Payment Fee as calculated by first determining an experience rate of Late Payments Fees at present rates. This is done by dividing the amount of total Late Payment Fees on Exhibit 102, Schedule 3, Page 3, Column 8, Line 12 by Total Sales and Transportation Revenues on Exhibit 102, Schedule 3, Page 3, Column 8, Line 10. This experience factor is then applied to the Additional Revenue Requirement on Line 1 of Exhibit 102, Schedule 3, Page 6 to determine the additional Late Payment Fees. Next is the determination of the Uncollectible Expense, followed by the Income Tax calculations to determine the Net Required Operating Income on Line 12.

V. <u>FTY/FPFTY – Exhibit 104 – Operations and Maintenance Expense</u>

Q. Did the Company utilize a budget-based methodology to determine O&M Expense for the FTY and the FPFTY as Columbia has done in the prior base rate case proceedings?

A. Yes. FTY and FPFTY levels of O&M expense begin with the budget as supplied and supported by Company witness Paloney (Columbia Statement No. 9) and Company

witness Bly (Columbia Statement No. 15). A month by month presentation can be found on Exhibit 104, Schedule 1, Pages 5 and 6. Ratemaking adjustments have been made to normalize and annualize the budget to arrive at Pro Forma O&M Expenses.

Q. Please describe Exhibit 104, Schedule 1.

A. Exhibit 104, Schedule 1 contains a total of six pages and provides a clear distinction between "Budget Amounts" and "Rate Making Adjustments" for both the FTY and the FPFTY. Company witnesses Paloney and Bly are supporting all budget amounts, while I am supporting all ratemaking adjustments.

Q. Please provide a brief description of each of the 6 pages of Exhibit 104, Schedule 1.

A. Page 1 references Pages 2 – 6 of the Exhibit.

Page 2 is the summary view of O&M Expense for all test years in this case. Column 1 presents the Normalized HTY, Column 3 presents the Normalized FTY and Column 5 presents the Normalized FPFTY. Columns 2 and 4 provide both the differences needed to arrive at budgeted amounts and the rate making adjustments that adjust the HTY to the FTY and the FTY to the FPFTY.

Pages 3 and 4 are formatted in a similar manner. Page 3 contains details for the FTY; while page 4 contains the details for the FPFTY. Page 3 starts with the Normalized HTY in Column 1, followed by the differences (Column 2) between the Normalized HTY and the Budgeted FTY (Column 3) which is supported by Company witnesses Paloney and Bly. Columns 4 and 5 provide Rate Making Adjustments and

References, followed by the Normalized FTY (Column 6). Similarly, Page 4 provides the details for the FPFTY, starting with the Normalized FTY (Column 1; from Page 3, Column 6) followed by the differences (Column 2) between the Normalized FTY and the Budgeted FPFTY (Column 3) which is also supported by Company witnesses Paloney and Bly. Columns 4 and 5 provide Rate Making Adjustments and References followed by the Normalized FPFTY (Column 6).

Pages 5 and 6 provide the monthly Budget Data for FTY (Page 5) and FPFTY (Page 6), supported by Company witnesses Paloney and Bly.

Q. Did you utilize the O&M budget for all the O&M items on Exhibit No. 104?

A. No. Lines 1 through 20 on Exhibit No. 104, Schedule No. 1, Column 3, Pages 3 and 4 reflect the O&M budget data used in the FTY and FPFTY periods. The O&M budget data was not utilized for the cost items noted on Lines 22 through 28 of these same pages. These items include:

- Line 22 – Rate Case Expense – the amounts reflect normalized costs associated with the current case that should be included in the revenue requirement in this case.
- Lines 23– Uncollectible Accounts – the uncollectible expense is reflective of the standard practice of using a three year average of charge-off experience of FTY and FPFTY revenues as provided by Company witness Battig.

- Lines 24 & 26 – Uncollectible Accounts – Unbundled – Gas & Total Rider USP – the amounts are adjusted to reflect the amounts included in revenues as provided by Company witness Battig.
- Line 25 – COVID-19 Uncollectible Expense amortization – the amounts reflect annualized COVID-19 amortization expense.
- Line 27 – Interest on Customer Deposits – this item is not included in the O&M budget.
- Line 28 – Other Adjustments to the FPFTY O&M not in the budget.

Q. What types of adjustments are you proposing to O&M expense for the FTY and FPFTY?

A. I am proposing the following ratemaking adjustments to determine Pro Forma O&M Expense for the FTY and FPFTY, which I will explain in detail later on in my testimony:

a) Annualization of Company Labor;
b) Amortization of deferred non-recurring pension contribution;
c) Removal of the negative OPEB expense;
d) Outside Services adjustments;
e) Annualization of building rents and leases;
f) Injuries and Damages adjusted to reflect HTY plus inflation;
g) Removal of fuel used in Company operations;
h) Advertising adjusted to a normalized level of recoverable expense;

i) NCSC costs adjusted to annualize labor and remove non-recoverable items;

j) Removal of other lobbying expenses from Company Memberships and Materials and Supplies;

k) Normalization of rate case expense;

l) Adjust Uncollectible expense;

m) Amortization of COVID-19 Uncollectible Expense;

n) Adjust Rider USP expense to match revenue;

and

o) Other Adjustments to the FPFTY.

A. <u>Labor</u>

Exhibit 104: *Schedule 1, Page 2, Line 1; Schedule 2, Page 1*

Q. Please provide a brief explanation of the labor adjustments.

A. Columbia has determined annualization adjustments for the FTY of $562,777 and for the FPFTY of $397,431. These adjustments are for normal pay increases and lobbying adjustments. Labor adjustments are charges prior to the timing of the annual budgeted increases, and reflect an O&M percentage of 51.48% as determined on Exhibit 4, Schedule 2, Page 5. The Lobbying adjustment is based upon the HTY adjustment, plus 3% to account for a wage increase.

B. <u>Prepaid Pension Deferral Amortization Adjustment</u>

Exhibit 104: *Schedule 1, Page 2, Line 4; Schedule 2, Page 2*

Q. Please describe the ratemaking adjustment for Prepaid Pension Deferral Amortization.

A. The Final Order approving the Settlement of Columbia's base rate case at Docket No. R-2018-2647577 permits Columbia to recover the deferral of prepaid pension O&M expense of $8,449,772 over a ten year period starting December 16, 2018. This ratemaking entry adjusts the associated budgeted amortization expense to an annual amount of $844,977 for the FTY and FPFTY.

C. OPEB – Other Post-Employment Benefits

Exhibit 104: *Schedule 1, Page 2, Line 5; Schedule 2, Page 3*

Q. Please explain the ratemaking adjustment for OPEB Expense as approved in the Company's prior rate case.

A. Provision Nos. 30 and 31 of the Settlement Agreement of the Company's 2018 base rate case address this subject by stating:

> 30. As established in the settlement of Columbia's base rate proceeding at R-2012-2321748, Columbia will be permitted to continue to defer the difference between the annual OPEB expense calculated pursuant to FASB Accounting Standards Codification ("ASC") 715, Compensation – Retirement Benefits (SFAS No. 106) and the annual OPEB expense allowance in rates of $0. Only those amounts attributable to operation and maintenance would be deferred and recognized as a regulatory asset or liability. To the extent the cumulative balance recorded reflects a regulatory asset, such amount will be collected from customers in the next rate proceeding over a period to be determined in that rate proceeding. To the extent the cumulative balance recorded reflects a regulatory liability, there will be no amortization of the (non-cash) negative expense, and the cumulative balance will continue to be

maintained.

31. Commencing with the effective date of rates, Columbia will deposit amounts in the OPEB trusts when the cumulative gross annual accruals calculated by its actuary pursuant to ASC 715 are greater than $0. If annual amounts deposited into OPEB trusts, pursuant to this Settlement, exceed allowable income tax deduction limits, any income taxes paid will be recorded as negative deferred income taxes, to be added to rate base in future proceedings.

Q. Is the Company proposing a change to these provisions?

A. No. The cumulative OPEB expense at the end of the HTY is less than zero, and the expected on-going OPEB expense continues to reflect a credit to expense. Therefore, the Company proposes to continue using this ratemaking treatment for OPEB expense.

Q. Do the ratemaking adjustments for OPEB Expense as presented on Exhibit 104, Schedule 2, Page 3 comply with the provisions as listed above?

A. Yes, the FTY and FPFTY adjustments remove from the budgets the credit OPEB expense of $1,070,000 and $969,000, respectively to reflect an adjusted expense level of $0. I emphasize that these credit amounts are not projected cash receipts, but just accounting credits.

D. <u>Outside Services</u>

Exhibit 104: *Schedule 1, Page 2, Line 7; Schedule 2, Page 4*

Q. Please explain the adjustment to outside services for the FTY and FPFTY.

A. The FTY and the FPFTY include adjustments to remove Lobbying Expenses, utilizing the HTY adjustment as the basis, plus inflation.

E. Rents and Leases

Exhibit 104: *Schedule 1, Page 2, Line 8; Schedule 2, Pages 5 & 6*

Q. Please explain the adjustment to rents and leases for the FTY and FPFTY.

A. Known changes to building leases attributable to contractual levels were included on Exhibit 104, Schedule 2, Page 5 and 6 resulting in an increase to the budget of $71,109 for the FTY claim and an increase of $124,262 for the FPFTY claim.

F. Injuries and Damages

Exhibit 104: *Schedule 1, Page 2, Line 11; Schedule 2, Page 7*

Q. Was an adjustment made for injuries and damages?

A. Yes. The FTY and FPFTY expense levels for injury and damages were adjusted to reflect the pro forma HTY claim of $382,017 plus applicable inflationary adjustments. As stated earlier in my testimony, the pro forma HTY claim reflects the average claim payments for the five years ending November 30, 2023.

G. Utilities and Gas Used in Company Operations

Exhibit 104: *Schedule 1, Page 2, Line 14; Schedule 2, Page 8*

Q. Please explain the adjustment for Gas Used in Company Operations.

A. The FTY and FPFTY O&M budget amounts include costs associated with Gas Used in Company Operations. In a manner similar to what was done in the HTY pro forma adjustments, an adjustment is also needed to eliminate these costs in the FTY and

FPFTY periods. The adjustments were calculated using the HTY adjustment level plus an inflationary adjustment.

H. Advertising

Exhibit 104: *Schedule 1, Page 2, Line 15; Schedule 2, Page 9*

Q. Please explain the adjustment for Advertising.

A. The FTY and FPFTY O&M budget amounts are not prepared at a level that identify the specific types of advertising. The HTY advertising included a portion of non-recoverable advertising, so for the future periods I have made adjustments to include a representative level of recoverable advertising. Therefore, the pro forma adjustment used to determine the HTY recoverable advertising was also used for FTY and FPFTY periods. This includes making significant reductions to the levels of advertising expense in the budget for both periods.

I. NiSource Corporate Services Company "NCSC"

Exhibit 104: *Schedule 1, Page 2, Line 20; Schedule 2, Pages 10-12*

Q. Are you sponsoring any ratemaking adjustments to NCSC for the FTY and FPFTY?

A. Yes. Exhibit 104, Schedule 2, Page 12 summarizes the ratemaking adjustments to NCSC for the FTY and FPFTY.

I have made adjustments to annualize labor and to remove non-recoverable items for both future periods. Page 11 provides adjustments to annualize labor; the annualization is similar to the adjustments that I am proposing on Exhibit 104,

Schedule 2, Page 1 for Company labor. The FTY adjustment represents a 4% increase of budgeted labor charges from December 2023 through February 2024, which annualizes labor for the months prior to the budgeted annual 4% merit increase to labor which occurred on March 1. In a similar fashion, the FPFTY has been adjusted to include a 3% increase of budgeted labor charges for January 2025 through February 2025.

Page 12 determines adjustments for the removal of non-recoverable items. The non-recoverable adjustments are based upon the HTY level of expense, plus incremental adjustments that are produced by using inflation factors.

J. Other Lobbying Expense

Exhibit 104: *Schedule 1, Page 2, Lines 13 & 17; Schedule 2, Page 13*

Q. Please describe these lobbying expense adjustments.

A. Adjustments have been made for the removal of the remaining lobbying expenses in Company Memberships and Materials and Supplies. The FTY and FPFTY adjustments are based upon the HTY level of expense adjusted for inflation.

K. Normalization – Rate Case Expenses

Exhibit 104: *Schedule 1, Page 2, Line 22; Schedule 2, Page 14*

Q. Has Columbia included an adjustment for rate case expense?

A. Yes. Exhibit 104, Schedule 2, Page 14 sets forth the Company's claim for rate case expenses. The estimated expenses for this rate case reflects costs to be incurred for Columbia's cost of capital witness, depreciation witness, energy efficiency witness,

outside counsel, and incremental costs associated with legal notices, employee expenses and materials & supplies. The entire rate case expense included for normalization is $1,008,000. Columbia proposes to normalize these costs over twelve months.

L. Normal Uncollectible Accounts Expense

(Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

Exhibit 104: *Schedule 1, Page 2, Line 23 & 24; Schedule 2, Page 15*

Q. Please explain the FTY and FPFTY claim for normal uncollectible accounts expense.

A. I have utilized the Uncollectible Accounts Average Write-off Rate as developed on Exhibit 4, Schedule 2, Page 26, which represents a three year average experience of net write-offs as a percentage of billed DIS revenues. This rate is applied to annualized FTY/FPFTY DIS revenues after adjusting for CAP revenue, to arrive at Total DIS Uncollectible Accounts Expense for the FTY and FPFTY.

Q. Has Columbia reflected the unbundling of uncollectibles related to gas costs?

A. Yes. Columbia has identified a portion of the normal uncollectibles that will be collected through the Merchant Function Charge.

Q. What amount is attributed to the uncollectibles related to gas costs?

A. Columbia has identified $1,206,507 in the FPFTY expenses associated with the unbundling of uncollectibles related to gas costs. This amount is included in the

O&M Expense claim and is offset by the same amount of revenues in Exhibit 103 as developed by Company witness Battig. As a result, the net impact to operating income is zero and does not impact the base rate increase requested in this case.

M. <u>Amortization of Deferred COVID-19 Uncollectible Expense</u>

Exhibit 104: *Schedule 1, Page 2, Line 25; Schedule 2, Page 16*

Q. Please describe the ratemaking adjustment for COVID-19 Uncollectible Expense Amortization.

A. The Final Order approving the Settlement of Columbia's base rate case at Docket No. R-2022-3031211 permits Columbia to recover the deferral of COVID-19 Uncollectible Expense of $2,832,363 over a four year period starting January 1, 2023. Exhibit 104, Schedule 2, Page 16 shows that no adjustment is required as the FTY and FPFTY correctly reflects the annualized level of amortization expense of $708,091.

N. <u>Total Rider USP Costs</u>

Exhibit 104: *Schedule 1, Page 2, Line 26; Schedule 2, Page 17*

Q. Please explain the test year adjustments.

A. The adjustments reflected in Exhibit 104 are a result of the matching of expenses to revenue, as Rider USP is a fully reconciled mechanism. As calculated in Exhibit 103, Rider USP revenues at present rates are $37,330,495 for the FTY and $37,168,342 for the FPFTY. As a result, the Rider USP net impact to operating income is zero with the expense offsetting present rate revenues. Therefore, Rider USP costs do not

impact the base rate increase requested in this case. Company witness Battig calculates the increase to Rider USP resulting from the proposed rate increase.

O. Other Adjustments

Exhibit 104: *Schedule 1, Page 2, Line 28; Schedule 2, Page 18*

Q. Please explain the FPFTY other adjustments.

A. The Company has identified the following proposed O&M adjustments for the FPFTY that are not in the budget:

- Line 1 – Additional O&M for Hydrogen Expense (Supported by Witness Paloney, Statement No. 9).

Q. Does this complete your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense at Present Rates

Line No.	Cost Element Description	R-2022-3031211 Rebuttal Position Normalized FPFTY Twelve Months Ended December 31, 2023 (1) $	Actual Twelve Months Ended December 31, 2023 (2) $	Difference (3)=(2)-(1) $
1	Labor	36,719,966	38,052,041	1,332,074
2	Incentive Compensation	2,570,000	3,760,617	1,190,617
3	Pension	-	20,222	20,222
4	Pension Deferral Amortization	844,977	844,977	-
5	OPEB	-	(719,786)	(719,786)
6	Other Employee Benefits	7,923,000	8,105,711	182,711
7	Outside Services	29,660,205	25,608,015	(4,052,190)
8	Building Leases	1,721,760	1,721,553	(207)
9	Other Rent and Leases	444,000	358,295	(85,705)
10	Corporate Insurance	6,674,000	4,819,611	(1,854,389)
11	Injuries and Damages	348,384	357,635	9,250
12	Employee Expenses	250,787	1,246,740	995,953
13	Company Memberships	471,806	681,690	209,884
14	Utilities and Fuel Used in Company Operations	2,120,490	2,001,194	(119,296)
15	Advertising	683,312	542,780	(140,532)
16	Fleet & Other Clearing	6,547,664	8,587,602	2,039,938
17	Materials & Supplies	6,184,646	6,694,842	510,196
18	Other O&M	2,679,867	2,537,510	(142,357)
19	PUC, OCA, OSBA Fees	2,387,000	2,590,782	203,782
20	NCSC	70,670,360	75,086,855	4,416,495
21	NCSC OPEB costs Amortization	45,000	45,000	-
22	**Operation and Maintenance Expense from Budget**	178,947,225	182,943,886	3,996,660
23	Rate Case Expense	1,254,200	-	(1,254,200)
24	Uncollectible Accounts	7,315,507	5,973,670	(1,341,837)
25	Uncollectible Accounts -Unbundled-gas	1,581,571	1,581,571	-
26	Total Rider USP	42,198,344	35,295,934	(6,902,410)
27	Interest on Customer Deposits	100,416	-	(100,416)
28	COVID-19 Amortization	708,091	708,247	157
29	Other Adjustments	14,853,147	-	(14,853,147)
30	**Total Operation and Maintenance Expense**	246,958,501	226,503,309	(20,455,192)

COLUMBIA STATEMENT NO. 4-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
BRITTANY KOMENDA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

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I. Introduction

Q. Please state your name and business address.

A. My name is Brittany Komenda. My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Lead Regulatory Analyst at NCSC.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony served in this proceeding by the Bureau of Investigation and Enforcement ("I&E") witness Christian Yingling and Pennsylvania Office of Consumer Advocate ("OCA") witness Greg R. Meyer concerning adjustments to Operations and Maintenance Expense ("O&M") for Rate Case Expense and Injuries and Damages, to witness Meyer's proposals for Labor Expense and Uncollectible Expense, and to OCA witness Nicholas A. DeMarco's proposal for the disallowance of the North Franklin deductible included in Injuries and Damages.

Q. Will you be providing an updated revenue requirement deficiency?

A. Yes. An updated revenue requirement deficiency which incorporates all adjustments provided by Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") rebuttal witnesses is labeled as Exhibit BJK-1R, attached hereto.

Q. How is your testimony organized?

A. First, I will discuss Columbia's updated revenue requirement and provide a brief explanation, including the sponsorship of each item that has contributed to the changes. Second, I will address the O&M proposals made by Witnesses Yingling Meyer, and DeMarco.

II. Exhibit BJK-1R, Updated Revenue Requirement

Q. Have you determined a revised revenue requirement?

A. Yes, Exhibit BJK-1R reflects an updated Exhibit 102, Schedule 3, Pages 3 through 6 and computes a revised revenue requirement of $123,640,376 as compared to the Company's originally stated revenue requirement of $124,138,477. This deficiency is noted on Page 3, Line 13 of Exhibit No. 102, reflected on page 1 of Exhibit BJK-1R.

Q. Can you provide a summary of the item that the Company is adjusting that impacts the revenue requirement?

A. Yes. Company witness Bly is supporting updated O&M expenses for NCSC, which are reflected in total O&M in Exhibit BJK-1R. The total impact for this update is a decrease to the Company's claim of $490,926.

Q. Is the Company proposing any additional changes impacting the revenue requirement and Exhibit 102?

A. Yes. The adjustment listed above, when worked through the Company's Cost of Service Model, results in updated amounts for Uncollectible Expense on Additional Revenue Requirement, Late Payment Fees, and Income Taxes, included in Exhibit BJK-1R, page 4.

Q. Does the Company agree with income tax adjustments that are derivative of other parties' other adjustments that have not been accepted by Columbia?

A. No. The Company does not agree. The income tax adjustment resulting from the adjustment identified above in my testimony has been derived using the same methodology as presented in the Company's original filing.

III. I&E's and OCA's Recommended Ratemaking Adjustments

A. Rate Case Expense

Q. Have you reviewed I&E witness Yingling's testimony regarding Rate Case Expense?

A. Yes.

Q. Please describe I&E's proposed changes to Rate Case Expense.

A. I&E proposes to change the amortization period from 12 months to 16 months, and also proposes to reduce the Company's overall budgeted claim for rate case expense by $263,894. The impact relating to the longer amortization further decreases annual expenses by $186,026, for a total reduction to Columbia's claim of $449,921.

Q. Do you agree with I&E recommended 16-month normalization period

for Rate Case Expenses versus the 12-month normalization period utilized by the Company? If not, please explain.

A. No, I do not agree. The Company utilized a 12-month period for normalizing Rate Case Expense because Columbia anticipates a need to file annual rate cases for the foreseeable future. During recent years, the Company has filed annual rate cases with only a few exceptions, therefore, a 12-month normalization period is appropriate, and the Company rejects I&E's associated adjustment.

Q. I&E recommends another reduction to the Company's claim for Rate Case Expense, do you agree? If not, please explain.

A. No. As with many of the adjustments proposed by witness Yingling, his adjustment relies on historical information to make assumptions about future expenses and has proposed an adjustment based upon Columbia's only fully-litigated case in 20 years, R-2020-3018835, (Columbia's "2020 Rate Case").

Q. Please explain further.

A. Columbia's budgeted expenses for this rate case reflect anticipated costs with filing a fully litigated case. However, basing an adjustment on only one historical occurrence of an actual litigated case is inappropriate and not reflective of the level of expenses that are expected. In addition, every case presents different issues, which can affect the litigation costs incurred. For example, OCA has proposed a major and novel depreciation adjustment in this case, which increases the need for outside expert and counsel time. For these reasons, Columbia rejects the proposed adjustment to reduce

the level of rate case expense based upon actual expenses incurred for the 2020 Rate Case.

Q. Has OCA proposed a reduction to the Company's budgeted claim for Rate Case Expense?

A. Yes, OCA witness Meyer proposes to reduce the Company's overall budgeted claim for rate case expense by approximately 40 percent based upon the 3-year average of the percent Meyer asserts Columbia has historically over requested in its last three rate cases.

Q. Do you agree with OCA's proposed reduction to Rate Case Expense? If not, please explain.

A. No. Columbia's budgeted expenses for this rate case reflect anticipated costs with filing a fully litigated case. Meyer has proposed an adjustment based upon one fully litigated case (R-2020-3018835) and two settled cases (R-2021-3024296 and R-2022-3031211). It is inappropriate to calculate an average based upon both litigated and settled cases as litigated cases would have additional testimony, use more resources, and generally incur more expenses than a settled case. Moreover, while the expense allowances in a settlement are unknown, it is reasonable to assume that parties' settlement positions assume a lower level of litigation cost.

B. <u>Injuries and Damages ("I&D")</u>

Q. Have you reviewed I&E's testimony regarding their proposed adjustment to I&D?

A. Yes.

Q. Please describe their Adjustment.

A. I&E recommends a 3-year historical average of cash payments and rejects the Company's adjustments to historical cash payments to reflect current (2023) dollars, and also rejects the use of inflation factors to determine the level of recovery for the FTY and the FPFTY, resulting in a decrease to the Company's claim for I&D by $158,393.

Q. What is Witness Yingling's basis for this adjustment?

A. I&E witness Yingling's stated basis is confusing. He disagrees with the Company's method of calculating its average of five-years, but then immediately states "I accept that the cash payments incurred five years ago to repair damaged property will cost more today due to inflation." (I&E Statement No. 1, p. 25). He offers no explanation why costs incurred three years ago will not cost more today due to inflation, where he agrees costs incurred five years ago will cost more today due to inflation. This is especially not logical given the substantial rate of inflation that has been experienced over the past three years as shown in Columbia Exhibit No. 4, Schedule 2, page 11.

Q. Is there a further error in Mr. Yingling's adjustment?

A. Yes. Mr. Yingling accepts that actual I&D payments should be reflected in the calculation. However, in his calculation, he incorrectly averages the per book accruals for I&D, taken from Columbia Exhibit No. 4, Schedule 1, page 2. Accruals and actual net payments can be substantially different, because accruals represent an

estimate of future I&D. If Mr. Yingling actually had used an average of the past three years cash payments, which are shown on Columbia Exhibit No. 4, Schedule 2, page 11, his recommended allowance would have been $298,705 [($367,013+$322,404+$206,698) ÷3], not $239,681.

Q. Have you reviewed OCA's testimony regarding their proposed adjustments to I&D?

A. Yes.

Q. Please describe Witness Meyer's Adjustment.

A. OCA witness Meyer recommends using historical test year expense and rejects using the Company's five-year average and the use of inflation factors to determine the level of recovery for the FTY and the FPFTY, resulting in a decrease to the Company's claim for I&D by $31,061.

Q. What is Witness Meyer's basis for this adjustment?

A. OCA witness Meyer claims using an inflation factor is unjustified as there is no "discernable trend of these expenses increasing" and "inflation adjustments do not represent known and measurable changes to the utility's revenue requirement." (OCA Statement No. 2, p. 27 – 28).

Q. What are your conclusions about Yingling's and Meyer's testimony regarding their proposed adjustment to I&D?

A. Columbia rejects I&E's and OCA's proposed method of determining I&D and the associated adjustment to the Company's claim and continues to support using a

multiyear average to account for the variable nature of associated costs, and inflation factors to account for the rising costs over time.

Q. Does OCA make any further proposed adjustments to I&D?

A. Yes. OCA witness DeMarco recommends a disallowance of the $25,000 deductible included in I&D expenses from the North Franklin Incident (Docket No. M-2022-3012079).

Q. What is Witness DeMarco's basis for this adjustment?

A. OCA witness DeMarco's claims ratepayers "should not pay a deductible expense because of the Company's actions resulting in the North Franklin Incident." (OCA Statement No. 7, p. 17).

Q. What are your conclusions about DeMarco's testimony regarding his proposed adjustment to I&D for the North Franklin Incident?

A. Columbia also rejects OCA's proposed disallowance of $25,000 to I&D expenses related to this deductible for two separate reasons. Columbia uses a five-year average of I&D actual expenses to account for the variable nature of associated costs. If Columbia's five-year average and Mr. DeMarco's adjustment were accepted, the result would be a decrease of approximately $5,000 to I&D and not $25,000 as proposed, because the deductible for this incident was only incurred in one year. Additionally, the deductible was paid in August of 2019; therefore, if OCA Witness Meyer's proposed adjustment is accepted to adjust I&D to the HTY expense, or if Mr.

Yingling's three-year average is accepted, the $25,000 deductible would not be included in the revenue requirement and no adjustment would be necessary.

C. <u>Uncollectibles Expense</u>

Q. Have you reviewed OCA's testimony regarding their proposed adjustment to Uncollectible Expense?

A. Yes.

Q. Please describe Witness Meyer's Adjustment.

A. OCA witness Meyer recommends using a three-year average of historical uncollectibles expense (net write offs), resulting in a decrease to the Company's claim for uncollectible expense by $1.4 million.

Q. What is Witness Meyer's basis for this adjustment?

A. OCA claims Columbia's "proposed level of uncollectibles expense is higher than every year dating back to 2019" and that OCA's "proposed level of uncollectibles expense of $8.3 million is conservative as it includes an abnormally high year of uncollectibles due to the effects of COVID." (OCA Statement No. 2, p. 26).

Q. Why is it inappropriate to use charge-offs and recoveries from Account 144 to determine net write-offs?

A. Net write offs included in Account 144 do not include the write-offs associated with CAP expected payments; therefore, net write offs would be understated using this approach. The "CAP expected payment" is the total billed amount a CAP customer must pay in order to remain a participant in the CAP Program. If a CAP customer

fails to make the required expected payment, then they no longer qualify to participate in the CAP Program. Subsequent to default of a CAP customer's expected payment and termination of eligibility in the CAP Program, their total cumulative expected payment amount (Accounts Receivable balance) is written-off as uncollectible expense to account 904. Due to the unpredictable nature of these types of customers the Company does not reserve in Account 144 for uncollectibles associated with these types of customers.

Q. Are there any additional issues with OCA's method of calculating uncollectible expense?

A. Yes. It is a generally accepted principle that uncollectible expense varies in relation to billed revenue for residential and small commercial and industrial customers, and Columbia's net write-off ratio reflects that relationship, taking into account that write-offs lag billed revenues, as shown on Columbia Exhibit No.4, Schedule 2, page 27. Columbia's base rates were increased in late December 2021 and late December 2022. As a result, the net write-off amounts for 2021 and 2022 are not representative of net write-offs at currently-effective rates. In addition, a write-off factor is required to determine uncollectible expense associated with the revenue increase at proposed rates. Using an average experience factor as a percentage of revenue, in lieu of average net charge offs, is a more accurate approach to reflect the level of expected uncollectible expenses because it incorporates the variable nature of revenue in the calculated amount.

Q. What are your conclusions about OCA's testimony regarding their proposed adjustment to Uncollectible Expense?

A. Columbia rejects OCA's proposed method of determining uncollectible expense and the associated adjustment to the Company's claim for the aforementioned reasons and continues to support using an experience factor of net write-offs as a percentage of revenue based on a multiyear average to account for the variable nature of uncollectible costs.

D. <u>Labor Expense</u>

Q. Have you reviewed OCA's testimony regarding their proposed adjustment to Labor Expense?

A. Yes.

Q. Please describe Witness Meyer's Adjustment.

A. OCA claims Columbia's proposed level of labor expense is overstated for the FPFTY and proposes an adjustment to reduce Columbia Gas' requested level of payroll expense by approximately $1.95 million based on Meyer's calculation below.

Q. What is Witness Meyer's basis for this adjustment?

A. OCA witness Meyer applied the projected payroll increases for the different periods of time and the months applicable to the FPFTY to the annualized labor amounts as of November 30, 2023. Meyer then applied the capitalization factor used by Columbia to the payroll increases to determine annualized payroll expense to be included in the cost of service. (OCA Statement No. 2, p. 10 – 11).

Q. Do you agree with Witness Meyer's basis for this adjustment?

A. No. Witness Meyer's use of a buildup method of calculating labor assumes that the only change to labor expense involves annual wage increases with no annualization of increases that occur within 2025. The Company's method of determining labor expenses for the FPFTY is to first use the budget for calendar year 2025 and adding an annualization adjustment to reflect a full twelve months of employee labor expenses for the FPFTY.

Q. What support does Witness Meyer provide for rejecting the Company's method?

A. Witness Meyer provides no support and does not mention the budget. He only states he believes the Company's labor expenses are overstated.

Q. What are your conclusions about OCA's testimony regarding their proposed adjustment to Labor Expense?

A. Columbia rejects OCA's proposed method of determining labor expense and the associated adjustment to the Company's claim and continues to support using Columbia's method of using the budget and annualizing the FPFTY. The annualization adjustment is a long-standing ratemaking adjustment and merely raises the level of payroll expense for all months in the FPFTY to the level of wage rates expected to be paid during the FPFTY. For example, pay increases for Exempt Employees are anticipated to be paid during the FPFTY starting March 1, 2025; the annualization adjustment for these employees effectively increases the expense to

reflect this wage increase to be effective January 1, and thus reflecting the entire test year at the level of wages that would be in effect at the end of the test period. Revenues at current rates are also reflective of annualized and normalized levels for the same period and a revenue deficiency (or sufficiency) is revealed by comparing these revenues to annualized expenses (at the determined rate of return on rate base, also valued at the end of the test period).

Q. Has the Commission accepted the principle that FPFTY labor expense should be annualized?

A. Yes. I am advised by counsel that the Commission accepted Columbia's labor annualization adjustment in the Columbia 2020 rate case order at Docket No. R-2020-3018835, and rejected a disallowance proposed by I&E. I note that this annualization is consistent with the annualization of revenues for the FPFTY, the use of FPFTY end plant balances and calculated depreciation expense on test year ending plant balances.

Q. Are there other issues with OCA's revenue requirement?

A. Yes. As further discussed in Columbia witnesses Spanos, Harding, and Covert's rebuttal testimony, OCA proposes adjustments to depreciation expense and rate base, but does not reflect the corresponding adjustments to accumulated depreciation and accumulated deferred income taxes that would be needed to determine an accurate revenue requirement.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Exhibit No. 102
Schedule 3
Page 3 of 6
Witnes: B. J. Komenda

Columbia Gas of Pennsylvania, Inc.
Statement of Income at Present and Proposed Rates
FTY = Future Test Year TME 11/30/24, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2025

Line No.	Description	Reference	TME November 30, 2023 Per Books	HTY Adjustments @ Present Rates	Pro Forma Historic Test Year @ Present Rates	FTY Adjustments @ Present Rates	Pro Forma Future Test Year @ Present Rates	FPFTY Adjustments @ Present Rates	Pro Forma Fully Projected Future Test Year @ Present Rates	Adjustments @ Proposed Rates	FPFTY @ Proposed Rates
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
			$	$	$	$	$	$	$	$	$
1	Operation Revenues										
2	Base Rate Revenues (Incl. Transportation)	Exhibit 3 / 103	560,938,569	(1,195,636)	559,742,933	9,971,509	569,714,442	(967,165)	568,747,277	117,524,421	686,271,698
3	Fuel Revenues	Exhibit 3 / 103	262,152,594	(92,044,466)	170,108,128	5,396,296	175,504,424	307,744	175,812,168	-	175,812,168
4	Rider USP	Exhibit 3 / 103	38,891,357	(2,397,898)	36,493,459	837,036	37,330,495	(162,153)	37,168,342	5,907,509	43,075,851
5	Gas Procurement Charge	Exhibit 3 / 103	399,661	31,473	431,134	16,502	447,636	2,240	449,876	-	449,876
6	Merchant Function Charge	Exhibit 3 / 103	2,098,223	(931,897)	1,166,326	34,472	1,200,798	5,709	1,206,507	-	1,206,507
7	Rider CC	Exhibit 3 / 103	42,012	3,332	45,344	728	46,072	(259)	45,813	-	45,813
8	Rider EE	Exhibit 3 / 103	865,222	361,397	1,226,619	28,134	1,254,753	(5,450)	1,249,303	-	1,249,303
8	Pipeline Penalty Refund	Exhibit 3	(18,503,728)	18,503,728	-	-	-	-		-	-
9	Total Sales and Transportation Revenue		846,883,910	(77,669,967)	769,213,943	16,284,677	785,498,620	(819,334)	784,679,286	123,431,930	908,111,216
10	Off System Sales Revenue	Exhibit 3 / 103	11,589,209	(11,589,209)	-	-	-	-	-	-	-
11	Late Payment Fees	Exhibit 3 / 103	1,897,169	(598,159)	1,299,010	27,500	1,326,510	(1,383)	1,325,127	208,446	1,533,573
12	Other Operating Revenues (Excl. Transportation)	Exhibit 3 / 103	102,666	-	102,666	-	102,666	-	102,666	-	102,666
13	Total Operating Revenues		860,472,954	(89,857,334)	770,615,619	16,312,177	786,927,796	(820,717)	786,107,079	**123,640,376**	909,747,455
							-				
14	Operating Revenue Deductions										
15	Gas Supply Expense	Exhibit 3 / 103	262,152,594	(92,044,466)	170,108,128	5,396,296	175,504,424	307,744	175,812,168	-	175,812,168
16	Off System Sales Expense	Exhibit 3 / 103	11,589,209	(11,589,209)	-	-	-	-	-	-	-
17	Gas Used in Company Operations		(823,312)	823,312	-	-	-	-	-	-	-
18	Operating and Maintenance Expense	Exhibit 4 / 104	228,194,954	(3,359,425)	224,835,529	(1,462,593)	223,372,936	(6,186,589)	217,186,347	1,780,929	218,967,276
19	Depreciation and Amortization	Exhibit 5 / 105	100,785,008	11,187,004	111,972,012	12,636,705	124,608,717	11,398,346	136,007,063	-	136,007,063
20	Net Salvage Amortized	Exhibit 5 / 105	5,870,533	(397,574)	5,472,959	91,655	5,564,614	(166,975)	5,397,639	-	5,397,639
21	Taxes Other Than Income Taxes	Exhibit 6 /106	3,789,421	47,011	3,836,432	450,973	4,287,405	343,350	4,630,755	-	4,630,755
22	Total Operating Revenue Deductions		611,558,407	(95,333,346)	516,225,060	17,113,036	533,338,096	5,695,877	539,033,973	1,780,929	540,814,902
23	Operating Income Before Income Taxes		248,914,547	5,476,012	254,390,559	(800,859)	253,589,700	(6,516,594)	247,073,107	121,859,447	368,932,554
24	Income Taxes	Exhibit 7 / 107	40,370,045	(1,523,942)	38,846,103	(2,630,456)	36,215,648	(3,246,658)	32,968,990	32,185,248	65,154,238
25	Investment Tax Credit	Exhibit 7 / 107	(223,159)	-	(223,159)	53,264	(169,895)	48,684	(121,211)	-	(121,211)
26	Operating Income		208,767,661	6,999,953	215,767,615	1,776,333	217,543,948	(3,318,620)	214,225,328	89,674,199	303,899,527
27	Rate Base	Exhibit 8 / 108	3,044,910,336	(146,881,130)	2,898,029,207	283,495,354	3,181,524,560	307,563,007	3,489,087,567	-	3,489,087,567
28	% Rate of Return Earned on Rate Base		6.86%		7.45%		6.84%		6.14%		8.71%

Exhibit No. 102
Schedule 3
Page 4 of 6
Witnes: B. J. Komenda

Columbia Gas of Pennsylvania, Inc.
Calculation of Proforma Interest Expense
FTY = Future Test Year TME 11/30/24, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2025

Line No.	Description	Pro Forma (1) $
	FTY Calculation	
1	Rate Base	3,181,524,560
2	Weighted Cost of Short &	
3	Long Term Debt	2.320%
4	Interest Expense	73,811,370
	FPFTY Calculation	
5	Rate Base	3,489,087,567
6	Weighted Cost of Short &	
7	Long Term Debt	2.320%
8	Interest Expense	80,946,832

Columbia Gas of Pennsylvania, Inc.
Rate of Return on Rate Base
Proposed Revenue Requirement
FTY = Future Test Year TME 11/30/24, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2025

Line No.	Description	Detail	Amount
			(1) $
1	Proforma Rate Base at Present Rates		3,489,087,567
2	Return on Rate Base		8.710%
3	Total Requirement		303,899,527
4	Less: Net Operating Income at Present Rates		214,225,328
5	Net Required Operating Income		89,674,199
6	Revenue Conversion Factor		1.37877313
7	Gross Revenue Requirement		123,640,376
8	Revenue Conversion Factor:		
9	Operating Revenue		1.00000000
10	Less: Uncollectibles		0.01440410
11	Income Before State Taxes		0.98559590
12	State Income Tax Effect Tax Rate		0.06850354
13	Less: State Income Tax		0.06751680
14	Income Before Federal Taxes		0.91807909
15	Less: Federal Tax @ 21%		0.19279661
16	Adjusted Operating Income		0.72528248
17	Revenue Conversion Factor		1.37877313

Exhibit No. 102
Schedule 3
Page 6 of 6
Witnes: B. J. Komenda

Columbia Gas of Pennsylvania, Inc.
Additional Revenue Requirement Adjustments
FTY = Future Test Year TME 11/30/24, FPFTY = Fully Projected Forecasted Test Year Period Ended December 31, 2025

Line No.		Description	Amount (1) $
1		Additional Revenue Requirement	123,431,930
2	Plus:	Late Payments	208,446
3		Total Revenue Requirement	123,640,376
4	Less:	Uncollectible Accounts Expense	
5		Line 3 X Uncollectible Rate	1,780,929
6		Income Before State Income Tax	121,859,447
7		State Income Taxes	
8		Exh 107, Pg 17, Col 3 Less Exh 107, Pg 17, Col 2	8,347,803
9		Income Before Federal Income Tax	113,511,644
10		Federal Income Taxes	
11		Line 9 Times 21%	23,837,445
12		Net Required Operating Income	89,674,199

COLUMBIA STATEMENT NO. 4-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REJOINDER TESTIMONY OF
BRITTANY KOMENDA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 30, 2024

I. Introduction

Q. Please state your name and business address.

A. My name is Brittany Komenda. My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rejoinder testimony?

A. I will respond to the surrebuttal testimony served in this proceeding by Pennsylvania Office of Consumer Advocate ("OCA") witness Greg R. Meyer concerning adjustments to Operations and Maintenance Expense ("O&M") for Labor Expense and Uncollectible Expense.

Q. Have you reviewed OCA witness Meyer's Surrebuttal testimony regarding Uncollectible Expense?

A. Yes. Witness Meyer generally agrees with my rebuttal testimony. However, Meyer has seen several times where a utility's uncollectible expense does not track with the level of revenues billed to customers and believes this is the case with Columbia Gas. Additionally, Meyer expects me to respond by stating the OCA's analysis is flawed because it does not recognize the time delay of uncollectible write-offs with the collection of sales revenue.

Q. Do you agree with OCA witness Meyer's Surrebuttal testimony regarding Uncollectible Expense?

A. No. Columbia disagrees with OCA's method of using dollars rather than a ratio to calculate uncollectible accounts expense. Columbia recognizes that there is not an exact ratio of uncollectibles to revenue from year to year, which is why CPA uses a 3 year average ratio. It is this ratio that is used to set uncollectible expense, both at present rates and proposed rates. I note that Mr. Meyer's revenue gross up factor includes this uncollectible accounts expense ratio. Furthermore, Meyer's Surrebuttal fails to acknowledge my argument in rebuttal testimony for why it is inappropriate to use charge-offs and recoveries from reserve Account 144 to determine net write-offs as they do not include CAP expected payments that are written off to expense account 904. Please see Table BJK-RJ-1 below for the 3 year average of CAP expected payments.

Table BJK-RJ-1

CAP Expected Payments in Account 904	
Year	Amount
2021	$998,340
2022	$828,998
2023	$893,469
3 Year Average	$906,936

If OCA's methodology for calculating uncollectible is accepted by the Commission the table above shows that an additional $906,936 would need to be added to OCA's 3

year average of net write-offs resulting in a decrease of $502,237 to uncollectible expense and not OCA's recommended adjustment of $1,409,173.

Q. Have you reviewed OCA witness Meyer's Surrebuttal testimony regarding Labor Expense?

A. Yes, Witness Meyers states that taking actual payroll expenses as of November 30, 2023, and increasing each payroll group for the anticipated wage increases that Columbia Gas has identified in its workpapers is a more accurate approach to annualizing wages as this approach relies on known and measurable labor expense.

Q. Do you agree that Mr. Meyer's labor annualization is more accurate?

A. No, Witness Meyer's labor adjustment uses annualized normal pay only and has overlooked the appropriate expenses for overtime pay, premium pay, other pay, and affiliate pay. Please see Confidential Attachment BJK-RJ-1 for Meyer's confidential labor workpaper. If Mr. Meyer were to include the HTY level of overtime pay, premium pay, other pay, and affiliate pay in his calculation to determine total labor expense there would be no need for an adjustment as shown in Table BJK-RJ-2 below.

Table BJK-RJ-2

Premium, Overtime, Other, & Affiliate Pay (Exh 4, Sch 2, Page 3)	$ 6,877,616
O&M % (Ex 4, Sch 2, Page 5)	51.48%
Net Premium, Overtime, Other, & Affiliate Pay	$ 3,540,567
Net Premium, Overtime, Other, & Affiliate Pay	$ 3,540,567
OCA's Proposed FPFTY (Exhibit GRM-SR-1, Page 6)	36,278,729
OCA's Proposed + Net Premium, Overtime, Other, & Affiliate Pay	$ 39,819,296

OCA's Proposed + Net Premium, Overtime, Other, & Affiliate Pay	$ 39,819,296
Columbia Proposed FPFTY Labor (Ex 104, Sch 1, Page 2)	(38,227,431)
Difference (Cost Savings Included in the Budget)	$ 1,591,865

I note that Columbia always incurs overtime, premium pay, other pay, and affiliate pay.

Q. Does this complete your Prepared Rejoinder Testimony?

A. Yes, it does.

CONFIDENTIAL

EXHIBIT BJK-RJ-1

COLUMBIA STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
JOHN J. SPANOS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. With what firm are you associated and in what capacity?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming) as President.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since June 1986.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals. I am also a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?

A. Yes, I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Will you outline your experience in the field of depreciation?

A. I have over 37 years of depreciation experience which includes expert testimony in more than 450 cases before approximately 46 regulatory commissions, including this Commission. These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have also supervised over 800 other depreciation or valuation assignments. Please refer to Appendix A for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the gas plant of Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company").

Q. Have you prepared exhibits presenting the results of your studies?

A. Yes. Exhibit No. 9 presents the results of the depreciation study as of November 30, 2023. Exhibit No. 109, Schedule No. 1, Attachment A presents the results of the depreciation study as of November 30, 2024. Exhibit No. 109, Schedule No. 1, Attachment B presents the results of the depreciation study as of December 31, 2025. In addition, I am responsible for the responses to the following filing requirements pertaining to depreciation under Section 53.53(a)(1) of the Commission's regulations: 3, 4, 5, 6, 7 and 17. I also sponsor Exhibit No. 5 and Exhibit No. 105, which are summaries of the results to Exhibit No. 9 and Exhibit No. 109, respectively.

Q. Please describe Exhibit Nos. 9 and 109.

A. Exhibit No. 9, Schedule No. 1, titled "2023 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2023," includes the results of the depreciation study as related to the original cost as of November 30, 2023. The report also includes the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment A, titled "2024 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2024," includes the results of the depreciation study as related to the estimated original cost as of November 30, 2024. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment B, titled "2025 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2025," includes the results of the depreciation study as related to the estimated original cost as of December 31, 2025.

Q. What were the purposes of your depreciation studies?

A. The purposes of the depreciation studies were to estimate the annual depreciation accruals related to gas plant in service for ratemaking purposes and, using Commission-approved procedures, to estimate the Company's book reserve as of November 30, 2024, and December 31, 2025.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent Annual Depreciation Report including service life study filed in August 2022?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used for over twenty years. For Accounts 391.1, 391.11, 391.12, 392, 394, 395 and 398, the claim is based on the straight line remaining life method of amortization. The accounts have a large number of units, but small asset values representing approximately 1 percent of the depreciable plant. The assets represent items located in office buildings, service centers, garages and warehouses. Given the difficulty in maintaining accounting records for these numerous assets and high cost for periodic inventories, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. All units are retired when the age of the vintage reaches the amortization period. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. What group procedure is being used in this proceeding for depreciable accounts?

A. The average service life procedure is used in the current proceeding for plant installed prior to 1976 and the equal life group procedure for 1976 and subsequent vintages. This calculation has been used in the same manner as the Company's most recent annual depreciation reports.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over twenty-five years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve approved by the Commission in the last proceeding.

Q. How was the book reserve used in the calculation of annual depreciation?

A. The book reserve by account was allocated to vintages to determine original cost less accrued depreciation by vintage. The total annual accrual is the sum of the results of dividing the original costs less accrued depreciation by the vintage composite remaining lives.

Q. How was the book reserve as of November 30, 2024, estimated?

A. The book reserve as of November 30, 2024, by account, was projected by adding estimated accruals, salvage and the amortization of net salvage, and subtracting estimated retirements and cost of removal from the book reserve as of November 30, 2023. Annual accruals were estimated using the annual accruals calculated as of November 30, 2023. For most accounts, salvage and cost of removal were estimated by (1) expressing actual salvage and cost of removal as a percent of retirements by account, for the most recent five-year period, and (2) applying those percents to the projected retirements by account. For the purpose of calculating the annual accruals, the projected book reserve by account was allocated to vintages based on calculated accrued depreciation as of November 30, 2024.

Q. Was the book reserve as of December 31, 2025, estimated using the same methodology?

A. Yes.

Q. Has a service life study of the Company's gas utility property been performed?

A. Yes. The most recent service life study was performed as of December 2021. The service life study is the basis for the service lives I used to calculate annual accruals.

Q. Briefly outline the procedure used in performing the service life study.

A. The service life study consisted of assembling and compiling historical data from the records related to the gas utility plant of the Company; statistically analyzing such data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning Company practices and plans as they relate to plant operations; and interpreting the above data to form judgments of service life characteristics.

Iowa type survivor curves were used to describe the estimated survivor characteristics of the mass property groups. Individual service lives were used for major individual units of plant, such as distribution buildings housing offices and shops. The life span concept was recognized by coordinating the lives of associated plant installed in subsequent years with the probable retirement date defined by the life estimated for the major unit.

Q. What statistical data were employed in the historical analyses performed for the purpose of estimating service life characteristics?

A. The data consisted of the entries made to record retirements and other transactions related to the gas plant during the period 1939-2021. The year 1939 is the first year continuing property records were maintained. These entries were classified by depreciable group, type of transaction, the year in

which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers, and balances. In the presentation of service life statistics, only the significant exposure points that were utilized in determining survivor curves were plotted. This process is utilized to show my judgment in service life determinations.

Q. What was the source of these data?

A. They were assembled from Company records related to its gas plant in service.

Q. Were the methods used in the service life study the same as those used in other depreciation studies for gas utility plant presented before this Commission?

A. Yes. The methods are the same ones that have been presented previously for Columbia Gas of Pennsylvania, Inc. and for other gas companies before the Pennsylvania Public Utility Commission and that have been accepted by the Commission in its past orders concerning gas utilities.

Q. What approach did you use to estimate the lives of significant structures such as office buildings and service centers?

A. I used the life span technique to estimate the lives of significant structures. In this technique, the survivor characteristics of the structures are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the structure such as plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation

for the structure by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation inasmuch as concurrent retirement of all years of installation will occur when the structure is retired.

Q. Has your firm used this approach in other proceedings before this Commission?

A. Yes, we have used the life span technique on many occasions before the Pennsylvania Public Utility Commission.

Q. What are the bases for the probable retirement years that you have estimated for each structure?

A. The bases for the estimates of probable retirement years are life spans for each structure that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other gas utilities for similar structures. Most of the life spans result in probable retirement dates that are many years in the future. As a result, the retirement of these structures is not yet subject to specific management plans. Such plans would be premature. At the appropriate time, studies of the economics of rehabilitation and continued use or retirement of the structure will be analyzed and the results incorporated in the estimation of the structure's life span.

Q. Are the factors considered in your estimates of service life presented in Exhibit No. 109, Schedule No. 1, Attachment A?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented by account on pages III-2 through III-8 of Exhibit No. 109, Schedule No. 1, Attachment A.

Q. Were there any material changes to life characteristics as a result of this rate proceeding?

A. No. There was no material change in the life estimate for plant accounts or subaccounts in this rate proceeding. All life estimates were based on the recent annual depreciation report and the service life study as conducted.

Q. Please outline the contents of Exhibit No. 109, Schedule No. 1, Attachment A.

A. Exhibit No. 109, Schedule No. 1, Attachment A is presented in eight parts. Part I, Introduction, sets forth the scope and basis of the study. Part II, Estimation of Survivor Curves, includes a description of the Iowa Curves and the formulation of the retirement rate method. Part III, Service Life Considerations, and Part IV, Calculation of Annual and Accrued Depreciation, include a description of the judgment utilized for life parameters and the explanation of depreciation procedures.

Part V, Results of Study, presents a description of the results and summaries of the depreciation calculations. Part VI, Service Life Statistics, presents the graphs and tables which relate to the service life study. Part VII, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations by account. Part VIII, Experienced and Estimated Net Salvage, presents the cost of removal and gross salvage by account for the years 2019 through 2023.

Table 1, pages V-4 through V-6 presents the estimated survivor curve, the original cost as of November 30, 2024, and the book reserve and calculated annual depreciation for each account or subaccount of Gas Plant. Table 2 on page V-7 presents the bringforward to November 30, 2024, of the book depreciation reserve as of November 30, 2023. Table 3 on pages V-8 and V-9 sets forth the calculation of the annual accruals used in the bringforward. Table 4, page V-10, presents the experienced and estimated net salvage during the five-year period, 2019 through 2023.

The section beginning on page VI-1 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VII-1 presents the depreciation calculations related to original cost. The tabulation on pages VII-3 through VII-6 presents the cumulative depreciated original cost by year installed. The tabulations on pages VII-8 through VII-68 present the calculation of annual depreciation by vintage by account for each depreciable group of utility plant.

Q. Please outline the contents of Exhibit No. 109, Schedule No. 1, Attachment B.

A. Exhibit No. 109, Schedule No. 1, Attachment B includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of December 31, 2025. The descriptions and explanations presented in Exhibit No. 109, Schedule No. 1, Attachment A are also applicable to the depreciation calculations presented in Exhibit No. 109, Schedule No. 1, Attachment B. The graphs and tables related to service life presented in Exhibit No. 109, Schedule No. 1, Attachment A also support the

service life estimates used in Exhibit No. 109, Schedule No. 1, Attachment B inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of December 31, 2025, are organized and presented in the same manner as those as of November 30, 2024.

Q. Please outline the contents of Exhibit No. 9.

A. Exhibit No. 9 includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of November 30, 2023. The descriptions and explanations presented in Exhibit No. 109, Schedule No. 1, Attachment A are also applicable to the depreciation calculations presented in Exhibit No. 9. The graphs and tables related to service life presented in Exhibit No. 109, Schedule No. 1, Attachment A also support the service life estimates used in Exhibit No. 9, inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of November 30, 2023, are organized and presented in the same manner as those as of November 30, 2024.

Q. Please use an example to illustrate the manner in which the study is presented in Exhibit Nos. 9, and 109.

A. I will use Account 376, Mains, as my example, inasmuch as it is the largest depreciable group and represents 69 percent of the original cost of depreciable gas plant as of November 30, 2024.

The retirement rate method was used to analyze the survivor characteristics of this group. The life tables for the 1939-2021 and 1982-2021 experience bands are presented on pages VI-48 through VI-55 of Exhibit No.

109, Schedule No. 1, Attachment A. The life tables, or original survivor curve, are plotted along with the estimated smooth survivor curve, the 65-R1, on page VI-47.

The calculations of the annual depreciation related to the original cost as of November 30, 2023, of gas plant are presented by type main on pages II-33 through II-39 of Exhibit No. 9. The calculation is based on the 65-R1 survivor curve, the attained age, and the allocated book reserve. The calculations as of November 30, 2024, are presented by type main on pages VII-33 through VII-36 of Exhibit No. 109, Schedule No. 1, Attachment A and are based in part on the bringforward of the book reserve. Also, the calculations as of December 31, 2025 are presented by type main on pages II-33 through II-36 of Exhibit No. 109, Schedule No. 1, Attachment B and are based in part on the bringforward of the book reserve. The tabulations in Exhibit Nos. 9 and 109 set forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. The totals are brought forward to Table 1 on page I-3 in Exhibit No. 9, page V-4 in Exhibit No. 109, Schedule No. 1, Attachment A and on page I-3 in Exhibit No. 109, Schedule No. 1, Attachment B.

Q. In what manner is net salvage incorporated in the depreciation calculations?

A. As stated on page IV-9 of Exhibit No. 109, Schedule No. 1, Attachment A, no adjustment for net salvage was made to the calculated annual depreciation amounts. The total calculated annual depreciation set forth on page I-6 of Exhibit No. 9, page V-10 of Exhibit No. 109, Schedule No. 1, Attachment A and

on page I-9 of Exhibit No. 109, Schedule No. 1, Attachment B should include an addition for the amortization of negative net salvage in accordance with the practice of this Commission. The amortization is based on experience during the period 2018 through 2022 for the calculation as of November 30, 2023, and on experience during the period 2019 through November 30, 2023, plus estimates for the last month of 2023 for the calculation as of November 30, 2024.

The amortization for the December 31, 2025 calculation is based on experience during the period 2020 through November 30, 2023, plus estimates for the period December 2023 through December 2024. The amounts of the five-year amortizations are calculated in Table 2 on page I-6 of Exhibit No. 9, in Table 4 on page V-10 of Exhibit No. 109, Schedule No. 1, Attachment A and in Table 4 on page I-9 of Exhibit No. 109, Schedule No. 1, Attachment B.

Q. Have you provided a monthly bringforward to December 31, 2025, of the plant and book depreciation reserve as of November 30, 2024

A. Yes, Exhibit JJS-01 at the end of this testimony provides the monthly detail of the plant in service, book depreciation reserve and the calculated depreciation. This exhibit agrees with the fully projected future test year plant and reserve balances as shown on Exhibit No. 109, Schedule No. 1, Attachment B, Table 1 on pages I-3 through I-5.

Q. Does this complete your testimony at this time?

A. Yes, it does.

APPENDIX A

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad,

and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December 2000, I was promoted to the position as Vice-President of

Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of

Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Energy Arkansas, Inc.; Black Hills

Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire; FirstEnergy Service Corporation; Northeast Ohio Natural Gas Corporation; Blue Granite Water Company; Spire Missouri, Inc.; Dominion Energy South Carolina, Inc.; South FirstEnergy Operating Companies; Dayton Power and Light Company; Liberty Utilities; East Kentucky Power Cooperative; Bangor Natural Gas; Hanover Borough Municipal Water Works; West Virginia American Water Company; Evergy Metro; Evergy Missouri West; Granite State Electric; Bluegrass Water; The Borough of Ambler; Newtown Artesian Water Company and Connecticut Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the

Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.:

"Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY,

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY,

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

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	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

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	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

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166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

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200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Corporation	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

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233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Cause No. 45029	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

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266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

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301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2019	HI PUC	Docket No. 2019-0117	Young Brothers, LLC	Depreciation
331.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
334.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
335.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
336.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
337.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
338.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation

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339.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation
340.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
341.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West	Depreciation
342.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
343.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
344.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
345.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
346.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
347.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
348.3	2020	OR PSC	UE 374	PacifiCorp	Depreciation
349.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
350.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
351.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy	Depreciation
352.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
353.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
354.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
355.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
356.	2020	OR PSC	UG 388	Northwest Natural Gas Company	Depreciation
357.	2020	MO PSC	Case No. GR-2021-0241	Ameren Missouri Gas	Depreciation
358.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
359.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
360.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
361.	2021	NC Util.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
362.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
363.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation
364.	2021	KS PSC	21-BHCG-418-RTS	Black Hills Kansas Gas	Depreciation
365.	2021	KY PSC	Case No. 2021-00190	Duke Energy Kentucky	Depreciation
366.	2021	OR PSC	Docket UM 2152	Portland General Electric	Depreciation
367.	2021	ILL CC	Docket No. 20-0810	North Shore Gas Company	Depreciation
368.	2021	FERC	ER21-1939-000	Duke Energy Progress	Depreciation
369.	2021	FERC	ER21-1940-000	Duke Energy Carolina	Depreciation
370.	2021	KY PSC	Case No. 2021-00183	NiSource Columbia Gas of Kentucky	Depreciation
371.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation
372.	2021	OH PUC	Case No. 21-0596-ST-AIR	Aqua Ohio	Depreciation
373.	2021	PA PUC	Docket No. R-2021-3026116	Hanover Borough Municipal Water Works	Depreciation
374.	2021	OR PSC	UM-2180	Idaho Power Company	Depreciation
375.	2021	ID PUC	Case No. IPC-E-21-18	Idaho Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY,

	Year	Jurisdiction	Docket No.	Client Utility	Subject
376.	2021	WPSC	6690-DU-104	Wisconsin Public Service Company	Depreciation
377.	2021	PAPUC	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
378.	2021	OH PUC	Case No. 21-637-GA-AIR; Case No. 21-638-GA-ALT; Case No. 21-639-GA-UNC; Case No. 21-640-GA-AAM	NiSource Columbia Gas of Ohio	Depreciation
379.	2021	TX PUC	Texas PUC Docket No. 52195; SOHA Docket No. 473-21-2606	El Paso Electric	Depreciation
380.	2021	MO PSC	Case No. GR.2021-0108	Spire Missouri	Depreciation
381.	2021	WV PSC	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
382.	2021	FERC	ER21-2736	Duke Energy Carolinas	Depreciation
383.	2021	FERC	ER21-2737	Duke Energy Progress	Depreciation
384.	2021	IN URC	Cause #45621	Northern Indiana Public Service Company	Depreciation
385.	2021	PA PUC	Docket No. R-2021-3026682	City of Lancaster	Depreciation
386.	2021	OH PUC	Case No. 21-887-EL-AIR; Case No. 21-888-EL-ATA; Case No. 889-El-AAM	Duke Energy Ohio	Depreciation
387.	2021	AK PSC	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
388.	2021	OK CC	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
389.	2021	FERC	Case ER-22-392-001	El Paso Electric	Depreciation
390.	2021	FERC	Case ER-21-XXX	MidAmerican Electric	Depreciation
391.	2021	PA PUC	Docket Nos. R-2021-3027385, R-2021-3027386	Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc.	Depreciation
392.	2022	FERC	Case ER-22-282-000	El Paso Electric	Depreciation
393.	2022	ILL CC	Docket No. 22-0154	MidAmerican Gas	Depreciation
394.	2022	MO PSC	Case No. ER-2022-0129	Evergy Metro	Depreciation
395.	2022	MO PSC	Case No. ER-2022-0130	Evergy Missouri West	Depreciation
396.	2022	PA PUC	Docket No. R-2022-3031211	NiSource Columbia Gas of Pennsylvania, Inc.	Depreciation
397.	2022	MA DPU	D.P.U. 22-20	The Berkshire Gas Company	Depreciation
398.	2022	PA PUC	R-2022-3031672; R-2022-3031673	Pennsylvania-American Water Company	Depreciation
399.	2022	SD PUC	Docket No. NG22-	MidAmerican Gas	Depreciation
400.	2022	MD PSC	Case No. 9680	NiSource Columbia Gas of Maryland	Depreciation
401.	2022	WYPSC	Docket No. 20003-214-ER-22	Black Hills Energy – Cheyenne Light, Fuel and Powe	Depreciation
402.	2022	MA DPU	D.P.U. 22.22	NSTAR Electric Company d/b/a Eversource Energy	Depreciation
403.	2022	NC Util Com	Docket No. W-218, Sub 573	Aqua North Carolina, Inc.	Depreciation
404.	2022	OR PUC	UM2213	Northwest Natural Gas	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY,

	Year	Jurisdiction	Docket No.	Client Utility	Subject
405.	2022	OR PUC	UM2214	Northwest Natural Gas	Depreciation
406.	2022	ME PUC	Docket No. 2022-00152	Central Maine Power	Depreciation
407.	2022	SC PSC	Docket No. 2022-254-E	Duke Energy Progress	Depreciation
408.	2022	NC Util Com	Docket No. E-2, SUB 1300	Duke Energy Progress	Depreciation
409.	2022	IN URC	Cause #45772	Northern Indiana Public Service Company	Depreciation
410.	2022	PA PUC	R-2022-3031340	The York Water Company	Depreciation
411.	2022	PA PUC	R-2022-3032806	The York Water Company	Depreciation
412.	2022	PA PUC	R-2022-3031704	Borough of Ambler	Depreciation
413.	2022	MO PSC	ER-2022-0337	Ameren Missouri	Depreciation
414.	2022	OH PUC	Case No. 22-507-GA-AIR	Duke Energy Ohio	Depreciation
415.	2022	PA PUC	R-2022-3035730	National Fuel Gas Distribution Corporation – PA	Depreciation
416.	2022	WY PSC	20003-214-ER-22	Cheyenne Light, Fuel and Power Company	Depreciation
417.	2022	NJ BPU	BPU Docket No. ER2303144	Jersey Central Power & Light Company	Depreciation
418.	2022	KY PSC	Case No. 2022-00372	Duke Energy Kentucky	Depreciation
419.	2022	TX PUC	SOAH Docket No. 473-23-04521	Aqua Texas, Inc.	Depreciation
420.	2022	NC Util Com	Docket No. E-7, Sub 1276	Duke Energy Carolinas, LLC	Depreciation
421.	2022	KY PSC	Case No. 2022-00432	Bluegrass Water	Depreciation
422.	2023	ILL CC	Docket No. 23-0069	The Peoples Gas Light and Coke Company	Depreciation
423.	2023	ILL CC	Docket No. 23-0068	North Shore Gas Company	Depreciation
424.	2023	WV PSC	Case No. 23-0030-E-D	Monongahela Power Company and The Potomac	Depreciation
425.	2023	ID PUC	AVU-E-23-01; AVU-G-23-01	Avista Corporation	Depreciation
426.	2023	ILL CC	Docket No. 23-0066	Northern Illinois Gas Company d/b/a Nicor Gas	Depreciation
427.	2023	SC PSC	Docket No. 2023-70-G	Dominion Energy South Carolina, Inc.	Depreciation
428.	2023	FERC	Docket No. ER23-xxx-00	Duke Energy Ohio, Inc.	Depreciation
429.	2023	WY PSC	Docket No. 30036-78-GR-23	Black Hills Wyoming Gas Company d/b/a Black Hills	Depreciation
430.	2023	PSC MD	Case No. 9695	The Potomac Edison Company	Depreciation
431.	2023	OR PUC	Case No. UM2277	Avista Corporation	Depreciation
432.	2023	FERC	Docket No. ER23-xxx-000	PPL Electric Utilities	Depreciation
433.	2023	OH PUC	Case No. 23-0154-GA-AIR	Northeast Ohio Natural Gas Corporation	Depreciation
434.	2023	DE PSC	PSC Docket No. 23-0601	Artesian Water Company	Depreciation
435.	2023	CO PUC	No. 23AL-0231G	Black Hills Colorado d/b/a Black Hills Energy	Depreciation
436.	2023	NH PUC	Docket No. DE 23-039	Granite State Electric d/b/a Liberty Utilities	Depreciation
437.	2023	MD PSC	Case No. 9701	Columbia Gas of Maryland	Depreciation
438.	2023	NY PSC	Case Nos. 23-E-0418; 23-G-0419	Central Hudson Gas and Electric	Depreciation
439.	2023	FERC	Docket No. ER23-xxx-000	Central Maine Power Company	Depreciation
440.	2023	SD PUC	Docket Number EL23-016	Northwestern Energy	Depreciation
441.	2023	CT PURA	Docket No. 23-08-32	Connecticut Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY,

	Year	Jurisdiction	Docket No.	Client Utility	Subject
442.	2023	OH PUC	Case 23-0894-GA-AIR	The East Ohio Gas Company d/b/a Dominion Energ	Depreciation
443.	2023	IN URC	Cause No. 45911	Indianapolis Power & Light	Depreciation
444.	2023	IN URC	Cause No. 45967	Northern Indiana Public Service Company	Depreciation
445.	2023	PA PUC	Docket No. R-2023-3043189 and Docket No. R-2023-3043190	Pennsylvania-American Water Company	Depreciation
446.	2023	IN URC	Cause No. 45988	Citizens Energy Group	Depreciation
447.	2023	NY PSC	Case No. 23-G-0627	National Fuel Gas Distribution Corporation	Depreciation
448.	2023	IN URC	Cause No. 45990	Southern Indiana Gas and Electric Company d/b/a Centerpoint Energy Indiana South	Depreciation
449.	2023	PA PUC	Docket No. R-2023-3044549	Peoples Natural Gas Company LLC	Depreciation
450.	2023	OR PUC	Docket No. UM-2312	Northwest Natural Gas Company	Depreciation
451.	2023	AZ PCC	Docket No. WS-21182A-23-2092	Northwest Natural Water Company, LLC	Depreciation
452.	2023	SC PSC	Docket No. 2023-388-E	Duke Energy Carolinas	Depreciation
453.	2023	ILL CC	Docket No. 23-	North Shore Gas Company	Depreciation
454.	2023	ILL CC	Docket No. 23-	The Peoples Gas Light and Coke Company	Depreciation
455.	2024	FERC	Docket No. ER24-768-000	Duke Energy Progress	Depreciation
456.	2024	FERC	Docket No. SPP-0007	Evergy Metro, Inc. and Evergy Missouri West, Inc.	Depreciation
457.	2024	NJ BPU	Docket No. WR24010057	Aqua New Jersey, Inc.	Depreciation
458.	2024	ILL CC	Docket No. 24-	Aqua Illinois, Inc.	Depreciation

PLANT ROLLFORWARD

	2024	2024			2025		
	NOV 30	DECEMBER			JANUARY		
Account	Begin. Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	1,932.08	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	3,294,840.04	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	1,126,771.92	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	1,072,969.89	0.00	0.00	1,072,969.89	0.00	0.00	1,072,969.89
352.10	206,940.78	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	387,525.49	0.00	0.00	387,525.49	0.00	0.00	387,525.49
354.00	947,637.58	0.00	0.00	947,637.58	0.00	0.00	947,637.58
355.00	104,476.92	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	8,309,674.29	20,865.67	1,946.48	8,328,593.48	16,188.80	1,279.51	8,343,502.77
374.50	3,233,024.97	0.00	0.00	3,233,024.97	0.00	0.00	3,233,024.97
375.34	6,914,119.03	40,861.94	3,536.93	6,951,444.04	51,939.08	3,708.79	6,999,674.33
375.60	86,083.56	0.00	0.00	86,083.56	0.00	0.00	86,083.56
375.70	49,858,856.05	180,884.23	3,617.68	50,036,122.60	0.00	4,733.96	50,031,388.64
375.80	16,515.16	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	2,963,847,366.30	22,058,064.96	1,848,425.93	2,984,057,005.33	17,126,057.65	1,203,925.88	2,999,979,137.10
378.00	191,604,503.26	4,763,294.10	66,525.96	196,301,271.40	3,086,788.21	132,321.23	199,255,738.38
379.10	119,158.02	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	887,974,148.56	7,537,906.55	640,868.59	894,871,186.52	5,632,274.93	402,879.16	900,100,582.29
381.00	47,122,525.62	131,809.57	11,517.05	47,242,818.14	104,152.64	7,670.45	47,339,300.33
381.10	24,893,142.41	23,260.51	2,032.42	24,914,370.50	18,379.88	1,353.61	24,931,396.77
382.00	48,320,969.29	222,610.08	19,712.57	48,523,866.80	176,709.85	13,206.96	48,687,369.69
383.00	19,149,059.95	116,187.61	10,737.91	19,254,509.65	93,619.59	7,326.70	19,340,802.54
384.00	3,509,358.71	2,539.53	236.90	3,511,661.34	1,990.01	157.28	3,513,494.07
385.00	8,784,388.23	95,634.32	8,096.57	8,871,925.98	74,198.69	5,269.97	8,940,854.70
387.00	136,698.14	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	16,050,396.45	0.00	0.00	16,050,396.45	0.00	0.00	16,050,396.45
387.50	2,201,371.95	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	49,821.42	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	3,707,095.72	0.00	31,580.89	3,675,514.83	0.00	0.00	3,675,514.83
391.11	91,303.67	0.00	0.00	91,303.67	0.00	0.00	91,303.67
391.12	483,895.58	0.00	10,859.79	473,035.79	0.00	0.00	473,035.79
392.00	25,616.89	0.00	0.00	25,616.89	0.00	0.00	25,616.89
394.00	22,831,412.84	194,993.32	186,223.74	22,840,182.42	186,157.23	0.00	23,026,339.65
394.12	18,450.18	0.00	0.00	18,450.18	0.00	0.00	18,450.18
395.00	264,921.24	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	948,698.04	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	2,397,793.12	168,490.27	12,920.00	2,553,363.39	127,351.93	12,586.67	2,668,128.65
398.00	1,027,393.04	0.00	11,311.50	1,016,081.54	0.00	0.00	1,016,081.54
303.00	51,994,426.78	1,548,696.71	960,754.89	52,582,368.60	1,122,155.31	333,152.08	53,371,371.83
303.60	8,088,184.47	70,434.11	78,571.68	8,080,046.90	693,406.16	856,730.04	7,916,723.02
375.71	5,619,476.62	166,970.05	3,339.40	5,783,107.27	0.00	4,369.80	5,778,737.47
NonDeprPlant	3,533,175.06	0.00	0.00	3,533,175.06	0.00	0.00	3,533,175.06
Total Plant	**4,390,356,119.32**	**37,343,503.53**	**3,912,816.88**	**4,423,786,805.97**	**28,511,369.96**	**2,990,672.09**	**4,449,307,503.84**

PLANT ROLLFORWARD

	2025			2025			2025		
	FEBRUARY			MARCH			APRIL		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	0.00	0.00	1,932.08	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	0.00	0.00	1,072,969.89	0.00	0.00	1,072,969.89	0.00	0.00	1,072,969.89
352.10	0.00	0.00	206,940.78	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	0.00	0.00	387,525.49	0.00	0.00	387,525.49	0.00	0.00	387,525.49
354.00	0.00	0.00	947,637.58	0.00	0.00	947,637.58	0.00	0.00	947,637.58
355.00	0.00	0.00	104,476.92	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	16,082.71	1,187.51	8,358,397.97	19,220.75	1,629.50	8,375,989.22	26,595.15	1,673.52	8,400,910.85
374.50	0.00	0.00	3,233,024.97	0.00	0.00	3,233,024.97	0.00	0.00	3,233,024.97
375.34	51,598.70	3,410.49	7,047,862.54	61,666.57	4,420.11	7,105,109.00	85,326.11	4,239.74	7,186,195.37
375.60	0.00	0.00	86,083.56	0.00	0.00	86,083.56	0.00	0.00	86,083.56
375.70	0.00	4,733.96	50,026,654.68	0.00	4,733.96	50,021,920.72	0.00	4,733.96	50,017,186.76
375.80	0.00	0.00	16,515.16	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	17,013,823.01	1,126,768.71	3,015,866,191.40	20,333,536.17	1,423,190.67	3,034,776,536.90	28,134,880.51	1,335,920.45	3,061,575,496.96
378.00	3,066,559.13	163,279.26	202,159,018.25	3,664,901.83	155,124.06	205,668,796.02	5,071,010.47	210,666.81	210,529,139.68
379.10	0.00	0.00	119,158.02	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	5,595,364.13	370,537.26	905,325,409.16	6,687,123.69	480,738.67	911,531,794.18	9,252,764.72	461,746.25	920,322,812.65
381.00	103,470.09	7,074.12	47,435,696.30	123,659.02	9,339.10	47,550,016.22	171,103.14	9,166.71	47,711,952.65
381.10	18,259.43	1,248.37	24,948,407.83	21,822.18	1,648.08	24,968,581.93	30,194.67	1,617.66	24,997,158.94
382.00	175,551.79	12,196.75	48,850,724.73	209,805.20	16,238.49	49,044,291.44	290,300.92	16,102.59	49,318,489.77
383.00	93,006.06	6,794.12	19,427,014.48	111,153.27	9,275.27	19,528,892.48	153,799.31	9,470.86	19,673,220.93
384.00	1,976.97	145.97	3,515,325.07	2,362.71	200.31	3,517,487.47	3,269.21	205.72	3,520,550.96
385.00	73,712.43	4,843.60	9,009,723.53	88,095.10	6,256.73	9,091,561.90	121,894.45	5,976.10	9,207,480.25
387.00	0.00	0.00	136,698.14	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	0.00	0.00	16,050,396.45	0.00	0.00	16,050,396.45	0.00	0.00	16,050,396.45
387.50	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	0.00	0.00	49,821.42	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	0.00	0.00	3,675,514.83	0.00	0.00	3,675,514.83	0.00	0.00	3,675,514.83
391.11	0.00	0.00	91,303.67	0.00	0.00	91,303.67	0.00	0.00	91,303.67
391.12	0.00	0.00	473,035.79	0.00	0.00	473,035.79	0.00	0.00	473,035.79
392.00	0.00	0.00	25,616.89	0.00	0.00	25,616.89	0.00	0.00	25,616.89
394.00	184,937.25	0.00	23,211,276.90	221,021.95	0.00	23,432,298.85	305,821.19	0.00	23,738,120.04
394.12	0.00	0.00	18,450.18	0.00	0.00	18,450.18	0.00	0.00	18,450.18
395.00	0.00	0.00	264,921.24	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	0.00	0.00	948,698.04	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	126,517.34	12,586.67	2,782,059.32	151,203.22	12,586.67	2,920,675.87	209,215.19	12,586.67	3,117,304.39
398.00	0.00	0.00	1,016,081.54	0.00	0.00	1,016,081.54	0.00	0.00	1,016,081.54
303.00	322,286.18	283,480.49	53,410,177.52	448,658.94	58,226.10	53,800,610.36	11,466,371.28	785,738.17	64,481,243.47
303.60	23,055.39	0.00	7,939,778.41	32,095.72	33,794.51	7,938,079.62	7,959,530.21	27,585.42	15,870,024.41
375.71	0.00	4,369.80	5,774,367.67	0.00	4,369.80	5,769,997.87	0.00	4,369.80	5,765,628.07
NonDeprPlant	0.00	0.00	3,533,175.06	0.00	0.00	3,533,175.06	0.00	0.00	3,533,175.06
Total Plant	**26,866,200.61**	**2,002,657.08**	**4,474,171,047.37**	**32,176,326.32**	**2,221,772.03**	**4,504,125,601.66**	**63,282,076.53**	**2,891,800.43**	**4,564,515,877.76**

PLANT ROLLFORWARD

	2025			2025			2025		
	MAY			JUNE			JULY		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	0.00	0.00	1,932.08	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	0.00	0.00	1,072,969.89	0.00	0.00	1,072,969.89	0.00	0.00	1,072,969.89
352.10	0.00	0.00	206,940.78	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	0.00	0.00	387,525.49	0.00	0.00	387,525.49	0.00	0.00	387,525.49
354.00	0.00	0.00	947,637.58	0.00	0.00	947,637.58	0.00	0.00	947,637.58
355.00	0.00	0.00	104,476.92	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	33,153.63	1,294.96	8,432,769.52	22,110.58	1,633.44	8,453,246.66	17,528.42	1,624.04	8,469,151.04
374.50	0.00	0.00	3,233,024.97	0.00	0.00	3,233,024.97	0.00	0.00	3,233,024.97
375.34	106,367.89	4,422.76	7,288,140.50	70,938.11	5,866.39	7,353,212.22	56,237.01	5,435.89	7,404,013.34
375.60	0.00	0.00	86,083.56	0.00	0.00	86,083.56	0.00	0.00	86,083.56
375.70	0.00	4,733.96	50,012,452.80	236,697.55	4,733.96	50,244,416.39	0.00	4,733.96	50,239,682.43
375.80	0.00	0.00	16,515.16	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	35,073,061.06	1,455,337.19	3,095,193,220.83	23,390,673.41	1,928,375.24	3,116,655,519.00	18,543,231.16	1,793,541.76	3,133,405,208.40
378.00	6,321,543.11	253,717.71	216,596,965.08	4,215,918.02	472,025.45	220,340,857.65	3,342,218.55	497,709.39	223,185,366.81
379.10	0.00	0.00	119,158.02	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	11,534,535.65	479,132.58	931,378,215.72	7,692,529.48	635,050.16	938,435,695.04	6,098,343.12	589,071.56	943,944,966.60
381.00	213,297.90	8,711.09	47,916,539.46	142,251.10	11,395.45	48,047,395.11	112,771.23	10,767.82	48,149,398.52
381.10	37,640.81	1,537.25	25,033,262.50	25,103.13	2,010.96	25,056,354.67	19,900.80	1,900.20	25,074,355.27
382.00	361,890.35	14,649.07	49,665,731.05	241,349.31	19,029.32	49,888,051.04	191,332.50	18,159.37	50,061,224.17
383.00	191,726.87	7,537.88	19,857,409.92	127,865.11	9,560.89	19,975,714.14	101,366.57	9,433.12	20,067,647.59
384.00	4,075.41	159.18	3,524,467.19	2,717.94	200.79	3,526,984.34	2,154.68	199.63	3,528,939.39
385.00	151,954.12	6,337.38	9,353,096.99	101,340.15	8,425.26	9,446,011.88	80,338.60	7,781.67	9,518,568.81
387.00	0.00	0.00	136,698.14	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	0.00	0.00	16,050,396.45	0.00	0.00	16,050,396.45	0.00	0.00	16,050,396.45
387.50	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	0.00	0.00	49,821.42	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	0.00	0.00	3,675,514.83	0.00	0.00	3,675,514.83	0.00	0.00	3,675,514.83
391.11	0.00	0.00	91,303.67	0.00	0.00	91,303.67	0.00	0.00	91,303.67
391.12	0.00	0.00	473,035.79	0.00	0.00	473,035.79	0.00	0.00	473,035.79
392.00	0.00	0.00	25,616.89	0.00	0.00	25,616.89	0.00	0.00	25,616.89
394.00	381,237.99	0.00	24,119,358.03	254,252.49	0.00	24,373,610.52	201,561.65	0.00	24,575,172.17
394.12	0.00	0.00	18,450.18	0.00	0.00	18,450.18	0.00	0.00	18,450.18
395.00	0.00	0.00	264,921.24	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	0.00	0.00	948,698.04	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	260,808.54	12,586.67	3,365,526.26	173,936.55	12,586.67	3,526,876.14	137,890.25	12,586.67	3,652,179.72
398.00	0.00	0.00	1,016,081.54	0.00	0.00	1,016,081.54	0.00	0.00	1,016,081.54
303.00	200,947.74	179,721.50	64,502,469.71	4,728,242.42	412,455.55	68,818,256.58	834,031.17	174,547.45	69,477,740.30
303.60	14,375.20	0.00	15,884,399.61	40,877.82	34,682.61	15,890,594.82	12,440.17	154,862.52	15,748,172.47
375.71	0.00	4,369.80	5,761,258.27	218,490.05	4,369.80	5,975,378.52	0.00	4,369.80	5,971,008.72
NonDeprPlant	0.00	0.00	3,533,175.06	0.00	0.00	3,533,175.06	0.00	0.00	3,533,175.06
Total Plant	**54,886,616.27**	**2,434,248.98**	**4,616,968,245.05**	**41,685,293.22**	**3,562,401.94**	**4,655,091,136.33**	**29,751,345.88**	**3,286,724.85**	**4,681,555,757.36**

PLANT ROLLFORWARD

	2025			2025			2025		
	AUGUST			SEPTEMBER			OCTOBER		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	0.00	0.00	1,932.08	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	0.00	0.00	1,072,969.89	0.00	0.00	1,072,969.89	0.00	0.00	1,072,969.89
352.10	0.00	0.00	206,940.78	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	0.00	0.00	387,525.49	0.00	0.00	387,525.49	0.00	0.00	387,525.49
354.00	0.00	0.00	947,637.58	0.00	0.00	947,637.58	0.00	0.00	947,637.58
355.00	0.00	0.00	104,476.92	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	18,044.28	1,626.13	8,485,569.19	16,842.18	1,481.16	8,500,930.21	18,731.79	1,787.11	8,517,874.89
374.50	0.00	0.00	3,233,024.97	0.00	0.00	3,233,024.97	0.00	0.00	3,233,024.97
375.34	57,892.06	6,082.11	7,455,823.29	54,035.33	5,757.77	7,504,100.85	60,097.81	6,142.09	7,558,056.57
375.60	0.00	0.00	86,083.56	0.00	0.00	86,083.56	0.00	0.00	86,083.56
375.70	0.00	4,733.96	50,234,948.47	236,697.55	4,733.96	50,466,912.06	0.00	4,733.96	50,462,178.10
375.80	0.00	0.00	16,515.16	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	19,088,955.54	2,045,784.05	3,150,448,379.89	17,817,259.89	2,496,501.96	3,165,769,137.82	19,816,264.71	1,985,365.14	3,183,600,037.39
378.00	3,440,579.51	567,548.03	226,058,398.29	3,211,370.01	306,982.18	228,962,786.12	3,571,669.18	205,388.48	232,329,066.82
379.10	0.00	0.00	119,158.02	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	6,277,816.41	658,021.79	949,564,761.22	5,859,591.75	622,601.95	954,801,751.02	6,517,007.77	665,329.55	960,653,429.24
381.00	116,090.07	11,687.24	48,253,801.35	108,356.22	10,953.98	48,351,203.59	120,513.22	12,076.23	48,459,640.58
381.10	20,486.48	2,062.45	25,092,779.30	19,121.68	1,933.05	25,109,967.93	21,267.04	2,131.10	25,129,103.87
382.00	196,963.38	19,407.91	50,238,779.64	183,841.79	18,095.29	50,404,526.14	204,467.90	20,290.18	50,588,703.86
383.00	104,349.76	9,562.43	20,162,434.92	97,398.04	8,749.88	20,251,083.08	108,325.60	10,409.73	20,348,998.95
384.00	2,218.09	199.89	3,530,957.59	2,070.32	182.07	3,532,845.84	2,302.60	219.68	3,534,928.76
385.00	82,702.95	8,750.52	9,592,521.24	77,193.32	8,297.22	9,661,417.34	85,854.02	8,803.59	9,738,467.77
387.00	0.00	0.00	136,698.14	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	0.00	0.00	16,050,396.45	0.00	0.00	16,050,396.45	0.00	0.00	16,050,396.45
387.50	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	0.00	0.00	49,821.42	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	0.00	0.00	3,675,514.83	0.00	0.00	3,675,514.83	0.00	0.00	3,675,514.83
391.11	0.00	0.00	91,303.67	0.00	0.00	91,303.67	0.00	0.00	91,303.67
391.12	0.00	0.00	473,035.79	0.00	0.00	473,035.79	0.00	0.00	473,035.79
392.00	0.00	0.00	25,616.89	0.00	0.00	25,616.89	0.00	0.00	25,616.89
394.00	207,493.58	0.00	24,782,665.75	193,670.47	0.00	24,976,336.22	215,399.30	0.00	25,191,735.52
394.12	0.00	0.00	18,450.18	0.00	0.00	18,450.18	0.00	0.00	18,450.18
395.00	0.00	0.00	264,921.24	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	0.00	0.00	948,698.04	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	141,948.33	12,586.67	3,781,541.38	132,491.81	12,586.67	3,901,446.52	147,356.71	12,586.67	4,036,216.56
398.00	0.00	0.00	1,016,081.54	0.00	0.00	1,016,081.54	0.00	0.00	1,016,081.54
303.00	347,920.47	596,357.34	69,229,303.43	32,205.66	251,613.15	69,009,895.94	498,267.72	115,533.28	69,392,630.38
303.60	24,889.19	0.00	15,773,061.66	435,184.68	26,459.09	16,181,787.25	35,644.58	0.00	16,217,431.83
375.71	0.00	4,369.80	5,966,638.92	218,490.05	4,369.80	6,180,759.17	0.00	4,369.80	6,176,389.37
NonDeprPlant	0.00	0.00	3,533,175.06	0.00	0.00	3,533,175.06	0.00	0.00	3,533,175.06
Total Plant	**30,128,350.10**	**3,948,780.32**	**4,707,735,327.14**	**28,695,820.75**	**3,781,299.18**	**4,732,649,848.71**	**31,423,169.95**	**3,055,166.59**	**4,761,017,852.07**

PLANT ROLLFORWARD

	2025			2025		
	NOVEMBER			DECEMBER		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	0.00	0.00	1,072,969.89	0.00	0.00	1,072,969.89
352.10	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	0.00	0.00	387,525.49	0.00	0.00	387,525.49
354.00	0.00	0.00	947,637.58	0.00	0.00	947,637.58
355.00	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	14,636.04	2,036.65	8,530,474.28	20,865.67	1,946.48	8,549,393.47
374.50	0.00	0.00	3,233,024.97	0.00	0.00	3,233,024.97
375.34	46,957.31	6,418.74	7,598,595.14	66,944.02	5,695.10	7,659,844.06
375.60	0.00	0.00	86,083.56	0.00	0.00	86,083.56
375.70	0.00	4,733.96	50,457,444.14	236,697.55	4,733.96	50,689,407.73
375.80	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	15,483,397.57	2,045,673.20	3,197,037,761.76	22,073,688.57	1,807,202.10	3,217,304,248.23
378.00	2,790,716.36	196,451.87	234,923,331.31	3,978,545.63	163,731.14	238,738,145.80
379.10	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	5,092,050.58	696,251.73	965,049,228.09	7,259,410.50	618,544.35	971,690,094.24
381.00	94,162.76	12,939.39	48,540,863.95	134,241.81	11,743.95	48,663,361.81
381.10	16,616.96	2,283.42	25,143,437.41	23,689.73	2,072.46	25,165,054.68
382.00	159,760.58	22,009.77	50,726,454.67	227,760.42	20,193.03	50,934,022.06
383.00	84,639.99	11,756.73	20,421,882.21	120,665.82	11,155.67	20,531,392.36
384.00	1,799.14	250.36	3,536,477.54	2,564.91	239.27	3,538,803.18
385.00	67,081.86	9,161.38	9,796,388.25	95,634.32	8,096.57	9,883,926.00
387.00	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	0.00	0.00	16,050,396.45	0.00	0.00	16,050,396.45
387.50	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	0.00	0.00	3,675,514.83	0.00	522.52	3,674,992.31
391.11	0.00	0.00	91,303.67	0.00	0.00	91,303.67
391.12	0.00	0.00	473,035.79	0.00	346,441.62	126,594.17
392.00	0.00	0.00	25,616.89	0.00	0.00	25,616.89
394.00	168,301.80	0.00	25,360,037.32	239,937.10	296,716.81	25,303,257.61
394.12	0.00	0.00	18,450.18	0.00	0.00	18,450.18
395.00	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	115,136.86	12,586.67	4,138,766.75	164,143.26	12,586.67	4,290,323.34
398.00	0.00	0.00	1,016,081.54	0.00	25,988.40	990,093.14
303.00	1,839,827.06	518,574.98	70,713,882.46	615,742.65	432,816.27	70,896,808.84
303.60	131,615.71	16,534.56	16,332,512.98	44,048.38	158,959.76	16,217,601.60
375.71	0.00	4,369.80	6,172,019.57	218,490.05	4,369.80	6,386,139.82
NonDeprPlant	0.00	0.00	3,533,175.06	0.00	0.00	3,533,175.06
Total Plant	**26,106,700.58**	**3,562,033.21**	**4,783,562,519.44**	**35,523,070.39**	**3,933,755.93**	**4,815,151,833.90**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2024							
	2024	'Accrual			'5-yr			'5-yr	DECEMBER							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							1	0	1	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,078,392
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		980,984
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		741,154
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	4	36	0	0	0		387,153
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		917,562
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,369	1,225	12,594	1,946	0	0		1,083,728
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,899,117
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	13,692	2,858	16,550	3,537	1,379	0		1,627,650
375.60	76,763	0.56	0.33		104	0.33		0	40	9	49	0	0	0		76,812
375.70	8,203,718	2.65			18			18	110,301	2	110,302	3,618	0	0		8,310,403
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,337
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	5,749,641	110,473	5,860,113	1,848,426	147,874	0		422,962,640
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	593,173	12,705	605,877	66,526	10,644	0		30,716,496
379.10	39,930	8.17			6			6	811	1	812	0	0	0		40,742
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,473,698	321,091	2,794,788	640,869	205,078	0		178,874,953
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	95,938	1,474	97,412	11,517	346	0		19,252,593
381.10	20,008,389	2.49			0			0	51,675	0	51,675	2,032	0	0		20,058,032
382.00	16,567,447	1.91			486			486	77,072	41	77,113	19,713	0	0		16,624,847
383.00	5,896,216	2.02	0.01		185	0.01		399	32,323	15	32,338	10,738	107	0		5,917,709
384.00	2,937,578	1.32			0			0	3,862	0	3,862	237	0	0		2,941,203
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	37,446	6,492	43,938	8,097	2,024	0		2,963,002
387.00	88,125	3.07			0			0	350	0	350	0	0	0		88,475
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	836	71,057	0	0	0		3,568,231
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,002,185
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,827	0	14,827	31,581	0	0		1,242,643
391.11	64,605	6.39			0			0	486	0	486	0	0	0		65,091
391.12	481,779	0.17			0			0	68	0	68	10,860	0	0		470,987
392.00	24,582	1.28			(936)			(815)	27	(78)	(51)	0	0	0		24,531
394.00	7,984,087	3.86			0			0	73,455	0	73,455	186,224	0	0		7,871,318
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,449
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		121,001
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		982,989
397.50	627,296	5.45			0			0	11,243	0	11,243	12,920	0	0		625,619
398.00	651,416	6.03			0			0	5,134	0	5,134	11,312	0	0		645,239
					0			0								
303.00	26,386,435				0			0	746,250	0	746,250	960,755	0	0		26,171,930
303.60	4,909,544				0			0	137,238	0	137,238	78,572	0	0		4,968,210
362.10	(155,603)				83,739			66,852	0	6,978	6,978	0	0	0		(148,625)
375.71	3,058,415				0			0	36,402	0	36,402	3,339	0	0		3,091,478
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,049
Total	**765,267,146**				**5,564,614**			**5,397,639**	**10,420,875**	**463,718**	**10,884,593**	**3,912,817**	**367,453**	**0**	**0**	**771,871,469**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	JANUARY							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,096,404
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		993,172
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		768,962
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,185
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		920,081
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,393	1,158	12,550	1,280	0	0		1,094,998
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,902,000
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	13,777	2,878	16,655	3,709	1,446	0		1,639,149
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		76,852
375.70	8,203,718	2.65			18			18	110,491	2	110,493	4,734	0	0		8,416,161
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,366
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	5,784,568	111,874	5,896,442	1,203,926	96,314	0		427,558,842
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	604,873	20,336	625,209	132,321	21,171	0		31,188,213
379.10	39,930	8.17			6			6	811	1	812	0	0	0		41,554
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,490,523	302,320	2,792,844	402,879	128,921	0		181,135,996
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	96,158	1,523	97,682	7,670	230	0		19,342,375
381.10	20,008,389	2.49			0			0	51,715	0	51,715	1,354	0	0		20,108,393
382.00	16,567,447	1.91			486			486	77,364	41	77,404	13,207	0	0		16,689,045
383.00	5,896,216	2.02	0.01		185	0.01		399	32,484	33	32,518	7,327	73	0		5,942,827
384.00	2,937,578	1.32			0			0	3,864	0	3,864	157	0	0		2,944,909
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	37,778	3,737	41,515	5,270	1,317	0		2,997,930
387.00	88,125	3.07			0			0	350	0	350	0	0	0		88,824
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		3,639,254
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,011,669
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,257,406
391.11	64,605	6.39			0			0	486	0	486	0	0	0		65,577
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,054
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,491
394.00	7,984,087	3.86			0			0	73,769	0	73,769	0	0	0		7,945,087
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,503
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		122,177
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		982,499
397.50	627,296	5.45			0			0	11,857	0	11,857	12,587	0	0		624,890
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		650,345
					0			0								
303.00	26,386,435				0			0	757,436	0	757,436	333,152	0	0		26,596,213
303.60	4,909,544				0			0	134,445	0	134,445	856,730	0	0		4,245,925
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(143,054)
375.71	3,058,415				0			0	36,330	0	36,330	4,370	0	0		3,123,438
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,080
Total	**765,267,146**				**5,564,614**			**5,397,639**	**10,494,828**	**449,803**	**10,944,632**	**2,990,672**	**249,474**	**0**	**0**	**779,575,954**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	FEBRUARY							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,114,415
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,005,360
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		796,769
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,218
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		922,600
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,413	1,158	12,570	1,188	0	0		1,106,381
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,904,882
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	13,872	2,878	16,750	3,410	1,330	0		1,651,158
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		76,892
375.70	8,203,718	2.65			18			18	110,481	2	110,482	4,734	0	0		8,521,910
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,395
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	5,815,317	111,874	5,927,191	1,126,769	90,141	0		432,269,123
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	613,830	20,336	634,166	163,279	26,125	0		31,632,975
379.10	39,930	8.17			6			6	811	1	812	0	0	0		42,365
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,505,029	302,320	2,807,349	370,537	118,572	0		183,454,236
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	96,355	1,523	97,878	7,074	212	0		19,432,966
381.10	20,008,389	2.49			0			0	51,750	0	51,750	1,248	0	0		20,158,895
382.00	16,567,447	1.91			486			486	77,624	41	77,665	12,197	0	0		16,754,513
383.00	5,896,216	2.02	0.01		185	0.01		399	32,630	33	32,663	6,794	68	0		5,968,628
384.00	2,937,578	1.32			0			0	3,866	0	3,866	146	0	0		2,948,629
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	38,070	3,737	41,807	4,844	1,211	0		3,033,683
387.00	88,125	3.07			0			0	350	0	350	0	0	0		89,174
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		3,710,278
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,021,154
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,272,169
391.11	64,605	6.39			0			0	486	0	486	0	0	0		66,064
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,121
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,450
394.00	7,984,087	3.86			0			0	74,365	0	74,365	0	0	0		8,019,453
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,557
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		123,354
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		982,010
397.50	627,296	5.45			0			0	12,376	0	12,376	12,587	0	0		624,680
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		655,450
					0			0								
303.00	26,386,435				0			0	757,986	0	757,986	283,480	0	0		27,070,719
303.60	4,909,544				0			0	134,839	0	134,839	0	0	0		4,380,765
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(137,483)
375.71	3,058,415				0			0	36,258	0	36,258	4,370	0	0		3,155,327
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,110
Total	**765,267,146**				**5,564,614**			**5,397,639**	**10,552,065**	**449,803**	**11,001,868**	**2,002,657**	**237,659**	**0**	**0**	**788,337,506**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	MARCH							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,132,427
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,017,548
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		824,577
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,250
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		925,120
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,435	1,158	12,593	1,630	0	0		1,117,344
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,907,765
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	13,976	2,878	16,854	4,420	1,724	0		1,661,868
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		76,932
375.70	8,203,718	2.65			18			18	110,470	2	110,472	4,734	0	0		8,627,647
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,424
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	5,848,955	111,874	5,960,828	1,423,191	113,855	0		436,692,905
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	623,637	20,336	643,973	155,124	24,820	0		32,097,004
379.10	39,930	8.17			6			6	811	1	812	0	0	0		43,177
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,520,889	302,320	2,823,210	480,739	153,836	0		185,642,870
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	96,569	1,523	98,092	9,339	280	0		19,521,439
381.10	20,008,389	2.49			0			0	51,789	0	51,789	1,648	0	0		20,209,036
382.00	16,567,447	1.91			486			486	77,908	41	77,949	16,238	0	0		16,816,223
383.00	5,896,216	2.02	0.01		185	0.01		399	32,788	33	32,821	9,275	93	0		5,992,081
384.00	2,937,578	1.32			0			0	3,868	0	3,868	200	0	0		2,952,297
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	38,390	3,737	42,127	6,257	1,564	0		3,067,989
387.00	88,125	3.07			0			0	350	0	350	0	0	0		89,524
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		3,781,301
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,030,638
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,286,933
391.11	64,605	6.39			0			0	486	0	486	0	0	0		66,550
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,188
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,410
394.00	7,984,087	3.86			0			0	75,018	0	75,018	0	0	0		8,094,471
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,611
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		124,531
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		981,520
397.50	627,296	5.45			0			0	12,950	0	12,950	12,587	0	0		625,043
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		660,556
					0			0								
303.00	26,386,435				0			0	763,521	0	763,521	58,226	0	0		27,776,014
303.60	4,909,544				0			0	134,810	0	134,810	33,795	0	0		4,481,781
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(131,912)
375.71	3,058,415				0			0	36,187	0	36,187	4,370	0	0		3,187,144
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,141
Total	**765,267,146**				**5,564,614**			**5,397,639**	**10,619,163**	**449,803**	**11,068,967**	**2,221,772**	**296,172**	**0**	**0**	**796,888,528**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	APRIL							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,150,439
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,029,736
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		852,385
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,282
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		927,639
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,464	1,158	12,622	1,674	0	0		1,128,292
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,910,648
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	14,113	2,878	16,991	4,240	1,653	0		1,672,966
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		76,973
375.70	8,203,718	2.65			18			18	110,460	2	110,461	4,734	0	0		8,733,375
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,453
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	5,893,140	111,874	6,005,014	1,335,920	106,874	0		441,255,125
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	636,436	20,336	656,772	210,667	33,707	0		32,509,403
379.10	39,930	8.17			6			6	811	1	812	0	0	0		43,989
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,541,698	302,320	2,844,019	461,746	147,759	0		187,877,384
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	96,850	1,523	98,373	9,167	275	0		19,610,370
381.10	20,008,389	2.49			0			0	51,839	0	51,839	1,618	0	0		20,259,258
382.00	16,567,447	1.91			486			486	78,280	41	78,321	16,103	0	0		16,878,441
383.00	5,896,216	2.02	0.01		185	0.01		399	32,995	33	33,028	9,471	95	0		6,015,543
384.00	2,937,578	1.32			0			0	3,871	0	3,871	206	0	0		2,955,962
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	38,809	3,737	42,546	5,976	1,494	0		3,103,065
387.00	88,125	3.07			0			0	350	0	350	0	0	0		89,874
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		3,852,325
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,040,122
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,301,696
391.11	64,605	6.39			0			0	486	0	486	0	0	0		67,036
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,255
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,369
394.00	7,984,087	3.86			0			0	75,866	0	75,866	0	0	0		8,170,337
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,665
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		125,707
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		981,031
397.50	627,296	5.45			0			0	13,711	0	13,711	12,587	0	0		626,167
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		665,662
					0			0								
303.00	26,386,435				0			0	914,946	0	914,946	785,738	0	0		27,905,222
303.60	4,909,544				0			0	270,433	0	270,433	27,585	0	0		4,724,628
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(126,341)
375.71	3,058,415				0			0	36,115	0	36,115	4,370	0	0		3,218,889
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,172
Total	**765,267,146**				**5,564,614**			**5,397,639**	**10,987,030**	**449,803**	**11,436,833**	**2,891,800**	**291,856**	**0**	**0**	**805,141,705**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	MAY							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,168,451
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,041,923
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		880,193
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,314
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		930,158
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,503	1,158	12,661	1,295	0	0		1,139,658
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,913,531
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	14,293	2,878	17,171	4,423	1,725	0		1,683,989
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		77,013
375.70	8,203,718	2.65			18			18	110,449	2	110,451	4,734	0	0		8,839,092
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,481
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	5,951,543	111,874	6,063,417	1,455,337	116,427	0		445,746,777
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	653,147	20,336	673,483	253,718	40,595	0		32,888,574
379.10	39,930	8.17			6			6	811	1	812	0	0	0		44,801
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,569,235	302,320	2,871,556	479,133	153,322	0		190,116,484
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	97,222	1,523	98,746	8,711	261	0		19,700,143
381.10	20,008,389	2.49			0			0	51,907	0	51,907	1,537	0	0		20,309,627
382.00	16,567,447	1.91			486			486	78,775	41	78,815	14,649	0	0		16,942,607
383.00	5,896,216	2.02	0.01		185	0.01		399	33,272	33	33,305	7,538	75	0		6,041,235
384.00	2,937,578	1.32			0			0	3,875	0	3,875	159	0	0		2,959,678
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	39,364	3,737	43,101	6,337	1,584	0		3,138,245
387.00	88,125	3.07			0			0	350	0	350	0	0	0		90,223
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		3,923,348
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,049,606
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,316,459
391.11	64,605	6.39			0			0	486	0	486	0	0	0		67,522
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,322
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,328
394.00	7,984,087	3.86			0			0	76,971	0	76,971	0	0	0		8,247,308
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,719
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		126,884
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		980,542
397.50	627,296	5.45			0			0	14,721	0	14,721	12,587	0	0		628,302
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		670,768
					0			0								
303.00	26,386,435				0			0	915,247	0	915,247	179,722	0	0		28,640,748
303.60	4,909,544				0			0	270,679	0	270,679	0	0	0		4,995,307
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(120,770)
375.71	3,058,415				0			0	36,043	0	36,043	4,370	0	0		3,250,562
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,203
Total	**765,267,146**				**5,564,614**			**5,397,639**	**11,094,249**	**449,803**	**11,544,053**	**2,434,249**	**313,990**	**0**	**0**	**813,937,518**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	JUNE							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,186,463
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,054,111
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		908,001
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,347
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		932,677
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,539	1,158	12,696	1,633	0	0		1,150,721
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,916,413
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	14,458	2,878	17,336	5,866	2,288	0		1,693,171
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		77,053
375.70	8,203,718	2.65			18			18	110,700	2	110,702	4,734	0	0		8,945,060
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,510
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	6,004,787	111,874	6,116,661	1,928,375	154,270	0		449,780,792
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	668,151	20,336	688,487	472,025	75,524	0		33,029,511
379.10	39,930	8.17			6			6	811	1	812	0	0	0		45,612
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,594,367	302,320	2,896,687	635,050	203,216	0		192,174,905
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	97,563	1,523	99,087	11,395	342	0		19,787,493
381.10	20,008,389	2.49			0			0	51,968	0	51,968	2,011	0	0		20,359,584
382.00	16,567,447	1.91			486			486	79,228	41	79,269	19,029	0	0		17,002,847
383.00	5,896,216	2.02	0.01		185	0.01		399	33,526	33	33,559	9,561	96	0		6,065,138
384.00	2,937,578	1.32			0			0	3,878	0	3,878	201	0	0		2,963,355
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	39,870	3,737	43,607	8,425	2,106	0		3,171,320
387.00	88,125	3.07			0			0	350	0	350	0	0	0		90,573
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		3,994,372
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,059,091
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,331,223
391.11	64,605	6.39			0			0	486	0	486	0	0	0		68,008
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,389
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,288
394.00	7,984,087	3.86			0			0	77,993	0	77,993	0	0	0		8,325,300
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,773
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		128,061
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		980,052
397.50	627,296	5.45			0			0	15,651	0	15,651	12,587	0	0		631,367
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		675,874
					0			0								
303.00	26,386,435				0			0	976,435	0	976,435	412,456	0	0		29,204,727
303.60	4,909,544				0			0	270,785	0	270,785	34,683	0	0		5,231,409
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(115,199)
375.71	3,058,415				0			0	39,565	0	39,565	4,370	0	0		3,285,757
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,233
Total	**765,267,146**				**5,564,614**			**5,397,639**	**11,256,467**	**449,803**	**11,706,270**	**3,562,402**	**437,842**	**0**	**0**	**821,643,545**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	JULY							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,204,474
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,066,299
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		935,808
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,379
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		935,196
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,564	1,158	12,721	1,624	0	0		1,161,818
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,919,296
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	14,573	2,878	17,451	5,436	2,120	0		1,703,066
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		77,093
375.70	8,203,718	2.65			18			18	110,951	2	110,953	4,734	0	0		9,051,278
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,539
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	6,041,725	111,874	6,153,599	1,793,542	143,483	0		453,997,366
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	678,226	20,336	698,562	497,709	79,634	0		33,150,730
379.10	39,930	8.17			6			6	811	1	812	0	0	0		46,424
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,611,803	302,320	2,914,124	589,072	188,503	0		194,311,454
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	97,800	1,523	99,323	10,768	323	0		19,875,725
381.10	20,008,389	2.49			0			0	52,011	0	52,011	1,900	0	0		20,409,695
382.00	16,567,447	1.91			486			486	79,543	41	79,583	18,159	0	0		17,064,271
383.00	5,896,216	2.02	0.01		185	0.01		399	33,703	33	33,736	9,433	94	0		6,089,347
384.00	2,937,578	1.32			0			0	3,881	0	3,881	200	0	0		2,967,036
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	40,221	3,737	43,958	7,782	1,945	0		3,205,551
387.00	88,125	3.07			0			0	350	0	350	0	0	0		90,923
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		4,065,395
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,068,575
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,345,986
391.11	64,605	6.39			0			0	486	0	486	0	0	0		68,495
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,456
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,247
394.00	7,984,087	3.86			0			0	78,726	0	78,726	0	0	0		8,404,026
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,827
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		129,238
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		979,563
397.50	627,296	5.45			0			0	16,302	0	16,302	12,587	0	0		635,083
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		680,979
					0			0								
303.00	26,386,435				0			0	985,785	0	985,785	174,547	0	0		30,015,964
303.60	4,909,544				0			0	268,350	0	268,350	154,863	0	0		5,344,896
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(109,628)
375.71	3,058,415				0			0	39,493	0	39,493	4,370	0	0		3,320,879
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,264
Total	**765,267,146**				**5,564,614**			**5,397,639**	**11,330,658**	**449,803**	**11,780,461**	**3,286,725**	**416,103**	**0**	**0**	**829,721,179**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	AUGUST							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,222,486
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,078,487
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		963,616
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,411
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		937,715
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,586	1,158	12,743	1,626	0	0		1,172,935
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,922,179
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	14,674	2,878	17,552	6,082	2,372	0		1,712,164
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		77,133
375.70	8,203,718	2.65			18			18	110,941	2	110,942	4,734	0	0		9,157,487
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,568
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	6,074,392	111,874	6,186,265	2,045,784	163,663	0		457,974,185
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	686,969	20,336	707,305	567,548	90,808	0		33,199,680
379.10	39,930	8.17			6			6	811	1	812	0	0	0		47,236
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,627,245	302,320	2,929,565	658,022	210,567	0		196,372,431
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	98,010	1,523	99,533	11,687	351	0		19,963,220
381.10	20,008,389	2.49			0			0	52,048	0	52,048	2,062	0	0		20,459,680
382.00	16,567,447	1.91			486			486	79,822	41	79,863	19,408	0	0		17,124,726
383.00	5,896,216	2.02	0.01		185	0.01		399	33,860	33	33,894	9,562	96	0		6,113,583
384.00	2,937,578	1.32			0			0	3,883	0	3,883	200	0	0		2,970,719
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	40,531	3,737	44,269	8,751	2,188	0		3,238,881
387.00	88,125	3.07			0			0	350	0	350	0	0	0		91,272
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		4,136,419
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,078,059
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,360,749
391.11	64,605	6.39			0			0	486	0	486	0	0	0		68,981
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,523
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,207
394.00	7,984,087	3.86			0			0	79,384	0	79,384	0	0	0		8,483,410
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,881
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		130,414
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		979,073
397.50	627,296	5.45			0			0	16,881	0	16,881	12,587	0	0		639,377
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		686,085
					0			0								
303.00	26,386,435				0			0	982,262	0	982,262	596,357	0	0		30,401,869
303.60	4,909,544				0			0	268,775	0	268,775	0	0	0		5,613,672
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(104,057)
375.71	3,058,415				0			0	39,421	0	39,421	4,370	0	0		3,355,930
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,295
Total	**765,267,146**				**5,564,614**			**5,397,639**	**11,386,687**	**449,803**	**11,836,490**	**3,948,780**	**470,043**	**0**	**0**	**837,138,845**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	SEPTEMBER							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,240,498
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,090,675
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		991,424
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,444
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		940,234
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,607	1,158	12,765	1,481	0	0		1,184,219
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,925,062
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	14,773	2,878	17,651	5,758	2,246	0		1,721,812
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		77,173
375.70	8,203,718	2.65			18			18	111,192	2	111,193	4,734	0	0		9,263,946
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,597
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	6,105,677	111,874	6,217,550	2,496,502	199,720	0		461,495,513
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	695,803	20,336	716,140	306,982	49,117	0		33,559,720
379.10	39,930	8.17			6			6	811	1	812	0	0	0		48,048
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,642,309	302,320	2,944,629	622,602	199,233	0		198,495,225
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	98,215	1,523	99,738	10,954	329	0		20,051,676
381.10	20,008,389	2.49			0			0	52,085	0	52,085	1,933	0	0		20,509,833
382.00	16,567,447	1.91			486			486	80,095	41	80,136	18,095	0	0		17,186,766
383.00	5,896,216	2.02	0.01		185	0.01		399	34,015	33	34,048	8,750	87	0		6,138,793
384.00	2,937,578	1.32			0			0	3,885	0	3,885	182	0	0		2,974,422
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	40,834	3,737	44,572	8,297	2,074	0		3,273,082
387.00	88,125	3.07			0			0	350	0	350	0	0	0		91,622
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		4,207,442
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,087,543
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,375,513
391.11	64,605	6.39			0			0	486	0	486	0	0	0		69,467
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,590
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,166
394.00	7,984,087	3.86			0			0	80,029	0	80,029	0	0	0		8,563,439
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,935
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		131,591
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		978,584
397.50	627,296	5.45			0			0	17,447	0	17,447	12,587	0	0		644,237
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		691,191
					0			0								
303.00	26,386,435				0			0	979,152	0	979,152	251,613	0	0		31,129,408
303.60	4,909,544				0			0	275,764	0	275,764	26,459	0	0		5,862,976
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(98,486)
375.71	3,058,415				0			0	42,942	0	42,942	4,370	0	0		3,394,503
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,326
Total	**765,267,146**				**5,564,614**			**5,397,639**	**11,451,827**	**449,803**	**11,901,630**	**3,781,299**	**452,806**	**0**	**0**	**844,806,370**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	OCTOBER							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,258,510
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,102,863
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		1,019,232
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,476
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		942,754
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,630	1,158	12,787	1,787	0	0		1,195,219
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,927,945
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	14,874	2,878	17,752	6,142	2,395	0		1,731,026
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		77,214
375.70	8,203,718	2.65			18			18	111,443	2	111,444	4,734	0	0		9,370,656
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,626
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	6,137,724	111,874	6,249,597	1,985,365	158,829	0		465,600,916
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	705,392	20,336	725,728	205,388	32,862	0		34,047,198
379.10	39,930	8.17			6			6	811	1	812	0	0	0		48,859
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,657,694	302,320	2,960,014	665,330	212,905	0		200,577,004
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	98,424	1,523	99,948	12,076	362	0		20,139,185
381.10	20,008,389	2.49			0			0	52,123	0	52,123	2,131	0	0		20,559,825
382.00	16,567,447	1.91			486			486	80,374	41	80,414	20,290	0	0		17,246,890
383.00	5,896,216	2.02	0.01		185	0.01		399	34,172	33	34,205	10,410	104	0		6,162,484
384.00	2,937,578	1.32			0			0	3,887	0	3,887	220	0	0		2,978,090
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	41,144	3,737	44,881	8,804	2,201	0		3,306,958
387.00	88,125	3.07			0			0	350	0	350	0	0	0		91,972
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		4,278,466
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,097,028
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,390,276
391.11	64,605	6.39			0			0	486	0	486	0	0	0		69,953
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,657
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,125
394.00	7,984,087	3.86			0			0	80,687	0	80,687	0	0	0		8,644,126
394.12	17,395	0.00			648			648	0	54	54	0	0	0		17,989
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		132,768
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		978,094
397.50	627,296	5.45			0			0	18,025	0	18,025	12,587	0	0		649,675
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		696,297
					0			0								
303.00	26,386,435				0			0	984,578	0	984,578	115,533	0	0		31,998,452
303.60	4,909,544				0			0	276,373	0	276,373	0	0	0		6,139,349
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(92,915)
375.71	3,058,415				0			0	42,871	0	42,871	4,370	0	0		3,433,004
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,356
Total	**765,267,146**				**5,564,614**			**5,397,639**	**11,517,416**	**449,803**	**11,967,220**	**3,055,167**	**409,660**	**0**	**0**	**853,308,764**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	NOVEMBER							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,012	0	18,012	0	0	0		3,276,522
352.01	968,796	12.98			0			0	12,188	0	12,188	0	0	0		1,115,051
352.02	713,346	31.10			0			0	27,808	0	27,808	0	0	0		1,047,040
352.10	206,932	0.00			0			0	0	0	0	0	0	0		206,932
353.00	387,117	0.10	0.02		44	0.02		0	32	0	32	0	0	0		387,508
354.00	915,043	3.19			0			0	2,519	0	2,519	0	0	0		945,273
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,650	1,158	12,807	2,037	0	0		1,205,989
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,930,827
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	14,967	2,878	17,845	6,419	2,503	0		1,739,949
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		77,254
375.70	8,203,718	2.65			18			18	111,432	2	111,434	4,734	0	0		9,477,355
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,655
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	6,167,950	111,874	6,279,823	2,045,673	163,654	0		469,671,412
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	714,507	20,336	734,843	196,452	31,432	0		34,554,157
379.10	39,930	8.17			6			6	811	1	812	0	0	0		49,671
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,671,912	302,320	2,974,233	696,252	222,801	0		202,632,185
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	98,617	1,523	100,140	12,939	388	0		20,225,998
381.10	20,008,389	2.49			0			0	52,158	0	52,158	2,283	0	0		20,609,699
382.00	16,567,447	1.91			486			486	80,630	41	80,670	22,010	0	0		17,305,551
383.00	5,896,216	2.02	0.01		185	0.01		399	34,315	33	34,349	11,757	118	0		6,184,959
384.00	2,937,578	1.32			0			0	3,889	0	3,889	250	0	0		2,981,729
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	41,430	3,737	45,167	9,161	2,290	0		3,340,674
387.00	88,125	3.07			0			0	350	0	350	0	0	0		92,322
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		4,349,489
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,106,512
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,763	0	14,763	0	0	0		1,405,039
391.11	64,605	6.39			0			0	486	0	486	0	0	0		70,439
391.12	481,779	0.17			0			0	67	0	67	0	0	0		471,724
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,085
394.00	7,984,087	3.86			0			0	81,304	0	81,304	0	0	0		8,725,430
394.12	17,395	0.00			648			648	0	54	54	0	0	0		18,043
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		133,944
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		977,605
397.50	627,296	5.45			0			0	18,564	0	18,564	12,587	0	0		655,653
398.00	651,416	6.03			0			0	5,106	0	5,106	0	0	0		701,403
					0			0								
303.00	26,386,435				0			0	1,003,310	0	1,003,310	518,575	0	0		32,483,187
303.60	4,909,544				0			0	278,341	0	278,341	16,535	0	0		6,401,155
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(87,344)
375.71	3,058,415				0			0	42,799	0	42,799	4,370	0	0		3,471,433
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,387
Total	**765,267,146**				**5,564,614**			**5,397,639**	**11,593,778**	**449,803**	**12,043,582**	**3,562,033**	**423,186**	**0**	**0**	**861,367,126**

RESERVE BRINGFORWARD

			PROJECTED 24			PROJECTED 2025			2025							
	2024	'Accrual			'5-yr			'5-yr	DECEMBER							
Account	NOV 30 Begin. Balance	Rates 11-2024	COR % of Rets	Salvage % of Rets	Amort of NS 2019-2023	COR % of Rets	Salvage % of Rets	Amort of NS 2020-2024	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.05							0	0	0	0	0	0		1,932
351.20	3,060,380	6.56			0			0	18,319	0	18,319	0	0	0		3,294,840
352.01	968,796	12.98			0			0	11,721	0	11,721	0	0	0		1,126,772
352.02	713,346	31.10			0			0	25,931	0	25,931	0	0	0		1,072,970
352.10	206,932	0.00			0			0	9	0	9	0	0	0		206,941
353.00	387,117	0.10	0.02		44	0.02		0	16	0	16	0	0	0		387,525
354.00	915,043	3.19			0			0	2,365	0	2,365	0	0	0		947,638
355.00	104,477	0.00			0			0	0	0	0	0	0	0		104,477
374.40	1,073,080	1.64			14,695			13,890	11,671	1,158	12,829	1,946	0	0		1,216,872
374.50	1,896,234	1.07			0			0	2,883	0	2,883	0	0	0		1,933,710
375.34	1,616,016	2.37	0.39		34,292	0.39		34,535	15,068	2,878	17,946	5,695	2,221	0		1,749,979
375.60	76,763	0.56	0.33		104	0.33		0	40	0	40	0	0	0		77,294
375.70	8,203,718	2.65			18			18	111,683	2	111,684	4,734	0	0		9,584,307
375.80	9,308	2.10			0			0	29	0	29	0	0	0		9,684
376.00	419,098,827	2.32	0.08		1,325,670	0.08		1,342,482	6,200,531	111,874	6,312,404	1,807,202	144,576	0		474,032,039
378.00	30,187,789	3.67	0.16		152,458	0.16		244,036	724,307	20,336	744,644	163,731	26,197	0		35,108,872
379.10	39,930	8.17			6			6	811	1	812	0	0	0		50,483
380.00	176,926,111	3.33	0.32		3,853,086	0.32		3,627,844	2,687,226	302,320	2,989,546	618,544	197,934	0		204,805,252
381.00	19,167,044	2.44	0.03		17,687	0.03		18,279	98,824	1,523	100,348	11,744	352	0		20,314,249
381.10	20,008,389	2.49			0			0	52,195	0	52,195	2,072	0	0		20,659,822
382.00	16,567,447	1.91			486			486	80,905	41	80,945	20,193	0	0		17,366,304
383.00	5,896,216	2.02	0.01		185	0.01		399	34,469	33	34,502	11,156	112	0		6,208,193
384.00	2,937,578	1.32			0			0	3,891	0	3,891	239	0	0		2,985,381
385.00	2,929,185	5.09	0.25		77,900	0.25		44,847	41,739	3,737	45,476	8,097	2,024	0		3,376,029
387.00	88,125	3.07			0			0	350	0	350	0	0	0		92,671
387.40	3,497,174	5.25	0.03		10,036	0.03		9,636	70,220	803	71,023	0	0	0		4,420,512
387.50	1,992,701	5.17			0			0	9,484	0	9,484	0	0	0		2,115,996
390.10	49,821	0.00			0			0	0	0	0	0	0	0		49,821
391.10	1,259,397	4.82			0			0	14,762	0	14,762	523	0	0		1,419,280
391.11	64,605	6.39			0			0	486	0	486	0	0	0		70,925
391.12	481,779	0.17			0			0	42	0	42	346,442	0	0		125,325
392.00	24,582	1.28			(936)			(815)	27	(68)	(41)	0	0	0		24,044
394.00	7,984,087	3.86			0			0	81,483	0	81,483	296,717	0	0		8,510,197
394.12	17,395	0.00			648			648	0	54	54	0	0	0		18,097
395.00	119,824	5.33			0			0	1,177	0	1,177	0	0	0		135,121
396.00	983,478	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0		977,116
397.50	627,296	5.45			0			0	19,141	0	19,141	12,587	0	0		662,207
398.00	651,416	6.03			0			0	5,041	0	5,041	25,988	0	0		680,455
					0			0								
303.00	26,386,435				0			0	1,005,903	0	1,005,903	432,816	0	0		33,056,275
303.60	4,909,544				0			0	276,376	0	276,376	158,960	0	0		6,518,572
362.10	(155,603)				83,739			66,852	0	5,571	5,571	0	0	0		(81,773)
375.71	3,058,415				0			0	46,320	0	46,320	4,370	0	0		3,513,383
NonDeprPlant	235,018				369			369	0	31	31	0	0	0		235,418
Total	**765,267,146**				**5,564,614**			**5,397,639**	**11,655,447**	**449,803**	**12,105,251**	**3,933,756**	**373,416**	**0**	**0**	**869,165,207**

COLUMBIA STATEMENT NO. 5-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
JOHN J. SPANOS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

I. INTRODUCTION

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. With what firm are you associated and in what capacity?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming) as President.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since June 1986.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted Columbia Statement No. 5.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the depreciation-related testimony of Brian C. Andrews on behalf of the Pennsylvania Office of Consumer Advocate ("OCA"). Mr. Andrews has proposed the use of the Average Life Group ("ALG") procedure to calculate depreciation expense and depreciation annual accrual rates in an effort to "mitigate rate increases associated with Columbia Gas' significant rate base investment that has been occurring for several years and will continue to occur."[1] I will also respond to OCA witness Greg R. Meyer related to his adjustments to plant in-service and the need to reflect the associated change in rate base.

Q. Please summarize your rebuttal testimony.

[1] OCA Statement 4, p. 3, lines 12-14

A. Mr. Andrews has proposed a reduction in depreciation expense of $43.88 million based on an issue that the Commission has already clearly addressed and decided consistently for almost 40 years. The issue relates to the depreciation procedure that Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company") has been utilizing for developing depreciation rates and expense for 40 years. Columbia uses the Equal Life Group ("ELG") procedure instead of the Average Life Group ("ALG") procedure. The Average Life Group procedure is most commonly identified in Pennsylvania as the Average Service Life ("ASL") procedure. The use of the ELG procedure was established with the Pennsylvania Public Utility Commission ("PUC") during the 1980s and has been used by most utilities within the Commonwealth of Pennsylvania to calculate depreciation expense and annual depreciation accrual rates since that time spanning a period of approximately 40 years.

In my testimony, I will address the following topics. First, I will explain either Mr. Andrews lack of understanding of how depreciation expense and annual depreciation accrual rates are calculated within the confines of a rate case in the State of Pennsylvania, or how he seems to support the ELG procedure when developing the level of accumulated depreciation, but then contradicts the methodology to use the ALG procedure when calculating depreciation expense. Second, I will explain the impact of proposing such a radical reduction of depreciation expense to the Company. Third, I will explain why the recent decisions regarding ELG in other state jurisdictions that Mr. Andrews uses to support his ALG proposal are not applicable in this case. And lastly, I will show that the Company's proposed composite annual depreciation accrual rate of

2.58% calculated as of December 31, 2025 is consistent with the range of composite annual depreciation accrual rates of other gas distribution utilities within the United States regardless of the depreciation procedure utilized.

II. EQUAL LIFE GROUP VS AVERAGE LIFE GROUP

Q. What is the equal life group procedure?

A. For the ELG procedure, a group of property (e.g., a vintage within a property account) is subdivided into groups having equal service lives. The size of these "equal life groups" is based on the estimated survivor characteristics of the account. Depreciation can then be calculated for each equal life group based on the straight line method, meaning that an equal amount of the group's service value is recorded as depreciation expense in each year of service. The total depreciation for an account is then the summation of the calculated depreciation for each equal life group. Based on the survivor curve estimate for an account, the ELG procedure mathematically estimates the life for each unit in the account, and then depreciates each unit over its expected life. The procedure is also known as the Unit Summation Procedure.

Q. How does the ELG procedure differ from the ASL (also referred to as ALG) procedure?

While the ELG procedure calculates depreciation for each equal life group, the ASL (or ALG) procedure depreciates every asset within an account over the average life of the entire account. Using equal life groups, rather than an average life, as the basis for depreciation provides a more precise calculation that better matches recovery with consumption of assets by depreciating assets that have shorter lives than the average over their shorter lives (and the longer-lived assets

over their longer lives) as opposed to depreciating all assets over the average life for the group.

Q. Is ELG supported by depreciation authorities?

A. Yes. ELG is discussed and supported in authoritative depreciation texts and academic literature. For example, Robley Winfrey, who developed the Iowa survivor curves at Iowa State University and is regarded as a pioneer of utility depreciation practices, referred to the ELG procedure as "the only mathematically correct procedure."[2]

Depreciation Systems by Wolf and Fitch, also supports the appropriateness of ELG stating, "Application of the equal life group procedure is generally considered to better match the consumption of capital with service provided than does application of the average life procedure."[3]

Q. Please explain how depreciation is determined using the ELG procedure.

A. A simple two-unit example will demonstrate how the ELG procedure more appropriately matches cost recovery to consumption than the ASL procedure. In this example, each unit costs $1,000. Unit A will be in service for 5 years, and unit B will be in service for 15 years. There is no net salvage for these units.

For the ASL procedure, the average service life for the two units is 10 years ([5+15]/2), so the annual depreciation rate is 10% (1/10) throughout the lives of both units. For the first five years, the total annual depreciation amount is $200

[2] Robley Winfrey, Depreciation of Group Properties, Bulletin 155 (Ames, IA: Iowa State University Press, 1942, reprinted 1969); p. 71

[3] Frank K. Wolf and W. Chester Fitch, *Depreciation Systems* (Ames, IA: Iowa State University Press, 1994); p.75

($2,000 x 10%). At the end of year 5, the total annual accruals for the account is $1,000 ($200 x 5). Unit A is then retired, which results in a reduction in the plant in service and accumulated depreciation of $1,000, consistent with established plant retirement procedure. At the start of year 6, Unit B remains in service with an accumulated depreciation balance of $0. At this point, one-third of Unit B's service life has expired, and its full original cost must still be recovered.

For the remaining 10 years, $100 ($1,000 x 10%) of annual expense is accumulated in depreciation, for a total of $1,000 when Unit B is retired. Thus, at the time of Unit B's retirement, the Company will have fully recovered the total depreciable cost of both units. However, at the end of year five, only one unit remained in service with two-thirds of its life expectancy left but with 100% of that unit's original investment still to be recovered. As a result, the ASL procedure is ineffective in matching cost recovery to the actual consumption of the asset. This is a characteristic deficiency of the ASL procedure.

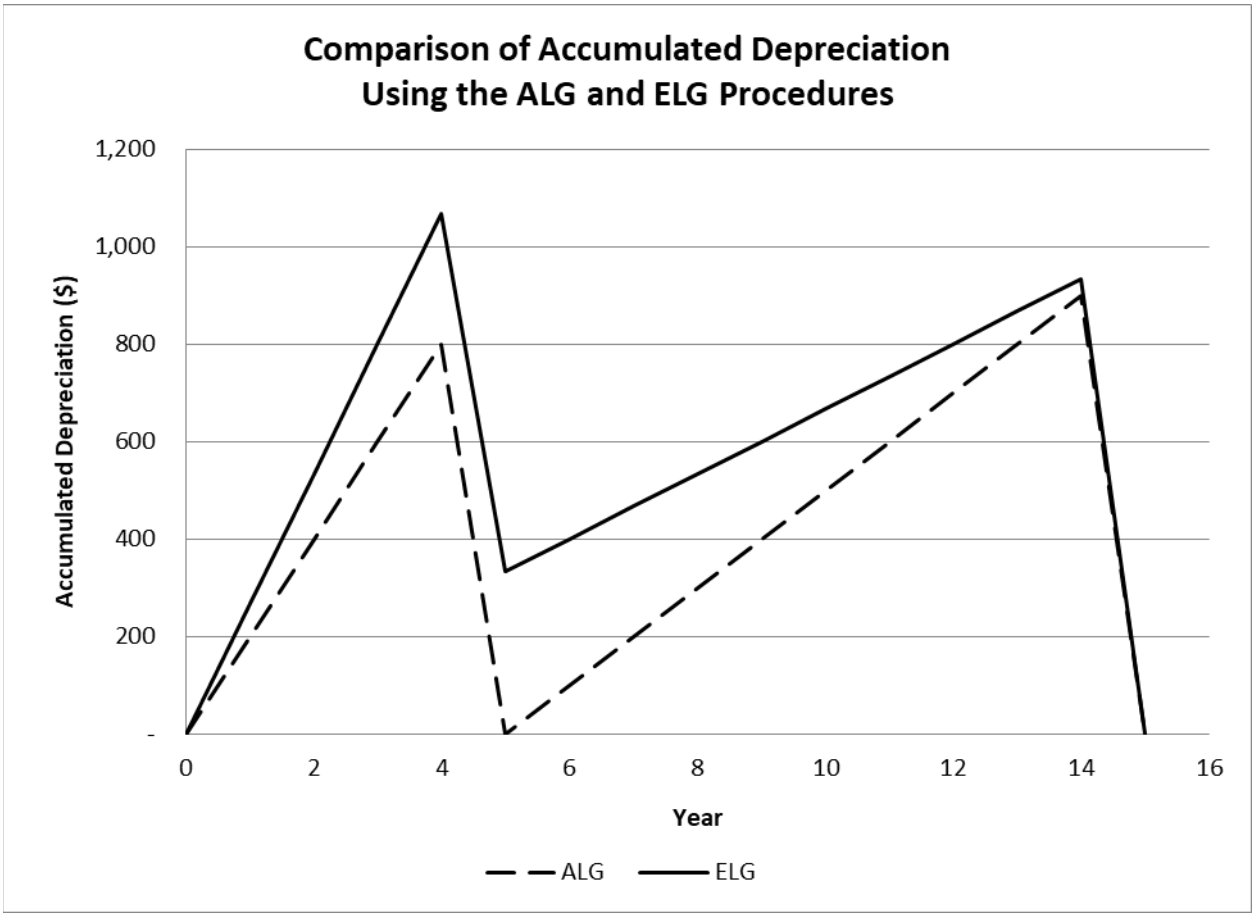
When depreciation is determined using the ELG procedure, the pattern of cost recovery better matches actual consumption. Using the same two-unit example, the annual depreciation expense under the ELG procedure is calculated by summing the annual expense for each equal life group. In this case, there are two equal life groups – one for Unit A, which has a life of 5 years, and one for Unit B, which has a life of 15 years. The annual depreciation rate for Unit A is 20% (1/5) and for Unit B is 6.67% (1/15). Thus, the annual accruals for years 1 through 5 will be $200 ($1,000 x 20%) for the first equal life group (Unit A) summed with $66.67 ($1,000 x 6.67%) for the second (Unit B), or $266.67. At

the end of year 5, when Unit A is retired, the total accruals would be $1,333.33 ($266.67 x 5). The retirement of Unit A results in a reduction of $1,000 in accumulated depreciation, and at the start of year 6, the $1,000 original cost of Unit B remains with $333.33 in accumulated depreciation. Thus, with one-third of Unit B's life consumed, accumulated depreciation is exactly one-third of the original cost for this unit.

In the years 6 through 15, the annual depreciation expense is $66.67 for a total of $666.67 over the 10-year period. After the retirement of Unit B, the accumulated depreciation is $0 ($1,000 of accruals less the $1,000 retirement of Unit B), and the full recovery of both units has been obtained.

As this example shows, the ELG procedure better matches the cost recovery of both units with their actual service lives. Figure 1 below provides a graph of the accumulated depreciation for both procedures. The end of year 5 provides the best illustration of the difference between the two procedures. Under the ELG procedure, Unit A is fully recovered when retired at the end of year 5; Unit B is one-third through its service life and has had one-third of its cost recovered. This contrasts with the ASL procedure, in which accumulated depreciation is $0 at the end of year 5, even though the only unit remaining in service has consumed one-third of its service life. Clearly, the ELG procedure provides a better match regarding the consumption of the service value for the two units. Additionally, rate base under ELG at the end of year 5 is $667 (=$1,000-$333) versus $1,000 (=$1,000 - $0) under ASL.

Figure 1. Comparison of Accumulated Depreciation Using the ALG and ELG Procedures



Q. You have provided a simple two-unit example demonstrating how ELG works. Do the same principles apply to larger property groups with many units?

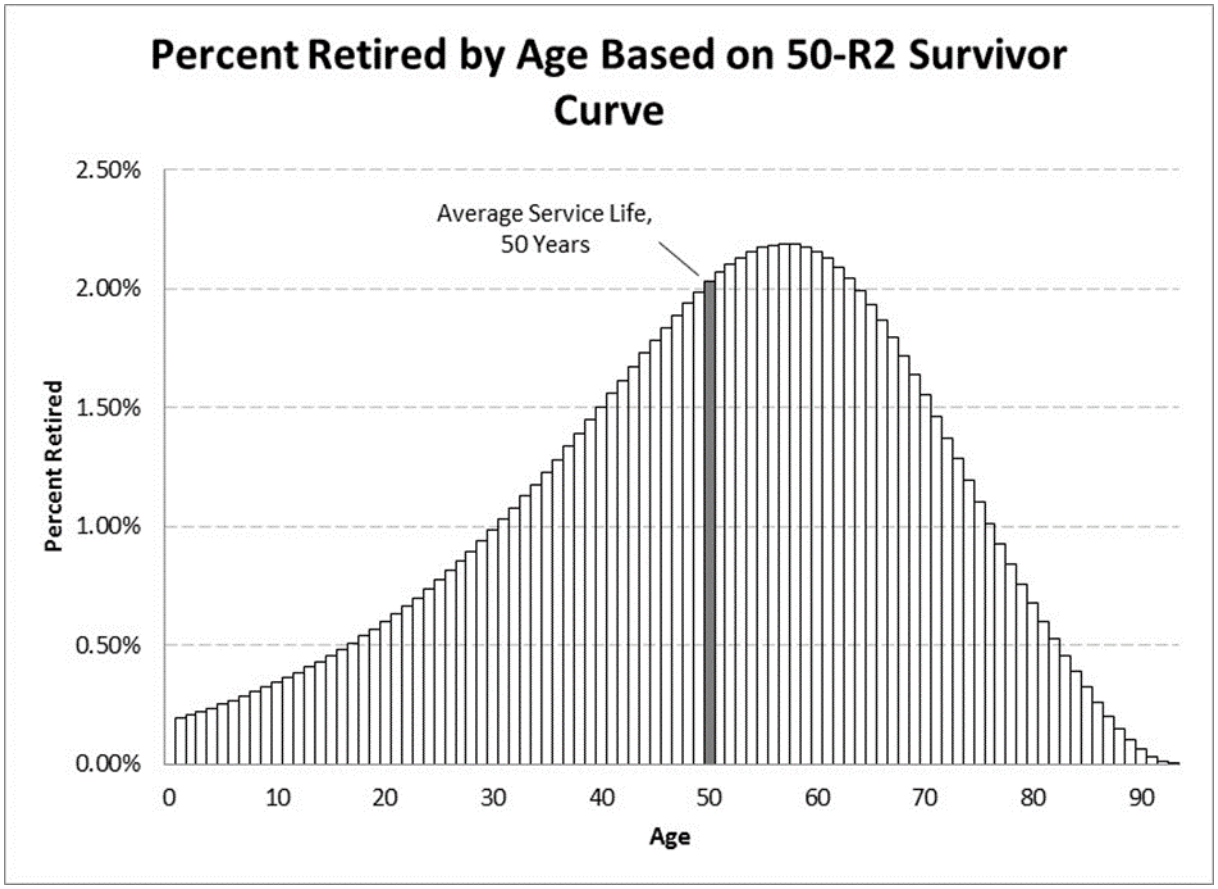
A. Yes. The same principles apply when the ELG procedure is applied to a large group of property with many units, as is typical of utility property. The survivor curve estimated for each property account can be used to divide an account into equal life groups. The survivor curve allows for the calculation of the percentage of the property account that is in each equal life group, which allows for the calculation of ELG annual depreciation accruals for the entire property group.

Under the ASL procedure, the depreciation expense for all property in the account is calculated based on the average service life for the entire group.

The ELG procedure recognizes the reality of dispersion. Specifically, it recognizes that in actual utility operations only a very small percentage of the account will be retired at the average service life. Figure 2 below is a chart of the frequency curve for the 50-R2 survivor curve. The frequency curve shows the percentage of property in this account that will be retired at each age, based on the estimated survivor curve. This percentage is also the size of each equal life group.

The shaded bar in Figure 2 represents the percentage of property that will have a life of 50 years. In other words, this shows the percentage of property that is expected to be in service for the average service life. Only 2.07% of the assets will be in service for exactly 50 years. In contrast, a majority, 97.93%, of the assets will have a service life different than 50 years.

Figure 2. Percent Retired by Age Based on 50-R2 Survivor Curve



The ELG procedure recognizes this dispersion and allocates costs for each equal life group over the expected life for that group. The service lives indicated by the 50-R2 survivor curves range from 1 year to 93 years. As a result, the ELG procedure allocates cost in a manner that approximates the result of each asset being depreciated over its actual life. Conversely, the ASL procedure depreciates every unit of property within an account over the same life, that is, the average life. As Figure 2 shows, this average life will be incorrect most of the time – in this example, the average life will be the wrong life for 97.93% of the individual assets.

Just as in the case for the two-unit example provided above, the ELG procedure better matches capital recovery with the actual lives forecast by the estimated survivor curve.

III. PENNSYLVANIA PRECEDENT

Q. Is the ELG procedure supported by other depreciation authorities?

A. Yes. ELG is discussed and supported in authoritative depreciation texts and academic literature. As noted previously, Robley Winfrey, who developed the Iowa survivor curves that are universally used in estimating service lives based on historical retirement data, referred to the ELG procedure as "the only mathematically correct procedure." [4]

Q. Are other commissions starting to implement the ELG procedure given the current regulatory environment?

A. Yes. The ELG procedure is being utilized for gas assets by the Texas Railroad Commission. It is also used in jurisdictions in Canada. The Federal Communications Commission ("FCC") first adopted ELG in the 1980s in the context of rapid technological change in the telecommunications industry at that time.[5]

ELG has also been adopted recently in Colorado in response to significant technological and regulatory changes facing the gas industry.[6] New York is also considering ELG for similar reasons in an active case in New York.[7]

[4] Robley Winfrey, Depreciation of Group Properties, Bulletin 155 (Ames, IA: Iowa State University Press, 1942, reprinted 1969); p. 71

[5] See, Id., pages 172 through 175 for a discussion of the use of the ELG procedure in the telecommunications industry

[6] Decision No. C22-0642 in Proceeding No. 22AL-0046G p. 51, lines 161-163

[7] New York State Department of Public Service Cases 24-E-0322 and 24-G-0323

Q. Has the ELG procedure been previously adopted in Pennsylvania?

A. Yes. ELG is the predominant method used in Pennsylvania for many years. Most Pennsylvania gas, electric and water utilities have used the ELG procedure since the 1980s. ELG was adopted for Columbia Gas of PA in 1980s related to vintages from the previous rate case and has been used for depreciation since this approval.[8] Generally, every five years beginning in the mid-1980s, the Company has filed a service life study report with the Commission for approval based on Commission regulations. In 2022, Columbia submitted its most recent five-year service life study report to the Commission and all depreciation parameters and methods, including the use of the ELG procedure, were approved. Additionally, Columbia submits annual depreciation reports to the Commission each year updating the Company's depreciation accrual rates for book purposes as well as identifying the underlying depreciation parameters and calculation methods and procedures used to determine depreciation expense. Under the Commission's regulation 52 Pa. Code §73.9(c), once such depreciation reports are filed and accepted "*[i]n subsequent ratemaking proceedings, the most recent annual depreciation report or service life study approved or deemed approved for accounting purposes only under this chapter, constitutes a rebuttable presumption as to the reasonableness of the accrued depreciation claimed for ratemaking purposes, and the burden of proving the unreasonableness of the accrued depreciation shall be on the challenging party*."

[8] ELG was adopted for many Pennsylvania utilities on a go-forward basis. For this reason, vintages of plant subsequent to the adoption of ELG use ELG while older vintages use ASL. For Columbia Gas of PA, vintages 1976 and subsequent use ELG and vintages 1975 and prior use ASL.

q. Are the Company's current depreciation rates based on the ELG procedure?

A. Yes. The Company's most recent annual depreciation report was filed on June 30, 2024 and most recent service life study was filed in August 2022. All have been approved for accounting purposes using the ELG procedure. The ELG procedure was also adopted in the most recent rate case, Docket No. R-2022-3031211.

Q. Since the use of ELG is the predominant and longstanding practice in Pennsylvania, has Mr. Andrews provided evidentiary support for his recommendation that the Company should deviate from this practice?

A. No. Mr. Andrews has provided very little evidence to support why the ALG method is more appropriate than ELG. None of Mr. Andrews' arguments support overturning longstanding precedent despite having the burden of doing so under 52 Pa. Code §73.9(c). He appears to disagree with ELG simply because it can produce higher depreciation rates, but he provides no evidence for why lower depreciation rates are more appropriate.

He has provided minimal justification to support his claim that the Company's approved depreciation rates or calculation procedures, which are based on longstanding precedent, are unreasonable. Further, Mr. Andrews ignores the issue of precedent, in effect only arguing that his proposal should be adopted because it results in lower depreciation expense and a short-term reduction in rates for current customers.

However, as I will explain, Mr. Andrews is incorrect that the longstanding use of ELG costs customers more than ASL. In fact, the opposite is true. Current

customers benefit from the continued use of ELG, because rate base is lower than had ASL been used for this time. The more precise recovery through ELG benefits customers over time, because shorter-lived assets are correctly recovered over their useful lives, resulting in a lower rate base and lower return on rate base that exceeds the higher annual depreciation expense. Further, the alleged benefit proposed by Mr. Andrews, of lower short-term rates, is the result of the *change* in procedure, not from the procedure itself. Over time, the ASL depreciation rates will result in a higher rate base and higher overall cost to customers.

IV. DEPRECIATION AND RATE BASE

Q. How does Mr. Andrews discuss the impact of ELG on customer rates?

A. Mr. Andrews states on page 20, lines 17 to 22 and page 21, lines 1 to 5 of his testimony "Utilities typically only update their depreciation expense recovered from customers in the context of a rate case, which is often not an every year occurrence. When depreciation rates for new assets are proposed using the ELG procedure, the rates put forward for approval would be analogous to the year 1 depreciation rate in this example. Therefore, if the ELG method were approved in a depreciation study, given this example and left in place for 10 years, the effective depreciation rate would be 37.82% every year. To be just to consumers and to produce reasonable rates, ELG depreciation rates should be updated each year and the corresponding depreciation expense adjusted in base rates; however, the ELG depreciation rates are not properly implemented and create intergenerational inequities, significantly overcharging customers in base rates based on the higher depreciation rates in earlier years."

Q. Does Columbia perform regular rate cases?

A. Yes. Including the instant rate case, Columbia has performed 13 rate cases since 2007.

Q. Is Columbia required by Pennsylvania regulations to update its depreciation expense and annual depreciation accrual rates each year by filing an Annual Depreciation Report?

A. Yes.

Q. Does Columbia's proposed ELG depreciation rates meet Mr. Andrews' stated requirements for ELG depreciation rates "to be just to consumers and to produce reasonable rates?"

A. Absolutely yes.

Q. Please explain this concept further.

A. Depreciation impacts customer rates in two ways. Depreciation expense is a direct component of the revenue requirement; however, accumulated depreciation[9] is also a *reduction* to rate base. A higher level of accumulated depreciation results in a lower rate base, a lower return on rate base and, therefore, lower customer rates when compared to a lower level of accumulated depreciation.

The implication of Mr. Andrews' testimony is that a utility has an incentive for higher depreciation because it results in higher customer rates, and thus more cash flow for the Company. However, in the long term, his description of the rate impact is fundamentally incorrect. Higher depreciation expense will, over time, result in higher accumulated depreciation. Because average depreciation rates

[9] Accumulated depreciation is the depreciation expense recorded to date, less recorded retirements and cost of removal, plus recorded gross salvage.

for a utility are typically in the 2% to 3% range and the return on rate base is higher (typically 7% to 8% or more), higher depreciation expense tends to produce lower customer rates over time. Mr. Andrews's suggestion that a utility has an incentive to "overcharge" for depreciation expense is simply incorrect.

The longstanding use of ELG depreciation rates for Pennsylvania utilities has resulted in a lower rate base than if ASL had been used. Customers today pay lower customer rates than if ASL had been used during the years since ELG's adoption. As a result, it has been in customers' interest, not only to use ELG but also to use it consistently.

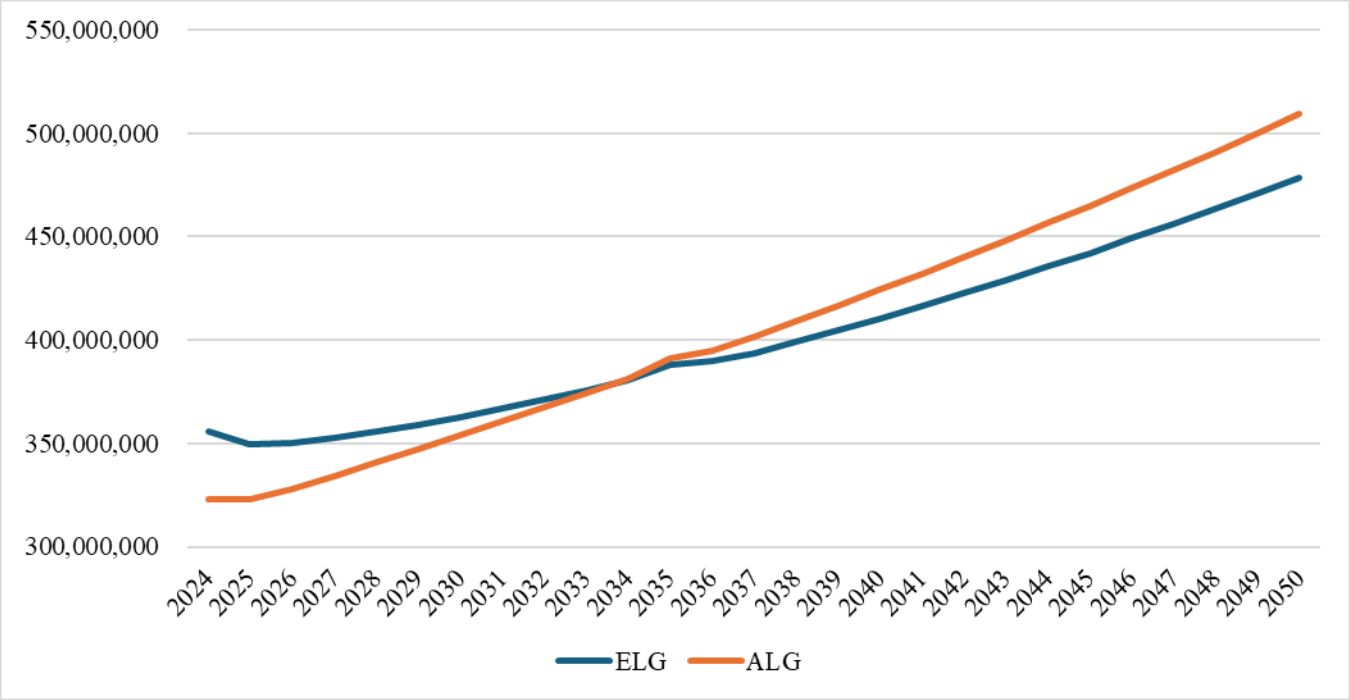
Over time ASL will result in higher customer rates than ELG. It is correct to assume that if the Company were to switch from ELG to ASL there would be a *short*-term benefit to current customers. However, this is not because ASL is in customers' best interest in the long term, but only because current customers would benefit from both lower ASL depreciation rates and from the lower rate base that exists due to the longstanding use of ELG.

Mr. Andrews' proposal is therefore not a recommendation that is in the long-term interest of lower customer rates. It is instead a short-term subsidy only to current customers who benefit from ELG depreciation rates that were paid by a previous generation of customers. The costs of a higher rate base will be paid for by future customers who will have to pay higher overall customer rates. Adopting ALG would serve as an intergenerational subsidy to current customers at the expense of other generations of customers.

Q. Can you illustrate this concept?

A. Yes, this concept is illustrated in Exhibit No. JJS-R-1, which forecasts plant and reserve balances for Columbia through 2050 under two scenarios: one adopting the ALG procedure and the other maintaining the currently-approved ELG procedure for vintages 1976 and newer. Figure 3 below shows a high-level estimate of the Company's revenue requirement for the period 2024 through 2050 under each of these scenarios. This demonstrates that while ELG leads to higher depreciation expenses in the short term, it results in lower revenue requirements over the long term. The ELG approach is arguably more beneficial to customers as it provides more stable and lower rates over time.

Figure 3. Comparison of Revenue Requirement



V. INTERGENERATIONAL INEQUITY

Q. Please explain the concept of "intergenerational equity."

A. Intergenerational equity is a ratemaking principle in which customers receiving the benefit from the use of an asset (e.g., from gas utility property used to provide

gas service) are the same customers who pay for the cost of that asset - no more, no less. There are two related concepts when considering intergenerational equity as it pertains to depreciation. The first is the inequity that results when customers pay for assets from which they receive no service. For example, if an asset is retired before becoming fully depreciated, then customers subsequent to the retirement will have to pay for an asset from which they are not receiving service. This is less equitable, as one generation of customers bears the cost of an asset from which they receive no service. Depreciation rates should be designed to avoid such an outcome. However, in real-world operations, circumstances can change such that assets are retired earlier than expected. This results in a situation that is different than designing depreciation rates to include intergenerational inequity, which should be avoided.

The second concept is related to the distribution of depreciation charges over the life of an asset. For example, if depreciation expense is higher in the earlier years of an asset's life and lower in later years (or vice versa), this also is less equitable because one generation of customers pays a higher share than the next.

In my professional opinion, the first concept related to intergenerational equity can be more detrimental to customers than the second. That is, there is greater inequity resulting from a customer paying for an asset from which they received no service than the inequity resulting from one generation paying a somewhat different share of the same asset than another generation.

Q. How does the ELG procedure calculate depreciation expense?

A. The ELG procedure calculates depreciation expense for assets with like lives within a depreciable group in accordance with the Iowa Survivor Curve proposed for the account and summing that depreciation expense for each similar life group of assets to develop an annual depreciation accrual rate applicable to the depreciable group. This procedure is designed to more appropriately match the recovery of the assets' costs to the period of time over which they are providing service to rate payers.

Q. How does the ALG procedure calculate depreciation expense?

A. The ALG procedure calculates depreciation expense by applying the same average service life from the proposed Iowa Survivor Curve to all assets within a depreciable group rather than grouping assets within a depreciable group by like lives. The ALG procedure operates with the assumption that some of the assets within a depreciable group will retire prior the average service life applied to the depreciable group and other assets will survive longer than the average service life applied to the depreciable group. Continuing, the ALG procedures assumes the over-recovery of the assets surviving longer than the average service life will offset the amount of the under-recovery of the assets retiring prior to reaching the average service life of the depreciable group.

Q. Does the use of ELG vs. ALG or vice versa impact the total amount of asset cost to be recovered?

A. No. Both procedures are designed to recover the total service value of an asset over the asset's service life.

Q. Has Mr. Andrews claimed that the ELG procedure produces intergenerational inequity?

A. Yes.[10]

Q. Why does Mr. Andrews make that claim?

A. Given the precise nature of the calculation process utilized in the ELG procedure, the level of depreciation expense associated with assets that are younger than the proposed average service life is higher than depreciation expense using the ALG procedure. Conversely, as the assets mature and the lives grow longer, the level of depreciation expense associated with assets that are older than the proposed average service life is lower than depreciation expense using the ALG procedure. Mr. Andrews' claim focuses on the higher level of depreciation expense calculated for younger assets while disregarding the associated lower level of depreciation expense calculated associated with the older, more mature assets within the depreciable group. Mr. Andrews' claim misrepresents this more accurate allocation of depreciation expense as intergenerational inequity.

Q. Does the use of the ELG procedure produce Intergenerational Inequity?

A. No, quite the opposite. The very nature of the ELG procedure more precisely calculates depreciation expense for assets with like lives within a depreciable group and sums that expense to develop an annual depreciation accrual rate applicable to the depreciable group. As a result, it more appropriately matches the recovery of the asset's cost to the period of time over which it is providing service to rate payers.

In contrast, there is a stronger argument that the ASL procedure results in intergenerational inequity. Because depreciation expense on shorter-lived assets

[10] Andrews, pp. 20-21, lines 10-15 and 1-2

occurs over the average service life, recovery for these assets is deferred. ELG produces a more equitable recovery by recovering these costs over the actual, shorter, service lives.

Q. Does the use of the ELG procedure require the calculation of annual depreciation rates to be updated more frequently than the ALG procedure to prevent intergenerational inequity?

A. No. Regardless of the procedure selected, the calculation of depreciation expense and annual depreciation accrual rates should be updated regularly to prevent intergenerational inequity and the inherent variable of plant activity.

Q. How frequently does Pennsylvania regulation require the calculation of depreciation rates?

A. Pennsylvania regulation requires utilities operating within the state to calculate and file updated depreciation rates annually. This annual requirement alleviates concern for the development of generational inequity.[11]

VI. RATE BASE FOR FORECASTED TEST YEAR

Q. What is the appropriate process for calculating the proposed depreciation expense and annual depreciation accrual rates during a rate case in Pennsylvania?

A. Pennsylvania provides for the calculation of proposed depreciation expense and annual depreciation accrual rates as of a Fully Projected Future Test Year ("FPFTY") date. This requires the development of plant and reserve balances as of the FPFTY. In the instant case, the FPFTY date is December 31, 2025.

[11] Bulletin 155, p. 71

Q. Please explain how the FPFTY levels of plant and accumulated depreciation (or "book reserve") are developed.

A. The process begins with the calculation of depreciation expense and annual deprecation accrual rates as of a Historical Test Year ("HTY") which is completed using historical, or actual, levels of Plant and Reserve. In the instant case, the HTY date is November 30, 2023. Once depreciation expense and annual depreciation accrual rates are calculated as of the HTY date, they are utilized along with projected levels of plant activity to develop the plant values and bring forward the book reserve to a Future Test Year ("FTY") date at which the levels of depreciation expense and annual depreciation accrual rates are calculated again. In the instant case, the FTY date is November 30, 2024. The final step to calculate the proposed depreciation expense and annual depreciation accrual rates is to utilize the FTY depreciation expense and annual depreciation accrual rates along with projected levels of plant activity to develop the plant values and bring forward the reserve to a FPFTY date where the proposed levels of depreciation expense and annual depreciation rates are calculated. In the instant case, the FPFTY date is December 31, 2025.

Q. Is it important to maintain a consistent process and consistent procedures during the process described above?

A. Yes, it is. Maintaining a consistent process and procedures eliminates the possibility of unnecessary swings in the level of depreciation expense and annual depreciation accrual rates such as what Mr. Andrews is proposing.

Q. Has Mr. Andrews followed the above describe Pennsylvania process when calculating his proposed levels of depreciation expense and annual depreciation accrual rates?

A. No.

Q. Please describe how Mr. Andrews has deviated from the Pennsylvania process described above.

A. Mr. Andrews has completely skipped portions of the process fast forwarding to the FPFTY and applies his proposed ALG alternative procedure to calculate depreciation expense and annual depreciation accrual rates as of December 31, 2025.

Q. Why is Mr. Andrews' proposal not appropriate?

A. There are two primary reasons why Mr. Andrews' proposal is not appropriate. First, Mr. Andrews is either unaware of the Pennsylvania process established for the calculation of proposed depreciation expense and annual depreciation accrual rates within a rate case, or he simply believes he does not need to adhere to established processes in Pennsylvania. Second, Mr. Andrews is displaying a lack of understanding as to the level of inconsistency he is proposing as he seems to support the level of reserve that has been developed in this rate case (and over the past 40 years) using the ELG procedure. Then he switches to his proposal to calculate depreciation expense and annual depreciation accrual rates as of the FPFTY date using the ALG procedure. This clearly is a contradiction in appropriate forecasting models and deliberately creates higher book reserve in order to artificially lower depreciation expense as of the FPFTY. If Mr. Andrews followed the standards properly he would forecast the book reserve for the FTY

and FPFTY using his recommended ALG procedure which will lower the book reserve as of each test year which would result in higher depreciation expense that what he has proposed in his testimony. Consequently, Mr. Andrews has erred in his statement that difference between the two procedures is $43.88 million because he has improperly applied the correct methodology for forecasted test years.

Q. Has Mr. Andrews correctly stated depreciation rates and depreciation expense if the ALG procedure were to be adopted?

A. No. Mr. Andrews' proposed ALG depreciation rates for the Fully Projected Future Test Years ("FPFTY") are incorrect because he is using a developed depreciation reserve balance that is based on projected ELG depreciation accruals.

Q. What is the correct level of the book depreciation reserve as of December 31, 2025 for Columbia if Mr. Andrews proposal using the average life group is utilized?

A. The attached Exhibit JJS-R2 sets forth the proper development of the projected book reserve for Columbia as of December 31, 2025 using the ALG procedure. This is a total reduction in book depreciation reserve of $39.8 million as compared to what Mr. Andrews has presented. This means that if Mr. Andrews' improper change to depreciation rates were adopted, the OCA recommended total rate base for Columbia should be increased by $39.8 million for developing depreciation rates and expense as of December 31, 2025.

Q. Has Mr. Andrews provided decisions regarding ELG procedure from other jurisdictions to support his proposed use of the ALG procedure?

A. Yes. Mr. Andrews cites decisions from Indiana and Kentucky to support his proposal of the ALG procedure in this case.

Q. Why are the Indiana and Kentucky decisions not applicable to the instant case?

A. Both the decisions referenced by Mr. Andrews were cases involving electric utilities with an asset base including electric generation, transmission and distribution assets which are significantly different assets involving significantly different costs associated with them and more importantly assets that are being recovered over much shorter remaining lives than originally planned.

Q. Was the Indiana decision referenced in Mr. Andrews' direct testimony based on a "change in landscape" and a "higher than average investment cycle"?

A. Yes. I have provided an excerpt from the Indiana decision referenced by Mr. Andrews below citing to both "a changed landscape" and "a higher than average investment cycle" as the basis of the Indiana Utility Regulatory Commission decision.

> While we have determined in the past that the ELG methodology was appropriate and acknowledge the weight given to precedent in many prior decisions, we always evaluate each case as it comes before us and do not need to approve the same methodology based on prior decisions, especially in light of a changed landscape. The use of ELG in a higher than average investment cycle has the effect of unnecessarily increasing the near term depreciation expense as compared to the use of ALG.[12]

Q. Does "a changed landscape" exist for Columbia?

[12] Final Order, Cause No. 45253, p. 90

A. No. Columbia is operating within the same "landscape" that has existed for its five most recent rate cases. The ELG procedure has been proposed and approved in each of those rate cases.

Q. Is Columbia experiencing "a higher than average investment cycle"?

A. No. The Company's current investment levels are associated with improving its infrastructure and maintaining the safety of the system. Those levels of investment will continue into the foreseeable future as noted by Mr. Andrews in his direct testimony on page 11 at lines 13-14 and page 12 at lines 1-2.

Q. Given "a changed landscape" and "a higher than average investment cycle" have not been substantiated in this case, is there a need to change the procedure utilized to calculate depreciation?

A. No.

Q. Is the Company's proposed 2.58% composite depreciation rate calculated using the ELG procedure as of December 31, 2025 reasonable and consistent with comparable gas distribution utilities in the United States?

A. Yes. In fact, in reviewing the composite depreciation rate utilized by various other gas distribution utilities one can see the average exceeds 2.58%. The attached Exhibit No. JJS-R3 sets forth composite depreciation rates of comparable gas distribution utilities from recent rate cases.

Q. Is the proposed 1.65% composite depreciation rate calculated by Mr. Andrews using the ALG procedure as of December 31, 2025 reasonable and consistent with other gas distribution utilities in the United States?

A. No, the 1.65% composite depreciation rate proposed by Mr. Andrews is unreasonably low and inconsistent with other gas distribution utilities in the industry. Additionally, the Company has been properly conducting annual depreciation updates per regulations which confirm a consistent recovery pattern for the asset utilization.

VII. FORECASTED PLANT IN SERVICE AND ACCUMULATED DEPRECIATION ADJUSTMENTS

Q. Has OCA Witness Greg R. Meyer proposed any adjustments to Columbia's rate base?

A. Yes. Mr. Meyer has proposed a reduction of $41 million to plant in-service as of December 31, 2025 based on his analysis of budgeted net plant (additions less retirements) vs. actual net plant for a 3 month period of January to March of 2024 during which Columbia's actual net plant was less than the budgeted net plant for that period.

Q. Has Mr. Meyer provided any additional analysis as to why he believes Columbia would not still be able to achieve its 2024 budgeted capital forecast in the remaining 9 months of 2024?

A. Yes. Mr. Meyer provided a comparison of budgeted annual capital additions from Columbia's 5 most recent rate cases vs. actual annual capital additions for the same periods in which he shows Columbia's actual capital additions are less than the budgeted capital additions in 4 of the 5 rates cases reviewed. Mr. Meyer then uses this comparison to support his proposed $41 million reduction to plant in-service as of December 31, 2025.

Q. Do you agree with Mr. Meyer's analysis and resulting proposal to reduce plant in-service by $41 million as of December 31, 2025?

A. No.

Q. Why do you disagree with Mr. Meyer's proposals?

A. First, Mr. Meyer's comparison of actual capital additions to budgeted capital additions associated with Columbia's past 5 rate cases actually displays Columbia's actual additions are more closely aligning with the budgeted projections over time during the sequence of rate cases Mr. Meyer provides in his testimony. The only exception is the 2021 rate case in which the actual additions were negatively impacted by COVID-19 and the subsequent supply chain issues. Second, given Mr. Meyer's proposed $41 million reduction to plant in-service is based on a comparison of only the first 3 months of 2024, it is very likely that Columbia could still achieve its budgeted annual capital forecast for the entire year of 2024. Further rebuttal to Mr. Meyer's proposal is provided by Columbia Witnesses Covert and Kempic.

Q. Do you have an additional concern with Mr. Meyer's proposal to reduce rate base?

A. Yes.

Q. What is your additional concern with Mr. Meyer's proposal to reduce rate base?

A. Mr. Meyer's proposal makes no reference to the impact to reduce plant in-service by $41 million would have on the level of accumulated depreciation as of December 31, 2025. Given the level of accumulated depreciation as of December 31, 2025 is brought forward from November 30, 2023, any proposed reductions

to plant in-service would also have a reducing impact to the level of accumulated depreciation which would reduce Mr. Meyer's proposed $4.4 million proposed reduction to Columbia's revenue requirement.

Q. Can you quantify the impact to accumulated depreciation, and in turn, the impact to Mr. Meyer's proposed $4.4 million reduction to Columbia's revenue requirement?

A. No. Mr. Meyer's proposal to reduce plant in-service have not been provided at the level of detail required (by plant account) to properly quantify the impact. In fact, without this required level of detail, there is no way for Mr. Meyer to properly calculate his proposal or for his proposal to be accurately verified.

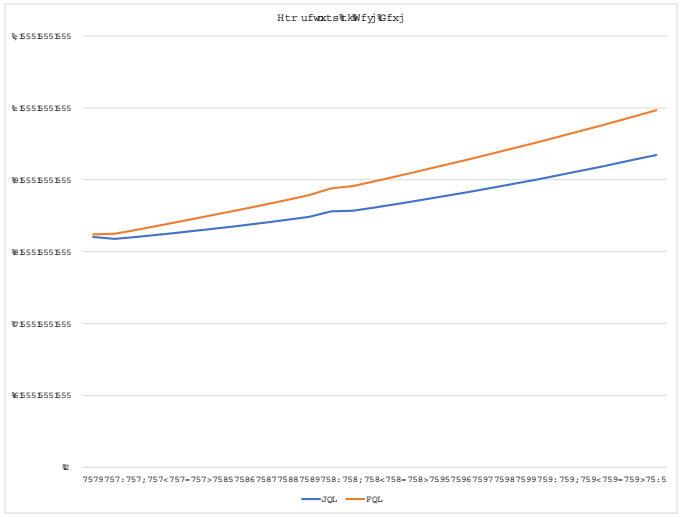
Q. Does this complete your Prepared Rebuttal Testimony?

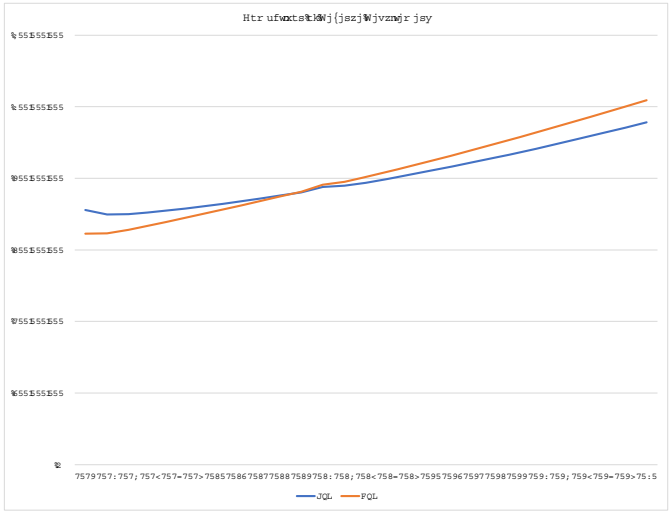
A. Yes, it does.

COLUMBIA GAS OF PA

Assumptions
0 *Future Net Salvage*
8.0% *Rate of Return*

		EQUAL LIFE GROUP								AVERAGE LIFE GROUP									
TEST YEAR	AVERAGE ORIGINAL COST	BOOK RESERVE	COMPOSITE REMAINING LIFE	FUTURE ACCRUALS	EXPENSE	RATE	RETURN	REVENUE REQUIREMENT	RATE BASE	BOOK RESERVE	COMPOSITE REMAINING LIFE	FUTURE ACCRUALS	EXPENSE	RATE	RETURN	REVENUE REQUIREMENT	RATE BASE	RETIREMENTS	NET SALVAGE
2023	3,951,190,370	668,050,842	33.1	3,283,139,528						668,050,842	51.6	3,283,139,528							
2024	3,942,602,855	737,026,132	33.8	3,205,576,723	99,321,756	2.52	256,446,138	355,767,894	3,205,576,723	701,383,662	51.4	3,241,219,193	63,679,287	1.62	259,297,535	322,976,822	3,241,219,193	30,346,466	-
2025	3,975,706,087	793,802,696	34.0	3,181,903,391	94,962,169	2.39	254,552,271	349,514,440	3,181,903,391	726,302,256	50.9	3,249,403,831	63,104,198	1.59	259,952,306	323,056,504	3,249,403,831	38,185,604	-
2026	4,061,982,026	855,905,733	34.2	3,206,076,293	93,454,557	2.30	256,486,103	349,940,660	3,206,076,293	758,756,137	50.4	3,303,225,889	63,805,402	1.57	264,258,071	328,063,473	3,303,225,889	31,351,520	-
2027	4,151,842,646	917,030,128	34.3	3,234,812,518	93,770,557	2.26	258,785,001	352,555,558	3,234,812,518	791,612,861	50.0	3,360,229,785	65,502,886	1.58	268,818,383	334,321,269	3,360,229,785	32,646,163	-
2028	4,243,392,622	978,030,031	34.3	3,265,362,591	94,364,348	2.22	261,229,007	355,593,355	3,265,362,591	825,487,051	49.5	3,417,905,571	67,238,635	1.58	273,432,446	340,671,081	3,417,905,571	33,364,444	-
2029	4,336,733,230	1,038,604,785	34.3	3,298,128,445	95,132,650	2.19	263,850,276	358,982,926	3,298,128,445	859,921,647	49.1	3,476,811,583	68,992,492	1.59	278,144,927	347,137,419	3,476,811,583	34,557,896	-
2030	4,431,704,890	1,099,032,381	34.3	3,332,672,508	96,130,375	2.17	266,613,801	362,744,176	3,332,672,508	895,011,640	48.7	3,536,693,249	70,792,771	1.60	282,935,460	353,728,231	3,536,693,249	35,702,778	-
2031	4,528,479,110	1,159,642,295	34.1	3,368,836,815	97,260,987	2.15	269,506,945	366,767,932	3,368,836,815	930,987,777	48.2	3,597,491,333	72,627,210	1.60	287,799,307	360,426,517	3,597,491,333	36,651,074	-
2032	4,626,927,769	1,220,280,938	34.0	3,406,646,831	98,798,998	2.14	272,531,746	371,330,744	3,406,646,831	967,489,531	47.8	3,659,438,238	74,662,110	1.61	292,755,059	367,417,169	3,659,438,238	38,160,356	-
2033	4,726,849,939	1,280,758,851	34.0	3,446,091,088	100,088,884	2.12	275,687,287	375,776,171	3,446,091,088	1,004,421,360	47.5	3,722,428,579	76,542,800	1.62	297,794,286	374,337,086	3,722,428,579	39,610,971	-
2034	4,828,666,325	1,341,820,952	33.9	3,486,845,372	101,429,355	2.10	278,947,630	380,376,985	3,486,845,372	1,042,486,638	47.1	3,786,179,687	78,432,532	1.62	302,894,375	381,326,907	3,786,179,687	40,367,254	-
2035	4,898,126,033	1,336,319,012	34.3	3,561,807,021	102,920,569	2.10	284,944,562	387,865,131	3,561,807,021	1,014,438,771	47.4	3,883,687,262	80,374,642	1.64	310,694,981	391,069,623	3,883,687,262	108,422,509	-
2036	4,969,340,946	1,399,259,893	34.2	3,570,081,054	103,965,308	2.09	285,606,484	389,571,792	3,570,081,054	1,055,299,084	47.1	3,914,041,862	81,884,741	1.65	313,123,349	395,008,090	3,914,041,862	41,024,428	-
2037	5,076,743,037	1,461,448,172	34.1	3,615,294,865	104,520,127	2.06	289,223,589	393,743,716	3,615,294,865	1,096,069,390	46.8	3,980,673,648	83,102,152	1.64	318,453,892	401,556,044	3,980,673,648	42,331,847	-
2038	5,186,174,659	1,524,206,743	34.0	3,661,967,916	106,168,063	2.05	292,957,433	399,125,496	3,661,967,916	1,137,750,545	46.5	4,048,424,114	85,090,647	1.64	323,873,929	408,964,576	4,048,424,114	43,409,492	-
2039	5,297,685,406	1,587,313,194	33.8	3,710,372,212	107,845,943	2.04	296,829,777	404,675,720	3,710,372,212	1,180,130,909	46.2	4,117,554,497	87,119,856	1.64	329,404,360	416,524,216	4,117,554,497	44,739,492	-
2040	5,410,800,991	1,650,070,160	33.7	3,760,730,831	109,647,429	2.03	300,858,466	410,505,895	3,760,730,831	1,222,431,671	45.9	4,188,369,320	89,191,225	1.65	335,069,546	424,260,771	4,188,369,320	46,890,463	-
2041	5,525,516,152	1,713,215,947	33.6	3,812,300,205	111,473,062	2.02	304,984,016	416,457,078	3,812,300,205	1,265,388,994	45.6	4,260,127,158	91,284,598	1.65	340,810,173	432,094,771	4,260,127,158	48,327,275	-
2042	5,642,187,435	1,776,709,837	33.5	3,865,477,598	113,355,017	2.01	309,238,208	422,593,225	3,865,477,598	1,308,943,029	45.3	4,333,244,406	93,415,162	1.66	346,659,552	440,074,714	4,333,244,406	49,861,128	-
2043	5,761,334,356	1,841,622,395	33.4	3,919,711,961	115,288,836	2.00	313,576,957	428,865,793	3,919,711,961	1,354,138,319	45.1	4,407,196,037	95,571,567	1.66	352,575,683	448,147,250	4,407,196,037	50,376,277	-
2044	5,883,111,499	1,907,189,071	33.3	3,975,922,428	117,316,175	1.99	318,073,794	435,389,969	3,975,922,428	1,400,170,288	44.8	4,482,941,211	97,781,468	1.66	358,635,297	456,416,765	4,482,941,211	51,749,499	-
2045	6,007,215,163	1,973,560,610	33.2	4,033,654,553	119,401,402	1.99	322,692,364	442,093,766	4,033,654,553	1,447,185,706	44.5	4,560,029,456	100,045,282	1.67	364,802,356	464,847,638	4,560,029,456	53,029,863	-
2046	6,132,367,685	2,038,017,357	33.1	4,094,350,328	121,554,748	1.98	327,548,026	449,102,774	4,094,350,328	1,492,449,696	44.3	4,639,917,990	102,361,990	1.67	371,193,439	473,555,429	4,639,917,990	57,098,001	-
2047	6,259,187,003	2,104,563,993	33.0	4,154,623,009	123,752,062	1.98	332,369,841	456,121,903	4,154,623,009	1,539,927,909	44.1	4,719,259,094	104,683,639	1.67	377,540,728	482,224,367	4,719,259,094	57,205,426	-
2048	6,389,394,400	2,172,584,989	32.9	4,216,809,411	125,951,995	1.97	337,344,753	463,296,748	4,216,809,411	1,589,025,301	43.9	4,800,369,099	107,028,392	1.68	384,029,528	491,057,920	4,800,369,099	57,930,999	-
2049	6,522,304,671	2,241,242,393	32.8	4,281,062,278	128,269,527	1.97	342,484,982	470,754,509	4,281,062,278	1,638,866,682	43.6	4,883,437,989	109,453,503	1.68	390,675,039	500,128,542	4,883,437,989	59,612,123	-
2050	6,657,473,112	2,310,518,966	32.7	4,346,954,146	130,665,849	1.96	347,756,332	478,422,181	4,346,954,146	1,689,413,477	43.4	4,968,059,635	111,936,071	1.68	397,444,771	509,380,842	4,988,059,635	61,389,276	-
					2,906,810,748		***7,921,125,789***						***2,285,705,259***		***8,683,068,778***				





COLUMBIA GAS OF PENNSYLVANIA, INC.

BRINGFORWARD TO DECEMBER 31, 2025, OF THE BOOK RESERVE AS OF NOVEMBER 30, 2023

		FUTURE TEST YEAR						FULLY PROJECTED FUTURE TEST YEAR					
ACCOUNT	BOOK RESERVE AS OF NOVEMBER 30, 2023	DEPRECIATION ACCRUALS	AMORTIZATION OF NET SALVAGE	PROJECTED RETIREMENTS	PROJECTED GROSS SALVAGE	PROJECTED COST OF REMOVAL	RESERVE AT END OF PERIOD	DEPRECIATION ACCRUALS	AMORTIZATION OF NET SALVAGE	PROJECTED RETIREMENTS	PROJECTED GROSS SALVAGE	PROJECTED COST OF REMOVAL	RESERVE AT END OF PERIOD
(1)	(2) +	(3) +	(4) -	(5) +	(6) -	(7) =	(8)	(9) +	(10) -	(11) +	(12) -	(13) =	(14)
DEPRECIABLE PLANT													
350.20	1,931						1,931	1					1,932
351.00	2,840,820	219,217	343				3,060,380	235,531					3,295,911
352.01	830,128	138,668					968,796	157,976					1,126,772
352.02	394,387	318,959					713,346	359,624					1,072,970
352.10	206,932						206,932	9					206,941
353.00	388,491	392	54	1,820			387,117	404	4				387,525
354.00	884,490	30,553					915,043	32,595					947,638
355.00	104,477						104,477						104,477
374.40	959,300	102,928	13,704	26,051			1,049,881	120,590	15,115	21,146			1,164,440
374.50	1,861,489	33,112		146			1,894,455	35,725					1,930,180
375.34	1,506,950	103,323	34,454	72,260		13,650	1,558,817	113,687	37,393	65,137		25,403	1,619,357
375.60	76,161	411	104				76,676	420	9				77,105
375.70	6,913,417	1,145,316	18	54,684			8,004,067	1,440,994	20	60,425			9,384,656
375.80	8,960	314					9,274	335					9,609
376.00	379,861,296	43,787,529	1,326,419	25,838,252		1,615,995	397,520,997	77,775,950	1,452,955	22,496,012		1,799,681	452,454,209
378.00	29,749,651	3,436,568	157,334	4,421,106		649,527	28,272,920	4,756,090	256,741	3,391,472		542,635	29,351,644
379.10	28,369	9,357	1,227			28	38,925	9,720	7				48,652
380.00	154,043,073	18,330,991	3,843,271	7,256,948		2,221,630	166,738,757	33,593,628	3,948,935	7,320,774		2,342,648	194,617,898
381.00	18,120,321	910,619	15,308	109,770		3,293	18,933,185	1,001,817	19,753	135,043		4,051	19,815,661
381.10	19,342,376	610,422		19,371			19,933,427	602,042		23,831			20,511,638
382.00	15,884,744	780,512	486	210,648			16,455,094	887,735	527	229,291			17,114,065
383.00	5,628,047	320,995	185	99,518		962	5,848,747	374,317	414	121,771		1,218	6,100,489
384.00	2,893,818	42,654		2,100			2,934,372	46,964		2,597			2,978,739
385.00	2,537,333	268,279	79,300	101,249		22,348	2,761,315	302,892	51,339	96,097		24,024	2,995,425
387.00	83,634	2,812					86,446	2,829					89,275
387.40	2,770,222	632,258	9,645	141,348		378	3,270,399	697,256	10,472				3,978,127
387.50	1,822,003	155,160					1,977,163	120,433					2,097,596
390.10	49,821						49,821						49,821
391.10	1,101,307	171,505		13,415			1,259,397	191,986		32,103			1,419,280
391.11	58,754	5,851					64,605	6,320					70,925
391.12	568,652	629		87,502			481,779	847		357,301			125,325
392.00	25,610	79	(1,109)				24,580	319	(893)				24,006
394.00	7,252,261	832,369	(100)	100,443			7,984,087	1,009,051		482,941			8,510,197
394.12	16,693	54	648				17,395		702				18,097
395.00	105,851	13,973					119,824	15,297					135,121
396.00	991,329		(7,851)				983,478		(6,362)				977,116
397.50	769,271	145		142,120			627,296	136,108		163,960			599,444
398.00	591,302	60,114					651,416	66,339		37,300			680,455
SUBTOTAL DEPRECIABLE PLANT	**661,273,671**	**72,466,068**	**5,473,440**	**38,698,751**	**0**	**4,527,812**	**695,986,617**	**124,095,831**	**5,787,131**	**35,037,201**	**0**	**4,739,660**	**786,092,718**
AMORTIZABLE PLANT													
303.00	29,165,856	9,030,470		11,809,891			26,386,435	11,772,811		5,102,971			33,056,275
303.60	3,680,671	1,588,408		359,535			4,909,544	2,997,208		1,388,180			6,518,572
362.10	(239,108)		83,505				(155,603)		73,830				(81,773)
375.71	2,678,297	472,819		92,701			3,058,415	510,745		55,777			3,513,383
SUBTOTAL AMORTIZABLE PLANT	**35,285,716**	**11,091,697**	**83,505**	**12,262,127**	**0**	**0**	**34,198,791**	**15,280,764**	**73,830**	**6,546,928**	**0**	**0**	**43,006,457**
NONDEPRECIABLE PLANT	**234,685**		**339**	**6**			**235,018**		**400**				**235,418**
TOTAL GAS PLANT	**696,794,072**	**83,557,765**	**5,557,284**	**50,960,884**	**0**	**4,527,812**	**730,420,426**	**139,376,595**	**5,861,361**	**41,584,129**	**0**	**4,739,660**	**829,334,593**

COMPANY	COMPOSITE DEPRECIATION RATE
COMPANY 01	2.95
COMPANY 02	2.84
COMPANY 03	2.81
COMPANY 04	2.41
COMPANY 05	2.53
COMPANY 06	2.63
COMPANY 07	2.60
COMPANY 08	2.63
COMPANY 09	2.86
COMPANY 10	2.40
COMPANY 11	2.61
AVERAGE	**2.66**

COLUMBIA STATEMENT NO. 5-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REJOINDER TESTIMONY OF
JOHN J. SPANOS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 30, 2024

List of Topics Addressed

Depreciation

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I. INTRODUCTION

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted Columbia Statements No. 5 and 5-R.

Q. What is the purpose of your rejoinder testimony?

A. The purpose of my rejoinder testimony is to respond to the arguments and positions presented by Mr. Brian Andrews in his surrebuttal testimony concerning the depreciation methodologies, specifically the appropriateness of continuing the longstanding practice of using the Equal Life Group ("ELG") procedure rather than the Average Life Group ("ALG") procedure for Columbia Gas of PA, Inc. ("Columbia" or "Company"). My testimony will address each of Mr. Andrews's key points and provide a detailed rebuttal supported by evidence and reasoning that underscore the advantages and correctness of the ELG method in this context. I will also comment on Mr. Meyer's adjustment to the book reserve (accumulated reserve) after Mr. Andrews corrected his calculations.

Q. Please provide a summary of the key elements of your rejoinder testimony.

A. First, I address Mr. Andrews' discussion of the precision of ELG and the survivor curve estimates. Mr. Andrews' discussion, in which he argues that the Commission should not believe the textbook Wolf & Fitch, is based on a life analysis that is significantly flawed. I then discuss recent cases in other jurisdictions to consider

moving to ELG, in part due to significant technological, environmental and regulatory changes underway. There is little justification for Columbia to move away from the ELG procedure it has used for more than four decades. I also provide context of Pennsylvania's depreciation practices and explain that the deferral of the recovery of future net salvage (primarily cost of removal), which is raised by Mr. Andrews', means that Pennsylvania utilities are behind in the recovery of capital costs relative to other jurisdictions.

I then address Mr. Andrews's discussion of affordability and explain that the historical and continued use of ELG means lower rates. Any change to ALG would be short lived and lead to higher costs for customers. Further, I caution against subsidizing customers today at the expense of future customers, especially given the technological changes that will occur in the coming decades. A short-sighted focus on affordability will likely cause disproportionate harm to future customers.

Finally, Mr. Andrews presents an update to an example illustrating ELG in his testimony. However, his example and claims that ELG rates result in intergenerational inequity if not updated annually are incorrect and only based on the over-simplifications he makes. I demonstrate that ELG depreciation rates are more stable than Mr. Andrews' assets and further will not decrease each year in the way he sets forth in his testimony.

II. EQUAL LIFE GROUP VS AVERAGE LIFE GROUP

Q. Does Mr. Andrews dispute that ELG results in more accurate depreciation rates?

A. Yes. Mr. Andrews' takes issue with well-researched depreciation textbooks and claims the opposite of Wolf and Fitch and Robley Winfrey, two well-respected authorities on depreciation. Notwithstanding his contradiction by well-researched textbooks, his argument that ELG is not precise is based only on his review of the life analysis for Account 376, Mains. Mr. Andrews argues that because a 78-L0 curve is a better mathematical fit than the estimate both he and I used, the ELG procedure is not as accurate (presumably because the 78-L0 survivor curve is a better estimate).

Q. Does Mr. Andrews's testimony demonstrate that ELG is not accurate?

A. No. As can be seen on page 4 of Mr. Andrews's testimony, a 78-L0 survivor curve expects that assets will live as long as 297 years. For this reason, no competent depreciation professional would estimate the 78-L0 survivor curve, as we should not expect gas mains to be in service for 297 years. The 65-R1 is an accurate estimate of the future service lives for this account and, as Mr. Andrews's graph in his testimony shows, fits the historical data similarly well to the 78-L0. Further, the data demonstrates that close to half of gas mains retire prior to the average service life of 65 years. The ELG procedure is more accurate because it properly allocates the costs of these assets over these shorter service lives.

Q. Please discuss Mr. Andrews's claims regarding the use of the ALG procedure in other jurisdictions.

A. Mr. Andrews argues that the use of ALG in other jurisdictions means that ELG should no longer be approved for Columbia.[1] Historically, most regulatory

[1] Surrebuttal Testimony of Brian C. Andrews, at 5:5-13.

commissions had used ALG prior to the 1980s due to the complexity of ELG calculations. While many utilities did not move to ELG once computing technology allowed for its adoption, some states, such as Pennsylvania, did. This provides more accurate depreciation rates and is beneficial to customers. As I have explained in my rebuttal testimony, ELG provides a more accurate recovery of costs. This, correctly, means higher depreciation in the earlier years of the life of a property group and lower depreciation in later years. ALG is most correctly thought of as a deferral of the recovery of shorter-lived assets.

Used consistently, both ELG and ALG can result in intergenerational equity, although ALG is more costly to customers. This is because customers pay a return on the deferral resulting from ALG depreciating over *average* life rather than *actual* life. Stated differently, ELG results in a lower rate base than ALG, which results in a lower return on rate base than under ALG. Because the rate base impact is larger than the difference in depreciation expense, ELG results in lower customer rates than ALG. Columbia customers today have benefited from the use of ELG for close to four decades, as rate base is lower than had ALG been used. Customers in other jurisdictions for which ALG has been the longstanding practice do not receive such benefit.

Q. Mr. Andrews disputes your discussion of whether there is a "change in landscape" for Columbia or whether the Company is in "higher than average investment cycle." Please address his discussion.

A. Mr. Andrews argues that because Columbia's capital expenditures are higher than in the past, it is in a change in landscape or higher than average investment cycle similar to recent findings in Indiana. However, the context of the Indiana decision

was the retirement of a significant fleet of coal generation and the resulting investment cycle in both generation and electric delivery infrastructure to incorporate newer generation and other technologies and customer expectations. In my rebuttal testimony, I drew a distinction between the investment cycle referred to in the Indiana decision and that of Columbia, which is a higher level of investment, but one that is generally consistent with other gas utilities and expected to continue in the future.

Q. Mr. Andrews argues that the short-term benefit of using ALG would improve affordability for customers. However, would changing to ALG result in a subsidy to current customers?

A. Yes. A change to ALG for Columbia means that customers benefit from the lower rate base due to the historical use of ELG, the deferral of recovery over average life and artificially low ALG rates due to the higher accumulated depreciation resulting from decades of use of the ELG procedure. The change to ALG, therefore, produces a subsidy for roughly the next 10 to 15 years, at which point ALG will result in higher customer rates.[2]

Q. Have other jurisdictions considered ELG, particularly in the context of technological and regulatory change in the energy industry?

A. Yes. Mr. Andrews only briefly acknowledges Texas, Canada and Colorado, but in my rebuttal testimony I discussed the use of ELG both in those jurisdictions and its proposed use in New York.[3] Because the ELG better matches the recovery of shorter-lived assets in a property group, it is better suited and more equitable

[2] *See* Exhibit No. JJS-R1 submitted with Mr. Spanos' Rebuttal Testimony
[3] Spanos Rebuttal Testimony at 10:20-21

during times of technological change. Further, because Pennsylvania depreciation practices already incorporate a significant deferral of the recovery of net salvage, it would not be reasonable to move towards further deferring depreciation expense (and the associated higher costs to customers). Mr. Andrews's proposal would move depreciation in the wrong direction at the worst time.

Q. Mr. Andrews also references that based on my list of cases that only 3 of 46 regulatory commissions have approved the use of the ELG procedure. Is this accurate?

A. No. There are other jurisdictions other than Texas, Colorado and Canada that have approved the ELG procedure as part of the list of cases I have been involved. He does not reflect others such as Oregon, Alabama, Indiana, Louisiana and Arkansas which approved ELG within some of the cases that I have submitted testimony in my career.

Q. Please explain how net salvage is deferred in Pennsylvania.

A. Mr. Andrews notes that future net salvage is not included in depreciation rates in Pennsylvania. As a result of a 1962 Superior Court Decision,[4] Pennsylvania is one of the only states in the country that defers the recovery of net salvage until after assets are retired. Industry standard depreciation practices (which Mr. Andrews typically follows) are to estimate future net salvage and include these estimates in depreciation rates. This approach, referred to as the "Traditional Method" for net salvage, results in intergenerational equity because customers pay for net salvage costs over the life of property (*i.e.,* during the time they provide service to

[4] *Penn Sheraton Hotel v. Pennsylvania Public Utility Commission*, 202 Pa. Super. 403, 195 A.2d 180 (Pa. Super. Ct. 1962).

customers). Pennsylvania, in contrast, defers recovery until after the assets are retired, meaning that current customers have to pay the costs of assets that no longer provide service. Mr. Andrews argues that this is one of the causes of Columbia's depreciation rates being lower than average, however, this raises a problem not a reason to defer costs further by changing to ELG.

Q. How does the deferral of the recovery of net salvage impact the Company's depreciation rates?

A. The Company's depreciation rates are too low to equitably recover the full service value of property.[5] Mr. Andrews is surely aware of this since he includes future net salvage in almost all of his proposed depreciation rates across the country. The use of the ELG procedure does help mitigate these deferrals. Mr. Andrews' proposal to move away from ELG would create further inequity and push a significant share of costs to future customers.

Q. Mr. Andrews updates an example from his direct testimony, which he discusses on pages 10 through 14 of his surrebuttal testimony. He concludes that ELG depreciation rates must be adjusted each year or intergenerational inequity will occur. Please address this claim.

A. Mr. Andrews' conclusion is incorrect because he uses an oversimplified example. In real world applications, plant is added and retired each year. As a result, ELG depreciation rates are fairly stable from year to year. While it is true that Columbia's customer rates are implemented on a less frequent basis, we perform annual depreciation reports (ADRs) which demonstrate that the composite ELG

[5] Service value is equal to the original cost less net salvage, where net salvage is gross salvage less cost of removal.

rates are relatively stable. For example, the table below summarizes the overall composite depreciation rates from the last 10 years, which illustrates that the ELG procedure results in consistent and stable depreciation rates over time. Additionally, depreciation rates have not declined significantly from year to year, as Mr. Andrews attempts to demonstrate. Therefore, Mr. Andrews' concerns about the fairness of ELG are unfounded.

Table 1. Columbia Gas of PA, Inc. Composite ELG Rates

Test Year (as of Dec 31)	Composite Rate
2014	2.36%
2015	2.39%
2016	2.49%
2017	2.56%
2018	2.55%
2019	2.56%
2020	2.54%
2021	2.69%
2022	2.67%
2023	2.65%

The composite rate for the future test year and fully projected future test year in the Company filing are 2.63 and 2.58%. respectively. Further, Mr. Andrews' example implies that a much higher depreciation rate will be "locked in", over-recovering depreciation. This is not true in real-world operations, as ELG rates do not need to decrease each year. As shown above, they can increase or decrease, just as can be the case with ALG rates.

III. MEYER ACCUMULATED RESERVE CHANGE

Q. Do you agree with Mr. Meyer's change to the book reserve (accumulated reserve) after he applies Mr. Andrews recalculations?

A. No. Mr. Meyer does not properly incorporate the accumulated reserve work that Mr. Andrews included in his surrebuttal after he recalculated depreciation as of December 31, 2025. As shown in Mr. Andrews calculations and presented in Mr. Meyer's Exhibit GRM-SR-1, page 7 of 13, the accumulated reserve adjustment was calculated to be $42, 718, 447. However, in Mr. Meyer's Exhibit GRM-SR-1, page 3 of 13, he uses exactly half of the 42,718,447 which is shown on line 6 as $21,359,224. His changes do not follow a consistent path to the recalculation of expense from Mr. Andrews if using the ALG procedure.

IV. CONCLUSION

Q. Is there anything in the testimony of the OCA witness that should influence the Commission to accept his depreciation recommendations?

A. No. My rejoinder testimony addresses and refutes Mr. Andrews' arguments regarding the Company's depreciation methodologies. Mr. Andrews' assertion that Gannett Fleming proposes ALG in other cases ignores Pennsylvania's 40-year successful use of ELG. While ELG can result in higher short-term depreciation rates, it more precisely aligns costs with asset service lives, avoids creating intergenerational subsidies, and produces lower overall rates for customers. Mr. Andrews' selective reference to other jurisdictions ignores Columbia's consistent use of ELG. Data from Annual Depreciation Reports (ADRs) show that composite

depreciation rates under ELG are stable. And, finally, Columbia's depreciation rates are generally lower than those in other states due to Pennsylvania's retroactive recovery of net salvage costs, which defers costs to future customers. ELG remains the most accurate and fair method for Columbia.

Q. Does this conclude your rejoinder testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
KEVIN L. JOHNSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

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I. Introduction

Q. Please state your name and business address.

A. My name is Kevin L. Johnson. My business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Lead Regulatory Studies Analyst in the Regulatory Studies Department at NCSC.

Q. Please briefly describe your professional experience.

A. I have over 20 years of experience working in various accounting, compliance, and regulatory functions primarily supporting NiSource companies, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"). In April 1999, I was hired by Columbia Gas of Ohio, Inc. ("COH") as a Financial Analyst in the Special Studies group, providing accounting support for the Columbia Gas Distribution Companies. In May 2002, I was promoted to the position of Accounting Manager of NCSC, overseeing its general books and records. From March 2010 through June 2015, I was the Manager of Consolidation Accounting and Securities and Exchange Commission Financial Reporting for NiSource, ensuring accurate and timely financial statement preparation. In July 2015, NiSource spun-off its gas transmission and storage business and created a new standalone entity named Columbia Pipeline Group ("CPG"). I was named Director,

Sarbanes-Oxley ("SOX") Compliance at CPG overseeing its overall SOX compliance program until early 2017 when this role ended after the acquisition of CPG by TC Energy. From mid-2017 until mid-2019, I was an Accounting Manager at JPMorgan Chase. In June 2019, I rejoined NCSC in the Regulatory Studies department as a Lead Regulatory Studies Analyst supporting various NiSource companies.

Q. Please describe your educational background.

A. I graduated from The Ohio State University in 1999 with a Bachelor of Science degree in Business Administration, majoring in Accounting. I am a Certified Public Accountant and a member of the Ohio Society of Certified Public Accountants.

Q. What are your responsibilities in your current position?

A. My responsibilities as a Lead Regulatory Studies Analyst include providing support for regulatory filings for several NiSource gas distribution companies, including, Columbia, Columbia Gas of Maryland, Inc., Columbia Gas of Kentucky, Inc., Columbia Gas of Virginia, Inc., and COH.

Q. Have you previously testified before this or any other regulatory agency?

A. I have presented direct testimony for Columbia Gas of Pennsylvania before the Pennsylvania Public Utility Commission in Case No. R-2022-3031211 as the Allocated Cost of Service and Rate Design witness and Case No. R-2008-2011621 supporting NCSC costs, Columbia Gas of Maryland before the Public Service Commission of Maryland in Case No. 9701 as the Allocated Cost of Service and Rate

Design witness and Case No. 9644 as the Cash Working Capital witness, and Columbia Gas of Kentucky in Case No. 2021-00183 as the Cash Working Capital, Allocated Cost of Service, and Rate Design witness. I have also provided Allocated Cost of Service and Rate Design support to witnesses in previous Columbia Gas of Pennsylvania and Columbia Gas of Maryland rate cases.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring Columbia's Allocated Cost of Service ("ACOS") studies and the proposed rate design shown in Exhibit 103, Schedule 8. In addition, I will be supporting the Company's residential rate structure proposals regarding the Weather Normalization Adjustment ("WNA") and Revenue Normalization Adjustment ("RNA"). As required by Section 53.53IV[1], Items 1 and 9 of the Commission's regulations, I prepared ACOS studies by rate class at present and proposed rates (Item 1) and a cost analysis supporting minimum charges for all rate schedules (Item 9). The studies and cost analysis are presented in Exhibit 111. Item 10 of Section 53.53 IV requires a cost analysis supporting demand charges. I did not prepare a cost analysis for demand charges because Columbia's present and proposed tariffs do not contain distribution demand charges.

Q. Please describe Exhibit No. 11.

A. Exhibit No. 11 addresses the Commission's filing requirements regarding ACOS studies as required by Section 53.53IV. The Company's ACOS studies are presented in Exhibit No. 111 and a detailed description of the methodologies are

[1] 52 Pa Code § 53.51, et. seq.

included in this testimony. The ACOS studies are based on the fully projected future test year ending December 31, 2025.

II. Allocated Cost of Service

Q. Are you responsible for the ACOS studies presented in Exhibit No. 111?

A. Yes, I am.

Q. Three ACOS studies are included in Exhibit No. 111. Is that correct?

A. Yes.

Q. Why did you conduct three ACOS studies?

A. Columbia has filed two studies in its base rate proceedings since the early 1980s that provide the outside limits of the possible allocations of mains to the various classes of service. The customer-demand study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class, while the peak and average study (Exhibit No. 111, Schedule 2) produces results that are generally more favorable to the residential class. Columbia has in the past submitted that the results of two such studies provided a reasonable range of returns for use as a guide in establishing appropriate rates. Columbia continues to believe that the two studies provide the reasonable range of returns for use in revenue allocation. However, Columbia recognizes this Commission's preference for the use of the peak and average study, and therefore used the peak and average study as the primary guide for the allocation of the revenue increase in this case.

Q. What is the basis of the third study and why did Columbia file it?

A. The third study, as presented in Exhibit No. 111, Schedule 3, is an average of the customer-demand study and the peak and average study. The average study with

its equal weighting of the two studies, provides the Company, the parties and the Commission with another set of returns that can be used as a guide in revenue allocation. In other words, the average study serves as another tool that can be used by the parties to inform the revenue allocation in setting cost-based rates.

Q. Could you provide a list of the schedules and attachments you are sponsoring through your testimony?

A. Yes. Table KLJ-1 below lists all the schedules and attachments that I am sponsoring.

Table KLJ-1

Schedule/Attachment	**Description**
Exh. No. 11	ACOS Studies
Exh. No. 111, Schedule No. 1	Customer-Demand Study
Exh. No. 111, Schedule No. 2	Peak and Average Study
Exh. No. 111, Schedule No. 3	Average Study
Exh. No. 111, Schedule Nos. 5 & 6	Bill Comparisons
Exh. No. 103, Schedule No. 8	Proposed Revenue Allocation, Rates
Statement No. 6, Exhibit KLJ-1	Development of Allocation Factors
Statement No. 6, Exhibit KLJ-2	Calculation of Allocation Factors
Statement No. 6, Exhibit KLJ-3	Factor Selection and Rationale
Statement No. 6, Exhibit KLJ-4	Intra-Class Adjustment of Storage Carrying Costs
Statement No. 6, Exhibit KLJ-5	ACOS Study Return Results
Statement No. 6, Exhibit KLJ-6	Gas Procurement Charge Calc.
Statement No. 6, Exhibit KLJ-7	Benchmark Distribution Revenue per Bill
Statement No. 6, Exhibit KLJ-8	Revenue Normalization Adjustment for Peak Period
Statement No. 6, Exhibit KLJ-9	Revenue Normalization Adjustment for Off Peak Period
Statement No. 6, Exhibit KLJ-10	Proposed Customer Charge Impacts
Statement No. 6, Exhibit KLJ-11	Residential Customer Charge Analysis

Q. Could you briefly describe the format of the ACOS studies that you are sponsoring?

A. The format is generally identical for the three studies except for the peak and average study, Exhibit No. 111, Schedule No. 2. It contains 30 pages, while the customer-demand study in Exhibit No. 111, Schedule 1 and the average study in Exhibit No. 111, Schedule 3 both contain 13 pages. The peak and average study contains the customer charge studies, which I will be discussing later in my testimony, and which are shown on pages 14 through 30 of Exhibit No. 111, Schedule No. 2. The rates of return that are shown on page 1 of each study are based on income generated using proposed rates, with page 2 showing the rates of return generated using current rates. Both page 1 and page 2 summarize the same allocated cost of service with the exception of forfeited discounts, income taxes and uncollectibles, which vary with the changes in revenue as a result of the change in current rates to proposed rates. The allocation of gross plant investment is shown on page 3, while page 4 contains the reserve for depreciation and page 5 contains depreciation and amortization expenses. Revenue by account and rate schedule is summarized on page 6 for both current and proposed rates and pages 7 and 8 contain the allocation for operation and maintenance ("O&M") expenses, while page 9 contains the allocation of taxes other than income. Rate base is detailed by rate schedule on page 10, with page 11 calculating Federal and Corporate Net Income taxes. The allocation factors are listed on pages 12 and 13.

Q. How were the rate schedules grouped in allocating the cost of service?

A. For residential and small general service, sales and delivery services were combined, respectively; Residential Sales Service ("RSS") and Residential Distribution Service ("RDS") were combined and presented in Column D of each study, and Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD") and Small General Distribution Service ("SGDS") were combined and presented in Column E of each study for Commercial and Industrial ("C&I") customers whose annual usage is less than 6,440 therms. SGSS, SCD and SGDS were combined and presented in Column F of each study for C&I customers whose annual usage is greater than 6,440 therms but less than 64,400 therms. Because essentially any customer can qualify and, therefore, switch between sales and distribution services under these schedules, it is reasonable to conclude that customer characteristics are the same for both types of services, i.e., size, consumption patterns, heat sensitivity, human need requirement, etc. With no long-term difference in the customers' profiles, the distribution cost to provide such service to these customers is the same whether the customer is a sales customer or distribution customer. For the larger customers, the studies present the cost of service for each rate schedule: Small Distribution Service and the lower band of Large General Sales Service ("SDS/LGSS") is presented in Column G of each study for C&I customers whose annual usage is greater than 64,400 therms but less than 540,000 therms. Large Distribution Service ("LDS") and the upper band of Large General Sales Service ("LGSS") is presented in Column H of each study for C&I customers whose annual usage is greater than 540,000 therms.

Main Line Sales Service ("MLS") and Main Line Distribution Service ("MLDS") are combined and presented in Column I due to their unique characteristic of proximity to an interstate pipeline. Costs and revenues attributable to customers taking service under the Flexible Rate Provisions and Negotiated Contract Service tariffs (combined and identified as "FLEX") are presented in Column J[2].

Q. How were Total Company O&M expenses determined by Federal Energy Regulatory Commission ("FERC") account in the allocated cost of service studies?

A. O&M expenses for the fully projected future test year presented in Exhibit 104 were based on cost element data, i.e., labor, benefits, insurance, etc. The ACOS studies' spreadsheets submitted in response to Standard Data Request No. GAS-COS-008 show a conversion of the forecasted O&M by description (cost element) to the FERC account, based on allocation percentages representative of the historic test year data (twelve months ending November 30, 2023).

Q. How was the demand component for each class determined?

A. The demand component by class was provided by NCSC's Energy Supply and Optimization Department and represents expected requirements under design day conditions. I note that the calculation reflects design day total requirements, and thus assumes suppliers will make deliveries necessary to meet customer requirements.

[2] Per paragraph No. 46 of the Joint Petition for Partial Settlement at Docket No. R-2018-2647557.

Q. Why were the MLS/MLDS customer groups excluded from the above described allocations of mains?

A. Customers served under rate schedules MLS/MLDS were excluded from the allocations of mains under all studies because these customers are served directly from an interstate pipeline or are in close proximity to an interstate pipeline. Accordingly, Columbia has little or no main investment associated with providing service to these customers. An inventory of the mains investment in serving these customers was made by studying the Company's plant records and maps on a customer-by-customer basis. The mains investment cost was then directly assigned to MLS/MLDS rate schedules. Therefore, it is appropriate to exclude them from the allocation of mains and mains related costs.

Q. Since a significant portion of the Company's investment and expense is related to mains and services, does the allocation of these items significantly impact the studies?

A. Yes, it does. Mains and services account for the majority of the Company's gross plant investment and distribution O&M expenses, excluding gas costs. The allocation of these items significantly influences the outcome of the studies. In addition, many other elements of O&M expenses are allocated on plant-related factors.

Q. How are purchased gas costs allocated in the studies?

A. Gas costs are directly assigned to each class at the pro forma levels determined by Company witness Battig (Columbia Statement No. 3) in her Exhibit No. 103, Schedule No.1, Pages 13 through 18.

Q. Were there any other major O&M expense items that you directly assigned?

A. Yes. As shown on Page 8, Line 8 of all three studies, I assigned recovery of costs from the Company's Universal Services Program ("USP") to the residential class. Under both current and proposed rates, these costs are recoverable from the residential class, whether sales or delivery service. Line 8 relates to the uncollectible component attributable to low-income residential customers enrolled in the Company's Customer Assistance Program ("CAP").

Q. How did you handle Uncollectibles related to unbundling?

A. Columbia utilizes three systems to bill customers, 1) Distributive Information System ("DIS") that bills monthly read customers for either sales or Choice transportation service, 2) Gas Measurement Billing ("GMB") that bills monthly read customers for either sales or Choice distribution service, and 3) Gas Transportation System ("GTS") that bills customers for traditional (non-Choice) distribution service. Please note the GMB and GTS billing systems do not bill residential customers. Because DIS billed net charge-offs are accounted for in the Company's accounting reports by customer class, the residential net charge-offs were assigned to the residential class. The DIS billed commercial net charge-offs were allocated between the SGSS1/SCD1/SGDS1 and SGSS2/SCD2/ SGDS2 rate classes based on DIS billed revenue within each class.

The portion of Account 904 related to the GMB and GTS billing systems and the COVID-19 deferral was allocated to GMB and GTS billed customers by rate class based on their GMB/GTS revenues.

Q. Please describe how you allocated plant Account 380 - Services and the related O&M accounts.

A. First, I identified the services related to MLS/MLDS and directly assigned them. The remaining investment in Account 380 - Services and the related O&M accounts were based on an actual assignment of services installed on customers' premises. Individual customer services were identified by size from the Company's DIS billing system and accumulated by customer class and rate schedule. Based on the historic test year per book data, the average unit price per size of pipe was determined and applied to the number of services under each rate schedule based on pipe size. The resulting values, by rate schedule, were converted to percentages and used to allocate service investment and related expenses.

Q. Please describe how you allocated plant Account 381 – Meters and Account 382 – Meter Installations in the studies.

A. First, I identified the services related to MLS/MLDS and directly assigned them. I assigned meters to the various rate classes based on an actual inventory of meters installed on customers' premises. Columbia recognizes four separate pressure groups for meters based on the meter's maximum cubic feet per hour gas flow ("CFH"), 0-500 CFH, 501-1000 CFH, 1001-1,500 CFH, and over 1,500 CFH. Each meter type varies in cost as the size increases. Individual installed meters as identified

on DIS were summarized by the four pressure groups. The capitalized property investment as identified on the Company's books and records for the four pressure groups was divided by the number of meters as reflected on the Company's books and records as of November 30, 2023, to develop a cost per meter for each group of meters. The costs per meter were multiplied by the identified installed meters in DIS to determine the investment for each rate class. The percentages were developed for Account 381 and used for assigning Account 381 Meters as well as the investment in Account 382 Meter Installations.

Q. Please describe how you allocated plant accounts 383 – House Regulators and 384 – House Regulator Installations.

A. Both of these accounts contain costs that are directly associated with the cost of house regulators. These regulators are installed where the distribution lines are transporting gas at intermediate, medium, or high pressure. Recognizing this fact and understanding, therefore, that customers being served by low pressure lines do not require house regulators, I developed an allocation factor that excludes customers served from low pressure lines from the total. The allocation factor uses total number of customers, grouped by rate class, as assigned in DIS. The resulting allocation percentages are then applied to the total capitalized property investment, as identified on the Company's books and records to determine the cost of house regulators for each applicable rate class.

Q. Please describe how you allocated plant Account 385 – Industrial Measurement & Regulation ("M&R") Equipment in the studies.

A. Using data retrieved from DIS, I obtained, for each active customer who has an M&R Station assigned to them, each station's rate schedule and station number. Then, I cross-referenced these station identification numbers to the Company's plant accounting records in order to identify the costs of each station. Then, I grouped these costs into the corresponding rate classes (excluding MLS/MLDS) and used the resulting totals as the basis for allocating all M & R plant.

Q. Do you provide a more complete description of how these factors were developed and the related calculations?

A. Yes. In Exhibit KLJ-1 attached to this testimony, entitled "Development of Allocation Factors", I provide a description for all allocation factors used for the studies. In Exhibit KLJ-2, I include all calculations of all allocation factors. And in Exhibit KLJ-3, I provide the rationale for factor selection, by account, as it pertains to the various categories of rate base and expense.

Q. Did you prepare a study in support of the Company's minimum or system charges?

A. I prepared two studies in support of the Company's minimum or system charges. They are contained in Exhibit No. 111, Schedule 2, pages 14 through 30.

Q. Please describe the two studies.

A. The study included in Exhibit 111, Schedule No. 2, pages 14 through 22 contains the Company's traditional customer charge study based on the customer-demand ACOS study and includes the customer portion of mains costs. Columbia has used this method in support of its customer charges in its previous general rate case filings.

The study presented on pages 23 through 30 of Schedule No. 2 is similar but excludes the customer component of mains and other operations.

Q. Why did you present the study excluding the customer component of mains?

A. I am aware that there have been disagreements concerning the inclusion of any mains costs as a customer component. Therefore, I included the alternative calculation excluding the customer component of mains. I also used the alternative study that excludes all mains cost to establish a minimum customer cost benchmark for determination of Columbia's customer charges.

Q. Why does the Company believe a customer component of mains should be included in a minimum system customer charge study?

A. The allocation of a portion of distribution mains costs on a customer basis is appropriate because of the way the distribution system is designed. Customer-related costs include, at a minimum, the cost incurred by the Company to extend its existing distribution system using a minimum size pipe (2" diameter) to attach a customer to the distribution system. Simply stated, the customer component of mains calculated in the ACOS represents a minimum fixed cost investment in mains to attach a customer to the distribution system and therefore, has a direct relationship to the number of customers served by the Company. At a minimum, fixed costs that have a direct relationship to the number of customers served by the Company should be recovered equally from all customers within a rate class, and that

is what a customer charge is designed to do. I will discuss the Company's proposed customer charges later in my testimony.

Q. Did you prepare a study supporting the intra-class adjustment of storage costs between the SGDS1 and the SGSS1/SCD1 classes and between the SGDS2 and the SGSS2/SCD2 classes?

A. Yes. I prepared a study, attached to this testimony as Exhibit KLJ-4, supporting the intra-class adjustment of storage costs from the SGDS1 and SGDS2 classes to the SGSS1, SGSS2, SCD1 and SCD2 classes. This adjustment is made because SGDS1 and SGDS2 customers are not priority customers for whom Columbia purchases gas in storage to serve.

Q. Please describe this study.

A. The study calculates the storage carrying costs, by rate class, by applying the proposed pre-tax rate of return (Line 6) to the allocated storage balances (Line 3) and utilizing Allocation Factor No. 25. The resulting storage carrying costs for the SGS1/SGDS1 class and the SGS2/SGDS2 class (Line 7) includes costs that would, without an adjustment, be assigned entirely to the SGDS1 class (Line 15) and SGDS2 class (Line 22). These costs are assigned to the SGSS1 and SCD1 classes and the SGSS2 and SCD2 classes ratably, using a factor derived from their projected throughput (Lines 13 & 14 under the heading "Ratio" for the SGSS1 and SCD1 classes and Lines 20 & 21 for the SGSS2 and SCD2 classes). No other intra-class adjustments are being supported or shown on this exhibit.

III. Revenue Allocation and Rate Design

a. Overview

Q. Please describe the rate design principles that the Company considered when developing the proposed revenue allocation and rates.

A. The principles that were used to guide the development of the Company's rate design include: efficiency, simplicity, continuity, fairness, and earnings stability. An efficient rate design provides accurate price signals and, thus, an accurate basis for consumers' decisions and provides the Company a reasonable opportunity to recover the cost of providing service. A simple rate structure is one that is understood by customers. The goal of rate continuity seeks gradual changes to rate design that will allow customers to adjust their consumption patterns, as needed. A fair rate design will consider the results of the allocated cost of service study in determining customer classes' total revenue responsibility. Finally, earnings stability means that the Company's earnings resulting from its rates should not vary significantly over the period of a few years.

Q. Please state the basis for the Company's proposed revenue allocation among the rate classes.

A. Consistent with the goal of continuity, Columbia seeks to move base rates closer to the allocated cost of service for each customer class gradually, so as to avoid rate shock to any particular rate class. The cost to serve each rate class is defined through the allocated cost of service study.

Q. How were the results of the cost allocation studies used in designing the proposed revenue requirements and rates?

A. The cost allocation studies were used as a guide for assigning additional revenue responsibility to customer groups. The peak and average study and the customer demand study provide information about class cost relationships and help establish a "zone of reasonableness" from which an appropriate revenue allocation and rate design can be derived. For this case, Columbia used the peak and average study as the primary study to establish class rates of return at current and proposed rates. The peak and average study was given primary consideration given the Commission's ruling on the matter in Columbia's 2020 rate case. However, Columbia believes the results from the other two studies can still be useful as other reference points in guiding the allocation of the proposed revenue increase. The results of the cost allocation studies support the Company's proposed rate schedules. Details concerning the application of the cost study results in the proposed rate design are provided later in this testimony.

Q. What are the results of the allocated cost of service studies at current rates?

A. Exhibit KLJ-5, attached to my testimony, shows the class-level return indices for each of the ACOS studies. Return indices compare individual class returns to the overall total Company return. A return index is calculated by dividing the class return by the total Company return. The total Company return index will always be 1.00. The closer an individual class's return is to the total Company return, the closer its index will be to 1.00 and to parity. The term "parity" in this context means that the class return and the total Company return are equal.

The return index for the residential class ranges from 0.74 under the Customer/Demand study to 1.21 under the Peak & Average study. The average ACOS study produces a residential return index of 0.94.

The SGS1/SCD1/SGD1 return indices are 1.09 for the Peak & Average study, 1.15 for the Customer/Demand study and 1.12 for the average ACOS study.

The SGS2/SCD2/SGD2 return indices are 1.08 for the Peak & Average study, 2.44 for the Customer/Demand study and 1.57 for the average ACOS study.

The SDS/LGSS return indices are 1.14 for the Peak & Average study, 3.93 for the Customer/Demand study and 1.93 for the average ACOS study.

The LDS/LGSS return indices are 0.34 for the Peak & Average study, 2.94 for the Customer/Demand study, and 0.92 for the average ACOS study.

The return index for the MLDS class indicates that, by directly assigning mains investment, the return is the same under each of the three ACOS studies showing a return that is above parity with a return index of 40.02.

The FLEX return indices are -0.56 for the Peak & Average study, -0.18 for the Customer/Demand study, and -0.47 for the average ACOS study.

Q. What is the primary goal of Columbia's class revenue allocation?

A. The primary goal in Columbia's approach to revenue allocation is to maintain a movement toward parity among the various rate classes, consistent with Commission decisions in previous Company rate cases. Movement toward parity, through a goal of equal rates of return by class, is a way of assuring that the revenue allocation process takes into account the overall Company return and the relative returns by

rate class. Each class's revenue increase is determined within the context of other rate class returns so that, over time, interclass returns remain close to one another rather than diverging. Maintaining a movement toward parity is a way to minimize potential cross-subsidization between classes.

Q. Do the Company's proposed rate increases for the various rate classes reflect the principle of gradualism?

A. Yes. First, Columbia's proposed rate increases for the various rate classes cause a movement of the unitized returns toward parity (unitized return of 1.00) for each of the rate classes but with no rate class yet reaching parity. Secondly, the range of base rate revenue increase percentages for any class was not to exceed 1.5 times the total system average increase of 20.69% (see Exhibit 103, Schedule No. 8, Page 1, Lines 21 through 38).

Q. Please describe the Company's proposed revenue allocation.

A. Columbia's allocation of the proposed base rate revenue increase, which is shown in Exhibit 103, Schedule No. 8, Page 4, Line 19, reflects the following allocations: 69.51% of the overall increase is applied to the residential class; 9.06% of the overall increase is applied to the SGS1/SCD1/SGDS1 class; 9.98% of the overall increase is applied to the SGS2/SCD2/SGDS2 class; 6.55% of the overall increase is applied to the SDS/LGS class; 4.88% of the overall increase is applied to the LDS/LGS class; 0.00% of the overall increase is applied to MLDS customers; and 0.00% of the overall increase is applied to the FLEX customers.

Exhibit 103, Schedule 8, Page 4, Lines 5 and 6 shows the movement toward parity produced by Columbia's proposed revenue allocation using the peak and average ACOS Study. The movement toward parity (unitized return of 1.00) measures each class's return versus the total Company return under current and proposed rates.

Q. Please explain why the revenue allocation to FLEX was limited to the revenue generated by increased customer charges.

A. Flex agreements are individually negotiated contracts with a customer who has provided a sworn affidavit that a lower rate is required to meet competition from an alternate fuel. Per the Flexible Rate Provisions of Columbia's tariff, the customer charge is not eligible for downward adjustment, and is not negotiable. The customer charges that flex customers are charged are set under the rate schedule in which the customer is receiving service under[3].

Q. Do flex rate agreements benefit Columbia's non-flex customers?

A. Yes. Revenue collected from flex rate customers contributes to the recovery of the Company's fixed costs. Absent flex rates, the Company may lose these customers to alternative fuels. Without the revenues from flex rate customers, the Company's non-flex customers would be assigned additional fixed cost recovery responsibility, and their rates would increase.

Q. Other than the ACOS studies, what guidelines or criteria have you considered in the design of the Company's rates?

[3] Columbia Gas of Pennsylvania Tariff, Supplement No. 221 to Tariff Gas – Pa. PUC. No. 9 Sixth Revised Sheet No. 68.

A. There are a number of criteria that I considered in the design of rates, including the following:

First, the design of Columbia's rates recognizes that rates must be just and reasonable and must not be unduly discriminatory. Columbia's proposed rate design also attempts to minimize cross-class subsidies.

Second, where rates require adjustment to achieve proper cost recovery, customer impact considerations have been factored into the rate design process. For instance, Columbia's proposed rate design moves each of the rate classes toward parity (unitized return of 1.00 and a total Company required rate of return of 8.71%) but recognizes a move to full parity of 1.00 in this case would not be consistent with the principle of gradualism.

Third, Columbia's proposed rate design provides for recovery of fixed costs through the customer charge at least proportional to the percentage recovery of fixed costs in current rates. In the case of the residential class, where the proportion of fixed costs has eroded since the 2012 rate case, Columbia's proposed rate design provides for recovery of an increasing proportion of fixed costs through the customer charge.

b. **Residential Rate Design**

Q. What are the new base rates proposed for residential customers?

A. Columbia proposes to increase the monthly residential customer charge from $16.75 to $26.00. The remaining residential revenue increase was assigned to the volumetric charge for a resulting rate of $10.2781 per Dth.

Q. How did Columbia determine a residential customer charge of $26.00?

A. Exhibit No. 111, Schedule 2, page 25, shows that the minimum monthly customer-based cost excluding distribution mains costs for the residential class is $28.71. The Company is proposing a monthly customer charge of $26.00 to move closer to the minimum monthly customer-based cost excluding distribution mains costs of $28.71. Additional reasons for increasing the Company's residential customer charge are discussed below.

Q. When was the last time the Company's residential customer charge increased?

A. Columbia's current residential customer charge of $16.75 was established in its 2012 rate case.

Q. How have residential customer-based costs excluding the costs of distribution mains increased since 2012?

A. Residential customer-based costs excluding costs related to distribution mains improvements has increased approximately 72%[4], but the customer charge has not increased. Columbia's proposed monthly customer charge of $26.00 reflects moving the customer charge toward the minimum monthly customer-based cost excluding distribution mains costs. This approximately 55% increase in the residential customer charge is still less than the 72% increase in customer-based costs excluding costs related to distribution mains since the 2012 rate case. In addition, the 55%

[4] The approximately 72% increase in residential customer-based costs excluding costs related to distribution mains improvements from 2012 to current is calculated by comparing the $82,848,400 on Exhibit 111, Schedule 1, Page 17, Line 37 in case R-2012-2321748 to the $142,894,323 on Exhibit 111, Schedule 2, Page 25, Line 37 in this case.

proposed increase in the residential customer charge amounts to an annual increase of approximately 4.6%, or approximately $0.77, per year since the 2012 rate case.

Q. Why does the Company believe increasing the residential class customer charge in this rate proceeding is necessary?

A. Historical recovery of fixed costs through the volumetric rate portion of the rate schedule inevitably results in the over or under recovery of those costs because the revenues generated from customers' volumetric use of gas can be greatly sensitive to customer usage fluctuations that vary due to conservation efforts or other changing consumption characteristics. In essence, customer-related costs that bear no relationship to customer gas consumption patterns should be recovered through the fixed portion of the rate design, i.e. the monthly customer charge.

Q. What is the percentage of current and proposed residential base revenue recovered by the fixed customer charge and volumetric rate?

A. As shown on Exhibit No. 103, Schedule No. 8, Page 5, Lines 12 and 14, the following table shows percentages base revenue recovered by the fixed customer charge and volumetric rate.

Table KLJ-2

Residential Base Revenue Fixed Charge and Volumetric Percentages				
	Residential Current Revenue	Percent of Current Revenue	Residential Proposed Revenue	Percent of Proposed Revenue
Fixed Customer Charge	$83,368,050	21.17%	$129,407,122	26.97%
Volumetric	$310,463,400	78.83%	$350,390,788	73.03%

Q. What are the implications if the Commission chooses to keep the residential customer charge at $16.75 instead of increasing to $26.00 as the Company requests?

A. If the customer charge portion of the revenue requirement is not increased in this case, the Company will have to increase the volumetric base rate by the entire revenue requirement increase approved by the Commission. As stated above, that would change the residential customer charge from the proposed $26.00 per month to the current $16.75 per month and shift the entire amount of the approved revenue requirement to the volumetric rate, changing it from $10.2781 per Dth to $11.6286 per Dth. Furthermore, the percentage of current base revenue recovered through a fixed charge would decrease from 21.17%, as shown in Table KLJ-2 above, to 17.38%.

Q. Does leaving the residential customer charge at $16.75 impact the customer affordability of the Company's customers?

A. Yes, establishing a higher monthly fixed customer charge will help to equalize the contribution each customer within the residential class makes towards recovery of the fixed costs attributable to the entire class. Recovering costs through the customer charge is preferable to including such costs in the volumetric block prices, which has the effect of causing some customers to pay too much while others pay too little. Customers will also incur more stable monthly bills since more fixed costs are recovered each month. The additional stability for customers is created by reducing the recovery of fixed costs on a volumetric basis, which can lead to higher bills in the winter versus the summer.

Q. Can you provide an example of the Company's residential customers having increased price stability by implementing the Company's proposed residential customer charge?

A. Yes. Exhibit KLJ-11 shows normalized usage for an average residential customer in Column 4 for the Fully Projected Future Test Year, 2025, as presented by Company witness Girata on Exhibit No. 10, Schedule No. 2, page 8 of 8. Columns 5 through 8 are used to compute the monthly total bills for this typical residential customer at the Company's proposed rates. If the Company does not increase the revenue requirement recovered through the customer charge in this case, then the volumetric base rates will need to be increased by the incremental revenue requirement approved by the Commission. As stated above, that would change the residential customer charge from the proposed $26.00 per month to the current $16.75 per month and shift the entire amount of the approved revenue requirement to the volumetric rate, changing it from $10.2781 per Dth to $11.6286 per Dth. Columns 10 through 13 on Exhibit KLJ-11 show the computation of the monthly total bills for this typical residential customer should the customer charge remain at $16.75/month and the volumetric rate increase to $11.6286 per Dth. Column 14 shows the bill impact difference by month comparing the Company's proposed customer charge of $26.00 to leaving it at $16.75. Table KLJ-3 below summarizes the shifts shown in Exhibit KLJ-11.

Table KLJ-3

Month	Normal Usage	Proposed Bill at $26.00 / $10.2781/Dth	Proposed Bill at $16.75 / $11.6286/Dth	Impact on Total Bill
Jan	15.88	$254.36	$266.55	($12.19)
Feb	16.21	$259.21	$271.85	($12.65)
Mar	13.53	$220.55	$229.56	($9.02)
Apr	8.92	$154.29	$157.08	($2.79)
May	4.01	$83.61	$79.77	$3.84
Jun	1.95	$54.04	$47.42	$6.62
Jul	1.17	$42.80	$35.12	$7.67
Aug	1.08	$41.51	$33.72	$7.79
Sep	1.11	$41.96	$34.21	$7.75
Oct	1.87	$52.88	$46.15	$6.73
Nov	5.42	$104.01	$102.08	$1.93
Dec	11.73	$194.67	$201.25	($6.59)
Annual	82.86	$1,503.88	$1,504.78	($0.90)

Q. What are your observations from analyzing Exhibit KLJ-11 and Table KLJ-3?

A. First, a residential customer with average usage incurred a slightly lower bill ($0.90) at the proposed rate than if the customer charge is maintained at its current $16.75. Second, by increasing the customer charge to $26.00 as the Company proposes instead of continuing to increase the volumetric rate and leaving the customer charge at $16.75, residential customers will see a shift in their bills from the heating months to the non-heating months when bills are typically lower. This shift will ease the burdens of residential customers in the heating months when usage is typically higher and reduce customer bill volatility. Third, this method of cost recovery is preferable to including such costs in the volumetric rates, as the customer charge will provide for increased recovery of a portion of the Company's fixed costs, which are incurred solely because of the existence of customers connected to the system. These

costs, such as the expense of reading meters and billing, occur regardless of whether gas is consumed and are not related to the demands placed on the system. Spreading these costs throughout the year via the customer charge aligns the collection of revenue with the principles of cost causation of these fixed customer-related costs.

Q. Did you do any other analysis regarding the customer affordability impacts to the Company's residential customers?

A. Yes. As shown on lines 14-26 on of Exhibit KLJ-11, I reviewed the billing determinants of the rate schedules making up the residential class, specifically the residential CAP customers.

Q. Can you provide the high-level requirements of the Customer Assistance Plan rate?

A. Yes. As noted on Page No. 139 of the Company's tariff, this rate is available to residential customers whose "total household income is equal to or less than 150% of the Federal Poverty Level" and "the customer is either over sixty years old or is payment-troubled (i.e., has at least one failed payment arrangement with the Company within the past 12 months, has received a termination notice from the Company within the past 12 months, has been verified as a current participant in another utility's CAP, or is unable to establish creditworthiness through the use of generally accepted credit scoring methodology)".

Q. What are your observations from analyzing residential CAP customer information in Exhibit KLJ-11?

A. Table KLJ-4 below summarizes the information from Exhibit KLJ-11.

Table KLJ-4

Month	Normal Usage	Proposed Bill at $26.00 / $10.2781/Dth	Proposed Bill at $16.75 / $11.6286/Dth	Impact on Total Bill
Jan	20.75	$324.41	$343.17	($18.77)
Feb	21.41	$333.91	$353.57	($19.66)
Mar	18.22	$288.14	$303.50	($15.36)
Apr	12.27	$202.50	$209.82	($7.32)
May	5.81	$109.57	$108.17	$1.40
Jun	2.53	$62.33	$56.49	$5.84
Jul	1.34	$45.25	$37.80	$7.44
Aug	1.20	$43.26	$35.63	$7.63
Sep	1.27	$44.25	$36.71	$7.54
Oct	2.64	$63.98	$58.29	$5.68
Nov	7.66	$136.20	$137.30	($1.10)
Dec	15.58	$250.04	$261.82	($11.78)
Annual	110.67	$1,903.81	$1,942.27	($38.45)

Residential CAP customers with average usage would incur lower total annual billings ($38.45) at the proposed increased monthly customer charge of $26.00 than if the customer charge is maintained at its current $16.75 per month, and the volumetric rate is increased. Second, by increasing the customer charge to $26.00, as the Company proposes instead of continuing to increase the volumetric rate and leaving the customer charge at $16.75, these CAP customers would experience lower bills in the heating season, even more so than the typical residential customer. Furthermore, by examining these billing determinants, the analysis shows these CAP customers would be paying more when the customer charge is at $16.75 while other lower usage customers in the residential class pay less for Columbia's delivery service.

Q. Why is there a need to increase the percent of base rate recovery through the customer charge now that Columbia has a Weather Normalization Adjustment ("WNA") mechanism?

A. The WNA normalizes the impact of weather on the recovery of residential usage based on base revenue during the winter months that the WNA is in effect. In doing so, the WNA affords the Company a greater opportunity to recover its authorized revenue requirement from its residential customers, while mitigating the impact of weather on the level of revenues collected from them. Thus, the WNA mechanism is beneficial to both Columbia and its customers. However, the WNA mechanism is not intended to address usage fluctuations that are attributable to conservation efforts or other changing consumption characteristics, intra-class subsidization of fixed cost recovery, weather effects of consumption outside the five winter months that the WNA is in effect, or weather effects of consumption for rate classes not covered by the WNA. It is for these reasons that it is important for the customer charges to recover an increased percent of base rate revenue recovery.

c. **Non-Residential Rate Design**

Q. Describe the new base rates proposed for Small General Service customers consuming less than or equal to 6,440 therms annually.

A. Columbia proposes to increase the customer charge from $29.92 to $36.55. The increased customer charge is proportional to the overall base revenue increase for the rate class. The remaining revenue requirement for this customer class would be recovered through the volumetric rates. Exhibit No. 111, Schedule No. 2, pages 16 and 25 shows that the minimum customer costs for this rate class range from $31.68 (excluding mains) to $81.63 (including mains). Columbia's customer charge proposal of $36.55 falls near the bottom end of the range of customer-based

costs. The remaining revenue is recovered through the volumetric base rates of $8.5194/Dth for SGSS1/SCD1 service and $8.4262/Dth for SGDS1 service.

Q. What are the customer-based costs for the Small General Service customers using between 6,440 and 64,400 therms annually?

A. The proposed SGSS2/SCD2/SGDS2 customer charge for customers whose usage is between 6,440 therms and 64,400 therms is $69.63. The increased customer charge is proportional to the overall base revenue increase for the rate class. The remaining revenue requirement for this customer class would be recovered through the volumetric rates. The volumetric charge will be $7.2574/Dth for SGSS/SCD service and $7.1644/Dth for SGDS service.

Q. Please explain why the SGDS customers in the two rate classes above have a different volumetric charge than the SGSS and SCD customers in those rate classes.

A. Consistent with previous base rate proceedings, Columbia re-allocated the storage working capital costs assigned to the SGSS/SCD/SGDS classes, as a whole, through the ACOS to SGSS/SCD classes only. As shown on Exhibit KLJ-4, Columbia has re-allocated $200,750 of storage working capital costs from the SGDS class to SGSS/SCD. This intra-class re-allocation is shown on Lines 16 of Exhibit 103, Schedule 8, Pages 6 and 7. As a result, the Company charges a different volumetric base rate to the SGSS and SCD customers than to the SGDS customers, and that principle will not change under proposed rates.

Q. Please summarize Columbia's SDS/LGSS rate design proposal.

A. The proposed SDS/LGSS customer charge for customers whose usage is between 64,400 therms and 110,000 therms is $326.09, and the proposed customer charge for customers whose usage is between 110,000 therms and 540,000 therms is $1,479.13. The increase in customer charges is proportional to the overall base revenue increase for the rate class. The remaining revenue requirement for this customer class would be recovered through the volumetric rates.

The volumetric base rate will be $5.5769/Dth for SDS/LGSS customers whose usage is between 64,400 therms and 110,000 therms and $5.2140/Dth for SDS/LGSS for customers whose usage is between 110,000 therms and 540,000 therms.

Q. Please summarize Columbia's LDS/LGSS rate design proposal.

A. Table KLJ-5 below shows the proposed customer charges for the LDS/LGSS rate class, which reflect an increase proportional to the base revenue increase for the rate class.

Table KLJ-5

Annual Usage Levels	Proposed Cust. Charge
> 540,000 to ≤ 1,074,000 Therms	$3,649.50
> 1,074,000 to ≤ 3,400,000 Therms	$5,676.46
> 3,400,000 to ≤ 7,500,000 Therms	$10,946.88
> 7,500,000 Therms	$16,217.29

Q. How is the LDS/LGSS volumetric based rate revenue requirement shown in Exhibit 103, Schedule 8, Page 8, Line 26 spread among the LDS/LGSS annual usage groups?

A. The volumetric base revenue requirement is split among the LDS/LGSS annual usage groups proportionately based on revenue produced from current volumetric base rates. (See Exhibit 103, Schedule 8, Page 8, Lines 28 through 31).

Q. Regarding each rate class's proposed customer charge, why did the Company use $26.00 for the proposed residential customer charge but proposed the customer charge for the other classes be increased proportional to the overall base revenue increase for the rate class?

A. In Exhibit KLJ-10, I analyze the current customer charges of each class (Line 6) in comparison to the calculated monthly customer charges excluding mains costs from the Peak & Average ACOS (Line 2). For the SDS/LGSS and LDS/LGSS classes, the weighted average of these classes' customer charges was also compared to the midpoint of the calculated monthly customer charges, excluding mains costs and the calculated monthly customer charges but including mains costs from the Peak & Average ACOS (Line 5). It is noted on Line 7 that the current customer charge percentage of the calculated monthly charge excluding mains (Peak & Average basis) is between 94% and 96% for the SGS/DS-1 and SGS/DS-2 classes. It is noted on Line 8 that the current customer charge percentage of the midpoint of the calculated monthly charge excluding mains (Peak & Average basis) and the calculated monthly charge including mains (Customer Demand basis) is between 126% and 103% for the SDS/LGSS and LDS/LGSS classes. However, the residential class current customer charge is 58% of the calculated monthly customer charge excluding mains (Peak & Average basis). With the residential class customer charge percentage of the

calculated monthly customer charge being much lower than the other classes, the Company proposed bringing the customer charge in-line with the other classes. The proposed customer charges for the non-residential classes were increased proportional to the overall base revenue increase for the rate class. Lines 10 & 11 show the percent of calculated monthly customer charges for each class's proposed customer charge produces at or above the minimum customer charge generated by the Company's Peak & Average ACOS for the RSS/RDS, SGS/DS-1, and SGS/DS-2 classes and above the minimum customer charge generated by the midpoint of the Company's Peak & Average and Customer Demand ACOS studies for the SDS/LGSS, and LDS/LGSS classes. Lines 10 and 11 also show all the classes' customer charges are more proportional to each other under proposed rates than current rates.

IV. Revenue Proof and Bill Comparisons

Q. Please provide a proof of the Fully Projected Future Test Year ("FPFTY") base revenue requirement by rate schedule.

A. Refer to Exhibit No. 103, Schedule No. 8.

Q. What are the class-level bill impacts resulting from the Company's proposal?

A. The class average bill impacts are shown on Exhibit No. 103, Schedule No. 8, Page 1, column 7.

Q. Is the Company providing graphs of the bill impacts?

A. Yes. Please refer to Exhibit No. 111, Schedule No. 5, pages 1-27. Graphs depicting Residential Sales Service are shown on pages 1-3, and pages 4-27 provide graphs for C&I customers.

Q. What is the range of bill impacts for residential customers?

A. Please refer to Exhibit No. 111, Schedule No. 6, page 1-3. These pages show monthly bill impacts for residential customers at various usage levels.

Q. Has the Company performed bill impact analyses at various usage levels for C&I customers?

A. Yes. Refer to Exhibit No. 111, Schedule No. 6, pages 4-27. These pages provide monthly bill impacts for Small General Sales Service and Large General Sales Service customers at various usage levels.

Q. Are the Revenue Proof and Bill Impacts in the same format as the prior Rate Case?

A. Yes. The Revenue Proof (Schedule No. 8) and Bill Impacts (Schedules No. 5 & 6) are in the same format as the last case. However, please note the impacts of the Company's proposed Municipal Levelization Charge, which is discussed by Company witness Paloney, is reflected in these schedules. Since the proposed Municipal Levelization Charge is revenue neutral, the impacts are shown on Exhibit 103, Schedule No. 8, page 1, line 18. The Bill Impacts and associated graphs also show the increased bills issued to residents of the City of Pittsburgh and the Borough of Perryopolis, and decreased bills issued to residents of Roscoe Borough and New Sewickley Township. All other customers not in the City of Pittsburgh, the Borough

of Perryopolis, Roscoe Borough, and New Sewickley Township will not see an impact from the proposed Municipal Levelization Charge.

V. Weather Normalization Adjustment ("WNA")

Q. Is Columbia proposing any changes to its current Weather Normalization Adjustment ("WNA") mechanism?

A. Columbia is proposing to eliminate the 3% deadband currently in effect in the Rider WNA mechanism.

Q. Why does the Company propose to eliminate the 3% deadband applicable to the currently effective Rider WNA?

A. In the 2018 Rate Case, the parties agreed to move the Rider WNA deadband from 5% to 3%. A 3% deadband means that a portion of revenue variation due to weather continues to be unaddressed. Thus, the goal of the WNA, to improve customer bill and revenue stability, is not fully realized. The deadband distorts the true effect of weather. For example, if a billing cycle is 2.5% colder or warmer than normal, no adjustment will be made. Additionally, as described later in my testimony, the Company proposes to implement a Revenue Normalization Adjustment ("RNA"), along with Rider WNA. Eliminating the 3% deadband would cause all billing adjustments related to weather to occur through the WNA in real time and would limit adjustments passing through the proposed RNA.

VI. Revenue Normalization Adjustment ("RNA")

Q. What other rate design proposal is Columbia making in this case?

A. Columbia is proposing the implementation of a RNA for the residential class in this case. The RNA provides a benchmark distribution revenue level regardless of changes in customers' actual usage levels. Rider RNA would adjust actual non-gas distribution revenue for the non-CAP residential customer class. Columbia's proposed RNA is designed to "break the link" between residential non-gas revenue received by the Company and gas consumed by non-CAP residential customers.

Q. How does the RNA promote revenue stabilization?

A. The RNA promotes revenue stabilization because it relies on distribution revenue per customer, not usage per customer. Once the Company's revenue requirement is set through a base rate case proceeding, then a benchmark revenue per residential customer is established. Through Rider RNA, the Company would refund any amount over the benchmark revenue per residential customer and would be allowed to collect any amount below the benchmark revenue per customer. Hence, the RNA "breaks the link" between residential non-gas revenue and gas consumed by non-CAP residential customers.

Q. How does the proposed RNA align with the Statements of Policy as outlined by the Commission in the alternative rate making Docket No. M-2015-2518883?

A. Each rate consideration identified in the Statements of Policy is listed below along with the relevant effect the proposed RNA has on each rate consideration:

1. Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

a. Columbia's proposed RNA is designed to recover the residential base revenues needed to satisfy the cost of service requirements determined in this proceeding while negating over or under recovery of costs.

2. Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

a. Columbia's RNA proposal has no identifiable effect on the capacity utilization of the residential class.

3. Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

a. Columbia's RNA benchmark revenue includes the anticipated volumetric base revenue derived from the fully projected future test year consumption.

4. Please explain how the ratemaking mechanism and rate design limit or eliminate inter-class and intra-class cost shifting.

a. Columbia's RNA minimizes inter-class cost subsidization by limiting the amount of cost recovery for the residential class to the revenue benchmark established in this case. Residential intra-class cost subsidization is reduced through Columbia's proposal of a higher customer charge for the residential class.

5. Please explain how the RNA limits or eliminates disincentives for the promotion of efficiency programs.

a. Reduced throughput will not lead to revenue and earnings erosion due to under-recovery because the link between level of throughput and base revenue recoveries is broken with the implementation of the RNA.

6. Please explain how the RNA impacts customer incentives to employ efficiency measures and distributed energy resources.

a. Customers will continue to have an incentive to pursue energy efficiency measures since, as proposed, approximately 30% of an average residential bill will still be subject to volumetric usage not related to base rate revenue recovery.

7. Please explain how the RNA impacts low-income customers and supports consumer assistance programs.

a. Columbia's proposed RNA only applies to non-CAP customers.

8. Please explain how the RNA impacts customer rate stability principles.

a. Columbia's proposed RNA enables the recovery of costs established in this case and, therefore, mitigates the potential under or over recovery of costs that could require a material rate adjustment in the near future.

9. Please explain how weather impacts utility revenue under the RNA.

a. The RNA, as proposed, will capture base revenue differences net of weather as the benchmark is based upon normal weather and the actual revenue will include billed WNA adjustments.

10. Please explain how the RNA impacts the frequency of rate case filings and affects regulatory lag.

a. The RNA is designed to mitigate the over or under recovery of the residential cost of service in this case. Future rate cases would still be required to capture cost of service changes that occur beyond the residential class and the fully projected future test year in this case.

11. Please explain if the RNA interacts 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).

a. Columbia's proposed RNA only applies to the recovery of costs included in determination of the residential base revenue requirement.

12. Please explain whether the RNA includes appropriate consumer protections.

a. The RNA, as proposed, establishes a Benchmark Distribution Revenue per Bill ("BDRB") residential customer. Rider RNA will refund any amount over the established benchmark and collect any amount below the benchmark. By design, the Company cannot retain revenue in excess of the BDRB which protects the customer from being over-charged. Columbia will submit two filings per year for the RNA mechanism, which can be reviewed and audited by the Commission, like the process for the Company's Purchased Gas Cost and Rider USP filings.

13. Please explain whether the RNA is understandable to customers.

a. Columbia's RNA is not a unique concept to the regulated utility industry, and similar versions have been implemented successfully in other jurisdictions in which Columbia operates. Columbia is also providing an RNA tariff that clearly shows the detail of how the mechanism works.

14. Please explain how the RNA will support improvements in utility reliability.

a. Columbia's cost of service reflects the investments and costs made for the continued enhancement of the safety and reliability of its system. The RNA reduces the volatility concerning the recovery of those costs.

Q. How frequently does the Company propose to compute Rider RNA and adjust residential customers' bills?

A. Columbia proposes to calculate Rider RNA and adjust residential customers' bills every six months based upon a comparison of benchmark distribution revenue to actual distribution billed revenue. Under the Company's proposal, Rider RNA would be credited or charged to all non-CAP residential bills (i.e., Rate RSS – Residential Sales Service, and Rate RDS – Residential Distribution Service (CHOICE)).

Q. Describe the time periods used to calculate the proposed benchmark base revenues for non-CAP residential customers.

A. The proposed benchmark distribution revenues will be calculated for two separate six-month periods. The first time period, or "Peak Period," includes billing cycles for October through March, and the second time period, or "Off-Peak Period,"

includes billing cycles for April through September. Although, the Company considered monthly RNA rate adjustments, Peak and Off-Peak Periods were selected to minimize rate fluctuations for customers. These specific six-month periods were selected to align Rider RNA rate changes with the gas cost rate changes. This helps to minimize the number of times customers' rates are changed annually.

Q. Please describe the timing of charging Rider RNA on residential customers' bills.

A. The RNA calculated for the Peak Period would be applied to the next Peak Period. Likewise, the RNA calculated for the Off-Peak Period would be applied to the next Off-Peak Period. For example, the RNA calculated for the Peak Period beginning with October 2025 billing cycles and ending with March 2026 billing cycles would be applied to residential customers' bills for the period beginning with October 2026 billing cycles and ending with March 2027 billing cycles. By lagging the adjustment until the next corresponding time period, the Company moderates the impact of any adjustment, because Peak Period adjustments are applied to Peak Period volumes.

Q. Explain the calculation of the Peak and Off-Peak Benchmark Distribution Revenue per Bill ("BDRB").

A. Columbia proposes to set Peak and Off-Peak BDRBs using weather normalized test year revenues for the FPFTY approved in this proceeding, divided by the number of residential bills for the applicable six-month period.

Q. How would the BDRB be utilized for Rider RNA?

A. For each period, the difference between the BDRB and the Actual Distribution Revenue per Bill ("ADRB") would be multiplied by the Actual Number of non-CAP Residential Bills ("ANB") to calculate base revenues to be collected or refunded to non-CAP residential customers.

Q. What are the Peak and Off-Peak BDRB levels proposed by Columbia?

A. Refer to Exhibit KLJ-7 for the calculation of the BDRBs proposed by the Company for the Peak and Off-Peak Periods. The BDRBs are based upon the Company's filed for revenue requirement. Exhibit KLJ-7 shows the following BDRB levels for Rider RNA:

	Peak BDRB		Off-Peak BDRB	
January	$185.50	April	$116.06
February	$188.42	May	$65.63
March	$161.67	June	$45.79
October	$45.40	July	$38.20
November	$80.53	August	$37.42
December	$143.51	September	$37.72
6-Month Total	$805.03		$340.82

Q. Would the Company need to adjust the BDRB levels after a final revenue requirement is approved by the Commission?

A. Yes. The proposed BDRB levels would need to be revised for the final revenue requirement approved by the Commission.

Q. When does the Company propose to reset the BDRB levels?

A. New BDRB levels for the Peak and Off-Peak Periods would be established with each base rate case filing.

Q. Has the Company filed a tariff for its RNA proposal?

A. Yes. The Company's RNA Rider is set forth on Page Nos. 145 and 145a of Columbia's proposed tariff (Exhibit 14, Schedule 2).

Q. Can you please explain how the RNA and WNA work together and why both are needed?

A. Although Rider RNA could serve the purpose of adjusting revenues for normal weather, Rider WNA does it more efficiently, for a few reasons. First, the WNA applies to each individual customer's consumption and usage patterns. This results in no cross-subsidization because of adjusting bills for normal weather. The WNA is billed in real time, so there is no lag in refund or recovery due to weather variances from normal. This means that there is no need for a reconciliation adjustment with Rider WNA. Additionally, by recovering or refunding the impact of weather through the WNA, the RNA would be mitigated to recovering distribution revenues that deviate from test year benchmark distribution revenues, exclusive of distribution revenues adjusted through Rider WNA.

Q. How will the WNA and RNA mechanisms operate to avoid double-counting adjustments in the RNA?

A. BDRB levels are based upon normal weather and ADRB will include monthly Rider WNA adjustments. Thus, the RNA will only capture any difference, net of weather.

Q. Have Columbia affiliates successfully implemented RNA with an existing WNA in place in other jurisdictions?

A. Yes. Similar alternative rate design mechanisms have been implemented in other jurisdictions. Columbia Gas of Maryland and Columbia Gas of Virginia have implemented RNA mechanisms in addition to an existing WNA mechanism. Experience from these other jurisdictions has been considered in the context of proposing a residential rate design for Columbia in this case.

Q. When does the Company propose to implement the RNA?

A. Columbia proposes to implement the RNA with January 2025 billing cycles. This initial Peak Period RNA ("RNAp") would become effective with October 2025 billing cycles.

Q. What additional filing(s) would occur related to Rider RNA?

A. The Company would submit two filings related to Rider RNA per year. The Peak Period RNA Filing would be submitted one day prior to the effective date of the Peak RNA adjustment and the Off-Peak Period RNA Filing would be filed one day prior to the effective date of the Off-Peak RNA adjustment.

Q. Please present Columbia's proposed RNA formula.

A. The Company's proposed RNA formula for the Peak Period is shown below:

$$\text{Peak Period:} \quad RNAp = \frac{[ANBp \times (BDRBp - ADRBp)]}{FTp}$$

RNA is the Revenue Normalization Adjustment for non-CAP residential customers for the applicable period.

BDRB is the Benchmark Distribution Revenue per Bill for non-CAP residential customers for the applicable period.

ADRB is the Actual Distribution Revenue per Bill for non-CAP residential customers for the applicable period. ADRB includes Rider WNA adjustments in the applicable months.

ANB is the Actual Number of non-CAP residential Bills for the applicable period. ANB will be computed using a six-month average.

FT is the Forecast Therms for residential non-CAP customers for the six-month period that the RNA will be applied.

Q. Is the calculation of the Off-Peak Period RNA similar to the Peak Period RNA?

A. Yes. The equations are the same for the six-month Off-Peak RNA ("RNAo") calculations.

Q. Does Columbia propose to apply interest to the RNA balances?

A. Yes. Refunds to customers shall be made with interest and recoveries from customers shall include interest at the prime rate for commercial borrowing in effect 60 days prior to the tariff filing and as reported in a publicly available source identified by the Commission or at an interest rate which may be established by the Commission by regulation.

Q. How does the Company plan to implement the RNA in the middle of the Peak Period?

A. For the initial Peak Period RNA, the Company will calculate benchmark revenues using three billing months: January, February and March. The actual distribution revenues and actual number of non-CAP bills would also include only January, February and March of 2025.

Q. Please provide sample RNA calculations for the initial Peak and Off-Peak periods.

A. Please refer to Exhibits KLJ-8 and KLJ-9 for sample RNA calculations for the initial Peak and Off-Peak Periods. Exhibit KLJ-8 shows the calculation of the RNAp adjustment for a three-month period because Columbia is proposing to begin tracking for the RNA starting with billing month January 2025. Line 3 of Exhibit KLJ-8 shows the monthly BDRBp levels proposed in this proceeding. The ADRBp would be input on line 7. For this sample calculation, ADRBp amounts were assumed for illustrative purposes because actual information for January through March 2025 is not available. Line 9 shows the subtraction of lines 3 and 7. The resulting difference is multiplied by an illustrative ANBp for each month to calculate revenue to be assigned to the RNAp (line 16) for collection in the next Peak Period. Line 18 shows forecasted Dth for the months of October 2025 through March 2026. The RNAp rate effective for October 2025 billing cycles through March 2026 billing cycles is calculated on line 20. Exhibit KLJ-9 shows the same computations for the initial Off-Peak Period, including the months of April

through September. The initial RNAo would be effective with April 2026 billing cycles.

Q. Does the RNA mechanism result in all non-CAP residential customers paying the same total distribution charge?

A. It does not. All non-CAP residential customers will continue to pay a customer charge and a volumetric rate. Through the RNA mechanism, an adjustment rate is calculated and applied to each non-CAP residential customer's usage in a future period. Thus, the RNA mechanism helps to balance revenue stability while allowing customers to experience any benefit from controlling their usage and conserving.

Q. Does the Company propose to reconcile the RNA collections or credits in future time periods?

A. Yes. Collections will be tracked and credited or charged in the next corresponding Peak or Off-Peak RNA Filing.

Q. Has the Company proposed any changes to the calculation of quarterly Rider USP as a result of the proposed RNA?

A. No. Because Columbia's proposed RNA does not apply to CAP customers, changes to Rider USP are not needed.

Q. Why not apply the RNA to CAP customers?

A. CAP customers' payments are defined by their ability to pay. Incorporating a charge or credit related to RNA would ultimately flow into the Rider USP charge. Columbia concluded that would add unnecessary complexity to the RNA.

VII. Other

Q. Did you prepare any other calculations?

A. Yes. I prepared the Gas Procurement Charge calculation as detailed in Exhibit KLJ-6.

Q. Did you propose making an adjustment to the Gas Procurement Charge?

A. No. Exhibit KLJ-6 shows the calculation of the Gas Procurement Charge in the 2021 Rate Case. Similar to the 2022 Rate Case, since the overall fundamentals of the Gas Procurement process did not change, the Company elected not to change the Gas Procurement Charge, but instead keep it at the 2021 calculated rate of $0.00113 per/therm.

Q. Did you make any adjustments to the Company's State Tax Adjustment Surcharge ("STAS")?

A. The STAS was reset to $0 in the Company's FPFTY.

Q. Does this complete your Prepared Direct Testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Direct Assignment

"Direct Assignment" refers to a specific identification and isolation of plant and/or expenses based on Columbia's accounting records and incurred exclusively to serve a specific customer or group of customers. Instances of the use of direct assignments in the study can be identified by the omission of an allocation factor number (generally in column c) and the use of the term "direct" immediately after the account number. The operative principle is to utilize direct assignment of plant and expenses wherever practicable and to allocate when accounting records do not indicate class categorization.

Factor No. 1 - Design Day

The quantities contained in Factor No. 1 represent the total demand projected to occur at Columbia's design peak day. See Exhibit KLJ-2, Page 1.

Factor No. 2- Throughput Excluding Transportation

Throughput quantities, excluding transportation, for the twelve months ending December 31, 2025, are the basis for Factor No. 2. See Exhibit KLJ-2, Page 2.

Factor No. 3- Throughput Excluding MDS

Factor No. 3 represents the throughput quantities excluding MDS quantities for the twelve months ending December 31, 2025. See Exhibit KLJ-2, Page 2.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 4- Gas Purchase Expense

Factor No. 4 is based on gas cost assigned to each rate schedule for the twelve months ending December 31, 2025 using the applicable Gas Cost Recovery ("GCR") rates. See Exhibit KLJ-2, Page 3.

Factor No. 5 - Composite of Factors No. 1 and Throughput

Factor No. 5 combines design day quantities included in Factor No. 1 and throughput quantities for the historic test year ended November 30, 2023 to produce a composite Factor No. 5. Factor No. 5 was used to allocate mains and mains related accounts for the Peak and Average Study. Please see Exhibit KLJ-2 Page 4 for the detail development of Factor No. 5.

Factor No. 6 - Average Number of Customers

Customers for each month of the twelve months ending December 31, 2025 were averaged and used to develop Factor No. 6. See Exhibit KLJ-2, Page 5.

Factor No. 7 – Current DIS Revenue

Factor No. 7 reflects gross charge-offs recorded during the twelve months ending November 30, 2023 to small usage customers through the Company's Distributive Information System ("DIS"). See Exhibit KLJ-2, Page 6.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 8 – Current GMB/GTS

Factor No. 8 reflects revenue to be billed during the twelve months ending December 31, 2025 to larger sales usage and transportation customers through the Company's Gas Measurement Billing and General Transportation Systems. See Exhibit KLJ-2, Page 7.

Factor No. 9 – Customer Deposits

Factor No. 9 represents customer security deposits collected from customers by class as of November 30, 2023. See Exhibit KLJ-2, Page 8.

Factor No. 10 - Forfeited Discounts

Factor No. 10 is based on the amount of forfeited discounts billed to customers during the twelve months ended November 30, 2023. See Exhibit KLJ-2, Page 9.

Factor No. 11 - Distribution Plant Excluding Other

Factor No. 11 ratios are based on the spread of distribution plant dollars, excluding gas plant accounts 375.70, 375.71, and 387, to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 11. See Exhibit KLJ-2, Page 10.

Factor No. 12 - Gross Plant

Factor No. 12 ratios are based on the spread of total plant dollars to the customer groups resulting from the application of the various allocation factors to each gas plant

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 12. See Exhibit KLJ-2, Page 13.

Factor No. 13 – Mains – Account 376

Factor No. 13 reflects the relationship based on the spread of dollars in account 376 Mains among all customer classes that resulted from allocating the Mains using composite Factor No. 5 for the Demand-Commodity Study and Factor No. 20 for the Customer-Demand Study for classes that could not be directly assigned. The dollars are aggregated and reduced to percentages to produce Factor No. 13. See Exhibit KLJ-2, Page 14.

Factor No. 14 – Composite Direct Plant – Accts 376 & 380

Factor No. 14 reflects the relationship based on the spread of dollars in accounts 376 Mains and 380 Services among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account are aggregated and reduced to percentages to produce Factor No. 14. See Exhibit KLJ-2, Page 15.

Factor No. 15 – Direct Assignment - Services

Factor No. 15 – reflects Services – Account 380 assigned by rate schedule based on an actual assignment of services installed on customers' premises. Individual customer services were identified by size kind from DIS and accumulated by customer class and rate schedule. Based on the historic test year per book data, average unit prices by service size were developed from the data and applied to the number of services under each rate schedule. The resulting values, by rate schedule were converted to

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

percentages and used to allocate service investment and related expenses. See Exhibit KLJ-2, Page 18.

Factor No. 16 – Direct Assignment – Meters

Meters were assigned to the various classes of customers based on meters installed on customers' premises. Columbia recognizes four separate pressure groups for meters. Each varies in cost as the size changes. Individually installed meters as identified in DIS were summarized by the four pressure groups. The capitalized property investment, as identified on the Company's books and records for the four pressure groups, was divided by the number of installed meters as reflected on the Company's books and records to develop a cost per meter for each group of meters. The costs per meter were multiplied by the identified installed meters in DIS to determine the investment for each customer class. The percentages were developed for account 381 and used for assigning account 381 Meters as well as the investment in account 382 Meter Installations since these costs are incurred in direct relation with meters. See Exhibit KLJ-2, Page 19.

Factor No. 17 – Direct Assignment - Ind M&R

Individual measuring stations are identified in DIS by customer by station number and Columbia's plant records by station number. The investments were aggregated by rate schedule and reduced to percentages to produce Factor No. 17. See Exhibit KLJ-2 Page 28.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 18 - Other Distribution Expense

Factor No. 18 is based on the spread of dollars to the various classes of customers within the following distribution expense accounts:

Page 7 - Distribution Expense Allocation

Line 19 Account 871 - Distribution Load Dispatch

Line 20 Account 874 - Mains & Services

Line 21 Account 875 - M & R - General

Line 22 Account 876 - M & R - Industrial

Line 23 Account 878 - Meters & House Regulators

Line 24 Account 879 - Customer Installation

Line 29 Account 886 - Structures & Improvements

Line 30 Account 887 - Mains

Line 31 Account 889 - M & R - General

Line 32 Account 890 - M & R - Industrial

Line 33 Account 892 - Services

Line 34 Account 893 - Meters & House Regulators

See Exhibit KLJ-2, Page 29.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 19 – O&M Excl Gas Pur, Uncollectibles, & A&G

Factor No. 19 is based on total Operating and Maintenance Expenses (Page 8, Line 37) less Gas Purchased Cost (Page 7, Line 1), Uncollectibles (Page 8, Lines 5, 6, 7, 9, & 10), USP Rider (Page 8, Line 8) and A&G Expenses (Page 8, Line 36). See Exhibit KLJ-2, Page 30.

Factor No. 20 Minimum System Mains

Factor No. 20 is a composite using customers and design day quantities to allocate mains. The development of the factor is presented on Exhibit KLJ-2, Page 31.

A minimum 2" system approach is used to determine the customer related cost component of mains. The concept is based on the assumption that in order for a customer to obtain service, mains of at least the most common, minimum size in the distribution system must be present. That portion of the Mains Account investment is considered customer-related and is computed by multiplying the total pipe quantity in the system by the cost per foot for the most prevalent size of mains, that being two inch. The cost of the minimum system, computed in that manner, is divided by the total cost of all mains to arrive at a Customer Component factor. The reciprocal of the Customer Component factor becomes the Demand Component factor and is used to allocate the remaining mains costs which are considered demand related and allocated using the appropriate design day factor.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 21 – House Regulators

Factor No. 21 is based on the bill counts for all customers that are not served by low pressure lines. These counts are segregated by customer class and converted to percentages to create Factor No. 21 and used for assigning account 383 House Regulators as well as the investment in account 384 House Regulator Installations since these costs are incurred in direct relation with House Regulators. See Exhibit KLJ-2, Page 32.

Factor No. 22 –Average Factor Nos. 5 & 20

Factor No. 22 is based on the average of Factor Nos. 5 and 20 on an equal basis and is used to average the Customer-Demand Study and the Peak and Average Study. See Exhibit KLJ-2, Page 33.

Factor No. 23 – Meters and House Regulators

Factor No. 23 reflects the relationship based on the spread of dollars in accounts 381 Meters, 381.10 Automatic Meter Reading, 382 Meter Installations, 383 House Regulators, and 384 House Regulator Installations (Page 3, Lines 34 through 39) among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account are aggregated and reduced to percentages to produce Factor No. 23. See Exhibit KLJ-2, Page 34.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 24 - Labor

Factor No. 24 is based on the allocation of labor charges with the various Federal Energy Regulatory Committee ("FERC") Accounts. The labor dollars allocated to the various rate classes are summed and converted to percentages to create Factor No. 24. See Exhibit KLJ-2, Page 35.

Factor No. 25 – Sales and CHOICE Transportation

Factor No. 25 is based on the sales and CHOICE transportation activity for the twelve months ending December 31, 2025. See Exhibit KLJ-2, Page 2.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 1
DESIGN DAY [1] (2023-2024)

LINE NO.	Rate	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX	Total
	Residential							
1	RS	326,100	0	0	0	0	0	326,100
2	RC2	31,100	0	0	0	0	0	31,100
3	RTC	92,200	0	0	0	0	0	92,200
	Commercial							
4	LDS/LGSS	0	0	0	0	14,700	0	14,700
5	LDS FLEX	0	0	0	0	0	15,100	15,100
6	SDS/LGSS	0	0	0	45,600	0	0	45,600
7	SGS2	0	0	58,200	0	0	0	58,200
8	SGS1	0	61,100	0	0	0	0	61,100
9	SGDS1 FLEX	0	0	0	0	0	200	200
10	SCD1	0	18,500	0	0	0	0	18,500
11	SCD2	0	0	20,000	0	0	0	20,000
12	SGDS1	0	3,000	0	0	0	0	3,000
13	SGDS2	0	0	29,700	0	0	0	29,700
14	SGDS2 FLEX	0	0	0	0	0	100	100
	Industrial							
15	LDS/LGSS	0	0	0	0	39,300	0	39,300
16	LDS FLEX	0	0	0	0	0	26,300	26,300
17	SDS/LGSS	0	0	0	10,400	0	0	10,400
18	SGS2	0	0	700	0	0	0	700
19	SGDS2	0	0	700	0	0	0	700
20	Total	449,400	82,600	109,300	56,000	54,000	41,700	793,000
21	MLDS							23,000
22	Other (Co. Used)							1,500
23	Total							817,500
24	**ALLOCATOR #1**	**56.670%**	**10.416%**	**13.783%**	**7.062%**	**6.810%**	**5.259%**	**100.000%**

[1] Includes Firm and Non-Firm Service. Volumes in MDth/Day.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS 2, 3, & 25
THROUGHPUT EXCLUDING TRANSPORTATION, THROUGHPUT EXCLUDING MLDS

LINE NO.		RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX	TOTAL
	Sales								
1	RSS	27,607,392	-	-	-	-	-	-	27,607,392
2	RDGSS	-	-	-	-	-	-	-	-
3	RC2 1/	2,701,478	-	-	-	-	-	-	2,701,478
4	SGSS1	-	4,173,031	-	-	-	-	-	4,173,031
5	SGSS2	-	-	4,167,949	-	-	-	-	4,167,949
6	NSS/MLSS-1	-	-	-	-	-	68,000	-	68,000
7	LGSS1 & 2	-	-	-	1,131,331		-	-	1,131,331
8	LGSS3 & greater	-	-	-	-	30,826	-	-	30,826
	Transportation								
9	RDS	3,782,137	-	-	-	-	-	-	3,782,137
10	RDGDS	-	-	-	-	-	-	-	-
11	SCD1	-	1,242,516	-	-	-	-	-	1,242,516
12	SCD2	-	-	1,696,556	-	-	-	-	1,696,556
13	SGDS1	-	209,051	-	-	-	-	-	209,051
14	SGDS2	-	-	2,934,306	-	-	-	-	2,934,306
15	SDS	-	-	-	6,299,377	-	-	-	6,299,377
16	LDS	-	-	-	-	11,464,785	-	-	11,464,785
17	FLEX							8,941,200	8,941,200
18	MLDS	-	-	-	-	-	5,639,000	-	5,639,000
19	Total Throughput Excl. Trans. (Allocator 2)	30,308,871	4,173,031	4,167,949	1,131,331	30,826	68,000	-	39,880,008
20	**ALLOCATOR #2**	76.000%	10.464%	10.451%	2.837%	0.077%	0.171%	0.000%	
21	Total Throughput Excl. MLDS (Allocator 3)	34,091,008	5,624,598	8,798,811	7,430,707	11,495,611		8,941,200	76,381,935
22	**ALLOCATOR # 3**	44.633%	7.364%	11.519%	9.728%	15.050%		11.706%	
23	**Sales and Choice Volume**	34,091,008	5,415,547	5,864,505	1,131,331	30,826	68,000	-	46,601,217
24	**ALLOCATOR #25**	73.155%	11.621%	12.584%	2.428%	0.066%	0.146%	0.000%	

NOTE: **1/ RC2 rate schedule is for CAP customers. They can be either CHOICE or Sales.**

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 4
GAS PURCHASE EXPENSE

LINE NO.		RSS/RDS GAS COST	SGS/DS-1 GAS COST	SGS/DS-2 GAS COST	SDS/LGSS GAS COST	LDS/LGSS GAS COST	MLDS GAS COST	FLEX GAS COST	TOTAL
1	RSS	113,353,192	-	-			-	-	113,353,192
2	RC2	11,092,000	-	-			-	-	11,092,000
3	RDS	6,161,102	-	-			-	-	6,161,102
4	SGSS	-	17,134,047	17,113,183			-	-	34,247,230
5	NSS	-	-	-			286,559	-	286,559
6	SCD	-	2,024,059	2,763,689			-	-	4,787,748
7	SGDS	-	79,405	1,033,232			-	-	1,112,637
8	LGS	-	-	-	4,645,130	126,570	-	-	4,771,700
9	TOTAL	130,606,294	19,237,511	20,910,104	4,645,130	126,570	286,559	-	175,812,168
10	**ALLOCATOR #4**	74.288%	10.942%	11.893%	2.642%	0.072%	0.163%	0.000%	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2023

ALLOCATED COST OF SERVICE — PAGE 1
PEAK & AVERAGE — WITNESS: K. L. Johnson

Line No.	Description	Alloc	Total Company	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX
1	Throughput Volumes (Total Company excl MLDS)		76,381,935	34,091,008	5,624,598	8,798,811	7,430,707	11,495,611	8,941,200
2	Percent Throughput		100.000%	44.633%	7.364%	11.519%	9.728%	15.050%	11.706%
3	Throughput Component		50.000%	22.316%	3.682%	5.760%	4.864%	7.525%	5.853%
4	Design Day Volumes (Total Company excl MLDS)		793,000	449,400	82,600	109,300	56,000	54,000	41,700
5	Percent Design Day Volumes		100.000%	56.670%	10.416%	13.783%	7.062%	6.810%	5.259%
6	Demand Component		50.000%	28.334%	5.208%	6.892%	3.531%	3.405%	2.630%
7	Demand/Commodity Factor		100.000%	50.650%	8.890%	12.652%	8.395%	10.930%	8.483%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 6
AVERAGE NO. OF CUSTOMERS

LINE NO.	TARIFF RATE SCHEDULES	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX	[1] Total No of Bills (Incl Final)	Final Bills
1	RSS	4,090,342	0	0	0	0	0	0	4,148,557	58,215
2	RC2	292,322	0	0	0	0	0	0	296,625	4,303
3	RDS	528,229	0	0	0	0	0	0	532,015	3,786
4	RDGDS	0	0	0	0	0	0	0	0	0
5	SGSS1	0	281,106	0	0	0	0	0	283,018	1,912
6	SGSS2	0	0	33,070	0	0	0	0	33,174	104
7	NSS	0	0	0	0	0	12	0	12	0
8	SCD1	0	85,642	0	0	0	0	0	85,914	272
9	SCD2	0	0	15,110	0	0	0	0	15,131	21
10	SGDS1	0	9,874	0	0	0	0	0	9,900	26
11	SGDS2	0	0	16,317	0	0	0	0	16,356	39
12	LGSS1 & 2	0	0	0	960	0	0	0	962	2
13	LGSS3 & greater	0	0	0	0	36	0	0	36	0
14	SDS	0	0	0	4,656	0	0	0	4,665	9
15	LDS	0	0	0	0	924	0	0	925	1
16	FLEX	0	0	0	0	0	0	144	144	0
17	MLDS	0	0	0	0	0	108	0	110	2
18	Total Number of Bills	4,910,893	376,622	64,497	5,616	960	120	144	5,427,544	68,692
19	Average Number of Customers	409,241	31,385	5,375	468	80	10	12		
20	**ALLOCATOR #6**	91.640%	7.028%	1.204%	0.105%	0.018%	0.002%	0.003%		

[1] Used only in the Customer Charge calculation.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 7
CURRENT DIS REVENUE

LINE NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
		Total	Residential	Commercial					
1	DIS Billed Net Charge-offs - Sales Only	10,799,719.38	10,149,216.71	650,502.67					
2	DIS Billed Revenue - Comm/Ind Sales Only	97,384,511		54,719,180	42,665,331	0	0	0	0
3	Percent	100.000%		56.189%	43.811%	0.000%	0.000%	0.000%	0.000%
4	Allocated DIS Billed Sales Net Charge-offs	10,799,719.38	10,149,216.71	365,510.95	284,991.72	0.00	0.00	0.00	0.00
		Total	Residential	Commercial					
5	DIS Billed Net Charge-offs - Choice Only	668,755.37	572,369.64	96,385.73					
6	DIS Billed Revenue - Comm/Ind Choice Only	47,602,094		15,062,865	32,539,229	0	0	0	0
7	Percent	100.000%		31.643%	68.357%	0.000%	0.000%	0.000%	0.000%
8	Allocated DIS Billed Choice Net Charge-offs	668,755.37	572,369.64	30,499.34	65,886.39	0.00	0.00	0.00	0.00
9	Total DIS Billed Net Charge-offs	11,468,474.75	10,721,586.35	396,010.29	350,878.11	0.00	0.00	0.00	0.00
10	**ALLOCATOR #7**	100.000%	93.487%	3.453%	3.060%	0.000%	0.000%	0.000%	0.000%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 8
CURRENT GMB/GTS REVENUE

LINE NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	CURRENT GMB/GTS REVENUE	69,564,912	-	72,371	1,517,244	35,388,525	27,336,389	2,109,812	3,140,571
2	**ALLOCATOR #8**	100.000%	0.000%	0.104%	2.181%	50.871%	39.296%	3.033%	4.515%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 9
DIRECT ASSIGNMENT - CUSTOMER DEPOSITS

LINE NO.		RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	TOTAL
1	Residential Unlisted	29,218	-	-	-	-	29,218
2	RS	2,163,447	-	-	-	-	2,163,447
3	RTC	173,799	-	-	-	-	173,799
4	Commercial Unlisted	-	27,280	-	-	-	27,280
5	SCC	-	48,072	-	-	-	48,072
6	LG1	-	-	-	24,526		24,526
7	SC2	-	-	20,050	-	-	20,050
8	SGS	-	938,011	-	-	-	938,011
9	SGT	-	27,420	-	-	-	27,420
10	SG2	-	-	259,510	-	-	259,510
11	Industrial Unlisted	-	-	-	404	-	404
12	SG3		1,012	-	-	-	1,012
13	TOTAL	2,366,464	1,041,795	279,560	24,930	-	3,712,749
14	**ALLOCATOR #9**	63.73900%	28.060%	7.530%	0.671%	0.000%	100.000%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 10
FORFEITED DISCOUNTS

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	487.00	FORFEITED DISCOUNTS - DIS	1,207,829	952,867	117,862	127,021	10,079	-	-	-
2	487.00	FORFEITED DISCOUNTS - GMB & GTS	117,494	-	122	2,563	59,771	46,171	3,563	5,304
3		TOTAL CURRENT SALES AND TRANSPORTATION REVENUE	1,325,323	952,867	117,984	129,584	69,850	46,171	3,563	5,304
4		**ALLOCATOR #10**	100.000%	71.897%	8.902%	9.778%	5.270%	3.484%	0.269%	0.400%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 11
DISTRIBUTION PLANT EXCLUDING ACCOUNTS 375.70, 375.71, & 387

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	374.10	LAND - CITY GATE & M/L IND M&R	21,944	11,114	1,951	2,776	1,842	2,398	-	1,862
2	374.20	LAND - OTHER DISTRIBUTION	3,361,035	1,702,364	298,796	425,238	282,159	367,361	-	285,117
3	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	48,300	8,478	12,065	8,006	10,423	-	8,090
4	374.40	LAND RIGHTS - OTHER DISTRIBUTION	8,454,020	4,281,961	751,562	1,069,603	709,715	924,024	-	717,155
5	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	-	-	-	-	-	-	-	-
6	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	13	7	1	2	1	1	-	1
7	374.50	RIGHTS OF WAY	3,233,025	1,637,527	287,416	409,042	271,412	353,370	-	274,258
8	374.50	DIRECT - RIGHTS OF WAY	-	-	-	-	-	-	-	-
9	375.20	M & R STRUCTURES - CITY GATE	7,026	3,559	625	889	590	768	-	596
10	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	2,032	357	508	337	439	-	340
11	375.40	M & R STRUCTURES - REGULATING	7,621,679	3,860,381	677,567	964,295	639,840	833,050	-	646,547
12	375.40	DIRECT - M & R STRUCTURES - REGULATING	27,126	-	-	-	-	-	24,324	2,802
13	375.60	M & R STRUCTURES - DIST. IND. M & R	86,084	0	730	15,539	25,081	33,969	-	10,765
14	375.80	M & R STRUCTURES - COMMUNICATION	16,515	8,365	1,468	2,090	1,386	1,805	-	1,401
15	376.00	MAINS	3,157,128,150	1,599,085,408	280,668,693	399,439,854	265,040,908	345,074,107	-	267,819,181
16	376.00	DIRECT - MAINS - MLDS	141,149	-	-	-	-	-	141,149	-
17	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,910,591	2,090,526	2,975,179	1,974,125	2,570,242	-	1,994,818
18	376.30	MAINS-BARE STEEL	36,427,802	18,450,682	3,238,432	4,608,846	3,058,114	3,981,559	-	3,090,171
19	376.30	DIRECT - MAINS-BARE STEEL	79,653	-	-	-	-	-	79,653	-
20	376.80	MAINS-CAST IRON	12,012	6,084	1,068	1,520	1,008	1,313	-	1,019
21	378.10	M & R EQUIP - GENERAL	1,442,966	730,862	128,280	182,564	121,137	157,716	-	122,407
22	378.20	M & R EQUIP - GENERAL - REGULATING	236,209,453	119,640,088	20,999,020	29,885,220	19,829,784	25,817,693	-	20,037,648
23	378.20	DIRECT - M & R EQUIP-GEN-REG	678,970	-	-	-	-	-	-	678,970
24	378.30	M & R EQUIP - LOCAL GAS PURCHASES	406,758	206,023	36,161	51,463	34,147	44,459	-	34,505
25	379.10	M & R EQUIP - CITY GATE	120,061	60,811	10,673	15,190	10,079	13,123	-	10,185
26	379.11	M & R EQUIP - EXCHANGE GAS	(903)	(457)	(80)	(114)	(76)	(99)	-	(77)
27	380.00	SERVICES	971,688,540	886,500,606	69,174,507	13,040,060	2,089,130	592,730	-	291,507
28	380.00	DIRECT - SERVICES	1,554	-	-	-	-	-	561	993
29	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
30	381.00	METERS	48,647,043	37,965,612	6,928,798	3,339,133	317,665	79,781	7,297	8,757
31	381.00	DIRECT - METERS - MLDS FLEX	16,319	-	-	-	-	-	-	16,319
32	381.10	AUTOMATIC METER READING	25,165,055	19,639,564	3,584,259	1,727,329	164,328	41,271	3,775	4,530
33	382.00	METER INSTALLATIONS	50,934,022	39,750,439	7,254,533	3,496,111	332,599	83,532	7,640	9,168
34	383.00	HOUSE REGULATORS	20,531,392	18,784,171	1,416,050	293,599	30,592	5,133	821	1,027
35	384.00	HOUSE REG INSTALLATIONS	3,538,803	3,237,651	244,071	50,605	5,273	885	142	177
36	385.00	IND M&R EQUIPMENT	8,401,123	-	71,242	1,516,487	2,447,751	3,315,083	-	1,050,560
37	385.00	DIRECT - IND M&R EQUIPMENT	486,902	-	-	-	-	-	486,902	-
38	385.10	IND M&R EQUIPMENT - LG VOLUME	995,901	-	8,445	179,770	290,166	392,982	-	124,537
39		TOTAL	4,609,496,046	2,767,523,743	397,883,628	463,704,861	297,687,100	384,699,117	752,264	297,245,333
40		**ALLOCATOR #11**	100.000%	60.039%	8.632%	10.060%	6.458%	8.346%	0.016%	6.449%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	301.00	Organizational Costs	100,099							
2	302.21	Franchises/Consent, Perpetual	26,216							
3	303.00	Misc Intangible Plant	4,809,062							
4	303.30	Misc Software	82,305,348							
5	305.00	Structures & Improvements	0							
6	301-303	TOTAL INTANGIBLE PLANT	87,240,726	52,378,459	7,530,620	8,776,417	5,634,006	7,281,111	13,959	5,626,154
7	350.10	Land	23,882							
8	350.20	Rights of Way	1,932							
9	351.20	Compressor Station Structures	3,294,840							
10	352.01	Wells Construction	1,126,772							
11	352.02	Wells Equipment	1,072,970							
12	352.10	Storage Leasehold and Rights	139,442							
13	352.12	Other Leases	67,498							
14	353.00	Lines	387,525							
15	354.00	Compressor Station Equipment	947,638							
16	355.00	Measuring & Regulating Equipment	104,477							
17	362.00	Gas Holders	0							
18	362.10	Environmental Remediation	0							
19	350-362	TOTAL UNDERGROUND STORAGE	7,166,976	5,243,001	832,874	901,892	174,014	4,730	10,464	0
20	374.10	LAND - CITY GATE & M/L IND M&R	21,944	11,114	1,951	2,776	1,842	2,398	0	1,862
21	374.20	LAND - OTHER DISTRIBUTION	3,361,035	1,702,364	298,796	425,238	282,159	367,361	0	285,117
22	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	48,300	8,478	12,065	8,006	10,423	0	8,090
23	374.40	LAND RIGHTS - OTHER DISTRIBUTION	8,454,020	4,281,961	751,562	1,069,603	709,715	924,024	0	717,155
24	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	0	0	0	0	0	0	0	0
25	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	13	7	1	2	1	1	0	1
26	374.50	RIGHTS OF WAY	3,233,025	1,637,527	287,416	409,042	271,412	353,370	0	274,258
27	374.50	DIRECT - RIGHTS OF WAY	0	0	0	0	0	0	0	0
28	375.20	M & R STRUCTURES - CITY GATE	7,026	3,559	625	889	590	768	0	596
29	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	2,032	357	508	337	439	0	340
30	375.40	M & R STRUCTURES - REGULATING	7,621,679	3,860,381	677,567	964,295	639,840	833,050	0	646,547
31	375.40	DIRECT - M & R STRUCTURES - REGULATING	27,126	0	0	0	0	0	24,324	2,802
32	375.60	M & R STRUCTURES - DIST. IND. M & R	86,084	0	730	15,539	25,081	33,969	0	10,765
33	375.70	M & R STRUCTURES - OTHER	50,689,408	30,433,414	4,375,510	5,099,354	3,273,522	4,230,538	8,110	3,268,960
34	375.71	M & R STRUCTURES - OTHER LEASED	6,386,140	3,834,174	551,252	642,446	412,417	532,987	1,022	411,842
35	375.80	M & R STRUCTURES - COMMUNICATION	16,515	8,365	1,468	2,090	1,386	1,805	0	1,401
36	376.00	MAINS	3,157,128,150	1,599,085,408	280,668,693	399,439,854	265,040,908	345,074,107	0	267,819,181
37	376.00	DIRECT - MAINS - MLDS	141,149	0	0	0	0	0	141,149	0
38	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,910,591	2,090,526	2,975,179	1,974,125	2,570,242	0	1,994,818

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
		DISTRIBUTION PLANT								
1	376.30	MAINS-BARE STEEL	36,427,802	18,450,682	3,238,432	4,608,846	3,058,114	3,981,559	0	3,090,171
2	376.30	DIRECT - MAINS-BARE STEEL	79,653	0	0	0	0	0	79,653	0
3	376.80	MAINS-CAST IRON	12,012	6,084	1,068	1,520	1,008	1,313	0	1,019
4	378.10	M & R EQUIP - GENERAL	1,442,966	730,862	128,280	182,564	121,137	157,716	0	122,407
5	378.20	M & R EQUIP - GENERAL - REGULATING	236,209,453	119,640,088	20,999,020	29,885,220	19,829,784	25,817,693	0	20,037,648
6	378.20	DIRECT - M & R EQUIP-GEN-REG	678,970	0	0	0	0	0	0	678,970
7	378.30	M & R EQUIP - LOCAL GAS PURCHASES	406,758	206,023	36,161	51,463	34,147	44,459	0	34,505
8	379.10	M & R EQUIP - CITY GATE	120,061	60,811	10,673	15,190	10,079	13,123	0	10,185
9	379.11	M & R EQUIP - EXCHANGE GAS	(903)	(457)	(80)	(114)	(76)	(99)	0	(77)
10	380.00	SERVICES	971,688,540	886,500,606	69,174,507	13,040,060	2,089,130	592,730	0	291,507
11	380.00	DIRECT - SERVICES	1,554	0	0	0	0	0	561	993
12	380.12	CSL REPLACEMENT	0	0	0	0	0	0	0	0
13	381.00	METERS	48,647,043	37,965,612	6,928,798	3,339,133	317,665	79,781	7,297	8,757
14	381.00	DIRECT - METERS - MLDS FLEX	16,319	0	0	0	0	0	0	16,319
15	381.10	AUTOMATIC METER READING	25,165,055	19,639,564	3,584,259	1,727,329	164,328	41,271	3,775	4,530
16	382.00	METER INSTALLATIONS	50,934,022	39,750,439	7,254,533	3,496,111	332,599	83,532	7,640	9,168
17	383.00	HOUSE REGULATORS	20,531,392	18,784,171	1,416,050	293,599	30,592	5,133	821	1,027
18	384.00	HOUSE REG INSTALLATIONS	3,538,803	3,237,651	244,071	50,605	5,273	885	142	177
19	385.00	IND M&R EQUIPMENT	8,401,123	0	71,242	1,516,487	2,447,751	3,315,083	0	1,050,560
20	385.00	DIRECT - IND M&R EQUIPMENT	486,902	0	0	0	0	0	486,902	0
21	385.10	IND M&R EQUIPMENT - LG VOLUME	995,901	0	8,445	179,770	290,166	392,982	0	124,537
22	387.10	OTHER EQUIP DISTRIBUTION	19,450	11,678	1,679	1,957	1,256	1,623	3	1,254
23	387.20	OTHER EQUIP ODORIZATION	117,248	70,394	10,121	11,795	7,572	9,786	19	7,561
24	387.42	OTHER EQUIP RADIO	119,609	71,812	10,325	12,033	7,724	9,983	19	7,714
25	387.44	OTHER EQUIP COMMUNICATION	566,537	340,143	48,904	56,994	36,587	47,283	91	36,536
26	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	15,294,665	9,182,764	1,320,236	1,538,643	987,730	1,276,493	2,447	986,353
27	387.45	DIRECT - OTHER EQUIP CUSTOMER INFO SER	69,585	0	0	0	0	0	69,585	0
28	387.50	GPS EQUIPMENT	2,201,372	1,321,682	190,022	221,458	142,165	183,727	352	141,967
29	374-387	TOTAL DISTRIBUTION	4,684,960,060	2,812,789,804	404,391,675	471,289,540	302,556,072	390,991,536	833,913	302,107,520

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
		GENERAL PLANT								
1	389.20	Land Rights	0							
2	390.10	Str, Communications	49,821							
3	391.10	OF&E Unspecified	3,674,992							
4	391.11	OF&E Data Handling Equipment	91,304							
5	391.12	OF&E Information Systems	126,594							
6	391.20	OF&E Air Cond Equip	0							
7	392.20	Trans Eq Trailers > $1,000	14,787							
8	392.21	Trans Eq Trailers $1,000 or >	10,830							
9	393.00	Stores Equipment	0							
10	394.10	Tools, Garage & Service Eq	395,117							
11	394.11	CNG Equip - Stationary	18,450							
12	394.12	CNG Equip - Portable	0							
13	394.20	Shop Equipment	0							
14	394.30	Tools & Other	24,897,294							
15	394.31	High Pressure Stopping	10,847							
16	395.00	Laboratory Equipment, Gas	264,921							
17	396.00	Power Operated Equipment	948,698							
18	397.00	Communication Equipment	0							
19	397.10	Communication Equipment-Telephone	0							
20	397.20	Communication Equipment-Radio	0							
21	397.40	Communication Equipment-Other	0							
22	397.50	Communication Equipment-Telemetering	4,290,323							
23	398.00	Miscellaneous Equipment	990,093							
24	389-398	TOTAL GENERAL PLANT	35,784,071	21,484,399	3,088,881	3,599,878	2,310,935	2,986,539	5,726	2,307,715
25		TOTAL	4,815,151,834	2,891,895,663	415,844,050	484,567,727	310,675,028	401,263,916	864,060	310,041,389
		ALLOCATOR #12		60.059%	8.636%	10.063%	6.452%	8.333%	0.018%	6.439%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 13
DIRECT PLANT - MAINS

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	376.00	MAINS	3,157,128,150	1,599,085,408	280,668,693	399,439,854	265,040,908	345,074,107	-	267,819,181
2	376.00	DIRECT - MAINS - MLDS	141,149	-	-	-	-	-	141,149	-
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,910,591	2,090,526	2,975,179	1,974,125	2,570,242	-	1,994,818
4	376.30	MAINS-BARE STEEL	36,427,802	18,450,682	3,238,432	4,608,846	3,058,114	3,981,559	-	3,090,171
5	376.30	DIRECT - MAINS-BARE STEEI	79,653	-	-	-	-	-	79,653	-
6	376.80	MAINS-CAST IRON	12,012	6,084	1,068	1,520	1,008	1,313	-	1,019
7		TOTAL	3,217,304,248	1,629,452,766	285,998,718	407,025,398	270,074,155	351,627,221	220,802	272,905,189
		ALLOCATOR #13	100.000%	50.648%	8.889%	12.651%	8.394%	10.929%	0.007%	8.482%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 14
COMPOSITE DIRECT PLANT - ACCOUNTS 376 & 380

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	376.00	MAINS	3,157,128,150	1,599,085,408	280,668,693	399,439,854	265,040,908	345,074,107	-	267,819,181
2	376.00	DIRECT - MAINS - MLDS	141,149	-	-	-	-	-	141,149	-
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,910,591	2,090,526	2,975,179	1,974,125	2,570,242	-	1,994,818
4	376.30	MAINS-BARE STEEL	36,427,802	18,450,682	3,238,432	4,608,846	3,058,114	3,981,559	-	3,090,171
5	376.30	DIRECT - MAINS-BARE STEEL	79,653	-	-	-	-	-	79,653	-
6	376.80	MAINS-CAST IRON	12,012	6,084	1,068	1,520	1,008	1,313	-	1,019
7	380.00	SERVICES	971,688,540	886,500,606	69,174,507	13,040,060	2,089,130	592,730	-	291,507
8	380.00	DIRECT - SERVICES	1,554	-	-	-	-	-	561	993
9	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
10		TOTAL	4,188,994,343	2,515,953,371	355,173,226	420,065,458	272,163,286	352,219,951	221,363	273,197,689
11		**ALLOCATOR #14**	100.000%	60.061%	8.479%	10.028%	6.497%	8.408%	0.005%	6.522%

Columbia Gas of Pennsylvania, Inc.
Services Allocation Factor
As of November 30, 2023

Line No.	Billing Rate	Rate Case Rate	Classification	BLANK	P	S	*	+	Total	Average Unit Cost	Total Cost	Key
1	808	FLEX	4"	0	0	0	1	0	1	5,784.36	5,784.36	8084"
2	809	FLEX	6"	1	0	0	0	0	1	6,266.89	6,266.89	8096"
3	809	FLEX	8"	0	0	0	1	0	1	7,612.29	7,612.29	8098"
4	810	FLEX	4"	1	0	0	0	0	1	5,784.36	5,784.36	8104"
5	810	FLEX	6"	1	0	0	0	0	1	6,266.89	6,266.89	8106"
6	833	FLEX	8"	0	0	0	0	1	1	7,612.29	7,612.29	8338"
7	846	FLEX	UNDER 3"	0	0	0	1	0	1	1,805.98	1,805.98	846UNDER 3"
8	846	FLEX	6"	0	0	0	0	1	1	6,266.89	6,266.89	8466"
9	875	FLEX	6"	2	0	0	0	0	2	6,266.89	12,533.78	8756"
10	875	FLEX	8"	0	0	0	1	0	1	7,612.29	7,612.29	8758"
11	879	FLEX	UNDER 3"	1	0	0	0	0	1	1,805.98	1,805.98	879UNDER 3"
12	880	FLEX	12"	1	0	0	0	0	1	160,483.09	160,483.09	88012"
13	881	FLEX	4"	1	0	0	0	0	1	5,784.36	5,784.36	8814"
14	881	FLEX	UNDER 3"	1	0	0	0	0	1	1,805.98	1,805.98	881UNDER 3"
15	882	FLEX	UNDER 3"	0	0	0	1	0	1	1,805.98	1,805.98	882UNDER 3"
16	LG1	SDS/LGSS	3"	3	0	0	0	0	3	2,578.69	7,736.07	LG13"
17	LG1	SDS/LGSS	4"	4	0	1	2	0	7	5,784.36	40,490.52	LG14"
18	LG1	SDS/LGSS	6"	0	0	0	1	0	1	6,266.89	6,266.89	LG16"
19	LG1	SDS/LGSS	UNDER 3"	20	0	0	4	2	26	1,805.98	46,955.48	LG1UNDER 3"
20	LG2	SDS/LGSS	3"	3	0	0	2	0	5	2,578.69	12,893.45	LG23"
21	LG2	SDS/LGSS	4"	14	0	0	1	1	16	5,784.36	92,549.76	LG24"
22	LG2	SDS/LGSS	6"	2	0	0	0	0	2	6,266.89	12,533.78	LG26"
23	LG2	SDS/LGSS	UNDER 3"	29	0	1	2	1	33	1,805.98	59,597.34	LG2UNDER 3"
24	LG3	LDS/LGSS	UNDER 3"	2	0	0	0	0	2	1,805.98	3,611.96	LG3UNDER 3"
25	LG4	LDS/LGSS	6"	1	0	0	0	0	1	6,266.89	6,266.89	LG46"
26	NSI	MDS/NSS	3"	1	0	0	0	0	1	2,578.69	2,578.69	NSI3"
27	RC2	RSS/RTS	UNDER 3"	17,656	115	73	2,362	2,639	22,845	1,805.98	41,257,613.10	RC2UNDER 3"
28	RC2	RSS/RTS	3"	0	1	0	0	0	1	2,578.69	2,578.69	RC23"
29	RC2	RSS/RTS	4"	2	0	0	0	0	2	5,784.36	11,568.72	RC24"
30	RC2	RSS/RTS	6"	1	0	0	0	0	1	6,266.89	6,266.89	RC26"
31	RC2	RSS/RTS	8"	1	0	0	0	0	1	7,612.29	7,612.29	RC28"
32	RC2	RSS/RTS	10"	1	0	0	0	1	2	111.64	223.28	RC210"
33	RS	RSS/RTS	10"	2	0	0	0	1	3	111.64	334.92	RS10"
34	RS	RSS/RTS	11-1/8"	1	0	0	0	0	1	0.00	0.00	RS11-1/8"
35	RS	RSS/RTS	3"	13	0	0	3	38	54	2,578.69	139,249.26	RS3"
36	RS	RSS/RTS	4"	16	1	1	4	59	81	5,784.36	468,533.16	RS4"
37	RS	RSS/RTS	5"	2	0	0	0	0	2	138.55	277.10	RS5"
38	RS	RSS/RTS	6"	6	0	0	2	3	11	6,266.89	68,935.79	RS6"
39	RS	RSS/RTS	8"	5	0	0	0	0	5	7,612.29	38,061.46	RS8"
40	RS	RSS/RTS	UNDER 3"	277,034	1,511	1,294	21,487	32,140	333,466	1,805.98	602,232,926.68	RSUNDER 3"
41	RTC	RSS/RTS	3"	2	0	0	0	4	6	2,578.69	15,472.14	RTC3"
42	RTC	RSS/RTS	4"	2	0	0	0	4	6	5,784.36	34,706.16	RTC4"
43	RTC	RSS/RTS	UNDER 3"	43,581	195	167	2,247	2,616	48,806	1,805.98	88,142,659.88	RTCUNDER 3"
44	SC2	SGSS2/SCD2/SGDS2	3"	28	1	0	4	1	34	2,578.69	87,675.46	SC23"
45	SC2	SGSS2/SCD2/SGDS2	4"	34	0	0	1	2	37	5,784.36	214,021.32	SC24"
46	SC2	SGSS2/SCD2/SGDS2	6"	1	0	0	0	0	1	6,266.89	6,266.89	SC26"
47	SC2	SGSS2/SCD2/SGDS2	UNDER 3"	940	4	9	121	83	1,157	1,805.98	2,089,518.86	SC2UNDER 3"
48	SCC	SGSS1/SCD1/SGDS1	3"	14	0	0	4	14	32	2,578.69	82,518.08	SCC3"
49	SCC	SGSS1/SCD1/SGDS1	4"	16	0	0	2	4	22	5,784.36	127,255.92	SCC4"
50	SCC	SGSS1/SCD1/SGDS1	UNDER 3"	4,330	39	26	1,215	1,446	7,056	1,805.98	12,742,994.88	SCCUNDER 3"

Columbia Gas of Pennsylvania, Inc.
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51	SG2	SGSS2/SCD2/SGDS2	10"	1	0	0	0	0	1	111.64	111.64	SG210"
52	SG2	SGSS2/SCD2/SGDS2	12"	1	0	0	0	0	1	0.00	0.00	SG212"
53	SG2	SGSS2/SCD2/SGDS2	3"	45	0	0	11	5	61	2,578.69	157,300.09	SG23"
54	SG2	SGSS2/SCD2/SGDS2	4"	51	2	0	12	12	77	5,784.36	445,395.72	SG24"
55	SG2	SGSS2/SCD2/SGDS2	6"	7	0	0	5	2	14	6,266.89	87,736.46	SG26"
56	SG2	SGSS2/SCD2/SGDS2	8"	1	0	0	0	0	1	7,612.29	7,612.29	SG28"
57	SG2	SGSS2/SCD2/SGDS2	UNDER 3"	2,047	11	8	261	234	2,561	1,805.98	4,625,114.78	SG2UNDER 3"
58	SG3	SGSS1/SCD1/SGDS1	3"	3	0	0	0	0	3	2,578.69	7,736.07	SG33"
59	SG3	SGSS1/SCD1/SGDS1	4"	3	0	0	2	0	5	5,784.36	28,921.80	SG34"
60	SG3	SGSS1/SCD1/SGDS1	6"	0	0	0	1	0	1	6,266.89	6,266.89	SG36"
61	SG3	SGSS1/SCD1/SGDS1	UNDER 3"	18	1	0	2	0	21	1,805.98	37,925.58	SG3UNDER 3"
62	SG4	SGSS2/SCD2/SGDS2	3"	2	0	0	3	0	5	2,578.69	12,893.45	SG43"
63	SG4	SGSS2/SCD2/SGDS2	4"	1	0	0	1	0	2	5,784.36	11,568.72	SG44"
64	SG4	SGSS2/SCD2/SGDS2	6"	2	0	0	0	0	2	6,266.89	12,533.78	SG46"
65	SG4	SGSS2/SCD2/SGDS2	UNDER 3"	25	0	0	5	1	31	1,805.98	55,985.38	SG4UNDER 3"
66	SG4	SGSS2/SCD2/SGDS2	10"	1	0	0	0	0	1	111.64	111.64	SG410"
67	SGS	SGSS1/SCD1/SGDS1	16"	0	0	0	1	0	1	0.00	0.00	SGS16"
68	SGS	SGSS1/SCD1/SGDS1	3"	24	0	0	18	58	100	2,578.69	257,869.00	SGS3"
69	SGS	SGSS1/SCD1/SGDS1	4"	36	0	0	13	40	89	5,784.36	514,808.04	SGS4"
70	SGS	SGSS1/SCD1/SGDS1	5"	1	0	0	1	1	3	138.55	415.65	SGS5"
71	SGS	SGSS1/SCD1/SGDS1	6"	1	0	0	0	1	2	6,266.89	12,533.78	SGS6"
72	SGS	SGSS1/SCD1/SGDS1	UNDER 3"	12,711	103	72	4,333	5,845	23,064	1,805.98	41,653,122.72	SGSUNDER 3"
73	SGT	INACTIVE	3"	1	0	0	0	0	1	2,578.69	2,578.69	SGT3"
74	SGT	INACTIVE	4"	4	0	0	1	1	6	5,784.36	34,706.16	SGT4"
75	SGT	INACTIVE	UNDER 3"	17	0	0	3	0	20	1,805.98	36,119.60	SGTUNDER 3"
76	TAG1	SGSS1/SCD1/SGDS1	3"	2	0	0	0	1	3	2,578.69	7,736.07	TAG13"
77	TAG1	SGSS1/SCD1/SGDS1	UNDER 3"	111	0	0	34	22	167	1,805.98	301,598.66	TAG1UNDER 3"
78	TAG2	SGSS2/SCD2/SGDS2	3"	12	0	0	1	0	13	2,578.69	33,522.97	TAG23"
79	TAG2	SGSS2/SCD2/SGDS2	4"	16	0	0	2	1	19	5,784.36	109,902.84	TAG24"
80	TAG2	SGSS2/SCD2/SGDS2	6"	2	0	0	0	0	2	6,266.89	12,533.78	TAG26"
81	TAG2	SGSS2/SCD2/SGDS2	UNDER 3"	229	1	0	20	5	255	1,805.98	460,524.90	TAG2UNDER 3"
82	TAG5	SGSS1/SCD1/SGDS1	3"	2	0	0	1	5	8	2,578.69	20,629.52	TAG53"
83	TAG5	SGSS1/SCD1/SGDS1	4"	7	0	0	1	3	11	5,784.36	63,627.96	TAG54"
84	TAG5	SGSS1/SCD1/SGDS1	UNDER 3"	516	2	1	66	125	710	1,805.98	1,282,245.80	TAG5UNDER 3"
85	TAG6	SGSS2/SCD2/SGDS2	3"	42	0	0	2	0	44	2,578.69	113,462.36	TAG63"
86	TAG6	SGSS2/SCD2/SGDS2	4"	56	0	0	9	4	69	5,784.36	399,120.84	TAG64"
87	TAG6	SGSS2/SCD2/SGDS2	6"	5	0	0	1	0	6	6,266.89	37,601.34	TAG66"
88	TAG6	SGSS2/SCD2/SGDS2	UNDER 3"	863	7	3	76	44	993	1,805.98	1,793,338.14	TAG6UNDER 3"
89	TI4	SDS/LGSS	12"	1	0	0	0	0	1	160,483.09	160,483.09	TI412"
90	TI4	SDS/LGSS	3"	14	0	0	2	0	16	2,578.69	41,259.04	TI43"
91	TI4	SDS/LGSS	4"	27	0	0	2	0	29	5,784.36	167,746.44	TI44"
92	TI4	SDS/LGSS	6"	4	0	0	1	1	6	6,266.89	37,601.34	TI46"
93	TI4	SDS/LGSS	UNDER 3"	129	0	0	9	6	144	1,805.98	260,061.12	TI4UNDER 3"
94	TI8	LDS/LGSS	3"	7	0	0	0	0	7	2,578.69	18,050.83	TI83"
95	TI8	LDS/LGSS	4"	14	0	0	1	1	16	5,784.36	92,549.76	TI84"
96	TI8	LDS/LGSS	6"	2	0	0	0	0	2	6,266.89	12,533.78	TI86"
97	TI8	LDS/LGSS	8"	1	1	1	0	0	3	7,612.29	22,836.88	TI88"
98	TI8	LDS/LGSS	UNDER 3"	24	0	0	3	2	29	1,805.98	52,373.42	TI8UNDER 3"
99	TIB	SDS/LGSS	3"	23	0	0	3	1	27	2,578.69	69,624.63	TIB3"
100	TIB	SDS/LGSS	4"	57	1	0	9	1	68	5,784.36	393,336.48	TIB4"
101	TIB	SDS/LGSS	6"	3	0	0	2	1	6	6,266.89	37,601.34	TIB6"
102	TIB	SDS/LGSS	UNDER 3"	133	1	0	17	4	155	1,805.98	279,926.90	TIBUNDER 3"
103	TIF	LDS/LGSS	3"	6	0	0	0	0	6	2,578.69	15,472.14	TIF3"
104	TIF	LDS/LGSS	4"	15	0	0	1	1	17	5,784.36	98,334.12	TIF4"
105	TIF	LDS/LGSS	6"	6	0	0	0	0	6	6,266.89	37,601.34	TIF6"

Columbia Gas of Pennsylvania, Inc.
Services Allocation Factor
As of November 30, 2023

106	TIF	LDS/LGSS	8"	1	0	0	0	0	1	7,612.29	7,612.29	TIF8"
107	TIF	LDS/LGSS	UNDER 3"	49	1	1	3	1	55	1,805.98	99,328.90	TIFUNDER 3"
108	TIG	LDS/LGSS	3"	1	0	0	0	0	1	2,578.69	2,578.69	TIG3"
109	TIG	LDS/LGSS	4"	1	0	0	0	0	1	5,784.36	5,784.36	TIG4"
110	TIG	LDS/LGSS	8"	0	0	0	1	0	1	7,612.29	7,612.29	TIG8"
111	TIG	LDS/LGSS	UNDER 3"	2	0	0	0	0	2	1,805.98	3,611.96	TIGUNDER 3"
112	TIH	LDS/LGSS	6"	0	0	0	1	0	1	6,266.89	6,266.89	TIH6"
113	TM1	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,805.98	1,805.98	TM1UNDER 3"
114	TM3	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,805.98	1,805.98	TM3UNDER 3"
115	TM4	MDS/NSS	6"	1	0	0	0	0	1	6,266.89	6,266.89	TM46"
116	TM5	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,805.98	1,805.98	TM5UNDER 3"
117	TMB	MDS/NSS	3"	1	0	0	0	0	1	2,578.69	2,578.69	TMB3"
118	TMB	MDS/NSS	4"	1	0	0	0	0	1	5,784.36	5,784.36	TMB4"
119	TMB	MDS/NSS	6"	2	0	0	1	0	3	6,266.89	18,800.67	TMB6"
120	TMB	MDS/NSS	8"	1	0	0	1	1	3	7,612.29	22,836.88	TMB8"
121	UNKNOWN			2,267	12	13	488	1,169	3,949	UNKNOWN	UNKNOWN	UNKNOWN
122				363,438	2,010	1,671	32,900	46,660	446,679		802,945,069.74	
123	Check Total			0	0	0	0	0	0			

			Total Cost	Percent
124		**RSS/RTS**	**732,427,019.52**	**91.233%**
125		**SGSS1/SCD1/SGDS1**	**57,148,206.42**	**7.119%**
126		**SGSS2/SCD2/SGDS2**	**10,773,853.65**	**1.342%**
127		**SDS/LGSS**	**1,726,663.67**	**0.215%**
128		**LDS/LGSS**	**492,426.50**	**0.061%**
129		**FLEX**	**239,231.41**	**0.030%**
130		**TOTAL BEFORE MDS/NSS**	**802,807,401.17**	**100.000%**
131		**INACTIVE**	**73,404.45**	
132		**MDS/NSS**	**64,264.12**	
133		**FLEX MDS**	**0.00**	
134		**TOTAL**	**802,945,069.74**	
135		**UNKNOWN**	**7,726,632.67**	
136	**101-1000**	**TOTAL ACCOUNT 380**	**810,671,702.41**	
137	**101-2000**	**CIAC**	**(832,898.00)**	
138	**101-4000**	**Relocation Reimbursements**	**(17,664.00)**	
139	**106**	**Completed Construction not Classified**	**247,658.10**	
140	**Total**	**Per Exhibit 8, Schedule 1**	**810,068,798.51**	
141				
142	**LEGEND for Headings**			
143	BLANK	One Customer Per Tap		
144	P	Primary Customer, No Master Valve		
145	S	Secondary Customer, No Master Valve		
146	*	Primary Customer, One Master Valve		
147	+	Secondary Customer, One Curb Valve Controls All		

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 16
METERS

LINE NO.	RATE CODE	RSS/RDS $	SGS/DS-1 $	SGS/DS-2 $	SDS/LGSS $	LDS/LGSS $	FLEX	MLDS $	TOTAL $
1	808	0.00	0.00	0.00	0.00	0.00	406.95	0.00	406.95
2	809	0.00	0.00	0.00	0.00	0.00	813.90	0.00	813.90
3	810	0.00	0.00	0.00	0.00	0.00	813.90	0.00	813.90
4	833	0.00	0.00	0.00	0.00	0.00	406.95	0.00	406.95
5	846	0.00	0.00	0.00	0.00	0.00	813.90	0.00	813.90
6	875	0.00	0.00	0.00	0.00	0.00	813.90	0.00	813.90
7	879	0.00	0.00	0.00	0.00	0.00	406.95	0.00	406.95
8	880	0.00	0.00	0.00	0.00	0.00	406.95	0.00	406.95
9	881	0.00	0.00	0.00	0.00	0.00	969.94	0.00	969.94
10	882	0.00	0.00	0.00	0.00	0.00	406.95	0.00	406.95
11	LG1	0.00	0.00	0.00	19,689.61	0.00	0.00	0.00	19,689.61
12	LG2	0.00	0.00	0.00	31,546.07	0.00	0.00	0.00	31,546.07
13	LG3	0.00	0.00	0.00	0.00	1,627.80	0.00	0.00	1,627.80
14	LG4	0.00	0.00	0.00	0.00	1,627.80	0.00	0.00	1,627.80
15	LG5	0.00	0.00	0.00	0.00	406.95	0.00	0.00	406.95
16	NSI	0.00	0.00	0.00	0.00	0.00	0.00	63.95	63.95
17	RCC	5,947.76	0.00	0.00	0.00	0.00	0.00	0.00	5,947.76
18	RC2	1,495,232.84	0.00	0.00	0.00	0.00	0.00	0.00	1,495,232.84
19	RS	22,272,413.83	0.00	0.00	0.00	0.00	0.00	0.00	22,272,413.83
20	RTC	3,243,907.38	0.00	0.00	0.00	0.00	0.00	0.00	3,243,907.38
21	SCC	0.00	1,152,284.77	0.00	0.00	0.00	0.00	0.00	1,152,284.77
22	SC2	0.00	0.00	551,780.59	0.00	0.00	0.00	0.00	551,780.59
23	SG2	0.00	0.00	1,214,919.97	0.00	0.00	0.00	0.00	1,214,919.97
24	SG3	0.00	11,055.02	0.00	0.00	0.00	0.00	0.00	11,055.02
25	SG4	0.00	0.00	19,125.78	0.00	0.00	0.00	0.00	19,125.78
26	SGS	0.00	3,534,598.12	0.00	0.00	0.00	0.00	0.00	3,534,598.12
27	TAG1	0.00	39,139.08	0.00	0.00	0.00	0.00	0.00	39,139.08
28	TAG2	0.00	0.00	123,670.94	0.00	0.00	0.00	0.00	123,670.94
29	TAG5	0.00	193,617.49	0.00	0.00	0.00	0.00	0.00	193,617.49
30	TAG6	0.00	0.00	466,824.15	0.00	0.00	0.00	0.00	466,824.15
31	TI4	0.00	0.00	0.00	66,368.89	0.00	0.00	0.00	66,368.89
32	TI8	0.00	0.00	0.00	0.00	21,724.33	0.00	0.00	21,724.33
33	TIB	0.00	0.00	0.00	108,401.50	0.00	0.00	0.00	108,401.50
34	TIF	0.00	0.00	0.00	0.00	28,411.15	0.00	0.00	28,411.15
35	TIG	0.00	0.00	0.00	0.00	2,441.70	0.00	0.00	2,441.70
36	TIH	0.00	0.00	0.00	0.00	406.95	0.00	0.00	406.95
37	ML1	0.00	0.00	0.00	0.00	0.00	0.00	406.95	406.95
38	ML5	0.00	0.00	0.00	0.00	0.00	0.00	813.90	813.90
39	TMA	0.00	0.00	0.00	0.00	0.00	0.00	406.95	406.95
40	TMB	0.00	0.00	0.00	0.00	0.00	0.00	2,034.74	2,034.74
41	TMC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	TM1	0.00	0.00	0.00	0.00	0.00	0.00	252.21	252.21
43	TM2	0.00	0.00	0.00	0.00	0.00	0.00	252.21	252.21
44	TM4	0.00	0.00	0.00	0.00	0.00	0.00	406.95	406.95
45	TM5	0.00	0.00	0.00	0.00	0.00	0.00	406.95	406.95
46	TOTAL	27,017,501.81	4,930,694.48	2,376,321.43	226,006.07	56,646.68	6,260.29	5,044.81	34,618,475.57
	SGT								9,364.06
	LIS								406.95
	SIS								406.95
	LOC								184,696.41
	LOF								895.34
	Total								34,814,245.28
47	**ALLOCATOR #16**	78.043%	14.243%	6.864%	0.653%	0.164%	0.018%	0.015%	100.000%

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurment Stations
As of November 30, 2023

Line No.	Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
1	37	10034190010	501054825	SGT	TAG6	49103	0030209	7,227.64	TAG6	SGSS2/SCD2/SGDS2
2	37	10047952001	400188814	SGT	TI4	45529	0030243	11,446.47	TI4	SDS/LGSS
3	37	10132034047	400473027	SG2		4097	0030272	1,504.40	SG2	SGSS2/SCD2/SGDS2
4	37	10132034047	400498427	SG2		4285	0030272	0.00	SG2	SGSS2/SCD2/SGDS2
5	37	10219299006	501195093	LG2		49394	0732195	41,114.02	LG2	SDS/LGSS
6	37	10257973005	500030237	SG4		48810	1232756	9,184.43	SG4	SGSS2/SCD2/SGDS2
7	37	10348091005	400518175	SG4		44452	1333017	3,025.61	SG4	SGSS2/SCD2/SGDS2
8	37	10375621158	500489101	SGT	TIB	47567	1333032	8,701.67	TIB	SDS/LGSS
9	37	10379912006	400498094	SG2		14628	1333032	1,501.31	SG2	SGSS2/SCD2/SGDS2
10	37	10416756005	500065176	SC2		47085	1333063	767.59	SC2	SGSS2/SCD2/SGDS2
11	37	10416756012	500416284	SG2		47469	1333025	17,948.01	SG2	SGSS2/SCD2/SGDS2
12	37	10421482002	500617033	SGT	TIB	49153	0551504	44,715.05	TIB	SDS/LGSS
13	37	10422436002	400343911	SGT	TIB	46123	0010155	8,766.90	TIB	SDS/LGSS
14	37	10468703002	400525452	SGT	TI4	48454	1292914	11,690.05	TI4	SDS/LGSS
15	37	10474924002	400303837	SGS		48831	1292988	967.26	SGS	SGSS1/SCD1/SGDS1
16	37	10501013005	400511506	SGT	TAG6	1276	0511316	2,306.59	TAG6	SGSS2/SCD2/SGDS2
17	37	10502637002	400473325	LG2		1352	0511314	4,068.67	LG2	SDS/LGSS
18	37	10506078005	400473264	SG2		1303	0511314	1,557.22	SG2	SGSS2/SCD2/SGDS2
19	37	10512980003	800800458	SG2		1268	1292906	1,708.84	SG2	SGSS2/SCD2/SGDS2
20	37	11017807002	400032470	SGT	TAG6	49445	1333068	22,686.73	TAG6	SGSS2/SCD2/SGDS2
21	37	11595685002	400526772	SC2		810	0030272	2,131.13	SC2	SGSS2/SCD2/SGDS2
22	37	12983111001	400473518	SGT	TIB	661	1232704	23,392.95	TIB	SDS/LGSS
23	37	12983117003	400473502	SG2		49426	1232718	2,234.73	SG2	SGSS2/SCD2/SGDS2
24	37	12983124002	400473470	SG3		593	0832295	916.28	SG3	SGSS1/SCD1/SGDS1
25	37	12983149001	800800461	SGT	TAG6	14545	1292906	5,738.98	TAG6	SGSS2/SCD2/SGDS2
26	37	12983153001	800800460	SGT	TI4	1414	1292906	5,172.69	TI4	SDS/LGSS
27	37	12983176001	400490973	SGT	TAG6	14491	1292969	3,560.97	TAG6	SGSS2/SCD2/SGDS2
28	37	12983177001	400484946	SGT	TI4	14324	1292906	855.29	TI4	SDS/LGSS
29	37	12983191002	400473426	SGT	TAG6	1444	0511312	4,555.38	TAG6	SGSS2/SCD2/SGDS2
30	37	12983192001	400473425	SGT	TI4	1443	0511396	3,807.64	TI4	SDS/LGSS
31	37	12983205001	400473388	SC2		4299	0511314	5,425.75	SC2	SGSS2/SCD2/SGDS2
32	37	12983206002	500135694	SGT	TI4	1405	0511314	2,319.74	TI4	SDS/LGSS
33	37	12983208001	400473368	SG2		4584	0511314	2,944.67	SG2	SGSS2/SCD2/SGDS2
34	37	12983210001	400473364	SGT	TI4	4614	0511314	2,618.96	TI4	SDS/LGSS
35	37	12983212001	400473357	SGT	TAG6	4548	0511395	15,160.98	TAG6	SGSS2/SCD2/SGDS2
36	37	12983214001	400473355	SGT	TAG6	4715	0511304	1,630.16	TAG6	SGSS2/SCD2/SGDS2
37	37	12983232001	400473302	SGT	TAG6	1335	0511320	4,728.84	TAG6	SGSS2/SCD2/SGDS2
38	37	12983239001	400473287	SGT	TAG2	1323	0511314	3,777.32	TAG2	SGSS2/SCD2/SGDS2
39	37	12983241018	400473429	SG2		49456	0511318	84,655.41	SG2	SGSS2/SCD2/SGDS2
40	37	12983242001	400473279	SG2		1318	0511303	2,708.28	SG2	SGSS2/SCD2/SGDS2
41	37	12983255002	400514019	SGT	TIB	1291	0511395	7,185.12	TIB	SDS/LGSS
42	37	12983259002	400473238	SGT	TIB	1280	0511396	247.56	TIB	SDS/LGSS
43	37	12983259002	500135609	SGT	TIB	1280	0511396	247.56	TIB	SDS/LGSS
44	37	12983262001	400513746	SGT	TI8	44092	0511363	(1,937.70)	TI8	LDS/LGSS
45	37	12983275001	400473402	SGT	TI4	1423	1112553	2,575.48	TI4	SDS/LGSS
46	37	12983276001	400473401	SGT	TI8	3382	1112553	12,914.58	TI8	LDS/LGSS
47	37	12983281001	400473412	SG2		1432	1112521	3,135.76	SG2	SGSS2/SCD2/SGDS2
48	37	12983287001	400473405	SGT	TIB	1426	1112521	6,824.22	TIB	SDS/LGSS
49	37	12983292002	400473346	LG2		1372	1112561	8,169.60	LG2	SDS/LGSS
50	37	12983297001	400473265	SGT	TIB	1302	1112569	4,329.43	TIB	SDS/LGSS
51	37	12983298001	400473267	SGT	TAG6	1305	1112569	1,771.37	TAG6	SGSS2/SCD2/SGDS2
52	37	12983301001	400473229	SGT	TAG6	4252	1112553	1,853.55	TAG6	SGSS2/SCD2/SGDS2
53	37	12983308005	400473411	SGT	TIB	1431	1112569	2,375.82	TIB	SDS/LGSS
54	37	12983314001	400473452	SGT	TAG6	1467	1292918	3,121.92	TAG6	SGSS2/SCD2/SGDS2
55	37	12983315001	400473443	SG2		4413	1292998	1,427.28	SG2	SGSS2/SCD2/SGDS2
56	37	12983318001	400473440	SGT	TAG6	1456	1292909	2,977.62	TAG6	SGSS2/SCD2/SGDS2

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurment Stations
As of November 30, 2023

Line No.	Co	PCID	PSID	Tar Rate	GTS Rate		Station No.	Tax District	Amt	Billing Rate	Rate Class
57	37	12983325001	400511507	SGT	TAG6		1403	1292914	2,761.08	TAG6	SGSS2/SCD2/SGDS2
58	37	12983331001	400473315	SGT	TAG6		4471	1292989	7,100.40	TAG6	SGSS2/SCD2/SGDS2
59	37	12983343001	400512909	SGT	TIB		3295	1252863	2,216.34	TIB	SDS/LGSS
60	37	12983349001	400473387	SG2			1408	1252858	1,774.66	SG2	SGSS2/SCD2/SGDS2
61	37	12983354001	400473366	SGT	TAG6		4044	1292919	1,330.60	TAG6	SGSS2/SCD2/SGDS2
62	37	12983355011	400473369	SGT	TIB		4469	1252855	2,663.14	TIB	SDS/LGSS
63	37	12983355011	400484838	SGT	TIB		14322	1252855	5,698.48	TIB	SDS/LGSS
64	37	12983355011	500163677	SGT	TIB		47388	1252855	76,674.68	TIB	SDS/LGSS
65	37	12983355011	500287938	SGT	TIB		47386	1252855	76,674.68	TIB	SDS/LGSS
66	37	12983359001	400473342	SGT	TIB		1364	1252858	1,770.49	TIB	SDS/LGSS
67	37	12983370001	400495171	SG2			3323	1252863	4,538.11	SG2	SGSS2/SCD2/SGDS2
68	37	12983403001	400472841	SGT	TIB		718	0732195	1,809.43	TIB	SDS/LGSS
69	37	12983428003	400502425	SGT	TIF		14126	0732153	(2,300.48)	TIF	LDS/LGSS
70	37	12983429002	400472946	SGT	TIB		807	0070409	1,814.29	TIB	SDS/LGSS
71	37	12983433001	400512973	SGT		810	44075	0732195	4,278.82	810	FLEX
72	37	12983434002	400472904	SGT		808	776	0732153	93,547.00	808	FLEX
73	37	12983451001	400473180	SGT	TI4		997	0732114	1,935.14	TI4	SDS/LGSS
74	37	12983453001	400473149	SGT	TAG5		974	0732111	3,769.98	TAG5	SGSS1/SCD1/SGDS1
75	37	12983465001	400473060	SGT	TIB		890	0732113	2,137.80	TIB	SDS/LGSS
76	37	12983467002	400473014	SGT	TIB		856	0070409	6,095.11	TIB	SDS/LGSS
77	37	12983474002	400472983	SGT	TI8		832	0732195	14,060.11	TI8	LDS/LGSS
78	37	12983477001	400472975	SG2			826	0732195	2,722.41	SG2	SGSS2/SCD2/SGDS2
79	37	12983480002	400472971	SG2			746	0732195	2,473.69	SG2	SGSS2/SCD2/SGDS2
80	37	12983501003	400473171	SGT	TAG6		989	0070461	14,165.67	TAG6	SGSS2/SCD2/SGDS2
81	37	12983504001	400473099	SGT	TIB		924	0070451	10,408.46	TIB	SDS/LGSS
82	37	12983508002	400508899	SGT	TI8		871	0070424	6,374.99	TI8	LDS/LGSS
83	37	12983509011	400473189	SGT	TI8		1005	0732158	7,244.26	TI8	LDS/LGSS
84	37	12983537001	400473198	LG2			1013	0070453	2,943.45	LG2	SDS/LGSS
85	37	12983577003	400472935	SGT	TIB		801	0070495	52,247.68	TIB	SDS/LGSS
86	37	12983589001	400472900	SGT	TAG6		772	0070478	886.49	TAG6	SGSS2/SCD2/SGDS2
87	37	12983606002	400472820	SGT	TAG6		702	0070495	23,896.62	TAG6	SGSS2/SCD2/SGDS2
88	37	12983611001	400503381	SGT	TI8		14705	0070403	3,827.45	TI8	LDS/LGSS
89	37	12983623002	400473179	SGT	TAG6		996	0310911	3,442.72	TAG6	SGSS2/SCD2/SGDS2
90	37	12983626001	400473108	SGT	TAG6		933	0310958	0.00	TAG6	SGSS2/SCD2/SGDS2
91	37	12983627001	400473107	SGT	TAG6		932	0310956	498.89	TAG6	SGSS2/SCD2/SGDS2
92	37	12983630001	400526948	SG2			4420	0333908	15,255.74	SG2	SGSS2/SCD2/SGDS2
93	37	12983644001	400512422	SGT	TIB		1155	1252896	9,541.33	TIB	SDS/LGSS
94	37	12983645004	400492992	SGT	TMB		1121	1252804	7,202.28	TMB	MDS/NSS
95	37	12983645004	500142415	SGT	TMB		1121	1252804	7,202.28	TMB	MDS/NSS
96	37	12983651001	400472750	SGT	TI8		1241	1252829	5,001.89	TI8	LDS/LGSS
97	37	12983663001	400505567	SGT	TAG2		14764	1252821	3,352.37	TAG2	SGSS2/SCD2/SGDS2
98	37	12983681002	400472637	SGT	TI4		1141	1252803	15,441.32	TI4	SDS/LGSS
99	37	12983693004	400506899	SGT	TI4		14766	1252821	4,992.09	TI4	SDS/LGSS
100	37	12983778004	400526322	SGT	TI4		44903	0030287	25,760.65	TI4	SDS/LGSS
101	37	12983801005	500151204	SGT		846	1225	0030205	6,621.55	846	FLEX
102	37	12983801005	800800501	SGT		846	1227	0030257	477.96	846	FLEX
103	37	12983811001	400472633	SGT	TIB		1138	0030298	34,962.92	TIB	SDS/LGSS
104	37	12983816001	400497901	SGT	TI4		14538	0030298	6,397.42	TI4	SDS/LGSS
105	37	12983829003	400471809	SGT	TIB		4526	1333017	4,064.30	TIB	SDS/LGSS
106	37	12983875003	501090417	SGT	TIB		49141	0030287	81,808.33	TIB	SDS/LGSS
107	37	12983915002	400472655	SGT	TIB		1159	0030216	15,518.72	TIB	SDS/LGSS
108	37	12983936001	400473091	SGT	TI8		916	0030225	13,874.35	TI8	LDS/LGSS
109	37	12983938001	400473088	SGT	TIF		913	0030225	25,841.42	TIF	LDS/LGSS
110	37	12983938002	400473011	SGT	TI8		49348	0030225	25,397.78	TI8	LDS/LGSS
111	37	12983939001	400473057	SGT	TIF		887	0030225	259,819.28	TIF	LDS/LGSS
112	37	12983954001	400518548	SGT	TAG2		1016	0030280	1,133.65	TAG2	SGSS2/SCD2/SGDS2

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Line No.	Co	PCID	PSID	Tar Rate	GTS Rate		Station No.	Tax District	Amt	Billing Rate	Rate Class
113	37	12983969001	400473144	SGT	TI8		4078	0030280	6,739.92	TI8	LDS/LGSS
114	37	12983971001	400473142	SGT	TI4		968	0030263	3,123.75	TI4	SDS/LGSS
115	37	12983982001	400473103	SGT	TI4		929	0030272	356.76	TI4	SDS/LGSS
116	37	12983988005	501249841	LG3			49452	0030209	296,072.43	LG3	LDS/LGSS
117	37	12983993001	400473045	LG1			881	0030235	2,455.77	LG1	SDS/LGSS
118	37	12983994003	400473044	SGT	TI4		880	0030235	2,280.48	TI4	SDS/LGSS
119	37	12984057001	400472794	SGT	TAG2		14003	0070452	2,817.69	TAG2	SGSS2/SCD2/SGDS2
120	37	12984098001	400526718	SGT	TM1		45180	1252822	3,030.87	TM1	MDS/NSS
121	37	12984098003	400490002	SGT	TI8		14453	0010154	2,352.32	TI8	LDS/LGSS
122	37	12984119001	400494178	SG2			1174	1252823	21,322.38	SG2	SGSS2/SCD2/SGDS2
123	37	12984122008	400472639	SGT	TIB		48825	1252822	13,064.41	TIB	SDS/LGSS
124	37	12984125001	400472585	SGT	TI4		4502	1252819	3,398.13	TI4	SDS/LGSS
125	37	12984129002	400472553	SGT	TIB		1070	1252807	3,851.22	TIB	SDS/LGSS
126	37	12984131002	500789128	SGT	TIB		48657	1252822	5,117.20	TIB	SDS/LGSS
127	37	12984147008	400520146	SGT	TI4		47452	1252807	223.81	TI4	SDS/LGSS
128	37	12984147011	501252751	LG2			49460	1252860	0.00	LG2	SDS/LGSS
129	37	12984148002	500185413	SGT			49412	0030241	45,918.09	SGT	INACTIVE
130	37	12984148003	400518885	SGT	TIB		44408	0030241	7,603.27	TIB	SDS/LGSS
131	37	12984150004	501030792	SGT		875	49154	0273860	1,099.50	875	FLEX
132	37	12984150004	800800371	SGT		875	4385	0273804	6,048.49	875	FLEX
133	37	12984150007	501179703	SG2			49333	0273860	1,099.50	SG2	SGSS2/SCD2/SGDS2
134	37	12984151020	400475666	SGT	TIF		1565	0273860	287.79	TIF	LDS/LGSS
135	37	12984151020	400514859	SGT	TIF		48789	0273860	1,099.50	TIF	LDS/LGSS
136	37	12984151020	400514976	SGT	TIF		48788	0273860	1,099.50	TIF	LDS/LGSS
137	37	12984151020	400526997	SGT	TIF		45666	0273860	1,099.50	TIF	LDS/LGSS
138	37	12984151020	500008214	SGT	TIF		48790	0273860	1,099.50	TIF	LDS/LGSS
139	37	12984151020	500130476	SGT	TIF		45665	0273860	1,099.50	TIF	LDS/LGSS
140	37	12984151020	500130460	SGT	TIF		45732	0273804	697.05	TIF	LDS/LGSS
141	37	12984151020	500130474	SGT	TIF		48526	0273860	1,099.50	TIF	LDS/LGSS
142	37	12984151020	500130459	SGT	TIF		48889	0273860	1,099.50	TIF	LDS/LGSS
143	37	12984151020	500136322	SGT	TIF		45731	0273804	697.05	TIF	LDS/LGSS
144	37	12984151020	500162068	SGT	TIF		45949	0273860	1,099.50	TIF	LDS/LGSS
145	37	12984151020	500198356	SGT	TIF		46017	0273804	697.05	TIF	LDS/LGSS
146	37	12984151020	500208315	SGT	TIF		46494	0273804	697.05	TIF	LDS/LGSS
147	37	12984151020	500555580	SGT	TIF		48444	0273860	1,099.50	TIF	LDS/LGSS
148	37	12984151020	500558423	SGT	TIF		48887	0273860	1,099.50	TIF	LDS/LGSS
149	37	12984151020	500612327	SGT	TIF		48438	0273804	697.05	TIF	LDS/LGSS
150	37	12984151020	500625771	SGT	TIF		48958	0273860	586.51	TIF	LDS/LGSS
151	37	12984151020	500659013	SGT	TIF		48965	0273860	1,099.50	TIF	LDS/LGSS
152	37	12984151020	500667297	SGT	TIF		48439	0273804	697.05	TIF	LDS/LGSS
153	37	12984151020	500667298	SGT	TIF		48440	0273860	(11,167.52)	TIF	LDS/LGSS
154	37	12984151020	500692603	SGT	TIF		48625	0273860	1,099.50	TIF	LDS/LGSS
155	37	12984151020	500707423	SGT	TIF		48970	0273804	697.05	TIF	LDS/LGSS
156	37	12984151020	500709556	SGT	TIF		48543	0273860	1,099.50	TIF	LDS/LGSS
157	37	12984151020	500716291	SGT	TIF		48471	0273860	1,099.50	TIF	LDS/LGSS
158	37	12984151020	500806647	SGT	TIF		48678	0273860	1,099.50	TIF	LDS/LGSS
159	37	12984151020	500856054	SGT	TIF		48736	0273804	697.05	TIF	LDS/LGSS
160	37	12984151020	500875536	SGT	TIF		48749	0273804	697.05	TIF	LDS/LGSS
161	37	12984151020	500918034	SGT	TIF		48624	0273860	1,099.50	TIF	LDS/LGSS
162	37	12984151020	500949336	SGT	TIF		48808	0273860	1,099.50	TIF	LDS/LGSS
163	37	12984151020	500949337	SGT	TIF		48809	0273860	1,099.50	TIF	LDS/LGSS
164	37	12984151020	800800356	SGT	TIF		4371	0273860	1,099.50	TIF	LDS/LGSS
165	37	12984151020	800800357	SGT	TIF		4373	0273860	1,099.50	TIF	LDS/LGSS
166	37	12984151020	800800358	SGT	TIF		4374	0273860	1,555.96	TIF	LDS/LGSS
167	37	12984151020	800800359	SGT	TIF		4375	0273860	1,235.30	TIF	LDS/LGSS
168	37	12984151020	800800360	SGT	TIF		4376	0273860	1,099.50	TIF	LDS/LGSS

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Line No.	Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
169	37	12984151020	800800361	SGT	TIF	4377	0273860	825.56	TIF	LDS/LGSS
170	37	12984151020	800800362	SGT	TIF	4378	0273860	1,152.36	TIF	LDS/LGSS
171	37	12984151020	800800364	SGT	TIF	4380	0273860	550.88	TIF	LDS/LGSS
172	37	12984151020	800800365	SGT	TIF	4381	0273804	697.05	TIF	LDS/LGSS
173	37	12984151020	800800366	SGT	TIF	4382	0273860	1,099.50	TIF	LDS/LGSS
174	37	12984151020	800800367	SGT	TIF	4383	0273860	2,705.00	TIF	LDS/LGSS
175	37	12984151020	800800369	SGT	TIF	14823	0273860	(237.74)	TIF	LDS/LGSS
176	37	12984151020	800800370	SGT	TIF	45243	0273804	697.05	TIF	LDS/LGSS
177	37	12984151020	800800354	SGT	TIF	49234	0273860	1,099.50	TIF	LDS/LGSS
178	37	12984151070	500599616	SGT		48888	0273860	1,099.50	SGT	INACTIVE
179	37	12984151071	500972343	SGT		48807	0273804	697.05	SGT	INACTIVE
180	37	12984151071	501078814	SGT		49357	0273860	1,099.50	SGT	INACTIVE
181	37	12984151071	501102376	SGT		49356	0273860	1,099.50	SGT	INACTIVE
182	37	12984156007	501140885	SGT	881	49402	1212650	0.00	881	FLEX
183	37	12984156007	501140884	SGT	881	49404	1212650	0.00	881	FLEX
184	37	12984156009	400498964	SGT	TIF	14387	0273821	5,213.78	TIF	LDS/LGSS
185	37	12984156009	501056289	SGT	TIF	49453	0273821	9,141.40	TIF	LDS/LGSS
186	37	12984188002	400472449	SGT	TIF	4450	0273804	353,710.72	TIF	LDS/LGSS
187	37	12984218002	400472435	SGT	TIB	1493	0551552	0.00	TIB	SDS/LGSS
188	37	12984219007	500165435	LG2		294	0551501	2,639.51	LG2	SDS/LGSS
189	37	12984221002	400472381	SGT	TIB	1490	0551501	5,370.70	TIB	SDS/LGSS
190	37	12984221004	501123144	SGT	TI8	49284	0551501	1,956.54	TI8	LDS/LGSS
191	37	12984230001	400472414	SGT	TI4	1513	0551554	1,524.62	TI4	SDS/LGSS
192	37	12984232001	400472408	NSI		1511	0551511	1,250.65	NSI	MDS/NSS
193	37	12984233004	400472404	SGT	TI8	1508	0551553	0.00	TI8	LDS/LGSS
194	37	12984233004	800800336	SGT	TI8	4507	0551553	1,590.31	TI8	LDS/LGSS
195	37	12984235003	400503659	SGT	TI4	14732	0551511	4,635.06	TI4	SDS/LGSS
196	37	12984235003	500232234	SGT	TI4	48041	0551511	1,250.65	TI4	SDS/LGSS
197	37	12984245001	400514975	SG4		44087	0010153	2,947.61	SG4	SGSS2/SCD2/SGDS2
198	37	12984247004	400472434	SGT	TIF	297	0010109	7,068.70	TIF	LDS/LGSS
199	37	12984247004	400472433	SGT	TIF	4339	0010109	4,963.02	TIF	LDS/LGSS
200	37	12984247004	800800335	SGT	TIF	14446	0010109	4,078.78	TIF	LDS/LGSS
201	37	12984250003	400507411	SGT	TI8	3215	0010154	2,625.29	TI8	LDS/LGSS
202	37	12984250003	400507413	SGT	TI8	3215	0010154	2,625.29	TI8	LDS/LGSS
203	37	12984252001	400472401	SGT	TAG6	1506	0010160	2,716.17	TAG6	SGSS2/SCD2/SGDS2
204	37	12984255005	400472391	SGT	TAG6	4293	0010158	3,969.19	TAG6	SGSS2/SCD2/SGDS2
205	37	12984257002	400472388	SGT	TIF	3334	0010120	389.22	TIF	LDS/LGSS
206	37	12984257002	500149512	SGT	TIF	1496	0010120	7,979.81	TIF	LDS/LGSS
207	37	12984261001	400472371	SGT	TIF	3384	0010114	417.56	TIF	LDS/LGSS
208	37	12984262001	400517972	SGT	TIB	44406	0010160	3,203.39	TIB	SDS/LGSS
209	37	12984264001	400472364	SGT	TIB	1477	0010117	2,125.64	TIB	SDS/LGSS
210	37	12984270006	400498095	SGT	TIB	14526	1333072	4,269.98	TIB	SDS/LGSS
211	37	12984273001	400522508	SGT	TIB	44530	0010105	4,338.27	TIB	SDS/LGSS
212	37	12984275001	400472429	SGT	TIB	1523	0010157	8,704.10	TIB	SDS/LGSS
213	37	12984276001	400511898	SGT	TIB	44051	0010157	2,268.56	TIB	SDS/LGSS
214	37	12984281001	400472403	SC2		1507	0010157	5,011.48	SC2	SGSS2/SCD2/SGDS2
215	37	12984282002	400472402	SGT	TI4	3499	0010119	1,353.99	TI4	SDS/LGSS
216	37	12984283001	400472399	SGT	TI4	3187	0010158	2,708.97	TI4	SDS/LGSS
217	37	12984291001	400472378	SGT	TAG6	1486	0010157	3,434.35	TAG6	SGSS2/SCD2/SGDS2
218	37	12984293002	400472376	SGT	TMB	285	0010109	13,185.56	TMB	MDS/NSS
219	37	12984293003	500925519	SGT		48785	0010109	16,768.97	SGT	INACTIVE
220	37	12984296001	400472372	SGT	TAG6	1483	0010104	2,598.74	TAG6	SGSS2/SCD2/SGDS2
221	37	12984299002	400472366	SGT	TI8	1479	0010157	4,617.06	TI8	LDS/LGSS
222	37	12984299002	500220827	SGT	TI8	46090	0010157	(4,696.74)	TI8	LDS/LGSS
223	37	12984318001	400051028	SGT	TI8	48031	1333063	767.59	TI8	LDS/LGSS
224	37	12984318001	400472328	SGT	TI8	3515	1333063	4,335.32	TI8	LDS/LGSS

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225	37	12984318001	400472327	SGT	TI8	3636	1333063	4,224.76	TI8	LDS/LGSS
226	37	12984318001	400494708	SGT	TI8	48033	1333063	767.59	TI8	LDS/LGSS
227	37	12984318001	400505362	SGT	TI8	48677	1333063	767.59	TI8	LDS/LGSS
228	37	12984318001	400507194	SGT	TI8	46075	1333063	767.59	TI8	LDS/LGSS
229	37	12984318001	400514810	SGT	TI8	48034	1333063	767.59	TI8	LDS/LGSS
230	37	12984318001	500005922	SGT	TI8	48032	1333063	767.59	TI8	LDS/LGSS
231	37	12984318001	500119649	SGT	TI8	45688	1333063	3,470.16	TI8	LDS/LGSS
232	37	12984321001	400472320	SGT	TAG6	3543	1333025	2,924.99	TAG6	SGSS2/SCD2/SGDS2
233	37	12984323001	400472318	SGT	TI8	3632	1333025	32,431.00	TI8	LDS/LGSS
234	37	12984324001	400472317	SC2		3542	1333025	1,613.38	SC2	SGSS2/SCD2/SGDS2
235	37	12984325001	400472316	SGT	TIF	3631	1333025	11,349.73	TIF	LDS/LGSS
236	37	12984325004	501256232	LG2		49420	1333025	77,066.90	LG2	SDS/LGSS
237	37	12984327001	400472263	SGT	TI4	4536	1333025	1,566.12	TI4	SDS/LGSS
238	37	12984329001	400526741	SGT	TMB	45205	1333025	29,437.80	TMB	MDS/NSS
239	37	12984343004	400490919	SGT	TIG	14417	1333063	14,980.65	TIG	LDS/LGSS
240	37	12984343004	500023117	SGT	TIG	48880	1333063	767.59	TIG	LDS/LGSS
241	37	12984343004	500535850	SGT	TIG	48881	1333063	767.59	TIG	LDS/LGSS
242	37	12984346001	400526951	SGT	TI8	44971	1333025	3,724.43	TI8	LDS/LGSS
243	37	12984351001	400472299	SGT	TI4	3527	1333025	5,492.43	TI4	SDS/LGSS
244	37	12984355002	400472293	LG1		3521	0010103	1,321.13	LG1	SDS/LGSS
245	37	12984357001	400472287	SGT	TIF	3625	1333063	135.13	TIF	LDS/LGSS
246	37	12984366001	400472272	SGT	TI8	3506	1333063	4,906.73	TI8	LDS/LGSS
247	37	12984368001	400472269	SGT	TIB	3504	1333063	1,455.66	TIB	SDS/LGSS
248	37	12984378001	400496892	SGT	TAG6	14565	1333017	2,669.44	TAG6	SGSS2/SCD2/SGDS2
249	37	12984382001	400493516	SGT	TIB	14532	1333017	15,284.02	TIB	SDS/LGSS
250	37	12984392002	400472214	LG2		3569	1333074	2,526.37	LG2	SDS/LGSS
251	37	12984392002	400472233	LG2		3649	1333074	8,902.25	LG2	SDS/LGSS
252	37	12984392002	800800313	LG2		3648	1333074	3,347.55	LG2	SDS/LGSS
253	37	12984433001	400474737	SGT	TIB	14041	1333014	5,102.18	TIB	SDS/LGSS
254	37	12984438005	400517692	SGT	TI8	14678	1333029	4,838.86	TI8	LDS/LGSS
255	37	12984438005	400526273	SGT	TI8	44876	1333029	5,910.79	TI8	LDS/LGSS
256	37	12984438005	800800325	SGT	TI8	3916	1333029	4,519.57	TI8	LDS/LGSS
257	37	12984440001	400472099	SGT	TIB	3909	1333032	(541.38)	TIB	SDS/LGSS
258	37	12984442001	400472096	SGT	TIG	14693	1333032	1,858.55	TIG	LDS/LGSS
259	37	12984443001	400472090	SGT	TIB	3901	1333095	1,466.35	TIB	SDS/LGSS
260	37	12984447001	400526359	SGT	TIF	3894	1333032	256,199.64	TIF	LDS/LGSS
261	37	12984448001	400472085	SGT	TI8	3893	1333027	932.88	TI8	LDS/LGSS
262	37	12984450007	500793520	SGT	TIF	48680	1333027	7,214.83	TIF	LDS/LGSS
263	37	12984453004	400505585	SGT	TIB	3881	1333029	14,787.78	TIB	SDS/LGSS
264	37	12984460001	400472065	SGT	TIB	3866	1333017	1,150.36	TIB	SDS/LGSS
265	37	12984472001	400472020	SGT	TAG6	3803	1333027	5,226.08	TAG6	SGSS2/SCD2/SGDS2
266	37	12984475001	400472016	SGT	TIB	3799	1333027	77.96	TIB	SDS/LGSS
267	37	12984477004	800800315	SC2		3793	1333027	14.60	SC2	SGSS2/SCD2/SGDS2
268	37	12984484006	400467049	SGT	TIB	47453	1333083	121.41	TIB	SDS/LGSS
269	37	12984484006	400471998	SGT	TIB	14566	1333083	4,151.32	TIB	SDS/LGSS
270	37	12984484006	500151812	SGT	TIB	47456	1333083	121.41	TIB	SDS/LGSS
271	37	12984490001	400526586	SGT	TIF	4037	1333079	49,883.89	TIF	LDS/LGSS
272	37	12984493001	400471935	SGT	TAG2	4516	1333095	1,233.13	TAG2	SGSS2/SCD2/SGDS2
273	37	12984497001	400471892	SGT	TIB	4173	1333095	226.77	TIB	SDS/LGSS
274	37	12984501001	400471867	SGT	TIF	4155	1333095	3,610.20	TIF	LDS/LGSS
275	37	12984507001	400471805	SGT	TIB	4556	1333014	5,773.32	TIB	SDS/LGSS
276	37	12984524001	400507001	SGT	TI4	14552	1333017	4,496.64	TI4	SDS/LGSS
277	37	12984529002	400495160	SGT	TM5	293	0290806	0.00	TM5	MDS/NSS
278	37	12984533001	400494422	SGT	TI8	14521	1333027	1,675.67	TI8	LDS/LGSS
279	37	12984534001	400491763	SGT	TAG6	14383	1333029	113.15	TAG6	SGSS2/SCD2/SGDS2
280	37	12984538001	400496374	SGT	TIB	14554	1333095	272.28	TIB	SDS/LGSS

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281	37	12984541001	400472240	SGT	TIB	4443	1333074	2,399.83	TIB	SDS/LGSS
282	37	12984542001	400499351	SC2		14534	1333029	2,404.34	SC2	SGSS2/SCD2/SGDS2
283	37	12984549001	400496547	SGT	TI4	14438	1333095	1,494.85	TI4	SDS/LGSS
284	37	12984569008	400472068	SGT	TIF	3869	1333029	15,669.22	TIF	LDS/LGSS
285	37	12984569008	400492606	SGT	TIF	47118	1333029	10,688.18	TIF	LDS/LGSS
286	37	12984569008	400505836	SGT	TIF	47356	1333029	10,263.24	TIF	LDS/LGSS
287	37	12984569008	400516746	SGT	TIF	47028	1333029	10,263.24	TIF	LDS/LGSS
288	37	12984592001	400471991	SGT	TI8	3698	1333069	9,772.77	TI8	LDS/LGSS
289	37	12984598001	400471984	SGT	TI4	3751	1333005	3,433.09	TI4	SDS/LGSS
290	37	12984606001	400471973	SGT	TIB	3736	1333026	7,338.45	TIB	SDS/LGSS
291	37	12984607002	400471965	SGT	TAG6	3728	1333027	4,576.34	TAG6	SGSS2/SCD2/SGDS2
292	37	12984611002	400471958	SGT	TIB	3723	1333029	7,465.84	TIB	SDS/LGSS
293	37	12984614001	400471948	SGT	TIB	3719	1333035	6,531.56	TIB	SDS/LGSS
294	37	12984622002	400471919	SGT	TAG6	3765	1333032	1,060.19	TAG6	SGSS2/SCD2/SGDS2
295	37	12984624003	400471915	SGT	TIB	3763	1333032	4,434.71	TIB	SDS/LGSS
296	37	12984628004	400471893	SGT	TIB	3686	1333029	1,522.87	TIB	SDS/LGSS
297	37	12984661001	400526647	SGT	TAG6	45046	1333014	2,190.07	TAG6	SGSS2/SCD2/SGDS2
298	37	12984661003	400500358	SGT	TIB	14657	0010101	23,195.59	TIB	SDS/LGSS
299	37	12984661004	500738669	SGT	TIB	48592	1333032	16,365.40	TIB	SDS/LGSS
300	37	13188422011	500079934	SGT	TI8	49385	0273806	3,326.29	TI8	LDS/LGSS
301	37	13188422011	500325346	SGT	TI8	49384	0273806	2,119.27	TI8	LDS/LGSS
302	37	13237020002	500135596	SGT	TI8	4638	0511396	31,407.24	TI8	LDS/LGSS
303	37	13241895007	501021913	SGT	TIF	49028	0030225	44,561.28	TIF	LDS/LGSS
304	37	13241895007	501028115	SGT	TIF	49013	0030225	44,561.28	TIF	LDS/LGSS
305	37	13264345002	400520745	SG2		1306	1292913	3,173.68	SG2	SGSS2/SCD2/SGDS2
306	37	13266182004	400473258	SGT	TMB	1296	1252858	2,294.81	TMB	MDS/NSS
307	37	13333833001	500159224	LG2		45928	0551501	6,277.25	LG2	SDS/LGSS
308	37	13409908003	800800444	SGT	TI4	289	0070406	2,190.25	TI4	SDS/LGSS
309	37	13503540001	500099035	SGT	TI4	45872	1252862	6,687.76	TI4	SDS/LGSS
310	37	13606384001	500209675	SGT	TI8	46079	1333028	14,613.78	TI8	LDS/LGSS
311	37	13629199001	500199977	SGT	TIF	46006	1112521	38,461.32	TIF	LDS/LGSS
312	37	13648145002	400473252	SC2		1289	1112521	24,071.02	SC2	SGSS2/SCD2/SGDS2
313	37	13676826001	500220820	SGT	TIF	46101	0030243	27,319.26	TIF	LDS/LGSS
314	37	13801660001	500224592	SGT	TAG6	46122	1292998	7,734.44	TAG6	SGSS2/SCD2/SGDS2
315	37	13807449005	500843197	SGT	TAG6	48733	0010160	10,929.56	TAG6	SGSS2/SCD2/SGDS2
316	37	13953098002	500268352	SG4		46701	0511314	2,164.21	SG4	SGSS2/SCD2/SGDS2
317	37	13959263001	400473271	SGT	TI8	1309	1292977	8,591.82	TI8	LDS/LGSS
318	37	13968541002	500296548	SGT	TM3	46567	0511324	286,814.93	TM3	MDS/NSS
319	37	14161126001	400472230	SGT	TIB	3588	1333034	3,800.39	TIB	SDS/LGSS
320	37	14203427002	400483822	SG2		14283	0511304	3,499.71	SG2	SGSS2/SCD2/SGDS2
321	37	14238571001	500337814	SGT	TIF	46961	1333007	9,157.29	TIF	LDS/LGSS
322	37	14303963001	500391455	SGT	TAG6	47285	0030260	12,062.59	TAG6	SGSS2/SCD2/SGDS2
323	37	14313747005	500338294	SGT	TAG6	47466	0010155	12,751.38	TAG6	SGSS2/SCD2/SGDS2
324	37	14318082003	400519776	SGT	TIB	47451	1333032	9,668.71	TIB	SDS/LGSS
325	37	14344230001	500212008	SGT	TIB	47252	1252822	9,625.99	TIB	SDS/LGSS
326	37	14351364003	500354179	SGT	TIB	47333	0591705	(9,801.11)	TIB	SDS/LGSS
327	37	14351364003	500371709	SGT	TIB	47605	0591705	9,031.53	TIB	SDS/LGSS
328	37	14351364003	500690713	SGT	TIB	49040	0591705	6,003.16	TIB	SDS/LGSS
329	37	14471914001	400526560	SGT	TIF	3908	1333032	12,192.53	TIF	LDS/LGSS
330	37	14492769002	500965975	LG2	TIB	49158	1112521	14,608.37	TIB	SDS/LGSS
331	37	14529317003	400472635	SGT	TI8	1139	1252856	13,623.23	TI8	LDS/LGSS
332	37	14529317003	800800373	SGT	TI8	14246	1252856	13,412.22	TI8	LDS/LGSS
333	37	14557113003	500054098	SGT	TI4	48084	0551501	28,878.63	TI4	SDS/LGSS
334	37	14738217002	400473525	SGT	TI4	621	0832206	3,136.89	TI4	SDS/LGSS
335	37	14860718003	400473280	SGT	TAG6	1313	0511314	14,364.41	TAG6	SGSS2/SCD2/SGDS2
336	37	14958276004	501161721	SGT	TIB	49323	1112501	31,261.72	TIB	SDS/LGSS

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337	37	14962898001	400504012	SC2			4067	0010104	1,319.79	SC2	SGSS2/SCD2/SGDS2
338	37	14997023001	400472421	SGT	TAG6		3491	0010157	1,735.53	TAG6	SGSS2/SCD2/SGDS2
339	37	15096104001	500587558	SGT	809		47842	0732195	6,753.16	809	FLEX
340	37	15096104002	501033523	SGT		809	49045	0732195	44,763.53	809	FLEX
341	37	15096113001	500587559	SGT	833		47843	0732195	30,296.36	833	FLEX
342	37	15107817004	500136220	SG4			1438	0511314	1,652.12	SG4	SGSS2/SCD2/SGDS2
343	37	15120198003	501174545	LG2			49367	1333032	64,145.58	LG2	SDS/LGSS
344	37	15190290003	500990795	SGT	TIB		48924	0511314	21,953.37	TIB	SDS/LGSS
345	37	15246690003	400478147	SG2			1122	1252821	10,996.30	SG2	SGSS2/SCD2/SGDS2
346	37	15310256001	400477241	SGT	TIB		3990	1333017	19.02	TIB	SDS/LGSS
347	37	15320799002	400514006	SGT	TAG6		4540	1252822	0.00	TAG6	SGSS2/SCD2/SGDS2
348	37	15399043001	400473272	SG4			1310	1292913	1,878.81	SG4	SGSS2/SCD2/SGDS2
349	37	15409498002	400472801	SG2			686	0030225	1,621.75	SG2	SGSS2/SCD2/SGDS2
350	37	15410029001	400524934	SG4			1465	0511314	2,137.32	SG4	SGSS2/SCD2/SGDS2
351	37	15410029003	400526421	SG2			1368	0511314	2,282.29	SG2	SGSS2/SCD2/SGDS2
352	37	15514483001	400473294	SG2			1329	1112521	1,293.77	SG2	SGSS2/SCD2/SGDS2
353	37	15514517001	500607489	SGT	TIF		48514	0551504	29,232.95	TIF	LDS/LGSS
354	37	15614278001	500732771	SGT	TAG6		48561	0030223	5,320.06	TAG6	SGSS2/SCD2/SGDS2
355	37	15630675002	501155646	SG2			49311	1292909	46,337.79	SG2	SGSS2/SCD2/SGDS2
356	37	15632066001	500494320	SGT	TIB		48533	1112512	10,803.64	TIB	SDS/LGSS
357	37	15674018001	500648810	SGT	TIF		48541	0273801	99,366.60	TIF	LDS/LGSS
358	37	15878297001	500766884	SGT	TAG6		48455	1333007	12,394.28	TAG6	SGSS2/SCD2/SGDS2
359	37	15932079001	500755822	SGT	TIF		48661	0511311	4,748.25	TIF	LDS/LGSS
360	37	16032404001	400493513	SC2			3428	1112521	1,471.35	SC2	SGSS2/SCD2/SGDS2
361	37	16266565001	400518893	SGT	TIB		934	0070495	1,261.32	TIB	SDS/LGSS
362	37	16316862001	400489632	SGT	TIB		48727	0010103	23,457.97	TIB	SDS/LGSS
363	37	16450594001	400526719	SGT	TIB		48743	1333083	6,816.35	TIB	SDS/LGSS
364	37	16656334003	501222616	SG2			49396	0511304	26,250.40	SG2	SGSS2/SCD2/SGDS2
365	37	16804444002	500146391	SGT	TI8		861	0070495	5,786.00	TI8	LDS/LGSS
366	37	16804444008	500175309	SGT	TIB		49139	0070495	10,910.27	TIB	SDS/LGSS
367	37	16919869001	500215263	SGT	TAG6		48787	1333095	28,470.64	TAG6	SGSS2/SCD2/SGDS2
368	37	16920048001	500959190	SGT	TIB		48797	0511395	9,062.42	TIB	SDS/LGSS
369	37	17000719005	400496375	SGT	TAG6		14550	1333027	1,701.93	TAG6	SGSS2/SCD2/SGDS2
370	37	17037445001	500962866	SGT	TIB		48814	0511306	6,626.36	TIB	SDS/LGSS
371	37	17097990001	400473352	SCC			4547	1252858	1,965.53	SCC	SGSS1/SCD1/SGDS1
372	37	17184483002	500193058	SGT	TIB		45604	0732195	(5,006.09)	TIB	SDS/LGSS
373	37	17187387006	400471902	SGT	TI8		4178	1333032	3,370.20	TI8	LDS/LGSS
374	37	17260071005	400504725	LG1			1363	1252858	1,728.41	LG1	SDS/LGSS
375	37	17264884002	400500238	SGT	TIH		14403	1333032	6,310.54	TIH	LDS/LGSS
376	37	17297010001	400474558	SGT	TI4		14055	1333035	5,282.49	TI4	SDS/LGSS
377	37	17374299002	400473323	LG1			1351	0511314	5,233.17	LG1	SDS/LGSS
378	37	17409498001	501027922	SGT	TIB		49021	1333095	13,667.74	TIB	SDS/LGSS
379	37	17439660003	800800314	SC2			4269	1333035	2,430.25	SC2	SGSS2/SCD2/SGDS2
380	37	17446577006	400498963	SGT	TI8		14518	0010160	5,361.20	TI8	LDS/LGSS
381	37	17509433003	501049268	SGT	TI8		49070	0511306	13,305.02	TI8	LDS/LGSS
382	37	17556648001	500988325	LG1			49016	1252829	60,039.91	LG1	SDS/LGSS
383	37	17613477001	501040193	SC2			49048	0832295	17,028.50	SC2	SGSS2/SCD2/SGDS2
384	37	17662964001	400472829	SGT	TIB		711	0030252	8,688.26	TIB	SDS/LGSS
385	37	17692241009	501080986	SGT	TI8		49302	1333017	65,532.25	TI8	LDS/LGSS
386	37	17766386001	501049150	SGT	TI8		49088	1333014	35,922.76	TI8	LDS/LGSS
387	37	18505018001	400473396	SG2			3248	1292914	1,663.84	SG2	SGSS2/SCD2/SGDS2
388	37	18540737001	500487109	SGS			47705	1292909	31,397.65	SGS	SGSS1/SCD1/SGDS1
389	37	18660393001	501083309	SG2			40519	1252820	22,691.51	SG2	SGSS2/SCD2/SGDS2
390	37	18703892001	400505131	SGT	TIF		689	0070477	20,627.81	TIF	LDS/LGSS
391	37	18776965001	400472097	SGT	TIF		3907	1333014	4,705.66	TIF	LDS/LGSS
392	37	18792064002	501099066	SGT	TAG6		49244	1333035	15,923.45	TAG6	SGSS2/SCD2/SGDS2

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393	37	18836110001	400473205	SGT	TIB		1018	0732111	3,880.29	TIB	SDS/LGSS
394	37	18885421001	500376080	SGT	TIB		49156	0010119	16,178.78	TIB	SDS/LGSS
395	37	18897692003	400472409	SGT	TIB		1512	0010160	1,660.38	TIB	SDS/LGSS
396	37	18985473001	501047288	SGT	TIB		49243	1333035	232.12	TIB	SDS/LGSS
397	37	18988904003	501281830	LG2			49425	0070479	30,748.80	LG2	SDS/LGSS
398	37	19022293001	400473231	SG2			4575	0511316	1,956.84	SG2	SGSS2/SCD2/SGDS2
399	37	19022293009	500132845	SG2			4575	0511316	1,956.84	SG2	SGSS2/SCD2/SGDS2
400	37	19046540001	400508038	SGT	TIB		14064	1333017	944.86	TIB	SDS/LGSS
401	37	19074397001	501115733	SGT	TIB		49265	1333017	15,284.02	TIB	SDS/LGSS
402	37	19114953001	500688577	SGT	TI4		48544	0511312	1,115.13	TI4	SDS/LGSS
403	37	19117144005	501102841	SGT	TI8		49282	0732108	169.67	TI8	LDS/LGSS
404	37	19117144005	501104644	SGT	TI8		49270	0732108	36,621.65	TI8	LDS/LGSS
405	37	19179996001	400472978	SGT	TIG		828	0030272	15,084.85	TIG	LDS/LGSS
406	37	19193822001	501050977	SGT	TI4		49272	0010103	14,333.13	TI4	SDS/LGSS
407	37	19252407003	800800378	SGT	TAG6		849	0030234	2,908.76	TAG6	SGSS2/SCD2/SGDS2
408	37	19336466001	400501188	SGT	TAG2		45609	1333032	256,199.64	TAG2	SGSS2/SCD2/SGDS2
409	37	19443642001	400472814	SGT	TIB		697	0070403	3,872.82	TIB	SDS/LGSS
410	37	19592009003	501149161	LG2			49340	1252822	15,220.72	LG2	SDS/LGSS
411	37	19623332001	400472345	SG2			3562	1333063	7,786.78	SG2	SGSS2/SCD2/SGDS2
412	37	19682099001	500296730	SGT	TIB		46707	0511304	26,250.40	TIB	SDS/LGSS
413	37	19791817001	500175440	SGT	TAG6		45528	0070452	31,255.79	TAG6	SGSS2/SCD2/SGDS2
414	37	19845214005	400472052	SGT	TIB		3847	1333032	7,154.80	TIB	SDS/LGSS
415	37	19854159001	501154755	SGT	TIB		49338	0273804	1,887.55	TIB	SDS/LGSS
416	37	19854159002	501162824	LG2			49322	1333029	10,263.24	LG2	SDS/LGSS
417	37	19866613001	501025433	SGT	TIB		48841	0190626	21,082.43	TIB	SDS/LGSS
418	37	19960243005	400484301	SG3			937	0070452	4,620.19	SG3	SGSS1/SCD1/SGDS1
419	37	19968875005	800800311	SGT	TIB		14595	1333029	2,936.12	TIB	SDS/LGSS
420	37	20159378001	500153126	SGT	TI8		45642	0070479	635.10	TI8	LDS/LGSS
421	37	20231700001	400472742	SGT	TI4		14101	1252807	5,736.00	TI4	SDS/LGSS
422	37	20231700003	400472014	SGT	TIB		3795	1333027	8,044.15	TIB	SDS/LGSS
423	37	20271953001	500214064	SGT	TI4		47053	1252822	32,337.79	TI4	SDS/LGSS
424	37	20271953003	500459284	LG1			47484	1252822	590.67	LG1	SDS/LGSS
425	37	20352622001	400493366	SGT	TIF		14458	1333025	4,349.04	TIF	LDS/LGSS
426	37	20403776001	501228775	SG2			49390	0010157	5,180.86	SG2	SGSS2/SCD2/SGDS2
427	37	20480473001	501093555	SGT	880		49361	1333014	467,690.79	880	FLEX
428	37	20480473002	400471977	SGT	TIB		4335	1333077	4,035.77	TIB	SDS/LGSS
429	37	20503074001	501173051	SGT	TIB		49398	1333029	2,105.64	TIB	SDS/LGSS
430	37	20540367001	501221207	SGT		810	49395	0732195	32,565.34	810	FLEX
431	37	20556961001	400494798	SGT	TIF		14599	0010160	121.29	TIF	LDS/LGSS
432	37	20665631001	400473191	SGT	TIF		1007	0030225	5,761.56	TIF	LDS/LGSS
433	37	20669499001	501163330	SGT	TIB		49411	0070452	31,255.79	TIB	SDS/LGSS
434	37	20688663001	400474751	SGT	TI4		4509	0030223	1,151.30	TI4	SDS/LGSS
435	37	20721676001	400472176	LG2			3969	1333095	7,763.66	LG2	SDS/LGSS
436	37	20733007001	400473253	LG2			1290	1292977	9,793.67	LG2	SDS/LGSS
437	37	20733007003	400288865	SG4			46395	1292977	4,562.60	SG4	SGSS2/SCD2/SGDS2
438	37	20733007004	400289580	SG4			46393	1292977	4,562.60	SG4	SGSS2/SCD2/SGDS2
439	37	20757032003	400471986	SGT	TAG6		3754	1333017	1,646.10	TAG6	SGSS2/SCD2/SGDS2
440	37	20875641001	400473354	SG2			1377	1292913	936.34	SG2	SGSS2/SCD2/SGDS2
441	37	20910648001	400472256	LG3			3642	1333074	279.49	LG3	LDS/LGSS
442	37	20915520001	400490462	SGT	TIB		14386	0010156	3,285.22	TIB	SDS/LGSS
443	37	21032523001	400493917	SGT	TMB		14046	0070452	125,098.41	TMB	MDS/NSS
444	37	21032523002	400505175	SGT		882	14699	0070468	23,377.51	882	FLEX
445	37	21051676001	400472854	SGT	TI4		733	0070471	42.30	TI4	SDS/LGSS
446	37	21069532001	400526998	SGT	TMB		14788	0070470	12,635.49	TMB	MDS/NSS
447	37	21079991001	400472075	LG4			3879	1333027	0.00	LG4	LDS/LGSS
448	37	21106925001	500922300	SGT	TIB		49427	0551509	49,416.98	TIB	SDS/LGSS

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurment Stations
As of November 30, 2023

Line No.	Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
449	37	21136528001	400473125	SC2		949	0030231	2,662.32	SC2	SGSS2/SCD2/SGDS2
450	37	21143096003	400472012	SG2		3792	1333027	600.79	SG2	SGSS2/SCD2/SGDS2
451	37	21170009004	500635532	LG2		48654	1333004	4,591.38	LG2	SDS/LGSS
452	37	21175050001	400472009	LG2		3788	1333027	4,470.87	LG2	SDS/LGSS
453	37	21255328001	400472437	SG2		3304	0010104	8,015.12	SG2	SGSS2/SCD2/SGDS2
454	37	21256476001	400498767	SGT	TI8	14635	0010119	4,285.84	TI8	LDS/LGSS
455	37	21286391001	400472886	SG3		760	0070471	3,829.02	SG3	SGSS1/SCD1/SGDS1
456	37	21334880001	500171349	SG2		45520	0030205	11,235.36	SG2	SGSS2/SCD2/SGDS2
457	37	21337959001	400526191	SGT	TIF	44761	0190613	52,867.22	TIF	LDS/LGSS
458	37	21350543001	500204877	SG2		48298	0030272	5,399.51	SG2	SGSS2/SCD2/SGDS2
459	37	21368534001	800800442	SG3		4410	0070458	1,250.67	SG3	SGSS1/SCD1/SGDS1
460	37	21382000001	400500097	SGT	TM4	14666	0010119	980.04	TM4	MDS/NSS
461	37	21401731001	400481256	LG1		1114	1252804	9,682.54	LG1	SDS/LGSS
462	37	21407113001	400510507	SGT	TAG2	926	0070495	457.93	TAG2	SGSS2/SCD2/SGDS2
463	37	21407113003	500146350	SGT	TAG2	926	0070495	457.93	TAG2	SGSS2/SCD2/SGDS2
464	37	21455068001	400498570	SG2		49393	0310911	12,392.69	SG2	SGSS2/SCD2/SGDS2

		Total Cost	Percent
465	**RSS/RTS**	**0.00**	**0.000%**
466	**SGSS1/SCD1/SGDS1**	**48,716.58**	**0.848%**
467	**SGSS2/SCD2/SGDS2**	**1,035,761.87**	**18.051%**
468	**SDS/LGSS**	**1,671,829.45**	**29.136%**
469	**LDS/LGSS**	**2,264,205.41**	**39.460%**
470	**FLEX**	**717,520.01**	**12.505%**
471	**TOTAL BEFORE MLDS/NSS**	**5,738,033.32**	**100.000%**
472	**MDS/NSS**	**489,133.12**	
473	**INACTIVE**	**66,682.61**	
474	**FLEX MLDS**	**0.00**	
475	**TOTAL**	**6,293,849.05**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 18
OTHER DISTRIBUTION O&M EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	871.00	LOAD DISPATCHING	351,332	177,943	31,230	44,447	29,491	38,397	25	29,800
2	874.00	MAINS & SERVICES	21,487,649	12,905,697	1,821,938	2,154,781	1,396,053	1,806,682	1,074	1,401,425
3	875.00	M & R - GENERAL	822,530	416,595	73,115	104,058	69,043	89,894	58	69,767
4	876.00	M & R - INDUSTRIAL	364,527	(0)	3,091	65,801	106,209	143,842	-	45,584
5	878.00	METERS & HOUSE REGULATORS	2,652,757	2,127,776	346,264	158,741	15,147	3,767	345	716
6	879.00	CUSTOMER INSTALLATIONS	6,731,153	6,141,033	479,191	90,332	14,472	4,106	-	2,019
7	886.00	STRUCTURES AND IMPROVEMEN	183,766	93,074	16,335	23,248	15,425	20,084	13	15,587
8	887.00	MAINS	14,250,198	7,217,440	1,266,700	1,802,793	1,196,162	1,557,404	998	1,208,702
9	889.00	M & R - GENERAL	1,669,918	845,780	148,439	211,261	140,173	182,505	117	141,642
10	890.00	M & R - INDUSTRIAL	141,201	-	1,197	25,488	41,140	55,718	-	17,657
11	892.00	SERVICES	2,517,097	2,296,423	179,192	33,779	5,412	1,535	-	755
12	893.00	METERS & HOUSE REGULATORS	568,175	455,733	74,164	34,000	3,244	807	74	153
13		TOTAL	51,740,303	32,677,494	4,440,856	4,748,730	3,031,971	3,904,742	2,703	2,933,808
14		**ALLOCATOR #18**	100.000%	63.157%	8.583%	9.178%	5.860%	7.547%	0.005%	5.670%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 19
O & M EXCLUDING GAS PURCHASED COST, UNCOLLECTIBLES, USP COSTS & A & G

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1		TOTAL PURCH GAS & UNDERGROUND STORAGE	177,140,868	131,593,246	19,382,965	21,068,195	4,680,213	127,526	288,723	-
2		TOTAL DISTRIBUTION O&M	66,486,039	41,990,458	5,706,483	6,102,093	3,896,071	5,017,602	3,440	3,769,891
3		TOTAL CUSTOMER ACCOUNTS	57,148,422	54,815,912	1,068,836	451,537	427,328	322,685	24,963	37,162
4		TOTAL CUSTOMER SERVICE & INFORMATION	1,422,809	1,303,862	99,995	17,131	1,494	256	29	43
5		TOTAL SALES	25,733	23,582	1,809	310	27	5	1	1
6		TOTAL	302,223,871	229,727,061	26,260,087	27,639,266	9,005,132	5,468,074	317,155	3,807,097
	LESS:									
7		GAS PURCHASED COST	175,812,168	130,606,294	19,237,511	20,910,104	4,645,130	126,570	286,559	-
8	904.00	UNCOLLECTIBLES-DIS REVENUE	7,752,525	7,247,603	267,695	237,227	-	-	-	-
9	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	754,150	-	784	16,448	383,644	296,351	22,873	34,050
10	904.00	UNCOLLECTIBLES-UNBUNDLED GAS	1,206,507	1,121,429	42,565	42,513	-	-	-	-
11	904.00	DIRECT USP UNCOLLECTIBLES	37,168,342	37,168,342	-	-	-	-	-	-
12	904.00	UNCOLLECTIBLES-DIS COVID-19 DEFERRAL	645,316	603,287	22,283	19,747	-	-	-	-
13	904.00	UNCOLLECTIBLES-GMB/GTS COVID-19 DEFERRAL	62,775	(0)	65	1,369	31,934	24,668	1,904	2,834
14		TOTAL	223,401,783	176,746,954	19,570,903	21,227,408	5,060,708	447,589	311,336	36,884
15		TOTAL	78,822,088	52,980,106	6,689,184	6,411,858	3,944,425	5,020,485	5,818	3,770,213
16		**ALLOCATOR #19**	100.000%	67.216%	8.486%	8.135%	5.004%	6.369%	0.007%	4.783%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2023

ALLOCATED COST OF SERVICE — PAGE 1
CUSTOMER/DEMAND — WITNESS: K. L. Johnson

Line No.	Description	Alloc	Total Company	RS/RDS	SGS1/SCD1/SGDS1	SGS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	FLEX
			Footage	Amount	Unit Cost				
1	2" Pipe		15,086,659	422,915,781	$28.03				
2	All Pipe		41,520,570	2,119,867,012					
3	Unit Cost of 2" x All Pipe Footage			1,163,821,577					
4	Customer Component			54.901%					
5	Demand Component			45.099%					
6	Number of Customers (Total Company excl MLDS)		446,561	409,241	31,385	5,375	468	80	12
7	Percent Customers		100.000%	91.642%	7.028%	1.204%	0.105%	0.018%	0.003%
8	Customer Component		54.901%	50.314%	3.858%	0.661%	0.058%	0.010%	0.002%
9	Design Day Volumes (Total Company excl MLDS)		793,000	449,400	82,600	109,300	56,000	54,000	41,700
10	Percent Design Day Volumes		100.000%	56.670%	10.416%	13.783%	7.062%	6.810%	5.259%
11	Demand Component		45.099%	25.557%	4.698%	6.216%	3.185%	3.071%	2.372%
12	**Minimum System Allocation Factor**		**100.000%**	**75.869%**	**8.556%**	**6.877%**	**3.243%**	**3.081%**	**2.374%**

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 21
HOUSE REGULATORS

All Customers Excluding Low Pressure Customers

LINE NO.	Rate	RS/RTS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MLDS	FLEX	TOTAL
1	RC2	155,208	0	0	0	0	0	0	155,208
2	RS	2,852,656	0	0	0	0	0	0	2,852,656
3	RTC	390,273	0	0	0	0	0	0	390,273
4	LG1	0	0	0	456	0	0	0	456
5	LG2	0	0	0	470	0	0	0	470
6	LG3	0	0	0	0	24	0	0	24
7	LG4	0	0	0	0	12	0	0	12
8	NSI	0	0	0	0	0	12	0	12
9	SGS	0	190,018	0	0	0	0	0	190,018
10	SG2	0	0	26,387	0	0	0	0	26,387
11	SG3	0	323	0	0	0	0	0	323
12	SG4	0	0	507	0	0	0	0	507
13	EDSTIB1	0	0	0	0	0	0	12	12
14	TAG1	0	1,111	0	0	0	0	0	1,111
15	TAG2	0	0	2,427	0	0	0	0	2,427
16	TAG5	0	5,665	0	0	0	0	0	5,665
17	TAG6	0	0	11,431	0	0	0	0	11,431
18	TIB	0	0	0	2,546	0	0	0	2,546
19	TIF	0	0	0	0	360	0	0	360
20	TIG	0	0	0	0	36	0	0	36
21	TIH	0	0	0	0	12	0	0	12
22	TI4	0	0	0	2,064	0	0	0	2,064
23	TI8	0	0	0	0	480	0	0	480
24	TMA	0	0	0	0	0	12	0	12
25	TM1	0	0	0	0	0	12	0	12
26	TM4	0	0	0	0	0	24	0	24
27	TM3	0	0	0	0	0	12	0	12
28	TMB	0	0	0	0	0	72	0	72
29	802	0	0	0	0	0	0	12	12
30	808	0	0	0	0	0	0	12	12
31	809	0	0	0	0	0	0	24	24
32	810	0	0	0	0	0	0	24	24
33	831	0	0	0	0	0	0	0	0
34	833	0	0	0	0	0	0	12	12
35	840	0	0	0	0	0	0	0	0
36	845	0	0	0	0	0	0	0	0
37	846	0	0	0	0	0	0	12	12
38	847	0	0	0	0	0	0	0	0
39	848	0	0	0	0	0	0	0	0
40	857	0	0	0	0	0	0	0	0
41	868	0	0	0	0	0	0	0	0
42	873	0	0	0	0	0	0	0	0
43	875	0	0	0	0	0	0	12	12
44	876	0	0	0	0	0	0	0	0
45	877	0	0	0	0	0	0	0	0
46	879	0	0	0	0	0	0	12	12
47	880	0	0	0	0	0	0	12	12
48	881	0	0	0	0	0	0	12	12
49	882	0	0	0	0	0	0	12	12
50	SCC	0	59,069	0	0	0	0	0	59,069
51	SC2	0	0	12,376	0	0	0	0	12,376
52	**Total**	**3,398,137**	**256,186**	**53,128**	**5,536**	**924**	**144**	**168**	**3,714,223**
53	**ALLOCATOR #21**	91.490%	6.897%	1.430%	0.149%	0.025%	0.004%	0.005%	100.000%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 22
AVERAGE ALLOCATORS 5 & 20

LINE NO.		RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX	TOTAL
1	ALLOCATOR #5	50.650%	8.890%	12.652%	8.395%	10.930%	8.483%	100.000%
2	ALLOCATOR #20	75.869%	8.556%	6.877%	3.243%	3.081%	2.374%	100.000%
3	TOTAL OF BOTH STUDIES	126.519%	17.446%	19.529%	11.638%	14.011%	10.857%	
4	AVERAGE OF BOTH STUDIES	63.260%	8.723%	9.765%	5.819%	7.006%	5.429%	100.000%
5	**ALLOCATOR #22**	63.260%	8.723%	9.765%	5.819%	7.006%	5.429%	100.000%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 23
METERS AND HOUSE REGULATORS - ACCOUNTS 381, 382, 383, & 384

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	381.00	METERS	48,647,043	37,965,612	6,928,798	3,339,133	317,665	79,781	7,297	8,757
2	381.00	DIRECT - METERS - MLDS FLEX	16,319	-	-	-	-	-	-	16,319
3	381.10	AUTOMATIC METER READING	25,165,055	19,639,564	3,584,259	1,727,329	164,328	41,271	3,775	4,530
4	382.00	METER INSTALLATIONS	50,934,022	39,750,439	7,254,533	3,496,111	332,599	83,532	7,640	9,168
5	383.00	HOUSE REGULATORS	20,531,392	18,784,171	1,416,050	293,599	30,592	5,133	821	1,027
6	384.00	HOUSE REG INSTALLATIONS	3,538,803	3,237,651	244,071	50,605	5,273	885	142	177
7		TOTAL	148,832,634	119,377,436	19,427,711	8,906,778	850,457	210,601	19,675	39,976
8		**ALLOCATOR #23**	100.000%	80.210%	13.053%	5.984%	0.571%	0.142%	0.013%	0.027%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 24
LABOR

LINE NO.	ACCT. NO.	ACCOUNT	ALLOC FACTOR	TOTAL COMPANY	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	816.00	WELLS	25	-	-	-	-	-	-	-	-
2	817.00	LINES	25	-	-	-	-	-	-	-	-
3	818.00	COMPRESSOR STATION	25	-	-	-	-	-	-	-	-
4	820.00	M & R	25	-	-	-	-	-	-	-	-
5	821.00	PURIFICATION	25	-	-	-	-	-	-	-	-
6	832.00	WELLS	25	-	-	-	-	-	-	-	-
7	834.00	COMPRESSOR STATION	25	-	-	-	-	-	-	-	-
8	836.00	PURIFICATION	25	-	-	-	-	-	-	-	-
9	870.00	SUPERVISION & ENGINEERING	18	5,902,521	3,727,855	506,613	541,733	345,888	445,463	295	334,673
10	871.00	LOAD DISPATCHING	13	260,001	131,685	23,112	32,893	21,825	28,416	18	22,053
11	874.00	MAINS & SERVICES	14	9,685,573	5,817,252	821,240	971,269	629,272	814,363	484	631,693
12	875.00	M & R - GENERAL	13	502,398	254,454	44,658	63,558	42,171	54,907	35	42,613
13	876.00	M & R - INDUSTRIAL	17	197,131	(0)	1,672	35,584	57,436	77,788	-	24,651
14	878.00	METERS & HOUSE REGULATORS	23	1,669,958	1,339,473	217,980	99,930	9,536	2,371	217	451
15	879.00	CUSTOMER INSTALLATIONS	15	4,880,490	4,452,617	347,442	65,496	10,493	2,977	-	1,464
16	880.00	OTHER	18	2,089,546	1,319,695	179,346	191,779	122,447	157,698	105	118,477
17	885.00	SUPERVISION & ENGINEERING	18	151,918	95,947	13,039	13,943	8,902	11,465	8	8,614
18	886.00	STRUCTURES AND IMPROVEMENTS	13	4,175	2,114	371	528	350	456	0	354
19	887.00	MAINS	13	3,777,297	1,913,125	335,764	477,866	317,066	412,821	264	320,390
20	889.00	M & R - GENERAL	13	1,104,579	559,447	98,186	139,740	92,718	120,720	77	93,690
21	890.00	M & R - INDUSTRIAL	17	48,822	(0)	414	8,813	14,225	19,265	-	6,105
22	892.00	SERVICES	15	1,250,353	1,140,734	89,013	16,780	2,688	763	-	375
23	893.00	METERS & HOUSE REGULATORS	23	318,663	255,599	41,595	19,069	1,820	453	41	86
24	894.00	OTHER EQUIPMENT	18	490,315	309,669	42,084	45,001	28,733	37,004	25	27,801
25	902.00	METER READING	6	248,961	228,148	17,497	2,998	261	45	5	8
26	903.00	CUSTOMER RECORDS AND COLLECTION EXPENSE	6	1,791,540	1,641,768	125,909	21,570	1,881	323	36	54
27	920.00	SALARIES	19	2,890,953	1,943,183	245,326	235,179	144,663	184,125	202	138,274
28	921.00	OFFICE SUPPLIES & EXPENSES	19	594,424	399,548	50,443	48,356	29,745	37,859	42	28,431
29	923.00	OUTSIDE SERVICES EMPLOYED	19	-	-	-	-	-	-	-	-
30		TOTAL		37,859,616	25,532,314	3,201,703	3,032,086	1,882,121	2,409,280	1,855	1,800,259
31		**ALLOCATOR #24**		100.000%	67.439%	8.457%	8.009%	4.971%	6.364%	0.005%	4.755%

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

GROSS INTANGIBLE & DISTRIBUTION PLANT - GENERAL LEDGERS 101, 106 AND 107 – PAGE 3

INTANGIBLE PLANT - PAGE 3 (101-106-107)

Accounts 301, 302 and 303

Intangible plant was allocated on the basis of Distribution plant excluding Accounts 375.7, 375.71 and 387, Factor No. 11, due to its indirect relationship with all other plant.

UNDERGROUND STORAGE PLANT - PAGE 3 (101-106-107)

Accounts 350 through 355

Underground Storage Plant was allocated using Factor No. 25 – Sales and CHOICE Transportation activity for the historic test year reflecting its peaking support for sales and CHOICE customers.

DISTRIBUTION PLANT - PAGE 3 (101-106-107)

Account 375.60

Structures for large customers, not directly assigned, were allocated using Factor No. 17 since these structures involve house measuring and regulating stations serving the larger customer groups only.

Account 376 – Mains

Non-directly assigned mains were allocated by rate schedule based on the weighting of design day and annual throughput, Factor No. 5, for the peak and average study. For the Customer-Demand study, such investment was based on Factor No. 20, which provides a customer component based on a 2" "Minimum System" with the remaining portion assigned on design-day. For the Average study, Factor No. 5 and Factor No. 20 are averaged to assign the Mains costs to the various rate schedules. Please see Exhibit KLJ-1 for a detailed description of Factor Nos. 5 and 20.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Direct Mains

Mains for Main Line Delivery Service ("MLDS") were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Mains - Related Accts

Accounts related to/or supports the mains gas plant account were allocation on Factor No. 5 under the Peak and Average study, Factor No. 20 under the Customer-Demand study, and Factor No. 22 under the Average study since these accounts directly support the mains investment. The mains-related accounts generally include the follow gas plant accounts: 374.10, 374.20, 374.30, 374.40, 374.41, 374.50, 375.20, 375.31, 375.40, 375.80, 378.10, 378.20, 378.30, 379.10 and 379.11.

Direct Mains - Related Accts

Similarly to the Mains - Related Accounts above, these are accounts that support the mains that were directly assigned to MLDS and include accounts 374.40, 374.50, 375.40, and 378.20. Like direct – mains, the amounts were identified from the Company's maps and accounting records and directly assigned.

Account 380 - Services

Account 380 - Services was assigned by rate schedule based on each customer's service size and the average unit cost of that size service on the Company's plant accounting records. This methodology represents virtually a direct assignment of costs to the various rate classes.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Like mains, services for MLDS were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Accounts 381 and 382

Meters and Meter Installations were allocated using Factor No. 16, which was based on an actual inventory of meters installed on customer premises as explained in Statement 6. This methodology represents a direct assignment of costs to the various rate classes.

Accounts 383 and 384

House Regulators and House Regulator Installations were allocated using Factor No. 21 which is based on number of customers by rate class that are not served from a low pressure main. Because customers served off low pressure mains do not require a House Regulator, those customers are not included in the allocation factor as explained in Statement No. 6.

Account 385

Industrial Measuring and Regulating Stations were allocated using Factor No. 17, which was based on a review of Columbia's records as explained in Statement 6. Measuring stations were segregated by rate schedule by identifying measuring stations in the plant accounting records with the individual customers in the Distributive Information System ("DIS"). This methodology represents a direct assignment of costs to the various rate classes.

Dist Plant Excl Other Allocated

This investment consists of gas plant accounts 375.70, 375.71 and all 387 and was allocated to the various rate schedules using Factor No. 11. Factor No. 11 was based on distribution plant specifically assigned and was used to assign general investment and costs that support the distribution system.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

General Plant

General plant includes items such as general tools (cars, trucks, backhoes, etc), communication equipment, office furniture and fixtures, and other miscellaneous equipment. Like general distribution plant, this plant investment supports the delivery of natural gas and, therefore, Factor No. 11 was used to assign the investment.

RESERVE FOR DEPRECIATION - PAGE 4

Depreciation Reserve was calculated on an account-by-account basis using the same allocation factors that were used to allocate all gross plant accounts.

DEPRECIATION & AMORTIZATION EXPENSE and NET NEGATIVE SALVAGE - PAGE 5

Depreciation and amortization expense was allocated by gas plant account on the same allocations as the Gross Original Cost. Amortization of net negative salvage was allocated using Factor 11 based on its remediation of distribution type facilities.

OPERATING REVENUE AT CURRENT AND PROPOSED RATES - PAGE 6

Sales and Transportation Revenue

Sales and transportation revenue was directly assigned as presented in Exhibit No. 103 for the fully projected future test year and supported by Witness Mays.

Accounts 487

Forfeited discounts were allocated using Factor No. 10, which was developed from actual forfeited discounts billed by rate class during the historic test year the twelve months ended November 30, 2023.

Accounts 488, 493 and 495

Miscellaneous Revenue and Other revenue were allocated using Factor No. 6 - Average Number of Customers since costs incurred throughout these accounts are directly related to the customers served. Rent Revenue was allocated using Factor No. 11 because the rent is derived

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

mostly from the rent of Company-owned office buildings, making the use of the Distribution Plant allocator appropriate.

OPERATING EXPENSES – PURCHASED GAS EXPENSES - PAGE 7

Gas purchased cost

These costs were directly assigned based on revenue for the fully projected future test year as presented in Exhibit No. 103.

Account 807

Gas Purchase Expense and Gas Procurement Expenses were allocated using Factor No. 4, which is based on the direct assignment of gas costs. Factor No. 4 was used reflecting the relationship of these costs to gas purchase costs. Gas purchase expense related to the gas procurement activity was also allocated using Factor No. 4.

OPERATING EXPENSES – UNDER STORAGE EXPENSES - PAGE 7

Accounts 814 through 837

Underground Storage Plant Expense was allocated using Factor No. 25 – Sales and CHOICE Transportation.

DISTRIBUTION EXPENSES – OPERATIONS - PAGE 7

Accounts 870, 880, 881

General costs for supervision and engineering, rents and other items of the distribution function were allocated using Factor No. 18, Other Distribution Expense, because these costs benefit customers in the way that all other distribution costs provide benefit.

Account 871

Distribution Load Dispatch Expenses were allocated on Factor No. 13 – Direct Plant – Mains because these are costs incurred monitoring and directing the flow of gas through the distribution system.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 874

Mains and Services Operation Expenses (a dual function account) were allocated on Factor No. 14 – Composite Direct Plant - Mains and Services combined.

Accounts 875

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures because these costs are incurred in direct relation with mains.

Accounts 876

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 – Direct Assignment – IND M&R - because these costs are incurred in direct association with the stations in Account 385.

Accounts 878 and 879

Meters & House Regulators Expenses were allocated using Factor No. 23, which was based on an actual inventory of meters and house regulators installed on customer premises as explained in Statement No. 6. This methodology represents virtually a direct assignment of costs to the various rate classes. Expenses for Customer Installations were allocated using Factor No. 15, because these expenses are related to the customer service lines.

DISTRIBUTION EXPENSES – MAINTENANCE - PAGE 7

Accounts 885 and 894

General costs for supervision and engineering and maintenance costs of other equipment of the distribution function were allocated using Factor No. 18 - Other Distribution Expense - because these costs benefit customers in the same way that all other distribution costs provide benefit.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 886

Structures and Improvements Expense was allocated using Factor No. 13, reflecting the spread of Account 376 Mains among all customer classes, because these plant and expense functions are directly related.

Account 887

Mains Maintenance Expense was allocated using Factor No. 13, which reflects the spread of Account 376 Mains among all customer classes, because plant and expense functions are directly related.

Accounts 889

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures because these costs are incurred in direct relation with mains.

Accounts 890

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 - Direct Assignment – IND M&R - because these costs are incurred in direct relation with the stations in Account 385.

Account 892

Expenses for Services were allocated using Factor No. 15, which was based on size of service and size of customer as explained above under Gas Plant Account 380 – Services and in Statement No. 6.

Account 893

Meters & House Regulators Expenses and Customer Installations were allocated using Factor No. 23, which was based on a weighted average cost of meters and house regulators as explained in Statement No. 6.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

CUSTOMER ACCOUNTS, CUSTOMER SERVICE AND INFORMATIONAL AND SALES EXPENSES - PAGE 8

Account 904 – Uncollectibles – DIS Revenue & Uncollectibles GMB/GTS Revenue and Covid-19 Deferral

These cost categories represent traditional bad debts. They have been separated between the residential and commercial classes of customers and allocated based on the historical charge-offs and revenue, related to each, as included in Factor No. 7 for DIS and Factor No. 8 for GMB/GTS, respectively.

Account 904 Uncollectibles – Unbundled

These costs were directly assigned to each rate schedule matching revenue for the fully projected future test year, as presented in Exhibit No. 103 for the Merchant Function Charge.

Account 904 – Direct USP Uncollectibles

These uncollectibles are directly related to the Company's Customer Assistance Program ("CAP") available to residential customers and are recoverable from the residential class whether sales or delivery service. The amounts shown are reflected in revenue for the fully projected future test year as presented in Exhibit No. 103.

Customer Accounts

Customer Accounts includes meter reading, customer records, and credit and collection activities recorded in accounts 901 through 903, 905, and 921. These costs were allocated using Factor No. 6, Average Number of Customers, because they are directly related to the number of customers served. Interest on Customer Deposits was allocated using Factor No. 9, because the interest is directly related to the amount of customer deposits.

Customer Service Information

Customer Service and Informational Costs are reflected in accounts 907 through 910 plus related costs in 921 and 931. These costs were allocated using Factor No. 6, because all customers

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

may benefit except account 908 – Direct USP/LIURP/HEEP. These costs include the recovery of specific customer programs benefiting residential customers. The amounts reflect the recovery included in revenue as presented in Exhibit No. 103 for the fully forecasted rate year.

Sales Expense

Sales expenses, accounts 912 and 913, were allocated using Factor No. 6, Average Number of Customers, because these activities directly support customers served.

ADMINISTRATIVE AND GENERAL EXPENSES - PAGE 8

Admin. & General Expenses (Line 33)

General Office Expenses, and to a lesser degree, District and Local Office Expenses in this function classification, plus Company-wide expenses excluding Employee Benefits, Account 926, such as Injuries and Damages, Insurance, and Regulatory Commission Expense, were all allocated using Factor No. 19 - Total Operation & Maintenance Excluding Gas Purchased, A & G, Uncollectibles and USP rider costs. These costs are regarded as overhead to the entire Company operation and, therefore, follow the allocation of the aggregate of all other previously allocated O&M costs. Employee Pensions & Benefits, Account 926, was allocated on Factor No. 24, Labor, because they are directly related to company labor. Account 923 – Multifamily House Line Reimbursement costs are a residential program and therefore the costs are directly assigned to the residential class.

TAXES OTHER THAN INCOME - PAGE 9

Property taxes are directly related to tangible property and, accordingly, have been allocated based on Factor No. 11 - Distribution Plant excluding Other, due to a direct relationship with Plant in Service. Similarly, PA Capital Stock and License and Franchise Taxes were allocated using Factor No. 11, as they are also related to Plant in Service. Federal Unemployment Insurance, State Unemployment Insurance and F.I.C.A. (payroll based taxes) are all labor-related and, accordingly, have been allocated based on Factor No. 24 – Labor. State Sales and Use Tax and Other Taxes

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

were allocated using Factor 19 because these taxes are generally related to the purchase of supplies.

RATE BASE SUMMARY - PAGE 10

Account 154

Materials and Supplies were allocated based on No. Factor 11, Distribution Plant Excluding Other, reflecting the primary future use of such inventory.

Account 164 & 117

Gas Stored Underground, both current and long term, was allocated based on Factor No. 25, Sales and CHOICE Transportation, reflecting the support of these customers in meeting their design day and seasonal requirements.

Account 165

Prepayments consist primarily of commission fees and corporate insurance, therefore they were allocated using Factor No. 19, Total O&M Excluding Gas Purchased Costs, A&G, Uncollectibles, and USP Rider Costs. The exception being Cloud Based Assets that, like Intangible Plant was allocated on the basis of Distribution Plant excluding Accounts 375.7, 375.71 and 387, Factor No. 11, due to its indirect relationship with all other plant.

Accounts 190, 254, 282 and 283

All deferred income taxes included in rate base are plant related and, therefore, Factor No. 12, Gross Plant, was used.

Account 235

Customer Deposits were allocated using Factor No. 9, Direct Assignment – Customer Deposits.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Accounts 252 and 186

Customer advances, other deferred credit and materials and supplies were allocated using Factor No. 11 - Distribution Plant Excluding Other, due to their direct relationship with all other gas plant accounts.

FEDERAL AND STATE INCOME TAX - PAGE 11

All of the Company's tax adjustments over book are plant related, i.e., tax depreciation over book depreciation and, therefore, the tax deductions were allocated using Factor No. 12, Gross Plant.

In calculating the Federal and State income taxes for each rate schedule, the effective Federal and State income tax rates were used. Income taxes were calculated for each rate class.

Columbia Gas of Pennsylvania, Inc.
Intra Class Adjustment from SGDS to SGSS and SCD at Proposed ROE of 11.75%
For the 12 Months Ending December 31, 2025

Ln. No.	Item	Total	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	Account 117	3,794,693	2,776,008	440,981	477,524	92,135	2,504	5,540
2	Account 164	35,252,442	25,788,924	4,096,686	4,436,167	855,929	23,267	51,469
3	Allocated Storage Per ACOS Study using Allocation Factor #25	39,047,135	28,564,932	4,537,668	4,913,691	948,064	25,771	57,009
4	Sales & CHOICE Transportation (Dth)	46,601,217.1	34,091,008	5,415,547	5,864,505	1,131,331	30,826	68,000
5	Factor 25 Allocation of Storage	100%	73.155%	11.621%	12.584%	2.428%	0.066%	0.146%
6	Pre-Tax as Filed	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%	11.11%
7	Revenue Requirement related to storage assigned to rate schedule (Ln. 6 * Ln. 7)	4,336,725	3,172,531	503,971	545,733	105,296	2,862	6,332
8	Rate Per Dth	0.0931						

Ln. No.		Total DTH	% of Total	Included In Proposed Rates	Ratio	Redistributed Per Settlement
13	SGSS1 - Subject to Storage	4,173,030.8	74.190%	373,896	0.7706	14,447
14	SCD1 - Subject to Storage	1,242,516.4	22.090%	111,327	0.2294	4,301
15	SGDS1 - Not Subject to Storage	209,051.1	3.720%	18,748		(18,748)
		5,624,598.3	100.000%	503,971		0

Ln. No.		Total DTH	% of Total	Included In Proposed Rates	Ratio	Redistributed Per Settlement
20	SGSS2 - Subject to Storage	4,167,949.4	47.370%	258,514	0.7107	129,349
21	SCD2 - Subject to Storage	1,696,555.7	19.280%	105,217	0.2893	52,653
22	SGDS2 - Not Subject to Storage	2,934,305.7	33.350%	182,002		(182,002)
		8,798,810.8	100.000%	545,733		0

Unitized Returns at Current Rates and Proposed Rates

Ln.	Study (Mains Allocation Method)	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	Peak & Average Current Rates	1.21	1.09	1.08	1.14	0.34	40.02	(0.56)
2	Peak & Average Proposed Rates	1.20	1.08	1.05	1.09	0.41	28.17	(0.39)
3	Customer/Demand Current Rates	0.74	1.15	2.44	3.93	2.94	40.02	(0.18)
4	Customer/Demand Proposed Rates	0.78	1.13	2.23	3.50	2.66	28.17	(0.13)
5	Average of P/A & C/D Current Rates	0.94	1.12	1.57	1.93	0.92	40.02	(0.47)
6	Average of P/A & C/D Proposed Rates	0.96	1.10	1.47	1.78	0.91	28.17	(0.33)

Columbia Gas of Pennsylvania , Inc
Calculation of Gas Procurement Charge
Proposal to Maintain Current Rate[1]

		Rate Case Calculation		
		Amount	**Rate**	
1	**Labor and Benefits** [2]			
2	Accounting Support	$4,531.43		
3	Gas Supply Support	$203,428.42		
4	Legal Support	$5,685.68		
5	Regulatory Support	$84,506.70		
6	Treasury Support	$11,999.46		
7	**Total Labor and Benefits (Line 2 + Line 3 + Line 4 + Line 5 + Line 6)**	**$310,151.69**		
8	**Outside Services - Legal Support**	**$61,000.00**		
9	**Information Technology Systems Maintenance**			
10	Gas Source	$49,021.00		
11	% of customers taking Sales Service	80.00%		
12	**Cost allocated to Sales Service Customers (line 10 * Line 11)**	**$39,216.80**		
13	**TOTAL (line 7 + line 8 + line 12)**	**$410,368.49**		
14	Total Sales (Therms)	362,959,766 [3]		
15	Gas Procurement Charge (Line 13 / Line 14)		$0.00113	per / therm
16	Gas Procurement Charge (Line 15 * 10)		$0.01130	per / Dth

(1) The Company proposes to maintain the current Gas Procurement Charge as the overall fundamentals of the calculation have not changed. The current charge was calculated in the 2021 Rate Case.

(2) Labor charges include payroll, benefits and taxes.

(3) 2021 Rate Case - Fully Projected Future Test Year Gas Service Sales per Exhibit 103, Sch. 1, Page 14, Line 49, less Rate NSS Sales as NSS is not subject to GPC.

Columbia Gas of Pennsylvania, Inc.
Benchmark Distribution Revenue per Bill (BDRB)
For the 12 Months Ending December 31, 2025

Number of Bills

	Residential FPFTY RS	Residential RTC FPFTY	Residential RS Final Bills	Residential RTC Final Bills	New Residential Customers	Residential Customer Attrition	Total
January	341,467.0	45,117.0	3,663.0	244.0	0.0	(1,342.0)	389,149.0
February	342,082.0	44,921.0	3,684.0	233.0	262.0	(1,343.0)	389,839.0
March	342,235.0	44,577.0	3,864.0	246.0	530.0	(1,343.0)	390,109.0
April	341,310.0	44,265.0	4,209.0	330.0	801.0	(1,339.0)	389,576.0
May	340,068.0	44,013.0	5,709.0	344.0	1,016.0	(1,333.0)	389,817.0
June	338,863.0	43,872.0	6,827.0	354.0	1,180.0	(1,329.0)	389,767.0
July	338,074.0	43,802.0	5,839.0	365.0	1,506.0	(1,326.0)	388,260.0
August	337,787.0	43,802.0	6,127.0	352.0	2,156.0	(1,325.0)	388,899.0
September	338,187.0	43,841.0	4,963.0	298.0	2,488.0	(1,326.0)	388,451.0
October	339,464.0	43,824.0	4,410.0	306.0	3,537.0	(1,331.0)	390,210.0
November	341,495.0	43,679.0	4,557.0	454.0	3,930.0	(1,337.0)	392,778.0
December	343,705.0	42,516.0	4,363.0	260.0	4,213.0	(1,340.0)	393,717.0
Total	4,084,737.0	528,229.0	58,215.0	3,786.0	21,619.0	(16,014.0)	4,680,572.0

Volumes (Dth)

	Residential FPFTY RS	Residential RTC FPFTY	Residential RS Final Bills	Residential RTC Final Bills	New Residential Customers	Residential Customer Attrition	Total
January	5,283,926.8	773,774.7	0.0	0.0	2,413.0	(21,206.0)	6,038,908.5
February	5,398,469.0	777,326.0	0.0	0.0	6,283.0	(21,620.0)	6,160,458.0
March	4,494,196.0	662,865.8	0.0	0.0	10,295.0	(18,053.0)	5,149,303.8
April	2,948,875.7	463,186.2	0.0	0.0	13,370.0	(11,945.0)	3,413,486.9
May	1,311,308.8	182,594.1	0.0	0.0	14,359.0	(5,230.0)	1,503,031.9
June	643,667.4	95,198.8	0.0	0.0	14,045.0	(2,587.0)	750,324.2
July	389,173.6	57,762.4	0.0	0.0	15,329.0	(1,565.0)	460,700.0
August	359,093.1	55,391.1	0.0	0.0	19,157.0	(1,451.0)	432,190.2
September	371,074.1	53,744.0	0.0	0.0	19,682.0	(1,487.0)	443,013.1
October	613,015.6	100,661.0	0.0	0.0	25,457.0	(2,498.0)	736,635.6
November	1,788,418.6	275,966.3	0.0	0.0	26,890.0	(7,227.0)	2,084,047.9
December	3,919,980.5	567,564.0	0.0	0.0	29,491.0	(15,710.0)	4,501,325.5
Total	27,521,199.2	4,066,034.4	0.0	0.0	196,771.0	(110,578.0)	31,673,425.6

Calculation of Benchmark Distribution Revenue per Bill (BDRB)

	Bills	Rate	Customer Based Revenue	Volumes (Dth)	Rate/Dth	Volumetric Based Revenue	BDRB
	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=((3+6)/1)
January	389,149	$ 26.00	$ 10,117,874	6,038,908.5	$ 10.2781	$ 62,068,505	$ 185.50
February	389,839	$ 26.00	$ 10,135,814	6,160,458.0	$ 10.2781	$ 63,317,803	$ 188.42
March	390,109	$ 26.00	$ 10,142,834	5,149,303.8	$ 10.2781	$ 52,925,059	$ 161.67
April	389,576	$ 26.00	$ 10,128,976	3,413,486.9	$ 10.2781	$ 35,084,160	$ 116.06
May	389,817	$ 26.00	$ 10,135,242	1,503,031.9	$ 10.2781	$ 15,448,312	$ 65.63
June	389,767	$ 26.00	$ 10,133,942	750,324.2	$ 10.2781	$ 7,711,907	$ 45.79
July	388,260	$ 26.00	$ 10,094,760	460,700.0	$ 10.2781	$ 4,735,121	$ 38.20
August	388,899	$ 26.00	$ 10,111,374	432,190.2	$ 10.2781	$ 4,442,094	$ 37.42
September	388,451	$ 26.00	$ 10,099,726	443,013.1	$ 10.2781	$ 4,553,333	$ 37.72
October	390,210	$ 26.00	$ 10,145,460	736,635.6	$ 10.2781	$ 7,571,214	$ 45.40
November	392,778	$ 26.00	$ 10,212,228	2,084,047.9	$ 10.2781	$ 21,420,053	$ 80.53
December	393,717	$ 26.00	$ 10,236,642	4,501,325.5	$ 10.2781	$ 46,265,074	$ 143.51
Total	4,680,572.0		$ 121,694,872	31,673,425.6		$ 325,542,636	$ 1,145.85
BDRBp (Oct-Mar)							$ 805.03
BDRBo (Apr-Sep)							$ 340.82

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAp")
Peak Period RNAp Effective October 2025 through March 2026

Line No.		Line Applications	Oct	Nov	Dec	Jan	Feb	Mar	Jan - Mar
	Non-CAP Residential Customers:								
1	**Benchmark Distribution Revenue per Bill ("BDRBp")**								Three month
2		Per Docket							BDRBp
3	Monthly BDRBp	R-2024-3046519	$ 45.40	$ 80.53	$ 143.51	$ 185.50	$ 188.42	$ 161.67	$ 535.59
4									
5	**Actual Distribution Revenue per Bill ("ADRBp")**								Three month
6									ADRBp
7	Monthly ADRBp*		NA	NA	NA	$ 181.25	$ 185.00	$ 158.35	$ 524.60
8									Total
9	Monthly BDRBp - Monthly ADRBp	ln 3 - ln 7				$ 4.25	$ 3.42	$ 3.32	$ 10.99
10									
11	**Actual Number of non-CAP residential Bills ("ANBp")**								
12									Average ANBp
13	Monthly ANBp*		NA	NA	NA	387,343	387,801	387,645	387,596
14									
15									
16	**Revenue to be Assigned to RNAp Rate**					$ 1,646,207.75	$ 1,326,279.42	$ 1,286,981.40	$ 4,259,683.70
17									
18	**Forecast Decatherms (Dth) for Effective RNAp Period (FTp)***		713,677	2,064,385	4,487,545	6,057,702	6,175,795	5,157,062	24,656,164
19									
20	**RNAp Rate Effective October 2025 through March 2026**	ln 16 / ln 18							$ 0.1728

* For illustrative purposes only.

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAo")
Off-Peak Period RNAo Effective April 2026 through September 2026

Line No.		Line Applications	Apr	May	Jun	Jul	Aug	Sep	Apr - Sep
	Non-CAP Residential Customers:								
1	**Benchmark Distribution Revenue per Bill ("BDRBo")**								
2		Per Docket							Total BDRBo
3	Monthly BDRBo	R-2024-3046519	$ 116.06	$ 65.63	$ 45.79	$ 38.20	$ 37.42	$ 37.72	$ 340.82
4									
5	**Actual Distribution Revenue per Bill ("ADRBo")**								
6									Total ADRBo
7	Monthly ADRBo*		$ 113.00	$ 67.20	$ 46.00	$ 36.12	$ 38.00	$ 38.00	$ 338.32
8									Total
9	Monthly BDRBo - Monthly ADRBo	ln 3 - ln 7	$ 3.06	$ (1.57)	$ (0.21)	$ 2.08	$ (0.58)	$ (0.28)	$ 2.50
10									
11	**Actual Number of non-CAP residential Bills ("ANBo")**								
12									Average ANBo
13	Monthly ANBo*		386,438	384,972	383,661	382,816	382,546	383,000	383,906
14									
15									
16	**Revenue to be Assigned to RNAo Rate**		$ 1,182,500.28	$ (604,406.04)	$ (80,568.81)	$ 796,257.28	$ (221,876.68)	$ (107,240.00)	$ 959,763.75
17									
18	**Forecast Decatherms (Dth) for Effective RNA Period (FTo)***		3,316,223	1,614,072	830,226	495,881	469,677	468,424	7,194,503
19									
20	**RNAo Rate Effective April 2026 through September 2026**	ln 16 / ln 18							$ 0.1334

* For illustrative purposes only.

Columbia Gas of Pennsylvania, Inc.
Proposed Customer Charge Impact
For the 12 Months Ending December 31, 2025

Line		Bills	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS
1	**Calculated Monthly Customer Charge (excl. Mains) (Peak & Average)**						
2	**Exhibit 111, Schedule 2, Page 25, Line 39**		$28.71	$31.68	$59.53	$300.62	$1,711.06
3	**Calculated Monthly Customer Charge (incl. Mains) (Customer / Demand)**					$926.85	$6,174.02
4	**Exhibit 111, Schedule 2, Page 16, Line 43**						
5	**Midpoint**					$613.74	$3,942.54
6	**Current Customer Charges**		$16.75	$29.92	$57.00	$775.86 1/	$4,055.72 2/
7	**Percent of Calculated Monthly Customer Charge (excl. Mains)**		**58%**	**94%**	**96%**		
8	**Percent of Midpoint @ Current Rates**					**126%**	**103%**
9	**Proposed Customer Charges**		$26.00	$36.55	$69.63	$947.18 3/	$4,955.55 4/
10	**Percent of Calculated Monthly Customer Charge (excl. Mains)**		**91%**	**115%**	**117%**		
11	**Percent of Midpoint @ Proposed Rates**					**154%**	**126%**

Footnotes:

1/ SDS/LGSS - Current Rates

	Bills	
> 64,400 to ≤ 110,00 Therms Annually	2,596	$267.11
>110,000 to ≤ 540,000 Therms Annually	3,031	$1,211.59
Weighted Average		$775.86

2/ LDS/LGSS - Current Rates

	Bills	
> 540,000 to <= 1,074,000 Therms Annually	529	$2,986.82
> 1,074,000 to <= 3,400,000 Therms Annually	372	$4,645.73
> 3,400,000 to <= 7,500,000 Therms Annually	48	$8,959.14
> 7,500,000 Therms Annually	12	$13,272.55
Weighted Average		$4,055.72

3/ SDS/LGSS - Proposed Rates

	Bills	
> 64,400 to ≤ 110,00 Therms Annually	2,596	$326.09
>110,000 to ≤ 540,000 Therms Annually	3,031	$1,479.13
Weighted Average		$947.18

4/ LDS/LGSS - Proposed Rates

	Bills	
> 540,000 to <= 1,074,000 Therms Annually	529	$3,649.50
> 1,074,000 to <= 3,400,000 Therms Annually	372	$5,676.46
> 3,400,000 to <= 7,500,000 Therms Annually	48	$10,946.88
> 7,500,000 Therms Annually	12	$16,217.29
Weighted Average		$4,955.55

Columbia Gas of Pennsylvania, Inc
Impact on Monthly Bill of Customer Charge at Proposed Rate ($26.00) vs. Current Rate ($16.75)
All Residential Customers

[1] Line	[2] Year	[3] Month	[4] Normal Usage *1 Dth	[5] Customer Charge $26.00	[6] Distribution Charge $10.2781	[7] Gas Supply Charge $4.1059	[8] Total Bill @ Proposed Rate [5]+[6]+[7]	[9] Normal Usage *1 Dth	[10] Customer Charge $16.75	[11] Distribution Charge $11.6286	[12] Gas Supply Charge $4.1059	[13] Total Bill @ Current Rate [10]+[11]+[12]	[14] Impact on Total Bill [8]-[13]
1	2025	Jan	15.88	$26.00	$163.17	$65.18	$254.36	15.88	$16.75	$184.61	$65.18	$266.55	$ (12.19)
2	2025	Feb	16.21	$26.00	$166.64	$66.57	$259.21	16.21	$16.75	$188.54	$66.57	$271.85	$ (12.65)
3	2025	Mar	13.53	$26.00	$139.01	$55.53	$220.55	13.53	$16.75	$157.28	$55.53	$229.56	$ (9.02)
4	2025	Apr	8.92	$26.00	$91.67	$36.62	$154.29	8.92	$16.75	$103.71	$36.62	$157.08	$ (2.79)
5	2025	May	4.01	$26.00	$41.17	$16.45	$83.61	4.01	$16.75	$46.58	$16.45	$79.77	$ 3.84
6	2025	Jun	1.95	$26.00	$20.04	$8.00	$54.04	1.95	$16.75	$22.67	$8.00	$47.42	$ 6.62
7	2025	Jul	1.17	$26.00	$12.00	$4.79	$42.80	1.17	$16.75	$13.58	$4.79	$35.12	$ 7.67
8	2025	Aug	1.08	$26.00	$11.08	$4.43	$41.51	1.08	$16.75	$12.54	$4.43	$33.72	$ 7.79
9	2025	Sep	1.11	$26.00	$11.41	$4.56	$41.96	1.11	$16.75	$12.91	$4.56	$34.21	$ 7.75
10	2025	Oct	1.87	$26.00	$19.20	$7.67	$52.88	1.87	$16.75	$21.73	$7.67	$46.15	$ 6.73
11	2025	Nov	5.42	$26.00	$55.74	$22.27	$104.01	5.42	$16.75	$63.07	$22.27	$102.08	$ 1.93
12	2025	Dec	11.73	$26.00	$120.52	$48.15	$194.67	11.73	$16.75	$136.36	$48.15	$201.25	$ (6.59)
13	Total	Annual	82.86	$312.00	$851.66	$340.22	$1,503.88	82.86	$201.00	$963.56	$340.22	$1,504.78	$ (0.90)

Notes:
*1) Refer to Exhibit No. 10, Schedule No. 2, Page 8 of 8; Witness Girata

Columbia Gas of Pennsylvania, Inc
Impact on Monthly Bill of Customer Charge at Proposed Rate ($26.00) vs. Current Rate ($16.75)
Residential CAP Customers

[1] Line	[2] Year	[3] Month	[4] Normal Usage Dth	[5] Customer Charge $26.00	[6] Distribution Charge $10.2781	[7] Gas Supply Charge $4.1059	[8] Total Bill @ Proposed Rate [5]+[6]+[7]	[9] Normal Usage *1 Dth	[10] Customer Charge $16.75	[11] Distribution Charge $11.6286	[12] Gas Supply Charge $4.1059	[13] Total Bill @ Current Rate [10]+[11]+[12]	[14] Impact on Total Bill [8]-[13]
14	2025	Jan	20.75	$26.00	$213.23	$85.18	$324.41	20.75	$16.75	$241.24	$85.18	$343.17	$ (18.77)
15	2025	Feb	21.41	$26.00	$220.02	$87.89	$333.91	21.41	$16.75	$248.92	$87.89	$353.57	$ (19.66)
16	2025	Mar	18.22	$26.00	$187.31	$74.83	$288.14	18.22	$16.75	$211.92	$74.83	$303.50	$ (15.36)
17	2025	Apr	12.27	$26.00	$126.11	$50.38	$202.50	12.27	$16.75	$142.69	$50.38	$209.82	$ (7.32)
18	2025	May	5.81	$26.00	$59.72	$23.86	$109.57	5.81	$16.75	$67.56	$23.86	$108.17	$ 1.40
19	2025	Jun	2.53	$26.00	$25.96	$10.37	$62.33	2.53	$16.75	$29.37	$10.37	$56.49	$ 5.84
20	2025	Jul	1.34	$26.00	$13.75	$5.49	$45.25	1.34	$16.75	$15.56	$5.49	$37.80	$ 7.44
21	2025	Aug	1.20	$26.00	$12.33	$4.93	$43.26	1.20	$16.75	$13.95	$4.93	$35.63	$ 7.63
22	2025	Sep	1.27	$26.00	$13.04	$5.21	$44.25	1.27	$16.75	$14.75	$5.21	$36.71	$ 7.54
23	2025	Oct	2.64	$26.00	$27.14	$10.84	$63.98	2.64	$16.75	$30.70	$10.84	$58.29	$ 5.68
24	2025	Nov	7.66	$26.00	$78.75	$31.46	$136.20	7.66	$16.75	$89.09	$31.46	$137.30	$ (1.10)
25	2025	Dec	15.58	$26.00	$160.08	$63.95	$250.04	15.58	$16.75	$181.12	$63.95	$261.82	$ (11.78)
26	Total	Annual	110.67	$312.00	$1,137.43	$454.38	$1,903.81	110.67	$201.00	$1,286.88	$454.38	$1,942.27	$ (38.45)

COLUMBIA STATEMENT NO. 6-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
KEVIN L. JOHNSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

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I. Introduction

Q. Please state your name and business address.

A. My name is Kevin L. Johnson. My business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Lead Regulatory Studies Analyst in the Regulatory Studies Department at NCSC.

Q. Have you previously filed testimony in this matter?

A. Yes, I previously submitted Columbia Statement No. 6.

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony, I will respond to certain testimony served in this proceeding by other parties. I will be addressing several arguments and conclusions presented in the direct testimony of Mr. Sakaya, witness for the Bureau of Investigation and Enforcement ("I&E"), Mr. Mierzwa, witness for the Office of Consumer Advocate ("OCA"), and Mr. Ewen, witness for the Office of Small Business Advocate ("OSBA"), on the subjects of Allocated Cost of Service Studies ("ACOSS"), revenue allocation to rate classes, rate design, the establishment of a Revenue Normalization Adjustment ("RNA") mechanism, and the Weather Normalization Adjustment ("WNA"). I will also be responding to the of Mr. Crist, witness for the Pennsylvania State University ("PSU"), on the subjects of ACOSS,

revenue allocation to rate classes, and rate design. In addition, I will be addressing several arguments and conclusions presented in the direct testimony of Ms. Warabak, witness for Pennsylvania Weatherization Providers Task Force ("WPTF") on the subject of rate design, and OCA witness Mr. Colton on the subjects of rate design, RNA, and WNA and OCA witness Dismukes on the subjects of RNA and WNA.

Q. Is the Company making any changes to what it originally filed in this proceeding?

A. Yes. As further discussed below, the Company is withdrawing its request to eliminate the WNA 3 percent deadband, as the design of the WNA is currently controlled by a prior settlement among parties.

II. Allocated Cost of Service

Q. The Company presented three separate ACOSS (Customer/Demand, Peak & Average, and Average Study). Please explain why three studies were prepared and why the Company principally relied upon the Peak & Average study as a guide to revenue allocation.

A. The difference between the Customer/Demand Study and the Peak & Average Study is the allocation of mains and mains-related costs. Both studies rely, in part, on the peak demand of customers as an allocator. However, the Customer/Demand Study relies, in part, upon the number of customers in each class, while the Peak & Average Study relies, in part, upon the average demand of each class. The Customer/Demand Study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class while the Peak & Average Study (Exhibit No. 111,

Schedule 2) produces results that are generally more favorable to the residential class. Columbia Gas of Pennsylvania ("Columbia" or "CPA") recognizes that no one cost of service study is the "right" study and, in the past, concluded that the results of two such studies provide a reasonable range of returns for use as a guide in establishing appropriate rates. The third study, as presented in Exhibit No. 111, Schedule 3, is an average of the Customer/Demand Study and the Peak & Average Study ("Average Study") and represents what Columbia believes is a reasonable range of revenue responsibility. This Average Study, with its equal weighting of the two former studies, provides the Company, the parties and the Commission with a range of returns that can be used as a benchmark or guide in revenue allocation.

In Columbia's 2020 rate case (Docket No. R-2020-3018835, p. 218, Order entered February 19, 2021), the Commission stated, "we find that the Peak & Average allocation methodology is the most appropriate allocation methodology to use in this proceeding because it is based on the premise of load-based investment." Consistent with the Commission's Order in the 2020 rate case and with the methodology used since the 2021 rate case, the Company continues to utilize the Peak & Average Study as the primary study to serve as a guide to allocate the proposed revenue increases in this case.

Q. Other than the Peak and Average ACOSS, what other guidelines or criteria did Columbia consider in the design of the Company's revenue allocation among the rate classes?

A. As noted in my direct testimony (Statement 6) on page 17: "Columbia believes the results from the other two studies (Customer/Demand and Average) can still be useful as another reference point in guiding the allocation of the proposed revenue increase. The results of the cost allocation studies support the Company's proposed rate schedules." In addition, on Page 21 on my direct testimony, I noted that "First, the design of Columbia's rates recognizes that rates must be just and reasonable and must not be unduly discriminatory".

Q. What is I&E witness Sakaya's preferred allocated cost of service method and what is the basis of his preference?

A. Mr. Sakaya agreed with the Company's use of the Peak & Average Study consistent with the Commission's ruling in the 2020 rate case (Docket No. R-2020-3018835). Mr. Sakaya also recommends that the Company continue to utilize the Peak and Average ACOSS to establish rates in future rate cases and for the Company to continue to classify flex rate customers as a separate class in future cost of service studies.

Q. What is OCA witness Mierzwa's preferred allocated cost of service method and what is the basis of his preference?

A. Mr. Mierzwa also agreed with the Company's use of the Peak & Average Study, consistent with the Commission's ruling in the 2020 rate case (Docket No. R-2020-3018835).

Q. What is OSBA witness Ewen's preferred allocated cost of service method and what is the basis of his preference?

A. Mr. Ewen states on page 12 of his direct testimony that "While I disagree with the Commission's findings regarding mains cost allocation in the 2020 base rates case, I rely generally on the method employed by the Company in its P&A ACOSS for reasons of Commission precedent with respect to Columbia."

Q. What is PSU witness Crist's preferred allocated cost of service method and what is the basis of his preference?

A. Mr. Crist states on Page 19 of his direct testimony that the Company's Customer-Demand ACOSS study (Exhibit No. 111, Schedule 1) should be the preferred approach by the Commission. Mr. Crist supports his preference on Page 19 of his direct testimony by stating that "the allocated increase to the LDS/LGSS class is exceptionally excessive."

Q. Did Mr. Crist address the Commission's Order in Columbia's 2020 base rate proceeding?

A. Yes. Mr. Crist expressed his opinion that the reason the Commission selected the Peak & Average Study in Columbia's 2020 rate case is because there was an "error" in the Company's Customer-Demand Study. The "error" that Mr. Crist is referring to is the separation of gas main investment by operating pressure. Mr. Crist explained that Columbia did not separate gas mains investment by operating pressure in its Customer-Demand Study presented this case. On page 13 of Mr. Crist's testimony, he pointed out that "In her Recommended Decision ALJ Dunderdale stated, 'The ALJ recommends the Commission use the Peak & Average COSS, as promoted by OCA, in this base rate proceeding. Columbia Gas' Customer

Demand COSS would be the preferred method, but it contains serious flaws that skews its reliability and makes it unsuitable for use at this time and with this NGDC.'" Mr. Crist also quotes the Commission's 2020 rate case Order in which the Commission stated, "we are not persuaded to reverse the ALJ's Recommended Decision that adopted the OCA's P&A ACOSS and methodology in this proceeding." PSU Statement No. 1, p. 14.

Q. What is the Company's response to Mr. Crist's analysis of the 2020 rate case Order?

A. From these statements it seems possible that Columbia's separation by operating pressure of customers, design day volumes and throughput that made up the mains allocation factors in that case was the "error" identified by the ALJ and that because Mr. Mierzwa's Peak and Average study was the only study presented that did not first separate by operating pressure, that may have been the deciding factor in the Commission's Decision to use the Peak and Average study in that case. The Company did not separate mains by operating pressure in this case.

Q. Do you agree with Mr. Crist that the Peak and Average study should not be used and that modifications should be made to the Customer/Demand ACOSS to "produce a result that represents actual data"?

A. No. Columbia has consistently advocated in its prior rate cases for the use of the Peak and Average study in the determination of allocating revenue requirement to the rate classes. However, Columbia has never advocated for the Peak and Average study as the sole basis of revenue requirement allocation. Various factors, including gradualism,

value of service and alternative cost studies, are appropriately considered in revenue requirement allocation. The Company agrees with Mr. Crist, and stated its agreement in data request PSU 3-006, that it is reasonable to assume Columbia has not built 13 miles of dedicated mains to each LDS/LGSS customer. The Company, however, does not agree that its Customer/Demand study, or any of its studies, should be modified to "represent actual data." Each of the three ACOSS submitted by the Company in this case are valuable tools for revenue allocation, but each produces varying results. The various ACOSS presented are each accurate and should not be modified. For this case, Columbia used the Peak and Average study as the primary study to establish class rates of return at present and proposed rates. The Peak and Average study was given primary consideration by the Commission in Columbia's 2020 rate case. Columbia believes the results from the other two studies can still be useful as another reference point in guiding the allocation of the proposed revenue increase. While the Company believes using the Customer/Demand study as a reference point is appropriate, modifying the Customer/Demand study and using it to guide the proposed revenue increase, as Mr. Crist suggests, should not be considered.

Q. How do the positions of the parties differ from the Company's on the use of the ACOSS?

A. As previously mentioned, a combination of preferences exists among the parties as to which distribution mains allocation method they prefer and which should be used as a guide in the allocation of proposed revenue increases in this case. Witness Mierzwa

and Witness Sakaya both recommend the use of the Peak & Average Study, citing Commission precedent.

Witness Ewen disagrees with the findings regarding mains cost allocation in the 2020 rate case by the Commission. However, he accepts using the Company's Peak & Average methodology for reasons of Commission precedent.

Mr. Crist rejects the Company's Peak & Average and Average studies based on what he has identified as facts and engineering and, instead, recommends that a modified Customer/Demand study should be the sole basis of the allocation of proposed revenue increases in this case. Mr. Crist further adds "The Peak & Average method used in the other COSS conducted by the Company does not apply cost causation accurately because it allocates the costs of gas mains based in large part on the average demand or annual throughput and that is a violation of cost causation principles. This allocation result (sic) in cost-shifting and cross-class subsidization, which is contrary to the principles of ratemaking." PSU Statement No. 1, 18-19.

The Company recognizes this Commission's preference for the use of the Peak and Average study and, therefore, the Company used the Peak and Average study as the primary guide for the allocation of the proposed revenue increase in this case. While the Company believes the use of the three studies is appropriate, absent further guidance from the Commission, it has concluded that the Peak and Average study should be used as the primary guide. However, the Company does not believe that basing the revenue allocation in this case entirely on the Peak & Average Study would produce a reasonable result, particularly with respect to allocation of mains cost to the

LDS/LGSS class. The Company also does not agree with Mr. Crist that a modified Customer/Demand study should be the sole basis of allocating revenue requirement among the rate classes.

III. Revenue Allocation

Q. How do the positions of the parties differ from the Company's proposed allocation of revenue requirement among the rate classes?

A. I&E witness Sakaya agrees with the Company's use of the Peak and Average methodology to allocate proposed revenue increases among the different customer classes.

OCA witness Mierzwa has assigned an increase of 2.0 times the system average to the LDS/LGSS rate class. Mr. Mierzwa's allocated revenue requirement to the LDS/LGSS class is in excess of the 1.5 times average system increase, which represents the upper bound for rate gradualism used by the Commission in Columbia's 2020 rate case (Docket No. R-2020-3018835). Therefore, the Company does not support Mr. Mierzwa's recommendation.

OSBA witness Ewen reallocated flex rate shortfall to other classes based on a revenue – cost metric to help determine progress toward cost-based rates. The Company assigned the increase to the Customer Charge to the Flex customers first and then used the limits of gradualism toward parity to assign the revenue requirement in this case. Mr. Ewen relies on an alternative ACOSS to make adjustments to each class with the exception of the Company's proposal for the MDS and Flex rate classes, but also assigned the LDS/LGSS class an increase of 2.0 times the system average. By doing so,

Mr. Ewen's allocated revenue requirement to the LDS/LGSS class is in excess of the 1.5 times average system increase, which represents the upper bound for rate gradualism used by the Commission in Columbia's 2020 rate case (Docket No. R-2020-3018835). For this reason, the Company does not agree with Mr. Ewen's proposed revenue allocation.

PSU witness Crist used his modified Customer/Demand cost study to lower the LDS/LGSS class apportionment of rate base from $85,515,193 to $30,753,663 and as a result produces a revenue requirement of $15,800,000 to the LDS/LGSS class. This is a substantial reduction from revenues at current rates for the class of $27,382,567. Mr. Crist offers no recommendation as to what class would be responsible for this $11.5 Million proposed revenue reduction for the LDS/LGSS class. Since Mr. Crist used a modified Customer/Demand study to allocate revenue, the Company does not agree with his proposed revenue allocation, and does not support his proposed rate reduction for this class.

IV. Scale Back of Rates

Q. What does I&E witness Sakaya propose in the event the Commission recommends less than the Company's requested revenue requirement request?

A. I&E witness Sakaya recommends that all customer charges and usage rates that have a proposed increase be scaled back proportionately based on the ACOSS that is ultimately approved by the Commission.

Q. What are other parties in the case recommending with respect to scale-back of proposed revenue distribution in the event that Columbia's authorized increase is less than its requested increase?

A. OCA witness Mr. Mierzwa recommends a proportionate scale-back of the increase for each rate class with the exception of the MLDS and Flex rate classes.

Q. What is the Company's position with regard to I&E's and OCA's scaleback recommendations?

A. As discussed above, Columbia disagrees with Mr. Mierzwa's proposed revenue allocation and therefore, does not support his scaleback recommendation. Since Mr. Sakaya and the Company agree on the proposed revenue allocation, the Company agrees with Mr. Sakaya on his scaleback approach.

V. Customer Charge

Q. What changes did I&E witness Sakaya recommend in regard to the Company's customer charge proposals, and do you agree with the proposals?

A. I&E witness Sakaya recommends the residential class customer charge be lowered from the Company's proposed $26.00 to $20.46. Witness Sakaya's proposed $20.46 residential customer charge is based upon proposed rate increases across all other classes. Mr. Sakaya did not recommend adjustments to the proposed customer charges for the other rate classes.

Mr. Sakaya notes on Page 19 of his direct testimony that Columbia's customer cost analysis excluding mains supports a customer charge of $28.71. Columbia recognizes

that the customer cost analysis shows a minimum floor in which fixed costs should be recovered and that the study ultimately supports the Company's proposed $26.00 residential class customer charge. However, since Columbia's current residential customer charge of $16.75 has not changed since the 2012 rate case, the Company does appreciate I&E's recognition that an increase to the residential customer charge is appropriate.

Q. Mr. Mierzwa, on page 16 of his direct testimony, states that "Columbia has included uncollectible expenses (Account 904) of $9,214,766 in its calculation, which is not a direct customer cost." Mr. Mierzwa suggests these costs should not be included in the customer charge calculation. Do you agree?

A. No. It is important to note that not only are direct customer costs appropriately included in the customer charge calculation, but it is also appropriate to include customer-based costs and associated overhead. Assigning 100% of uncollectible cost to the volumetric base rates for recovery essentially creates an intra-class subsidy to those lower use customers. Because the customer charge is a portion of the customers' bills that become uncollectible, those who pay the customer charge should help pay for the uncollectible accounts the charge generates and, therefore, the uncollectible expenses (Account 904) be included in the customer charge calculation.

Q. Mr. Mierzwa, on page 16 of his direct testimony, claims that Columbia's current monthly residential customer charge is already the highest in the Commonwealth, and the proposed charge is inconsistent with the

Commission's goal of encouraging energy conservation. As such, Mr. Mierzwa recommends that the existing $16.75 monthly charge be maintained. Do you agree?

A. Columbia's residential customer charge should be based on the fixed costs incurred by Columbia and approved by the Commission as recoverable through the customer charge. Columbia's residential customer charge should not be determined by the cost of service of other local distribution companies ("LDCs") in Pennsylvania. Even using the customer cost study that excludes mains costs, customer costs exceed the proposed customer charge. Customer costs continue to rise as service lines, regulators and meters are replaced as part of infrastructure improvement. There has been no corresponding increase to the residential customer charge since 2012.

Q. Does the Company agree with Mr. Ewen's proposed SGS1 and SGS2 customer charges?

A. The Company recommends assigning class-average increases to the customer charges for the SGS1 and SGS2 classes and is proposing a $36.55 customer charge for the SGS1 class and $69.63 for the SGS2 class. Mr. Ewen is using the customer charge resulting from the customer cost study as a maximum charge to recover fixed costs through fixed recovery and is recommending a $31.68 customer charge for the SGS1 class and $59.53 for the SGS2 class. The Company sees the customer charge resulting from the customer cost study as an establishment of a minimum charge to recover fixed costs through the customer charge and, therefore, opposes the OSBA's proposal to lower the Company's proposed customer charges for the SGS1 and SGS2 classes.

Q. WPTF witness Warabak states on page 3 of her direct testimony, "Further, an increase in the fixed monthly charge, as requested by the Company, would negatively impact a customer's motive and ability to conserve energy. The Company's proposal if granted would increase rates, discourage conservation and leave a customer with less ability to conserve energy and less ability to reduce their bills." OCA witness Colton states on page 74 of his testimony that "This increase in the part of the total bill that is comprised of fixed charges impedes the ability of low-income customers to control their bills through a reduction in their usage." Do you have any comments on witness Warabak's and witness Colton's statements?

A. Yes. The customer will continue to have substantial incentive to conserve under the Company's proposed rates, as consumption charges will still increase over current charges. The Company's proposal also does not change commodity gas cost charges. If the Company does not increase the revenue requirement of the customer charge in this case, it will have to increase the volumetric base rate by the entire revenue requirement increase approved by the Commission. As stated in my direct testimony, that would change the residential customer charge from the proposed $26.00 per month to the current $16.75 per month and shift the entire amount of the approved revenue requirement to the volumetric rate, changing it from $10.2781 per Dth to $11.6286 per Dth. However, Table KLJ-1R below shows that, at the residential average monthly usage of 70 therms (7.0 Dth) in this case, the customer's bill is essentially identical ($97.95 vs $98.15) under Columbia's proposed residential customer charge

and Ms. Warabak's and Mr. Colton's proposed residential customer charge. Table KLJ-2R shows the difference in the customer's monthly bill if the customer reduced consumption by 1.35 Dth per month by replacing a furnace.[1] The result would be an additional $1.62 ($84.07 - $82.45) per month savings to the customer under witnesses Warabak's and Colton's proposals not to change the customer charge as compared to the Company's rate design. While Ms. Warabak's and Mr. Colton's proposals would result in $1.62 per month savings if a customer chose to replace a furnace, it is unlikely that $1.62 per month savings would motivate a customer to purchase a new furnace, which is what would be required to achieve the 1.35 Dth per month reduction in usage in this example. Therefore, Ms. Warabak's assertion that increasing the customer charge would "negatively impact a customer's motive and ability to conserve energy" and Mr. Colton's statement that the increased customer charge would "discourage conservation and leave a customer with less ability to conserve energy and less ability to reduce their bills" are not supported. The Company's proposed residential customer charge increase is appropriate and should be accepted.

Table KLJ-1R

	Columbia's Proposed Residential Rates	Warabak and Colton's Proposed Customer Charge Change
Customer Charged Amount	$26.00	$16.75
Volumetric Charged Amount	$10.2781 * 7.0 = $71.95	$11.6286 * 7.0 = $81.40
Total Base Rate Charged Amount	$97.95	$98.15

[1] The Company assumes an annual reduction of 16.2 Dth due to a furnace replacement. (16.2 Dth / 12 Months = 1.35 Dth per month). 7.0 Dth – 1.35 Dth = 5.65 Dth.

Table KLJ-2R

	Columbia's Proposed Residential Rates	Warabak and Colton's Proposed Customer Charge Change
Customer Charged Amount	$26.00	$16.75
Volumetric Charged Amount	$10.2781 * 5.65 = $58.07	$11.6286 * 5.65 = $65.70
Total Base Rate Charged Amount	$84.07	$82.45

VI. Revenue Normalization Adjustment ("RNA")

Q. On page 11 of his direct testimony, I&E witness Sakaya states three reasons for his recommendation to deny the Company's proposed RNA in this case. Please address each of his reasons.

A. Mr. Sakaya listed his reasons as follows. First, the Commission recently determined the RNA was unnecessary in the Company's 2020 base rate proceeding. Second, the policy statement cited by the Company does not allow the Company to abandon the necessity to charge just and reasonable rates. Third, the use of the FPFTY already provides projected lower usage levels.

In reply to Mr. Sakaya's first reason, the Commission did not determine that the RNA was not necessary. The Commission stated the following in Docket No. R-2020-3018835, at pages 264-265, (Order entered February 19, 2021):

> The ALJ recommended that the Commission deny the RNA proposal. The ALJ reasoned that Columbia failed to prove the RNA Rider is needed and reasonable, or that the RNA Rider will result in rates that are just, reasonable and in the public interest. Further, the Company did not show its current rates and systems of revenue streams will fail to provide revenue stability. R.D. at 403.

Although the ALJ merely found that Columbia failed to prove the RNA was needed in that case, it is also to be noted that Columbia did not file any exceptions to this issue in the 2020 case, and thus did not present full argument to the Commission on this issue.

Columbia's financial health directly relies upon its ability to recover the cost of service approved by the Commission through the base non-gas revenues upon which its base rates were established. As customers conserve, the volumetric base rate recovers less base revenue than required to recover the Company's cost of service.

In months the WNA is not in effect, there are still variances between actual and normal usage due to a variety of undefined factors. As a result, the volumetric base rate recovers either less or more base revenue than required to recover the Company's cost of service depending on those variances.

The proposed RNA addresses these shortfalls of the volumetric base rates' ability to accomplish the objective of providing Columbia with a more reasonable opportunity to recover its costs, which are substantially fixed and do not vary in relation to usage.

As for Mr. Sakaya's second reason, Mr. Sakaya assumes that Columbia is abandoning the necessity to charge just and reasonable rates by pointing to the Commission's Policy Statement on Alternative Ratemaking as adopted by the Commission at Docket No. M-2015-2518883. This is not the case. The base rates established by the Commission in the case will be just and reasonable. The RNA mechanism does not replace the billings of the base rates established in this case. The RNA does complement the residential rate design in this case to better ensure the revenue

requirement assigned to the residential class is not over or under recovered due strictly to rate design.

As for Mr. Sakaya's third reason, Mr. Sakaya suggests the core reason justifying an RNA is already being addressed by the use of the FPFTY and its projected lower usage levels. Although the use of the FPFTY may assist in volumetric base rates' ability to recover Columbia's fixed costs, it does not eliminate the need for an RNA. To the extent that actual usage is greater than or less that what was forecasted for this case, the revenue collected will be different than what is approved by the Commission in this case. Even though "projected lower usage levels" are included in the billing determinates of the FPFTY, actual conservation, actual weather within the 3% WNA tolerance level, and other variances all contribute to recovery variances caused by a volumetric base rate.

Q. On pages 18 through 24 of his direct testimony, OCA witness Mierzwa addresses the 14 factors for consideration identified in the Commission's statement of policy on alternative rate making. What comments do you have on Mr. Mierzwa's responses to Columbia's claims?

A. Of the 14 factors, Mr. Mierzwa agreed in principle with Columbia on 4 considerations. I will comment on those considerations where he differs.

> Consideration 1: Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.
>
> COLUMBIA: Columbia's proposed RNA is designed to recover the residential base revenues needed to satisfy the cost of service

> requirements determined in this proceeding while negating over or under recovery of costs.
>
> OCA: The Company's response does not indicate how the mechanism aligns revenues with cost causation as to fixed and variable costs. The RNA provides for the recovery of fixed costs on a volumetric basis; therefore, it does not align utility revenues with cost causation principles as to both fixed and variable costs.

OCA Statement No. 5 at 19. The RNA is designed to recover the residential base revenues needed to satisfy the cost of service requirements determined in this proceeding while negating over or under recovery of costs. Residential base revenues consist of customer charge revenues and volumetric base rate revenues and were established using cost causation principles. The customer charge recovers a portion of the Company's fixed monthly costs regardless of changes in usage per customer and, therefore, does not contribute to the RNA rate. Volumetric base rate charges recover the fixed costs the customer charge does not recover and all variable costs. To the extent the residential customer's monthly usage per customer differs from the benchmark established in this proceeding by the Commission, the Company will either over recover or under recover the fixed and variable costs through the variable base rates that the Company is authorized to bill by the Commission. The proposed RNA is designed to recover/pass back the under/over collected amount charged by the variable base rates for recovery of those fixed and variable costs caused by the change in usage per customer. Therefore, the mechanism more closely aligns actual revenues to costs.

> <u>Consideration 3</u>: Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

> COLUMBIA: Columbia's RNA benchmark revenue includes the anticipated volumetric base revenue derived from the fully projected test year consumption.
>
> OCA: The RNA adjustment or "true-up" mechanism creates the anomaly where customers see rate increases when they reduce consumption and rate decreases when they increase consumption.

OCA Statement No. 5 at 19. The RNA mechanism and the Company's rate design do reflect the customer's anticipated consumption levels as provided in the fully projected future test year.

> Consideration 4: Please explain how the ratemaking mechanism and rate design limit or eliminate inter-class and intra-class cost shifting.
>
> COLUMBIA: Columbia's RNA minimizes inter-class cost subsidization by limiting the amount of cost recovery for the residential class to the revenue benchmark established in this case. Residential intra-class cost subsidization is reduced through Columbia's proposal of a higher customer charge for the residential class.
>
> OCA: The RNA is only applicable to the Residential class and, therefore, does not affect interclass cost shifting. The Company's higher Residential customer charge proposal, which should be rejected, is unrelated to the RNA. OCA witness Roger Colton explains that, with respect to interclass cost shifting, the RDM 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.

OCA Statement No. 5 at 19-20. I disagree with the OCA. The Company's proposed higher residential customer charge is related to the RNA in that it reduces the amount of revenue subject to recovery through the RNA for all customers, including low-income customers.

> Consideration 5: Please explain how the RNA limits or eliminates disincentives for the promotion of efficiency programs.
>
> COLUMBIA: Reduced throughput will not lead to revenue and earnings erosion due to under-recovery because the link between level of throughput and base revenue recoveries is broken with the implementation of the RNA.
>
> OCA: The Company has not demonstrated that the lack of an RNA has been a major obstacle for the promotion of its voluntary energy efficiency & conservation (EE&C) activities. The Company has been able to implement methods to improve consumer efficiency without an RNA. Moreover, there has been a long-term trend of per-customer declining gas consumption (i.e. improved natural gas efficiency use) without an RNA.

OCA Statement No. 5 at 20 The Company's RNA does not affect customers' ability to pursue energy efficiency measures. Further the Company will continue to promote the use of energy efficiency measures to its customers through the Company's Energy Efficiency programs via Columbia's website, social media, emails, newsletters, bill inserts, and Google ads.

> Consideration 6: Please explain how the RNA impacts customer incentives to employ efficiency measures and distributed energy resources.
>
> COLUMBIA: Customers will continue to have an incentive to pursue energy efficiency measures since approximately 30% of an average residential bill is still subject to volumetric usage not related to base rate revenue recovery.
>
> OCA: The RNA reduces the incentive for Residential customers to pursue energy efficiency programs. Base rate revenue savings that would ordinarily be achieved through usage reductions will be offset by higher usage charges under the RNA.
>
> More specifically, the proposed RNA could provide a disincentive to ratepayers to undertake energy conservation efforts because they would be required to pay for gas they did not

> use. Revenue savings to individual customers that would ordinarily be achieved through usage reductions would be offset by surcharges to all customers under the RNA. Hence, if customers save money on their monthly gas bill due to efficient consumption, customers will be forced to share their bill savings with the utility. Moreover, with the high and apparently never-ending rate increases that Columbia Gas has implemented and will apparently continue to seek, customers are already incented to conserve gas without a new RNA surcharge.

OCA Statement No. 5 at 20-21. Columbia disagrees with OCA's comments. When an individual residential customer decides to reduce usage, the customer pays less to the Company through volumetric charges. The shortfall of base revenue from the customer will be made up by the entire residential class, not just the residential customers that choose to conserve. This encourages other residential customers to conserve as well.

> Consideration 7: Please explain how the RNA impacts low-income customers and support consumer assistance programs.
>
> COLUMBIA: Columbia's proposed RNA only applies to non-CAP customers.
>
> OCA: The RNA will not impact CAP customers.
>
> However, as OCA witness Colton points out, not all low-income customers are enrolled in CAP and for those customers not enrolled in CAP, the RNA will be applied to their bills and have the same effect of being a disincentive to energy efficiency as non-low-income customers. Additionally, OCA witness Colton addresses how the RNA could affirmatively harm non-CAP, low income customers that do not have the financial means to pursue investments in energy efficiency and conservation measures.

OCA Statement No. 5 at 21. For the reasons set forth above in response to Consideration 6, Columbia disagrees with Mr. Mierzwa and Mr. Colton that the RNA will have the same effect of being a disincentive to energy efficiency.

> Consideration 8: Please explain how the RNA impacts customer rate stability principles.
>
> COLUMBIA: Columbia's proposed RNA enables the recovery of costs established in this case and, therefore, mitigates the potential under or over recovery of costs that could require a material rate adjustment in the future.
>
> OCA: Under the current regulatory standard in Pennsylvania, base rate cost under and over recoveries are currently not tracked and are not eligible for recovery in future base rate proceedings. The RNA will not change this standard.
>
> The proposed RNA would add another surcharge to customers' bills and the Company has not shown how it would reduce the frequency of Columbia Gas base rate filings. Thus, it does not appear that a new RNA surcharge would improve rate stability. In contrast, under traditional cost-of-service ratemaking, if a utility experiences sales reductions and under-recovery, it cannot simply achieve the same result as an RNA true-up by filing another base rate case with adjusted sales forecasts. When a utility files a general rate increase, all relevant information is reviewed to determine just and reasonable rates, not just sales forecasts. Traditional ratemaking produces rate stability.

OCA Statement No. 5 at 21-22. Columbia was referring to mitigating the potential material rate adjustment caused when the billing determinants used in a rate case to design rates are materially different than the usage per customer experienced currently. Absent an RNA mechanism, the Company's only option is to file a rate case to redesign the base rates in order to have a reasonable opportunity to recover the revenue requirement allowed by the Commission.

> Consideration 9: Please explain how weather impacts utility revenue under the RNA.
>
> COLUMBIA: The RNA, as proposed will capture base revenue differences net of weather as the benchmark is based upon normal weather and the actual revenue will include billed WNA adjustments.

OCA: Weather will not impact utility revenue under the RNA.

OCA Statement No. 5 at 22. Columbia disagrees with the OCA, to the extent WNA does not address weather impact within the 3% band and to the extent it impacts weather outside the months the WNA is in effect, weather may impact the RNA.

> Consideration 12: Please explain whether the RNA includes appropriate consumer protections.
>
> COLUMBIA: The RNA as proposed establishes a Benchmark Distribution Revenue per Bill ("BDRB") residential customer. Rider RNA will refund any amount over the established benchmark, and collect any amount below the benchmark. By design, the Company cannot retain revenue in excess of the BDRB, which protects the customer from being over-charged. Columbia will submit two filings per year for the RNA mechanism, which can be reviewed and audited by the Commission, similar to the process for the Company's PGC and Rider USP filings.
>
> OCA: The RNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony and the testimony of OCA witness Colton and OCA witness Dismukes.

OCA Statement No. 5 at 23. Mr. Mierzwa states, "The RNA does not include appropriate consumer protections" and references the testimony of OCA witnesses Colton and Dismukes.

Mr. Colton claims on page 93 of his direct testimony that the proposed RNA will impose disproportionate adverse impacts on low-income customers and will disincentivize energy efficiency measures. The proposed RNA does not apply to CAP customers and for the reasons set forth above in response to Considerations 6 and 7,

Columbia disagrees with Mr. Colton that the RNA will have the same effect of being a disincentive to energy efficiency.

Mr. Dismukes, on page 47 in his direct testimony, claims the Company's proposal has no ratepayer protection mechanisms. As mentioned above, the Company cannot retain revenue in excess of the BDRB, which protects the customer from being over-charged. Columbia will submit two filings per year for the RNA mechanism, which can be reviewed and audited by the Commission, similar to the process for the Company's PGC and Rider USP filings. The RNA does protect the consumer from the Company over collecting fixed costs through volumetric base rates due solely to rate design.

> Consideration 13: Please explain whether the RNA is understandable to customers.
>
> COLUMBIA: Columbia's RNA is not a unique concept to the regulated utility industry and similar versions have been implemented successfully in other jurisdictions in which Columbia operates. Columbia is also providing an RNA tariff that clearly shows the detail how the mechanism works.
>
> OCA: Columbia has not provided any evidence that the RNA will be understandable to customers.

OCA Statement No. 5 at 23. Columbia's affiliates in other states have successfully billed an RNA to residential customers in Virginia since 2010 and in Maryland since 2013. It is Columbia's understanding that these billings have been done with minimal inquiries. Experience shows that customers do not have difficulty understanding the RNA concept.

Q. On page 24 of Mr. Mierzwa's direct testimony, he states, "A new customer is likely to have purchased a more energy-efficient gas appliance than an

average existing customer, and would have lower usage than an average customer, all else being equal. This would increase Columbia's earnings beyond what they would have been without the RNA because Columbia's margins would be based on average Residential customer margins." Is this statement accurate?

A. Based on Columbia's historical customer usage data, it is much more likely that just the opposite will occur. As it pertains to new customers, it is more likely that the RNA will decrease Columbia's earnings below what it would have been without an RNA. Mr. Mierzwa's premise that new customers are likely to have purchased more energy-efficient gas appliances than an average existing customer, and would have lower usage than an existing average customer, all else being equal, does not account for the fact that new houses, although on average more energy efficient than existing houses, are also on average larger and, therefore, do actually use more gas than existing houses. This is demonstrated on Exhibit 103 Schedule 1, Page 13, Lines 2 – 4, which shows 27,607,392.2 Dth and 4,148,557 bills for all customers (including new construction) on rate RSS. That equates to an average use per customer of 79.9 Dth (27,607,392.2/ 4,148,557 x 12 months). Exhibit 103, Schedule 4, Page 14, shows the forecasted usage per customer per month for new construction for the test year. Adding the monthly usage per customer results in 82.9 Dth (15.88 + 16.21 + 13.53 + 8.92 + 4.01 + 1.95 + 1.17 + 1.08 + 1.11 + 1.87 + 5.42 + 11.73). The data shows that new construction actually is expected to use 3.0 more Dth (82.9 – 79.9) per customer per month than the average for all RSS customers.

Q. On page 25 of Mr. Mierzwa's direct testimony, he states, "the RNA would unreasonably apply to those Residential customers whose usage is relatively constant over time." Do you agree?

A. No. Residential customers are subject to weather variations. To the extent the WNA does not address weather impact within the 3% deadband and to the extent the customer's usage is impacted by weather outside the months that the WNA is in effect, even those residential customers who have a relatively constant usage over time will experience differences that will be picked up by the RNA. As for those residential customers who do not use gas for heat, those customers are already enjoying an intra-class subsidy from heating customers because a portion of their fixed costs are being collected through the volumetric base rate.

Q. On page 25 of Mr. Mierzwa's direct testimony, he states, "conversion of a volumetric rate into rates that yield a given revenue, regardless of the amount of service purchased, converts Columbia's volumetric rate into take-or-pay billing feature." Do you agree?

A. No. If a residential customer does not use any gas, they will not be charged a volumetric rate. This is not the case under a take-or-pay contract. If the residential class as a whole exceeds the weather normalized usage per customer established in the rate case by the Commission, each residential customer will receive a portion of the over recovery until the entire over collection is passed back. This is not the case under a take-or-pay contract. However, base rates are designed to offer the Company a reasonable opportunity to recover the authorized revenue requirement approved by

the Commission. The RNA is a mechanism that helps ensure that the Company does not over recover or under recover due solely to rate design.

Q. On pages 25 and 26 of Mr. Mierzwa's direct testimony, he states, "The proposed RNA operates to change rates, automatically, between rate cases, simply as a function of Residential distribution revenues being different from benchmark revenues due to factors other than weather. There is no review of Columbia's costs, or the volumes and attendant revenues from other customer classes that are not included under RNA." Do you agree?

A. No. Mr. Mierzwa is bringing up two separate circumstances that could occur whether the Company has an RNA for the residential class or not. Neither of these circumstances impacts the revenues Columbia receives through the RNA mechanism. The RNA is a mechanism that complements residential rate design to better ensure that Columbia has a reasonable opportunity to recover the revenue requirement approved by the Commission and to ensure customers a better opportunity not to be charged more than their cost of service established when current rates were designed. I provide two examples to illustrate these concepts.

Circumstance 1, Columbia's cost of service differs from the revenue requirement established by the Commission in the last rate case. By design, any deviation of Columbia's cost to serve residential customers between rate cases has no impact to the RNA rate because the RNA is based on the Commission-approved revenue requirement. This is no different than if the Company has no RNA; base rate revenue

recovery does not change between rate cases even if Columbia's cost of service does change.

Circumstance 2, Mr. Mierzwa alleges that if residential usage per customer were to fall over time, while SGSS1/DS-1 deliveries increased, Columbia's residential rates would be increased under RNA with no recognition of the increased SGSS1/Ds1 distribution service revenues. Witness Mierzwa's statement is flawed for a few reasons. First, he assumes that lower residential use per customer implies lower distribution costs. However, a drop in average residential customer usage does not simply translate to lower costs for Columbia. On the contrary, he assumes that higher commercial usage is not associated with higher costs. It is possible that increased SGSS1/DS-1 usage could result in incremental costs, but the level of costs would depend upon the unique set of circumstances surrounding the load growth.

Q. On page 26 of Mr. Mierzwa's direct testimony, he states, "Columbia's current system of rates and charges, which include fixed monthly customer charges, a Purchased Gas Adjustment mechanism, a Weather Normalization Adjustment, and a Distribution System Improvement Charge, provide for revenue stability and Columbia has not demonstrated that this stability is inadequate." Do you agree?

A. No. None of the mechanisms listed by Mr. Mierzwa address the revenue stability that Columbia's proposed RNA will provide. First, the Purchased Gas Adjustment mechanism does not help to stabilize revenues for distribution service. The gas cost adjustment is merely a tracker to collect costs related to the gas commodity to pass

through to customers and it is not a revenue stream for Columbia. Second, Columbia's residential customer charge does not fully recover the fixed costs of service for residential customers. Please refer to my direct testimony and schedules for detailed customer cost studies. Third, as discussed above, the RNA would provide stability to the extent the WNA does not address weather impact within the 3% deadband and to the extent the customer's usage is impacted by weather outside the months that the WNA is in effect. Finally, the DSIC includes a cap equal to 5 percent of distribution revenues, which limits its usefulness for Columbia due to the Company's high rate of infrastructure replacement.

Q. On page 26 of Mr. Mierzwa's direct testimony, he states "The Company proposed a similar RNA in its last litigated base rate case. In that proceeding the ALJ determined that the Company failed to prove that the RNA would result in rates that were just and reasonable, in the public interest, and the Company did not demonstrate that its current rates and systems of revenue streams failed to provided revenue stability." Do you have any comments?

A. First, Columbia did not submit exceptions to the ALJ's recommendation regarding the RNA, and therefore, full arguments were not presented to the Commission in the last litigated rate case. Second, the following additional evidence not shown in that rate case demonstrates that Columbia's current rates and systems of revenue streams fail to provide revenue stability.

Again, the RNA is a mechanism that complements residential rate design to better ensure that Columbia has a reasonable opportunity to recover the revenue requirement approved by the Commission and to ensure customers a better opportunity not to be charged more than their cost of service established when current rates were designed.

Table KLJ-3R

Year	Basis	Residential Average Usage per Customer (Dth)
2014	Actual Normalized for Weather	90.3
2015	Actual Normalized for Weather	86.4
2016	Actual Normalized for Weather	85.6
2017	Actual Normalized for Weather	85.7
2018	Actual Normalized for Weather	87.3
2019	Actual Normalized for Weather	85.1
2020	Actual Normalized for Weather	83.2
2021	Actual Normalized for Weather	83.6
2022	Actual Normalized for Weather	83.0
2023	Actual Normalized for Weather	81.8
2025	Projected	82.9

Table KLJ-3R above shows that residential usage per customer normalized for weather has shown consistently decreasing levels from 2014 over the past 11 years. At current rates, a 1 Dth drop in usage amounts to an annual reduction of $3,552,125 in volumetric revenue to the Company (390,048 customers x $9.1069/Dth x 1Dth).

Q. On Page 22 of his direct testimony, OSBA witness Ewen opposes the Company's request for a RNA by stating, "If approved for the residential class, the Company will almost certainly rely on the precedent to support extending the mechanism to other rate classes, particularly the small commercial classes." What are your thoughts?

A. Columbia's affiliates in other states have successfully billed an RNA to residential

customers in Virginia since 2010 and Maryland since 2013. Currently, RNA for these two affiliates impacts only the residential class. CPA's proposal in this case is limited to the residential class and, therefore, does not affect the commercial and industrial classes.

VII. Weather Normalization Adjustment ("WNA")

Q. On Page 53 of his direct testimony, OCA witness Dismukes cites Columbia's 2021 rate case settlement that the WNA would continue until a final order is entered in the Company's first rate case filed after May 31, 2026 is approved. What is the Company's response to OCA witness Dismukes?

A. Based on a review of the 2021 rate proceeding settlement relating to the Company's WNA, the Company acknowledges the WNA approval period runs until a final order is entered in Columbia's first rate case after May 31, 2026, and respectfully withdraws its proposal to eliminate the 3 percent WNA deadband in this proceeding. Columbia, OCA, OSBA and I&E, among others, were all signatories to that Settlement. Withdrawing the proposal to make changes to the WNA to eliminate the 3 percent WNA deadband in this proceeding addresses the concerns of I&E witness Sakaya, OCA witnesses Colton, Dismukes, and Mierzwa, and OSBA witness Ewen, who all recommended the Company's proposal to make changes to the agreed-upon WNA pilot be denied.

Q. On Page 54 of his direct testimony, Mr. Dismukes discussed the effect of Columbia's proposal to remove the 3 percent deadband in this case by

stating, "Counsel informs me that since Columbia is proposing to modify the provisions of the WNA approved in Docket No. R-2021-3024296, whether the WNA should continue in effect requires evaluation in this proceeding. The Company has not provided this evaluation in the current proceeding." With the Company removing its proposal to make changes to the WNA pilot to eliminate the 3 percent deadband, do you believe the Company's WNA should be evaluated in this proceeding on whether it should continue?

A. No, the Company does not believe its WNA requires evaluation in this proceeding on whether it should continue as agreed upon in the settlement entered in Docket No. R-2021-3024296. The PUC approved the settlement in the 2021 base rate case, which specifically provided that the WNA with the 3 percent deadband would continue until a final order is entered in the Company's first rate case filed after May 31, 2026.

Q. Based on the Company's withdrawal of the proposal to eliminate the 3 percent WNA deadband and, therefore, making no proposal to change the 2021 rate case settlement term that the WNA continue until a final order is entered in Columbia's first rate case filed after May 31, 2026, do you agree with OCA witnesses Colton, Dismukes, and Mierzwa that Columbia's WNA should end?

A. No, based on the information discussed above, any proposal to end the Company's WNA in this matter should be denied.

Q. Although you believe the WNA should continue per the 2021 rate case order, have you prepared responses to OCA regarding the elimination of the Company's WNA?

A. Yes. Please see my discussion below.

Q. What are the principles of rate design as stated in The American Gas Association ("AGA") Gas Rate Fundamentals book (Pages 152 – 156)[2]?

A. The following are some typical objectives of rate design, as well as a brief description of each objective, as stated in the AGA Gas Rate Fundamentals book:

- Achieving the revenue requirement
- Economic efficiency
- Fairness or equity
- Simplicity and administrative ease
- Conservation of resources
- Stability and gradualism
- Social goals
- Environmental protection
- Employment
- Balance of payments

The Revenue Requirement

Meeting the utility's annual revenue requirement is a singularly obvious goal of ratemaking because continued service and providing for expansion require an equality of revenue and revenue requirements. By definition, a fundamental purpose of pricing is to provide sufficient revenue to cover the firm's expenditures. This goal can be extended to include ratemaking that ensures continuing profitability such that the

[2] Uhler, R. G. (Ed.). (1987). Gas Rate Fundamentals (Fourth ed.). Arlington, VA: American Gas Association Rate Committee.

need for subsequent rounds of rate increases is mitigated.

Economic Efficiency

Economic efficiency requires proper reflection of cost in price so that a utility customer's purchasing decisions result in an efficient allocation of resources.

Fairness or Equity

Most people believe that a rate based on the cost of providing service is fair. The goal of fairness is frequently mandated by statute although no definitive standards exist. If such and objective of pricing is statutory, it may constrain the attainment of other goals.

Simplicity and Administrative Ease

The goal of simplicity implies rates that should be easily understood (i.e., the user can determine the expected cost of service). Simple rates minimize the need for employee and customer education as well as reduce record keeping and administrative costs.

Conservation of Resources

Conservation of resources or the prevention of waste is closely akin to economic efficiency. Conservation also means avoiding the use of energy that is worth less to consumers than its cost to society. Conservation could also be defined as using less of a natural resource today so as to have more to use in the future when it may have higher economic value.

Stability and Gradualism

The goal of stability recognizes historical relationships among customers in terms of the proportion of system costs each customer group bears. Stability leads to a policy of

gradualism in rate changes if substantial increases (or decreases) are called for in the context of a single rate case. Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operation are minimized.

Social Goals

Social ratemaking goals involve rate designs that advance the welfare of a particular group in society. For example, utility "lifeline" rates can reduce the impact of rate increases on customers least able to pay for gas service, such as people on fixed incomes. For such customers, higher utility prices may mean a significant decrease in well-being. Nevertheless, subsidies for one group regardless of its need, mean shifting the economic burden to others.

Environmental Protection

Rates that are economically efficient will optimize the use of scarce resources and, by definition, minimize adverse environmental effects. Thus, to great extent, this objective parallels the goal of economic efficiency.

Employment

Given that full employment is an important nation objective, gas utility rates that enhance the prospect of employment serve an essential purpose. Nondiscriminatory rates for the industry that both attract new business and retain existing employees might be viewed as enhancing this goal.

Balance of Payments

The balance of international payments is a vital national economic and political

concern. Pricing that minimizes the use of imported fuels could be regarded as an important objective.

Q. What is arguably the most important principal of rate design?

A. The most important principal of rate design is fairness. As stated in the Gas Rate Fundamentals book (Page 154), "Most people believe that a rate based on the cost of providing service is fair." Most of the principles listed above are rooted in fairness. The goal is to provide a rate design that provides a reasonable opportunity for a utility to recover the Cost of Service approved by the utility commission established when rates are designed.

Q. What is the purpose of the Weather Normalization Adjustment ("WNA")?

A. Because the Company has no control of the weather, the purpose of the WNA is to adjust for revenue overages and shortfalls caused by rate design due solely to unpredictable changes in temperature.

Ratemaking requires a prediction of test year volumes. For gas utilities, volumes can vary substantially due to temperature changes. Because of this, it has been standard practice for many years to base projections on "normal" temperatures. The Company defines "normal" temperatures using a 20-year average. Once the "normal" temperature is determined, the Company adjusts historic usage to reflect projected usage at "normal" temperatures, as explained by Columbia Witness Mr. Girata. That information is then used to develop the FPFTY usage projection. As customers are billed the designed rates, actual temperatures vary, sometimes substantially, from the 20-year average, resulting in uncontrollable, and unpredictable, variances from the

usage used to design rates. Therefore, designed residential volumetric base rates will either over or under recover the residential Cost of Service approved in the Company's most recent rate case.

In the interest of fairness to both the Company and the customer, the WNA compensates for this fundamental rate design issue. The WNA mitigates the impact of the revenue overage or shortfall of the residential volumetric base rate design caused solely by weather.

The WNA is a fair mechanism as it only recovers the impact of weather on rate design, and it is calculated for each residential customer based on the customer's heating usage per degree day and billed on a real time basis. The customer essentially pays the same amount they would have paid had the original rate design used the same weather that occurred in the month the customer is billed.

Q. In which case did the Commission approve a WNA for the Company?

A. In case No. R-2012-2321748, the Commission approved the Company's WNA and it has approved the continuation of the WNA in each of the seven rate cases the Company has completed since 2012. Nothing has changed since the R-2012-2321748 order, with exception of the deadband being reduced from the original 5% to the current 3%, and in fact the WNA has accomplished what it was intended to do, which was to compensate for the differential of actual weather in real-time billing to the 20-year average weather used in designing the residential volumetric base rate in the most recent rate case. The continuation of the WNA has been subjected to defined terms of years in various settlements over that time. As discussed above, the Commission

approved a settlement in the Company's 2021 base rate case (R-2021-3024296) permitting the WNA, with a 3% deadband, to continue until a final order is entered in the Company's first base rate case filed after May 31, 2026.

Q. OCA Witness Mierzwa states on pages 32 through 34 of his direct testimony that the Commission should not allow Columbia's current WNA to remain in effect and lists five reasons why. Do you agree with Mr. Mierzwa's assessment?

A. No. I will address each of his objections to continuing the Company's WNA. First, Mr. Mierzwa apparently objects because the WNA from October 2013 through April 2024 collected $59.1 million from residential customers on a net basis. He also points out in his Table 5 the amount collected by the WNA has been $63,822,460 over the last 5 heating season. And finally, he states on page 32 lines 10 through 11, that "This detrimental impact on consumers is likely to continue." However, Mr. Mierzwa gives no additional support for this conclusion.

When Mr. Mierzwa makes his conclusion about the net $59.1 million that was collected by the Company through the WNA, he does not take into account the reason why it was necessary for the WNA to compensate the Company, which was because the residential volumetric usage since the inception of the WNA has more often than not been less than the residential usage used to design rates, as approved by the Commission, due solely to temperatures being warmer than projected.

The cause of the under recovery of $59.1 million through the residential volumetric base rates from October 2013 through April 2024 is that the 20-year average

temperatures used in designing the residential volumetric rates in rate cases during that time were under calculated for the actual weather incurred when billing the residential customer. Normal temperatures used to develop projected usage in the rate cases were in some years greater and in other years less than the actual temperatures resulting, on a net basis, in understating the residential volumetric base rates approved in the rate cases. The WNA simply compensated the under designed residential volumetric base rates approved in the rate cases.

It is important to note that Mr. Mierzwa also did not take into account data provided to the OCA in response to data request OCA-12-021 (attached to my rebuttal testimony as Exhibit KLJ-2R), which shows that since the inception of the WNA 58% of the time the WNA has benefited the Company and 42% of the time it has benefited the Company's residential customers to which it applies.

Simply stated, 58% of the time actual temperatures that occurred when billing residential volumetric base rates, were warmer than the design "normal" temperatures, resulting in lower residential volumetric revenues than what was required to recover the residential cost of service approved in the last rate case due solely to temperatures. The WNA compensates for the under designed residential base rates when applied to actual usage.

Q. Is the net $59.1 million the WNA collected from residential customers from October 2013 through April 2024 a detrimental impact on residential customers as stated by Mr. Mierzwa on page 32 lines 7 through 8 of his direct testimony?

A. No. If temperatures were predictable in advance and rates had been designed consistent with actual temperatures, the net revenue differential would not have existed. Furthermore, if temperatures had been colder than normal throughout this period of time, as occurred during a portion of the ten years referenced by Mr. Mierzwa, there would have been no net collection from customers, but instead a net return of revenues to customers.

Q. Are there any notable contributors to the size of the WNA recovery in recent years?

A. There are two factors that stand out that have contributed to the amounts billed through the WNA that should be noted. First, the weather that occurred in 2023 was 12.9% warmer than normal, which was the second warmest year in the last 50 years, when 1998 was 13.0% warmer than normal. Second, per Table KLJ-4R below, the percentage of residential base revenue recovered through the residential volumetric base rate has grown proportionally greater than the revenue recovered through the residential customer charge over the same period. This is due to the residential customer charge not changing since the implementation of the WNA in October 2013. By recovering a greater percentage of revenue through the volumetric rate, over time, this naturally increases the variability of the revenues subject to the WNA mechanism.

Table KLJ-4R

Rate Case Year	Residential Fixed Base Revenue Recovery	Residential Variable Base Revenue Recovery	Total Residential Base Revenue Recovery	Percentage Variable Base Revenue Recovery
2012	$77,269,358	$116,137,004	$193,396,362	60.051%
2014	$78,381,874	$142,844,682	$221,226,556	64.569%
2015	$78,797,260	$164,929,400	$243,726,660	67.670%
2016	$79,308,587	$190,307,140	$269,615,727	70.585%
2018	$80,872,049	$209,253,402	$290,125,451	72.125%
2020	$81,671,392	$252,778,253	$334,449,645	75.580%
2021	$82,713,862	$289,365,151	$372,079,013	77.770%
2022	$83,182,694	$319,624,558	$402,807,252	79.349%

Q. Is the warmer than normal weather likely to continue?

A. No one knows, and Mr. Mierzwa does not offer any support to his statement on page 32 that it will continue. There have been past periods when temperature have been colder than normal. The only reason customers have been charged a net amount more over the recent past is because temperatures were substantially warmer than normal. Over time, assuming temperatures revert to a normal average, the net difference will shrink. With each rate case, the rates are redesigned based on the most recent 20 year normal. By doing so, the last 5 heating seasons that Mr. Mierzwa points out that have been warmer than normal will be included in the determination of the 20-year normal, making it less likely in theory to repeat in the future. However, if parties are asserting that weather will continue to be warmer than the 20-year norm, then the norm used in developing projected usage needs reconsidered, as it would be improper to establish

usage that is based upon temperatures that are colder than what is in fact anticipated.

Q. What was Mr. Mierzwa's second reason why the Commission should not allow Columbia's current WNA to remain in effect, and do you agree with his second reason?

A. His second reason, stated on pages 32 through 33 of his direct testimony, is "that automatic rate adjustments such as the WNA should be avoided because they weaken traditional regulatory principles and unreasonably shift risk to customers. To justify maintaining the WNA, Columbia should be required to demonstrate that it is necessary to avoid significant financial damage." I do not agree with this argument.

As stated above the WNA literally recovers the residential cost of service approved in the rate case that should have been recovered through the residential volumetric base rates. However, the revenue was not collected through the residential volumetric base rate solely because of warmer than normal weather and therefore, was collected through the WNA. In the case of colder than normal weather, the revenue was over collected through the residential volumetric base rate, so it was passed back to residential customers through the WNA. In the interest of fairness to both the Company and the customers, the WNA eliminates the over or under recovery of cost of service due solely to weather.

Q. What was Mr. Mierzwa's third reason why the Commission should not allow Columbia's current WNA to remain in effect, and do you agree with his third reason?

A. His third reason, stated on page 33 of his direct testimony, is that "similar to the

proposed RNA, the WNA inappropriately adjusts rates without considering other changes in total revenues and costs. The WNA changes rates, automatically, between rate cases, simply due to the impact of weather on Residential distribution revenues. There is no review of Columbia's costs, or the volumes and attendant revenues from Residential customers and other customer classes." This argument misperceives the intent of the WNA.

As stated above, the WNA is a mechanism that corrects a fundamental issue in volumetric base rate design. Because no one knows what the weather will be when a customer is billed in the future when rates go in effect, the Company uses estimated volumes that reflect usage at normal temperatures based on the most recent 20-year average to determine the residential volumetric base rate. In the interest of fairness to both the Company and customers, the entire purpose of the WNA is to compensate for this issue in rate design. The WNA mitigates the impact of the recovery overage or shortfall of the residential volumetric base rate design caused solely by the unpredictability of weather.

The purpose of the WNA is not to reopen the cost of service as Mr. Mierzwa suggests, as cost of service changes can only be considered in a rate case. The WNA is a rate design mechanism that is approved by the Commission at the time of rate design to compensate for the unknown denominator of the residential volumetric charge so that the base revenue charged to the customer is not impacted by weather.

Q. What was Mr. Mierzwa's fourth reason why the Commission should not allow Columbia's current WNA to remain in effect, and do you agree with

his fourth reason?

A. His fourth reason, stated on page 33 of his direct testimony, is that "the WNA embodies a take-or-pay pricing policy. Under the WNA, Residential customers pay for distribution they actually receive, and may pay for distribution service they do not receive, despite the customer having no immediate alternatives to Columbia's distribution service." I disagree with this reasoning as applied to the WNA.

As discussed earlier in this rebuttal, the WNA has no take-or-pay clauses and is not akin to a take-or-pay contract. Again, the WNA is a rate design mechanism. The cost to serve the residential customers has already been determined in the rate case and the WNA is simply a mechanism to recover the costs that the Commission has already established as being incurred by the Company to provide the distribution service the residential class requires. The WNA in no way requires the residential class to pay for more than the established cost of service in the last rate case. It is a balanced, customer-specific mechanism designed to address the impossibility to accurately project future temperatures.

Q. What was Mr. Mierzwa's fifth reason why the Commission should not allow Columbia's current WNA to remain in effect and do you agree with his fifth reason?

A. As his fifth reason, stated on pages 33 and 34 of his direct testimony, Mr. Mierzwa claims that "the WNA provides disincentives for energy efficiency. If a customer reduces their consumption due to the implementation of energy conservation measures and it is warmer than normal, a portion of the savings achieve [sic] by the

customer due to the energy conservation measure will be reduced which will provide a disincentive to implement further energy conservation measures." I disagree with this contention.

Mr. Mierzwa's logic is flawed in his statement that the WNA provides a disincentive for energy efficiencies. The WNA does not take away savings created by energy efficiencies, as it adjusts actual usage only to usage at normal temperatures. Importantly, it does not adjust actual usage to an assumed usage level. Using the formula for the WNA on page 162 of the Company's tariff, below is the calculation of a residential bill adjusted for the WNA where the customer used 118 therms in January 2024, when actual degree days were warmer than normal degree days.

WNBT = BLMT + [(NHDD / AHDD) x ((AMT – BLMT)]
138 therms = 9 therms + [(993 DDD / 838 DDD) x ((118 therms – 9 therms)]

WANT = WNBT – AMT
20 therms = 138 therms – 118 therms

WNA = WANT x Distribution Usage Charge
$18.21 = 20 therms x $0.91069/therm

Total Bill
$ 125.67 = $18.21 WNA + (118 therms * $0.91069/therm)

$ 125.67 = $18.21 WNA + $107.46 Actual Usage

Using the formula for the WNA on page 162 of the tariff, below is the calculation of a residential bill adjusted for the WNA where the same customer used 10% less therms because of energy conservation (118 therms * 90%) = 106 therms in January 2024.

WNBT = BLMT + [(NHDD / AHDD) x ((AMT – BLMT)]
124 therms = 9 therms + [(993 DDD / 838 DDD) x ((106 therms – 9 therms)]

WANT = WNBT – AMT

18 therms = 124 therms – 106 therms

WNA = WANT x Distribution Usage Charge
$16.39 = 18 therms x $0.91069/therm

Total Bill
$112.92 = $16.39 WNA + (106 therms * $0.91069/therm)

$112.92 = $16.39 WNA + $96.53 Actual Usage

Energy savings generated between original bill and energy efficient bill with WNA:

($12.75) = $112.92 energy efficiency bill - $125.67 original bill

Energy savings generated between original bill and energy efficient bill if no WNA applied:

($10.93) = (106 therms * $0.91069/therm) - (118 therms * $0.91069/therm)

($10.93) = $96.53 - $107.46

As you can see, in both cases the energy efficient bill is less than the original bill before energy efficiency - ($12.75) = $112.92 - $125.67 with the WNA and ($10.93) = $96.53 - $107.46 without the WNA.

In fact, with the WNA, the customer has a greater incentive for energy efficiency than without it because they have greater energy savings with the WNA ($12.75) as compared to savings of ($10.93) with no WNA.

Q. On pages 34 through 37 of Mr. Mierzwa's direct testimony, he lists the 14 factors for consideration identified in the Commission's statement of policy on alternative ratemaking and his claimed relevant effect of the WNA on each rate consideration. Please identify the 14 factors for

consideration along with the Company's response to Mr. Mierzwa's statements.

A. Consideration 1: Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

OCA: The WNA represents a clear misalignment between revenue and cost causation because it bills customers based on hypothetical usage, and not based on actual cost-based usage. The WNA provides for the recovery of fixed costs on a volumetric basis. Therefore, it does not align utility revenues with cost causation principles as to both fixed and variable costs.

COLUMBIA: The Company disagrees with Mr. Mierzwa. The WNA adjusts the customer's actual usage to determine the customer's weather normalized usage in order to apply the usage to the Residential volumetric base rate. The Residential volumetric base rate was established using cost causation principles to determine the Residential Cost of Service. However, the rate was established by dividing actual cost of service by weather normalized usage. It is because the Residential volumetric base rate established in the last rate case was based on weather normalized usage that the WNA is necessary to recover or pass-back revenue generated by the volumetric base rate due solely to weather.

Additionally, because of settlement agreements, unfortunately there has been no increase to the Residential customer charge in each of the Company's last seven rate cases, thereby forcing the entire increase in fixed costs to be recovered through the Residential volumetric rate. As a result, the Company recovers a significant portion of fixed costs through the Residential volumetric rate. These costs also do not vary due to changes in temperatures. Because of this, the Company requires the WNA mechanism that is designed to recover or pass-back the over or under recovery of fixed costs billed by the Residential volumetric base rate because of an inherent flaw in the design of the Residential volumetric base rate solely caused by weather.

In the interest of fairness to both the Company and the customer, the WNA compensates for this flaw in rate design. The WNA mitigates the impact of the recovery overage or shortfall of the Residential volumetric base rate design caused solely by weather. The customer essentially pays the same amount that

they would have paid had the original rate design used the same weather that occurred in the month the customer is billed.

Consideration 2: Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

OCA: The proposed WNA is unrelated to capacity utilization since the determining metric for the charge is weather not utilization.

COLUMBIA: The Company agrees.

Consideration 3: Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

OCA: 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.

COLUMBIA: The WNA does reflect customers' anticipated consumption levels, by adjusting to normal levels used for designing base rates. The Company believes, due to its inability to predict weather, it can only anticipate demand based on normal weather and design rates accordingly. However, because the Company does know the weather and customer's usage at time of billing, the WNA mechanism adjusts the revenue generated by the Residential volumetric base rate by way of the WNA to mitigate the effects of weather on the rate design.

Consideration 4: How the ratemaking mechanism and rate design limit or eliminate interclass and intra-class cost shifting.

OCA: The WNA is only applicable to the Residential class and, therefore, does not affect traditional interclass cost shifting.

COLUMBIA: The Company agrees.

Consideration 5: Please explain how the WNA limits or

eliminates disincentives for the promotion of efficiency programs.

OCA: The WNA disincentives energy efficiency programs because it imposes a disconnect between cost-savings for customers that participate in energy efficiency programs. The disincentive exists in that by relying upon temperature variances to impose a WNA regardless of reduced usage that may otherwise result from participation in an energy efficiency program, the WNA inserts an artificial variable that would mitigate at least some cost savings contingent on the weather. In addition, the Company has not demonstrated that the lack of a WNA would be a major obstacle for the promotion of its voluntary energy efficiency and conservation activities.

COLUMBIA: The Company's WNA only addresses variations due to weather and does not affect customers' ability to pursue energy efficiency measures, as demonstrated above. Further, the Company will continue to promote the use of energy efficiency measures to its customers.

Consideration 6: Please explain how the WNA impacts customer incentives to employ efficiency measures and distributed energy resources.

OCA: The WNA could provide a disincentive to employ energy efficiency measures for customers whose energy efficiency initiative takes place during periods of warmer than normal weather. This is because a portion of a customer's bill savings would be returned to the Company because the efficiency actions occurred when weather was warmer-than-normal. As such, the customer may perceive the WNA as a disincentive for deploying more energy efficiency measures.

COLUMBIA: As stated above, with the WNA, a customer has a greater incentive for energy efficiency than without it, because when weather is warmer than normal, the customer receives greater energy savings on both the residential volumetric rate billing as well as the WNA billing.

However, the Company's customers will continue to be incentivized to use energy efficiency measures because a reduction in the customer's usage will continue to reduce their overall bill.

Consideration 7: Please explain how the WNA impacts low-income customers and supports consumer assistance programs.

OCA: The impact of the WNA on Residential low-income customers would be the same as the impact on Residential non low-income customers. The WNA does not support customer assistance programs.

COLUMBIA: The Company agrees with Mr. Mierzwa. However, it is important to note under the Company's WNA mechanism, customers enrolled in CAP see lower bill variability for distribution costs during colder than normal billing cycles. Similarly, customers who are currently enrolled to pay their bills based on a percentage of their household income see little to no impact to their bills under the WNA mechanism.

Consideration 8: Please explain how the WNA impacts customer rate stability principles.

OCA: Under the current regulatory standard in Pennsylvania, base rate cost under and over recoveries are currently not tracked and are not eligible for recovery in future base rate proceedings. The WNA will not change this standard.

The proposed WNA would add another surcharge to customers' bills and the Company has not shown how it would reduce the frequency of Columbia Gas base rate filings. Thus, it does not appear that the WNA surcharge would improve rate stability. In contrast, under traditional cost-of-service ratemaking, if a utility experiences sales reductions and under-recovery, it cannot simply achieve the same result as a WNA by filing another base rate case with adjusted sales forecasts. When a utility files a general rate increase, all relevant information is reviewed to determine just and reasonable rates, not just sales forecasts. Traditional ratemaking produces rate stability.

In addition, the WNA decreases customer rate stability because it obscures price signals for customers by disassociating their monthly bill from their actual usage. As a result, a customer is less likely to be able to predict what their bill would be at the end of the month based off usage.

COLUMBIA: The American Gas Association Gas Rate Fundamentals book (Pages 152 – 156) states "The goal of stability recognizes historical relationships among customers in

terms of the proportion of system costs each customer group bears. Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are called for in the context of a single rate case, Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operation are minimized."
The Company's WNA ensures stability in that the customer will pay for the costs assigned to the residential volumetric base rate in the most recent rate case and the customer will not pay more or less than that amount solely because the actual weather for the month the customer is billed is different than the weather used to determine the rate design of the residential volumetric base rate. Further, the WNA has been on customers' bills for over 10 years, and thus will not add another charge to the bill.

Consideration 9: Please explain how the weather impacts utility revenue under the WNA.

OCA: Weather will directly impact utility revenue under the WNA.

COLUMBIA: The Company's WNA adjusts a customer's bill due to variations from normal weather during the heating season months (October through May). The WNA only applies to the Company's residential customers. The WNA only mitigates the revenue effect of weather on the original rate design of the Residential Volumetric base rate. The WNA does not guarantee 100% recovery of its cost of service.

Consideration 10: Please explain how the WNA impacts the frequency of rate case filings and affects regulatory lag.

OCA: Columbia files a rate case nearly every year. This is unlikely to change and a WNA does not prevent the Company from seeking additional rate increases. The WNA does not affect future revenue requirements and does not recover fixed costs that are incurred after a rate case that are over and above those approved by the Commission. Therefore, if future rate cases are driven by future investment needs or higher expenses and associated cost recovery, the WNA would not reduce the need for such cases.

COLUMBIA: The WNA does not impact the Company's rate case frequency or have an effect on regulatory lag.

Consideration 11: Please explain if the WNA interacts 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 (relating to standards for restructuring of electric industry) or system improvement charges66 Pa. C.S. § 1353 (relating to distribution system improvement charge).

OCA: The WNA will not interact with other revenue sources.

COLUMBIA: The Company's WNA only applies to distribution related charges recovering the base distribution revenue requirement from residential customers subject to the WNA during October through May of each year. WNA amounts will be subject to STAS and DSIC riders.

Consideration 12: Please explain whether the WNA includes appropriate consumer protections.

OCA: The WNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony and the testimony of OCA witness Colton and OCA witness Dismukes.

COLUMBIA: The Company's WNA mechanism adjusts bills to reflect the revenues that would be recovered under normal weather, on a per-customer basis, because that is how the residential volumetric base rate is designed.

Consideration 13: Please explain whether the WNA is understandable to customers.

OCA: Columbia has not provided any evidence that the WNA is understandable to customers.

COLUMBIA: The Company has been billing the WNA since October 2013. In fact, as stated above, the Company has billed Residential customers 31,954,946 times in the months that the WNA has been in effect and yet has received no measurable complaints. Unfortunately, as with any billing rate, there are customers who may not completely understand the reason for the WNA charge or refund. However, the fact that WNAs are in

effect in many states today, including Pennsylvania, is a testament to its effectiveness and acceptability.

Consideration 14: Please explain how the WNA will support improvements in utility reliability.

OCA: The WNA does not provide an incentive to increase the safety and reliability of Columbia's system.

COLUMBIA: The WNA mitigates the impact of weather in the recovery of the Commission-approved cost of service established in rate cases. In rate cases, there are costs to continue to enhance the safety and reliability of the Company's system. The WNA helps ensure that cost recovery is not impacted by warmer or colder than normal weather.

VIII. MUNICIPAL LEVELIZATION CHARGE ("MLC")

Q. On Page 30 of his direct testimony, OCA witness Mierzwa states, "the additional paving and restoration costs incurred to serve customers in the City of Pittsburgh and Borough of Perryopolis are reflected in the rates proposed by Columbia in this proceeding for all customers served by Columbia" and that "It is unreasonable to impose a charge on 22,604 customers for additional costs incurred to serve those customers and then credit the additional charges to 2,116 customers when the additional City of Pittsburgh and Borough of Perryopolis paving and restoration costs have been reflected in the rates of all Columbia customers. The MLC should be rejected." What are your thoughts on Mr. Mierzwa's comments?

A. While I do agree that the costs incurred for paving and restoration are included in the Company's cost of service, the MLC is a fair, revenue neutral mechanism. The MLC ensures that customers in the municipalities causing higher costs by requiring milling and overlay standards, which far exceed PennDOT standards, receive a charge and that

customers in municipalities with minimal milling and overlay requirements that cost far less than PennDOT standards receive a credit.

Q. On Page 30 of his testimony, OCA witness Mierzwa states the MLC should not be approved since "the MLC does not recognize differences in the costs associated with serving different customer classes." Have you prepared an allocation of the MLC to the various customer classes?

A. Yes. Provided in Table KLJ-5R below is the monthly Municipal Levelization Charge and Credit for each customer class included in the MLC based on "Allocation Factor 13 – Mains Account 376" from the Company's Peak and Average cost allocation study. Exhibit KLJ-1R to my Rebuttal Testimony details the MLC calculations.

Table KLJ-5R

	RSS/RDS	SDS/LGSS	SGS/DS-1	SGS/DS-2	Total
Municipal Levelization Charge	$0.46	$182.19	$1.67	$14.45	$0.70
Municipal Levelization Credit	$(4.88)	$(1,639.67)	$(22.84)	$(190.04)	$(7.44)

Q. Do you believe the MLC should be allocated to the customer classes based on the Mains allocation factor discussed above?

A. No. The MLC should be billed as the Company proposed as a monthly charge of $0.70 per bill to Columbia customers who are located in the City of Pittsburgh and the Borough of Perryopolis and a monthly credit of $7.44 per bill to customers located in

Roscoe Borough and New Sewickley Township as municipality ordinances have caused these costs and they are not directly associated with the customer class incurring the charge.

Q. Does this complete your prepared Rebuttal Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Municipal Levelization Charge/Credit
Allocation by Rate Class - Using Mains Allocation Factor - Workpaper

Rate Class	City of Pittsburgh	Borough of Perryopolis	New Sewickley Township	Roscoe Borough	Total Customers
RSS/RDS	20,727	655	1,694	332	23,408
SDS/LGSS	9	-	1	-	10
SGS/DS-1	974	68	52	24	1,118
SGS/DS-2	166	5	13	-	184
Total	**21,876**	**728**	**1,760**	**356**	**24,720**

Muncipal Levelization Charge					
	RSS/RDS	**SDS/LGSS**	**SGS/DS-1**	**SGS/DS-2**	**Total**
City of Pittsburgh	20,727	9	974	166	**21,876**
Borough of Perryopolis	655	-	68	5	**728**
Total Customers	**21,382**	**9**	**1,042**	**171**	**22,604**
# of Months	12	12	12	12	12
# of Bills	**256,584**	**108**	**12,504**	**2,052**	**271,248**
Mains Allocation	62.85%	10.42%	11.03%	15.70%	100.00%
$ 188,825	$ 118,677	$ 19,676	$ 20,827	$ 29,645	$ 188,825
Municipal Levelization Charge	**$ 0.46**	**$ 182.19**	**$ 1.67**	**$ 14.45**	**$ 0.70**
Revenue Check	$ 118,677	$ 19,676	$ 20,827	$ 29,645	$ 188,825

Muncipal Levelization Credit					
	RSS/RDS	**SDS/LGSS**	**SGS/DS-1**	**SGS/DS-2**	**Total**
New Sewickley Township	1,694	1	52	13	**1,760**
Roscoe Borough	332	-	24	-	**356**
Total Customers	**2,026**	**1**	**76**	**13**	**2,116**
# of Months	12	12	12	12	12
# of Bills	**24,312**	**12**	**912**	**156**	**25,392**
Mains Allocation	62.85%	10.42%	11.03%	15.70%	100.00%
$ (188,825)	$ (118,676)	$ (19,676)	$ (20,827)	$ (29,646)	$ (188,825)
Municipal Levelization Credit	**$ (4.88)**	**$ (1,639.67)**	**$ (22.84)**	**$ (190.04)**	**$ (7.44)**
Revenue Check	$ (118,676)	$ (19,676)	$ (20,827)	$ (29,646)	$ (188,825)

	Municipal Levelization Charge	Municipal Levelization Credit
Total Annual Revenue	$188,825	($188,825)
0030298PITTSBURGH	21,876	
0511365PERRYOPOLIS	728	
1252876ROSCOE		356
0070417NEW SEWICKLEY		1,760
Total Customers	22,604	2,116
	12	12
Number of Bills	271,248	25,392
Per Month	**$ 0.70**	**$ (7.44)**

Mains Allocation Factor #13	**RSS/RDS**	**SDS/LGSS**	**SGS/DS-1**	**SGS/DS-2**	**LDS/LGSS**	**MLDS**	**FLEX**	
	50.648%	8.394%	8.889%	12.651%	10.929%	0.007%	8.482%	100.000%
Rate Classes in MLC	**62.85%**	**10.42%**	**11.03%**	**15.70%**				100.000%

Question No. OCA 12-021
Respondent: M. Girata
K. Johnson
P. Moul

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

OFFICE OF CONSUMER ADVOCATE INTERROGATORIES
Set 12

Question No. OCA 12-021:

Please explain:

a. The extent to which weather variability affects the Company's natural gas sales and revenues. Please include any causal relationships (for instance, each 0.10 increase in temperature results in a decrease in revenues, all else held equal, of $X per year) that the Company has identified.
b. Whether the Company agrees with the general financial principle that rate of return and business risk are positively correlated (in other words, the greater the business risk, the higher the rate of return that will be necessary to compensate investors such as utility shareholders).
c. Whether the Company agrees that any regulatory mechanism that decreases the company's business risk associated with weather variability would (assuming all else held constant) decrease the Company's overall risk profile, which would, in turn, reduce the rate of return demanded by the Company's current and potential shareholders.

Response:

a. Given the deadband within the Company's WNA mechanism, there is not a linear relationship between weather variance and revenue impact. Therefore, a 0.10 increase in temperature cannot be directly related to a dollar decrease in revenue. OCA-12-021 Attachment A shows the Company's historical WNA adjustments back to the 2013-2014 heating season, which was the inception of the WNA. Over this period, customer bills were adjusted in 82 distinct months. Customer bills decreased 42% of the time. In months where customer bills increased, the adjustment allowed the Company to recover a portion of the revenue requirement that was previously approved in the latest Rate Case.

b. The Company agrees with the general financial principle that rate of return and business risk are positively correlated.

c. The Company's answer to the statement in Part C above depends upon how the rate of return is measured. If the rate of return is derived from market data for a Barometer Group that already has a particular regulatory mechanism in place, which deals with a same business risk as the subject utility, then the rate of return determination would be unaffected. That is to say, the benefits of a particular regulatory mechanism would be "baked in" to the investor established stock prices for the Barometer Group. In that case, applying the Barometer Group's cost of equity to the utility would align it with the Barometer Group's business risk profile.

Please see Statement 8 (Witness Paul Moul's Direct Testimony), Pages 8-9, that discusses the Company's WNA and its impact on the Company's business risk.

Year	Month	WNA Adjustment ($)	Customers	Customers Billed WNA	Average Bill Adjustment ($/Bill)
2013	10	116,993	370,430	195,202	0.60
2013	11	(96,024)	372,378	208,958	(0.46)
2013	12	(1,037,702)	374,774	335,197	(3.10)
2014	1	(614,395)	377,714	187,769	(3.27)
2014	2	(2,824,900)	379,194	371,925	(7.60)
2014	3	(2,873,765)	379,158	373,157	(7.70)
2014	4	(1,509,100)	378,855	344,824	(4.38)
2014	5	(517,307)	377,051	286,553	(1.81)
2014	6				
2014	7				
2014	8				
2014	9				
2014	10	(154,105)	372,652	173,140	(0.89)
2014	11	(29,346)	374,193	212,786	(0.14)
2014	12	(1,040,317)	377,052	316,488	(3.29)
2015	1	(123,040)	380,067	136,608	(0.90)
2015	2	(2,452,474)	381,236	300,811	(8.15)
2015	3	(6,426,978)	381,522	376,321	(17.08)
2015	4	(843,463)	380,331	241,457	(3.49)
2015	5	88,498	378,698	168,192	0.53
2015	6				
2015	7				
2015	8				
2015	9				
2015	10	86,754	374,555	202,109	0.43
2015	11	1,308,504	376,014	319,304	4.10
2015	12	3,378,490	378,740	368,328	9.17
2016	1	3,715,509	381,276	325,368	11.42
2016	2	(69,568)	382,944	109,976	(0.63)
2016	3	2,223,089	383,370	238,795	9.31
2016	4	1,367,686	381,978	176,834	7.73
2016	5	(488,420)	380,151	242,916	(2.01)
2016	6				
2016	7				
2016	8				
2016	9				
2016	10	457,492	377,809	209,136	2.19
2016	11	1,453,997	379,208	340,134	4.27
2016	12	393,092	381,253	173,936	2.26
2017	1	899,043	384,603	191,684	4.69
2017	2	5,405,512	386,139	379,789	14.23

Year	Month	WNA Adjustment ($)	Customers	Customers Billed WNA	Average Bill Adjustment ($/Bill)
2017	3	3,753,459	386,907	299,306	12.54
2017	4	943,085	385,154	260,077	3.63
2017	5	599,235	383,409	300,207	2.00
2017	6				
2017	7				
2017	8				
2017	9				
2017	10	1,126,344	381,249	219,185	5.14
2017	11	848,603	382,540	282,529	3.00
2017	12	(227,922)	385,109	153,911	(1.48)
2018	1	(5,562,857)	388,014	382,042	(14.56)
2018	2	1,513,734	389,653	251,281	6.02
2018	3	2,041,896	389,575	332,729	6.14
2018	4	(5,278,784)	388,433	380,722	(13.87)
2018	5	(513,284)	386,843	332,706	(1.54)
2018	6				
2018	7				
2018	8				
2018	9				
2018	10	497,411	384,525	218,178	2.28
2018	11	(1,773,574)	385,918	304,465	(5.83)
2018	12	(2,906,153)	388,851	331,820	(8.76)
2019	1	1,073,154	391,477	276,339	3.88
2019	2	(535,869)	392,747	167,878	(3.19)
2019	3	(1,304,831)	392,723	319,724	(4.08)
2019	4	60,600	391,788	263,298	0.23
2019	5	1,154,885	390,371	329,939	3.50
2019	6				
2019	7				
2019	8				
2019	9				
2019	10	-	-	-	
2019	11	(684,497)	389,429	275,571	(2.48)
2019	12	(1,286,549)	392,256	262,225	(4.91)
2020	1	4,416,086	394,870	378,905	11.65
2020	2	4,527,906	396,012	388,354	11.66
2020	3	2,634,710	396,024	386,497	6.82
2020	4	922,702	396,501	355,224	2.60
2020	5	(5,550,993)	396,966	383,775	(14.46)
2020	6				
2020	7				

Year	Month	WNA Adjustment ($)	Customers	Customers Billed WNA	Average Bill Adjustment ($/Bill)
2020	8				
2020	9				
2020	10	-	-	-	
2020	11	1,449,635	396,414	321,941	4.50
2020	12	2,538,030	397,117	359,429	7.06
2021	1	816,576	398,814	232,081	3.52
2021	2	(140,110)	399,717	238,001	(0.59)
2021	3	(80,845)	400,308	233,240	(0.35)
2021	4	3,439,610	400,183	375,297	9.17
2021	5	(2,695,738)	398,675	367,968	(7.33)
2021	6				
2021	7				
2021	8				
2021	9				
2021	10	-	-	-	
2021	11	1,471,285	396,926	283,415	5.19
2021	12	515,922	398,433	252,800	2.04
2022	1	4,139,627	401,083	314,474	13.16
2022	2	(2,976,544)	402,427	316,260	(9.41)
2022	3	3,170,309	402,677	374,336	8.47
2022	4	(1,430,302)	401,616	293,299	(4.88)
2022	5	(2,360,072)	399,898	355,618	(6.64)
2022	6				
2022	7				
2022	8				
2022	9				
2022	10	-	-	-	
2022	11	563,691	399,376	346,805	1.63
2022	12	176,747	401,598	191,333	0.92
2023	1	2,777,439	403,828	255,403	10.87
2023	2	8,958,741	404,837	396,863	22.57
2023	3	6,622,091	404,967	319,831	20.70
2023	4	167,002	404,153	274,497	0.61
2023	5	(1,824,436)	402,466	337,838	(5.40)
2023	6				
2023	7				
2023	8				
2023	9				
2023	10	-	-	-	
2023	11	1,854,911	401,206	314,102	5.91
2023	12	3,488,979	403,005	351,331	9.93

Year	Month	WNA Adjustment ($)	Customers	Customers Billed WNA	Average Bill Adjustment ($/Bill)
2024	1	6,185,432	405,599	382,522	16.17
2024	2	9,555,776	406,593	398,213	24.00
2024	3	10,302,390	406,718	397,106	25.94
2024	4	2,156,948	405,623	358,257	6.02
2024	5	-	-	-	

COLUMBIA STATEMENT NO. 6-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

SURREBUTTAL TESTIMONY OF
KEVIN L. JOHNSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

PUBLIC VERSION

July 25, 2024

I. Introduction

Q. Please state your name and business address.

A. My name is Kevin L. Johnson. My business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. Have you previously filed Direct and Rebuttal testimony in this matter?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. I will respond to the rebuttal testimony served in this proceeding by Mr. Crist, witness for the Pennsylvania State University ("PSU").

Q. Which statements of Mr. Crist do you wish to address in regard to the determination of the amount of gas mains cost that should be assigned to the LDS/LGSS class which resulted in Mr. Crist creating a modified Allocated Cost of Service Study ("ACOS") using information provided by the Company in response to data request PSU 5-001?

A. There are two primary statements from Mr. Crist's rebuttal testimony (PSU Statement No. 1-R) that I would like to address.

Statement 1. On page 9 of his rebuttal testimony, Mr. Crist references the Company's response to PSU 5-001, wherein for each LDS/LGSS customer, the Company provided the annual throughput, design day demand, and the distance between the customers' most upstream meter and the meter of the next closest upstream customer. Based on the response to PSU 5-001, Mr. Crist further testified that he calculated the feet of gas mains based on all customers in the LDS/LGSS

class and that his calculation shows that the miles of main assigned to each LDS/LGSS customer in the Company's Peak & Average COSS is clearly wrong. Mr. Crist asserts that: "This highlights how unrealistically overstated the Peak & Average COSS assessment of miles per LDS/LGSS customer is and why the Peak & Average COSS is a misrepresentation of actual costs caused by the LDS/LGSS customer class."

Statement 2. On pages 9 and 10 of his rebuttal testimony, Mr. Crist states:

> "Now that accurate data exist for all the customers of the LDS/LGSS class, the calculation of the gas mains investment can be performed and that amount can be allocated to the LDS/LGSS class by direct assignment in the ACOS. Direct assignment is appropriate and preferable when data exists for all customers of a class. Columbia did direct assignment of gas mains cost for the Mainline class, MDS. Direct assignment must also now be done for LDS/LGSS because the data exists to do so. Gas mains costs can be calculated in a similar manner as I did in my direct testimony."

Q. Please address Statement 1 above and indicate where you agree and disagree with Mr. Crist.

A. Mr. Crist's initial statement about the Company's response to PSU 5-001 is true. The data request asked for the Company to provide for each LDS/LGSS customer, the annual throughput, design day demand, and the distance between the customers'

most upstream meter and the meter of the next closest upstream customer. The Company provided the requested information in the response.

Mr. Crist also correctly stated, "Now instead of calculating the feet of gas mains based on the ten largest customers of the LDS/LGSS group, I am able to calculate the feet of gas mains based on all customers of the LDS/LGSS class. The data show that the longest distance of any LDS/LGSS customer gas mains is only **BEGIN CONFIDENTIAL** **END CONFIDENTIAL** and that the average distance for these customers is only **BEGIN CONFIDENTIAL** **END CONFIDENTIAL**

However, Mr. Crist then makes a false conclusion about the data in response to PSU 5-001. Mr. Crist states, "It shows in the aggregate there are **BEGIN CONFIDENTIAL** **END CONFIDENTIAL** of gas mains serving the entire LDS/LGSS class". That is not what the data shows. The data shows exactly what Mr. Crist first stated, "the distance between the customers' most upstream meter and the meter of the next closest upstream customer". What the data does not show is the footage of upstream gas mains that the LDS/LGSS customer shares with other customers.

Q. Can you please explain what you mean by "footage of upstream gas mains that the LDS/LGSS customer shares with other customers"?

A. The source of gas for all distribution customers are the upstream transmission pipelines. If a large volume transportation service customer is tapped directly to an upstream transmission pipeline, the customer qualifies for Columbia's mainline

distribution ("MLDS") Class I service. If an extremely large volume customer (annual throughput of not less than 2,146,000 therms) has two miles or less of distribution pipeline facilities connecting the customer to an upstream transmission pipeline, they would qualify for the Company's MLDS Class II service. The LDS/LGSS customers do not meet the MLDS requirements, which, assuming they meet the MLDS volumetric requirements, means they are tapped to a distribution gas main pipe segment at a point greater than two miles from an upstream transmission pipeline. There can be, and normally are, multiple pipe segments that make up an integrated mains system that serves the LDS/LGSS customer. Since these pipe segments can, and most often do, serve other customers in addition to the LDS/LGSS customer, the full cost of the pipe segment does not have to be assigned to the LDS/LGSS customer. However, at least a portion of the cost of each gas main pipe segment that is utilized in moving the gas from the transmission pipeline to the distribution gas main where the LDS/LGSS customer is served must be assigned to the LDS/LGSS customer.

Q. Do you agree with Statement 2 from Mr. Crist's rebuttal testimony on pages 9 and 10 where he states, "Now that accurate data exist for all the customers of the LDS/LGSS class, the calculation of the gas mains investment can be performed and that amount can be allocated to the LDS/LGSS class by direct assignment in the ACOS"?

A. No. Since the data in PSU 5-001 shows only the distance between the customers' most upstream meter and the meter of the next closest upstream customer and does

not include the footage of upstream gas mains that the LDS/LGSS customer shares with other customers, a direct assignment study cannot be performed with only the data shown in PSU 5-001.

Q. Did Columbia perform a direct assignment of gas mains for the MDS class?

A. Yes. In that study, Columbia identified and quantified all investment costs associated with the MDS customers including the footage of upstream gas mains that the MDS customer shares with other customers, if any. For cost allocation purposes, the MLDS customer class is allocated all of the distribution pipeline facilities connecting them to the transmission pipeline. Please note, some MDS customers are tapped directly to the transmission pipeline and therefore, there are no upstream distribution gas mains being shared with other customers.

Q. Should Columbia perform a direct assignment study for the LDS/LGSS class as Mr. Crist states on page 10 of his rebuttal testimony because the data exists to do so?

A. No. It is important to note that performing a direct assignment study for each of the LDS/LGSS customers would entail an analysis of hundreds of individual pipe segments involving shared use of gas mains with thousands of non-LDS/LGSS customers. There may be multiple paths to an upstream interstate pipeline, and at any time gas may flow to the customer via different paths. Pipe segment footage and customer maximum hourly flow of gas for all customers that utilize each pipe segment would have to be collected and analyzed.

Q. Does the 13 miles of gas mains assigned by the Peak and Average method to each LDS/LGSS customer, or a total of 1,040 miles of pipe, include both the distance between the customers' most upstream meter and the meter of the next closest upstream customer as well as the footage of upstream gas mains that the LDS/LGSS customer shares with other customers?

A. In theory, yes, it does. It includes all gas mains mileage assigned to the LDS/LGSS class using the Peak and Average method of allocation.

Q. Does this mean that the mileage of pipe assigned to the LDS/LGSS class by the Peak and Average method of allocation produces the actual Cost of Service of gas mains for the LDS/LGSS class?

A. No. The Peak & Average study is a method of allocating gas mains to Columbia's customer classes. It does not directly assign actual cost to customers within the LDS/LGSS rate class. Columbia does believe the average of 13 miles of gas mains assigned to each of the customers that make up the LDS/LGSS rate class using the Peak & Average method of allocation is excessive, although for the reasons explained earlier it is difficult to use a direct assignment method to quantify the exact amount of distribution mains that serve each customer. Therefore, Columbia is less aggressive than other parties in its allocation of revenue requirement to the LDS/LGSS class.

Q. Does this complete your prepared Surrebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 6-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REJOINDER TESTIMONY OF
KEVIN L. JOHNSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 30, 2024

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I. Introduction

Q. Please state your name and business address.

A. My name is Kevin L. Johnson. My business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. Have you previously filed Direct, Rebuttal and Surrebuttal testimony in this matter?

A. Yes.

Q. What is the purpose of your rejoinder testimony?

A. In my rejoinder testimony, I will respond to certain surrebuttal testimony served in this proceeding by other parties. I will be addressing several arguments and conclusions presented in the surrebuttal testimony of Mr. Ewen, witness for the Office of Small Business Advocate ("OSBA") on the subject customer charges and Office of Consumer Advocate ("OCA") witnesses Dismukes and Mierzwa on the subject of Weather Normalization Adjustment ("WNA") and

II. Customer Charges

Q. Mr. Ewen states in his surrebuttal testimony his opinion of how demand-related costs should be recovered in rates. Do you agree with Mr. Ewen's opinion?

A. No. On page 4 of Mr. Ewen's surrebuttal he surmises correctly, "It is possible that Witness Johnson is arguing that the costs that are classified as "demand related" in the ACOSS are "fixed costs," and that these costs are better recovered in a fixed customer charge". Mr. Ewen disagrees that demand related costs should be reflected

in customer charges, arguing that "recovering costs that are classified as demand-related with a commodity charge is much more consistent with cost causation than using a customer charge".

I agree with Mr. Ewen that it is probably not cost effective to recover demand-related costs with a demand charge for smaller customers, the question is whether the customer charge or the volumetric charge is a better proxy for demand-related costs. This is where I respectfully disagree with Mr. Ewen. For small customers, such as the SGS customers using < 6,440 therms annually, even the customers with the largest peak day demand can easily be served by a minimum sized main. Because the capacity requirements are essentially the same (i.e., minimum size main), the costs are similar and therefore it is appropriate to recover similar demand related fixed costs through the fixed monthly customer charge. The alternative that Mr. Ewen suggests, would recover a different amount of demand related fixed costs each month based on the customer's meter reading usage. For example, a customer using 10 Dth in a month would pay twice as much as a customer using 5 Dth even though both customers have the same minimum capacity requirements and therefore the same demand related cost.

As for the remaining commercial and industrial rate classes, Columbia has multiple levels of customer charges within the rate classes to limit the variance of peak day loads and of the associated cost. Similar to the SGS rate class, the remaining classes represent groups of customers where the capacity requirements are similar within the group and therefore it would be more appropriate to recover the demand

cost within a customer charge than a volumetric throughput rate.

III. Weather Normalization Adjustment ("WNA")

Q. On Page 8 of his surrebuttal testimony, regarding my rebuttal testimony, OCA witness Dismukes states, "the entirety of the rebuttal is nothing more than a restatement of the Company's support of the WNA, there is nothing in this rebuttal that provides any record evidence documenting how the WNA has led to demonstrable ratepayer benefits." Did you provide support of the WNA demonstrating ratepayer benefits?

A. Yes. On Page 40 of my rebuttal testimony, I stated, "since the inception of the WNA 58% of the time the WNA has benefited the Company and 42% of the time it has benefited the Company's residential customers to which it applies." Without the WNA in place, the Company's residential customers would have paid more 42% of the time solely due to weather conditions.

Q. On Page 9 of his surrebuttal testimony, OCA witness Dismukes states, "Because the WNA severs the link between revenue and sales altogether, the Company faces little to no risk associated with revenue variability (often referred to as "business risk")." Do you agree with Mr. Dismukes that with the WNA the Company faces little to no risk associated with revenue variability?

A. No. Under the WNA, the Company still faces sales risks due to customer additions/losses, conservation, and the 3 percent WNA deadband.

Q. On Page 9 of his surrebuttal testimony, OCA witness Dismukes provides updated information WNA revenue in his exhibit showing an increase in net WNA revenue from $59.1 million to $61.9 million. OCA witness Mierzwa also references the WNA impact over the last five years on Page 23 of his surrebuttal testimony. Please explain why reimbursements over the past five years has resulted in $66.6 million in WNA reimbursements to the Company.

A. Of the $66.6 million in WNA reimbursements, the majority, $53.7 million, occurred in the 2022/2023 and 2023/2024 heating seasons. There are two factors that stand out that have contributed to the amounts billed through the WNA that should be noted. First, the weather that occurred in the 2023/2024 heating season was 18.1% warmer than normal, with every month being greater than 10% warmer than normal. The 2022/2023 heating season was in total 8.9% warmer than normal with February and March being significantly warmer than normal at 19.1% and 17.5%, respectively. I have attached the respective WNA Summary Reports for the 2023/2024 and 2022/2023 heating seasons in Exhibit KLJ-RJ-1.

Second, the percentage of residential base revenue recovered through the residential volumetric base rate has grown proportionally greater than the revenue recovered through the residential customer charge over the same period. This is due to the residential customer charge not changing since the implementation of the WNA in October 2013. By recovering a greater percentage of revenue through the volumetric

rate, over time, this naturally increases the variability of the revenues subject to the WNA mechanism.

Q. On Page 25 of his surrebuttal testimony, OCA witness Mierzwa contends, "In the competitive markets, customers are charged for and pay for products based on the quantity of a product purchased. Customers are not charged for a product based on how much of a product they were expected to have purchased if actual weather and temperatures matched the historic projections. Assessing customer charges based on the quantity of a product that the seller expected a customer to have purchased based on actual weather or temperatures does not occur in the competitive markets. Therefore, assessing customers a WNA to reflect expected consumptions levels based on actual weather and temperatures is inconsistent with competitive markets, and the WNA should be eliminated." Do you agree with Mr. Mierzwa's contention?

A. No. Mr. Mierzwa's comparison of selling products in a nonregulated market are not relevant. If the products being sold in the nonregulated market were temperature driven for sales, it is unlikely that a nonregulated entity would project future sales on the basis of 20-year normal temperatures.

Q. On Page 25 of his surrebuttal testimony, OCA witness Mierzwa states, "I would note that no non-gas distribution utilities operating in Pennsylvania have been authorized to adopt rate adjustment mechanisms similar to Columbia's WNA" and then further states "simply allowing gas

utilities to charge WNA only harms customers without a benefit in electric rates to balance the scales." What are your thoughts?

A. Electric utilities not having a WNA is irrelevant to Columbia's case. Electric entity economics are not examined here, and OCA is free to make such a proposal in an electric case if it deems it appropriate.

Q. On Page 26 of his surrebuttal testimony, OCA witness Mierzwa contends it can be reasonably be expected that warmer than normal weather will continue and thus result in future WNA charges. What are your thoughts?

A. If Mr. Mierzwa and the OCA truly believe the weather will be warmer than normal in the future, they should be proposing residential sales based upon substantially warmer temperatures than the 20-year average.

Q. Does this complete your prepared Rejoinder Testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA

WNA Summary Report
2023-2024 Heating Season
November - May

	RESIDENTIAL		November	December	January	February	March	April	May	2023-2024 Season Average & Totals
1	Total Customers		401,206	403,005	405,599	406,593	406,718	405,623	403,999	404,678
2	WNA Customers		314,102	351,331	382,522	398,213	397,106	358,257	327,410	361,277
3	Customers within Deadband		87,104	51,674	23,077	8,380	9,612	47,366	76,589	43,400
4	WNA Revenue		$ 1,854,911	$ 3,488,979	$ 6,185,432	$ 9,555,776	$ 10,302,390	$ 2,156,948	$ 2,796,922	$ 36,341,357
5	WNA Volume Adjustment		203,536	382,994	678,881	1,048,750	1,130,831	236,479	306,853	3,988,324
6	Avg. WNA per Heating Customer		$ 5.91	$ 9.93	$ 16.17	$ 24.00	$ 25.94	$ 6.02	$ 8.54	$ 100.59

WEATHER

	Billing HDD's - Actual		395	738	917	831	626	485	167	4,159
	Billing HDD's - Normal		449	822	1,070	1,031	868	575	261	5,076
	Warmer (Colder) Than Normal		12.0%	10.2%	14.3%	19.4%	27.9%	15.7%	36.0%	18.1%
	Calendar HDD's - Actual		629	719	973	755	560	290	77	4,003
	Calendar HDD's - Normal		635	935	1,098	960	751	384	155	4,918
	Warmer (Colder) Than Normal		0.9%	23.1%	11.4%	21.4%	25.4%	24.5%	50.3%	18.6%

1	Total Residential Customers	The WNA applies to all active residential customer accounts, sales and choice.
2	Customers outside Deadband	Customers that fall outside the deadband of 97% to 103% and are billed WNA.
3	Customers within Deadband	Customers that fall within the deadband of 97% to 103% and are not billed WNA for that period.
4	Total WNA Revenue	Total WNA revenue from customers within the monthly period.
5	Total WNA Volume Adjustment	Volumes applicable to WNA adjustment.
6	Avg. WNA per Heating Customer	Total WNA revenue from customers divided by customers outside of deadband.

COLUMBIA GAS OF PENNSYLVANIA

WNA Summary Report
2022-2023 Heating Season
November - May

	RESIDENTIAL		November	December	January	February	March	April	May	2022-2023 Season Average & Totals
1	Total Customers		399,376	401,598	403,828	404,837	404,967	404,153	402,466	403,032
2	WNA Customers		346,805	191,333	255,403	396,863	319,831	274,497	337,838	303,224
3	Customers within Deadband		52,571	210,265	148,425	7,974	85,136	129,656	64,628	99,808
4	WNA Revenue		$ 563,691	$ 176,747	$ 2,777,439	$ 8,958,741	$ 6,622,091	$ 167,002	$ (1,824,436)	$ 17,441,274
5	WNA Volume Adjustment		67,079	21,989	305,358	983,581	726,974	18,125	(200,486)	1,922,620
6	Avg. WNA per Heating Customer		$ 1.63	$ 0.92	$ 10.87	$ 22.57	$ 20.70	$ 0.61	$ (5.40)	$ 57.52

WEATHER

	Billing HDD's - Actual		424	831	978	843	716	522	303	4,617
	Billing HDD's - Normal		440	820	1,071	1,042	868	563	266	5,070
	Warmer (Colder) Than Normal		3.6%	-1.3%	8.7%	19.1%	17.5%	7.3%	-13.9%	8.9%
	Calendar HDD's - Actual		617	973	857	712	740	340	170	4,409
	Calendar HDD's - Normal		635	935	1,104	934	755	386	155	4,904
	Warmer (Colder) Than Normal		2.8%	-4.1%	22.4%	23.8%	2.0%	11.9%	-9.7%	10.1%

1	Total Residential Customers	The WNA applies to all active residential customer accounts, sales and choice.
2	Customers outside Deadband	Customers that fall outside the deadband of 97% to 103% and are billed WNA.
3	Customers within Deadband	Customers that fall within the deadband of 97% to 103% and are not billed WNA for that period.
4	Total WNA Revenue	Total WNA revenue from customers within the monthly period.
5	Total WNA Volume Adjustment	Volumes applicable to WNA adjustment.
6	Avg. WNA per Heating Customer	Total WNA revenue from customers divided by customers outside of deadband.

COLUMBIA STATEMENT NO. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
RAYMOND A. BRUMLEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

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I. Introduction

Q. Please state your name and business address.

A. My name is Raymond A. Brumley. My business address is 121 Champion Way, Suite 100, Canonsburg, Pennsylvania 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as the Director of Construction.

Q. Please briefly describe your professional experience.

A. I began my career in 1992 with Columbia, and have held numerous operational positions with increasing responsibilities. From March of 2000 through June of 2002, I was responsible for scheduling work for Columbia Gas of Virginia, Inc. I moved into a Field Engineering role in June of 2002, where I designed capital work for the Company and Columbia Gas of Maryland, Inc. until March of 2011. I then became a leader within the construction department for Columbia, and from there took on roles of increased responsibilities as a Senior Operations Support and Leader Operations Support. In June 2016, I accepted the role of Contractor Performance Manager for the seven states within NiSource. I returned to Pennsylvania and Maryland in November of 2019 as the Manager, Construction Services and began my current role of Director of Construction on January 1, 2021.

Q. Please describe your educational background.

A. I completed coursework at California University of PA towards a Bachelor's Degree in Business Administration. I received numerous certificates and training opportunities throughout my career.

Q. What are your responsibilities in your current position?

A. My responsibilities include:

- Directing construction operations in executing the delivery of safe, reliable, efficient natural gas distribution service to our customers;
- Assuring construction is in compliance with Federal, State and local regulations as well as in alignment with industry best practices;
- Sponsoring the implementation and execution of capital construction initiatives that build consistency, collaboration, and efficiency across organizations; and
- Building and maintaining a network of contract resources that have the capacity and capability to execute on Columbia's capital program.

Q. Have you previously testified before this or any other regulatory agency?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("Commission") in a consumer complaint proceeding and in the Company's 2021 base rate case at Docket No. R-2021-3024296.

Q. What is the purpose of your testimony in this proceeding?

A. I will provide testimony in support of Columbia's plant additions through the Fully Projected Future Test Year ("FPFTY") (twelve-months ending December 31, 2025) and provide an overview of Columbia's ongoing replacement activities.

II. <u>Columbia's Projected Plant Additions through the FPFTY</u>

Q. Please explain Columbia's capital plant additions related to distribution plant claimed for the Future Test Year and Fully Projected Future Test

Year.

A. Columbia plans to maintain or increase its capital expenditures related to distribution plant in the 2024 through 2028 timeframe, with a planned spending program of over $300 million budgeted annually for replacement work, inclusive of mains, services, and measurement and regulation stations, over the 5-year period. This budget includes the following capital budget classes: Age and Condition, Betterment and Public Improvement.

A detailed description of Columbia's Age and Condition actuals for 2023, and the budgeted amount for 2024 and 2025 are provided in the following table.

Table 1

Budget Class - Age and Condition

Description	Total 2023 Actual	Total 2024 Projected	Total 2025 Projected
Measuring and Regulating Station	4,298	0	0
Compressor Stations	0	500,000	500,000
Mains - Leakage Elimination	239,554,279	222,730,000	197,978,000
Service Lines – Replaced	59,338,448	50,998,000	48,006,000
Customer Service Lines Replaced	16,361,880	16,999,000	16,002,000
Meters / 998 Int. Co. Meters	1,342,650	1,000,000	1,000,000
Meter Install – Replace	1,525,811	1,150,000	1,150,000
House Regulators - Replace	567,821	90,000	90,000
Plant Regulators – Replace - PODs	15,707,528	28,351,000	25,746,000
Reg Structures Replace	744,634	300,000	600,000
LV Excess Press Meas Sta	554,739	900,000	900,000
Corrosion Mitigation Ins	233,335	150,000	150,000
Service Regulators - Replacement	19,512	20,000	20,000
In-Line Inspection	788,689	3,828,000	13,406,000
Meter Move Out Program	1,661,094	3,000,000	3,000,000
	338,404,718	330,016,000	308,548,000

The table below (Table 2) depicts the three budget classes, Age and Condition, Betterment, and Public Improvement (rounded to the thousands). The differences

in Age and Condition shown between the two tables are the Shared Service expenditures shared among all NiSource companies. Those Shared Service expenditures are not included in Table 1 above.

Table 2

CPA Budget Class	2023 Actuals	2024 Approved	2025 Projected
Age and Condition	338,439,000	330,116,000	308,648,000
Betterment	17,030,000	12,697,000	22,184,000
Public Improvement	15,487,000	8,000,000	7,000,000

Q. Please provide some insight into Table 1 above.

A. Within our 2024 Age & Condition budget, Columbia is still projecting increases in unit cost expenditures for mainline and service line replacement work, primarily due to increased contractor pricing. Also, increases for unit costs per foot for mainline replacements and unit costs for service line replacements are expected, based on additional usage of flaggers and staging vehicles on job sites, beyond what is currently being used. Columbia has experienced an increase in work zone intrusions in recent years, which is a significant safety threat to our employees, our contractors, and the everyday work that we do. This safety initiative, for additional flaggers and staging vehicles at job sites, will help to minimize this growing threat to allow our workforce to concentrate on their tasks at hand and set-up and tear down in a safe and proficient manner. Section IV of my testimony, "Replacement Costs & Restoration Issues", provides further details on causes that continue to be significant drivers to the overall unit cost increase as well. With that stated, although Table 1 shows a very slight decline in overall estimated expenditures in mainline and respective service line

replacements, also shown are estimated increases in District Station / Point of Deliver ("POD") Replacements as well as In Line Inspections ("ILI"). Both are significant parts of Columbia's Safety Management System ("SMS"). Company witness McCaul (Columbia Statement No. 14) provides more information regarding SMS.

Within our Age and Condition budget, as shown in Table 3 below, are details and approximate estimates for work to be done in preparation of Columbia's ILI on our CAT Line in Emigsville during 2025.

Table 3

ection Project Name	Length (miles)	HCA (miles)	Diameter (in)	Original Install (year)	MAOP (PSIG)	2024 Estimated Expenditures (in millions)	2025 Estimated Expenditures (in millions)
CAT - Emigsville	6.2	2.6	12	1958	550	3.83	13.41

ILI of transmission pipelines, where viable, is an advanced inspection technique in use across the industry and is largely successful in susceptibility identification along the entire pipeline. The use of ILI on a transmission pipeline to identify threat conditions allows for proactive mitigation of targeted segments for replacement versus less effective system wide mitigation activities, such as over the ground Cathodic Protection surveys which can only detect external corrosion susceptibilities. Further, ILI detects all forms of metal loss and geometry changes occurring from mechanical damage, manufacturing defects, construction issues, external and internal corrosion & outside forces.

Columbia is focused on advancing ILI as the most effective and complete assessment method to identify threats in a proactive manner with the overall vision to prevent failures across its transmission pipeline effectively, efficiently, and completely. As part of a NiSource-wide multi-year, multi-phase program to improve ILI capabilities, two pipeline systems in Pennsylvania have been selected to be retrofitted for ILI. The goal is to complete design engineering, land acquisitions, and the purchase of long lead time materials in 2024, with construction execution planned for 2025 for the CAT Line in Emigsville.

Q. How was the budget for 2024 developed?

A. In addition to what is stated above, within our 2024 Age & Condition Budget, Columbia is projecting even higher unit cost expenditures for mainline and service line replacement work due to our current blanket contracts. Though this is competitively bid, based on the market conditions and demand for natural gas contractors, not just across Pennsylvania but other states as well, pricing will increase to the levels shown in our 2024 projections. Budget plans are derived based upon historical trends and known future projects.

For 2024, an allocation of over $290 million has been approved for the replacement of mains and service lines alone, to maintain the Company's momentum of replacing its aging infrastructure. Increased expenditures are forecasted in District Regulator / POD Replacements and ILI, as stated above. Also, Columbia shows increased expenditures on its Meter-Move Out Program, which the Company is conducting in compliance with Section 59.18 of the Commission's regulations.

III. Columbia's Pipeline Replacement Efforts

Q. How many feet of bare steel, wrought iron, and cast iron main have been eliminated from Columbia's system during its accelerated program, and how does that trend compare with the previous years?

A. Columbia began an accelerated replacement of bare steel, wrought iron, and cast iron pipe in 2007. Between 2007 and the end of 2023, Columbia retired the following footages of bare steel, wrought iron, and cast iron by year:

2007	355,764	feet
2008	528,567	feet
2009	344,488	feet
2010	322,583	feet
2011	553,765	feet
2012	415,240	feet
2013	452,636	feet
2014	413,667	feet
2015	496,610	feet
2016	478,790	feet
2017	509,428	feet
2018	302,606	feet
2019	516,689	feet
2020	387,821	feet
2021	440,036	feet
2022	433,930	feet
2023	482,076	feet
Total Actual (Through YE 2023)	**7,434,696**	feet

From 2007 through 2023, Columbia's replacement program eliminated an average of 437,335 feet per year. During the four (4) years from 2002 to 2005, the average annual rate of retirement was 196,948 feet, less than half the rate of retired footages of bare steel, wrought iron, and cast iron under the current program. Please note, as of the end of December 2022, Columbia has no known cast iron main left in its distribution system.

Q. Why does Columbia need to continue to replace its bare steel systems?

A. Columbia's Distribution Integrity Management Program ("DIMP") risk scoring continues to rank external corrosion on bare steel among our top system risks. Corrosion on first generation mains represents approximately 51% of all hazardous or potentially hazardous leakage cleared on mains in the Columbia distribution system as of year ending 2022. The Company believes that the accelerated replacement of the first-generation system is not only prudent, but is a requirement under the federal DIMP rule that Columbia continues to address very aggressively in a consistent and programmatic way.

Q. Is there another solution for addressing the issues with bare steel, short of replacement?

A. No. Corrosion leakage on unprotected steel does not slow down and the rate of leakage will only accelerate as the unprotected steel facilities continue to deteriorate. First generation unprotected steel pipe, some of it dating to the turn of the last century, has reached or soon will reach the end of its useful life and must be replaced in a timely, cost-effective manner.

Q. Do safe and reliable system operations requirements demand replacement of Columbia's unprotected steel facilities?

A. Yes. If left unchecked, continual system degradation due to unrelenting corrosion will challenge Columbia's ability to meet peak day needs and operate the system safely. Therefore, continuing Columbia's main replacement program is essential to minimize leakage and the associated public risks and additional strain on the system when required to meet peak day demands.

Q. Are you saying Columbia's system is unsafe?

A. No, I am saying the system is safe right now, as evidenced and described in Columbia witness McCaul's testimony (Columbia Statement No. 14) by our ability to address Type-1 and Type-2 leaks appropriately, as well as, all the other operational improvements, better emergency leak response, and a continued focus to reduce the backlog of open Type-2 leaks. Columbia's system is comprised of thousands of miles of wrought iron, bare steel, cathodically-protected steel, and plastic pipe. The material initially at risk is generally first-generation bare steel and wrought iron. Evidence further indicates that the corrosion with respect to unprotected coated steel is accelerating, gradually causing more leaks. Wrought iron is a hybrid of cast iron and bare steel that demonstrates very similar corrosion characteristics to that of bare steel. Additionally, "first generation" pre-1982 plastic pipe has demonstrated itself to be prone to stress propagation cracking under some circumstances due to the different composition of the base plastic material.

While the system is currently safe, Columbia must, as a prudent operator, address the systemic problem of replacing its unprotected steel and wrought iron facilities. And finally, the issues that are manifesting themselves on first generation plastic, also necessitate a measured replacement strategy geared to those locations where Columbia is uncovering this pipe in the course of replacing other facilities. Witness McCaul provides further testimony with respect to replacement of unprotected coated steel and first-generation plastic pipe.

Q. Will Columbia's accelerated replacement program provide customers with any other benefits besides the replacement of bare steel, wrought

iron, with plastic and cathodically protected steel?

A. Yes. Columbia is replacing the segmented, 19th and early 20th century low-pressure designs of its first-generation system with a more integrated, 21st century system design. This integrated, higher pressure system (up to a maximum of 99 pounds operating pressure, though we will typically operate at 60 pounds per square inch gauge ("PSIG")) will enable Columbia to substantially reduce the current need for district pressure regulator stations throughout its system, resulting in a safer, easier, and more reliable system to operate. Instead, each residence will have a small domestic-sized regulator installed just upstream of the meter to reduce the pressure before it enters the house. Also, a distribution system operating at these higher pressures will enable Columbia to install new safety devices in areas to be upgraded. As part of the upgrade, Columbia is installing excess flow valves ("EFVs") on nearly all services connected to the replaced mains.[1] The EFVs will shut off gas to a residence or business in the event of a large pressure differential that is indicative of a major gas leak or a service damaged by excavation. Over time, this results in a system where services are much less vulnerable to safety risks from third-party damage.

Q. How will main replacements affect the Company's leak repair experience?

A. The long term view is that as bare steel and wrought iron are removed from the

[1] An exception may be granted to installing an EFV on multifamily residences and non-residential (e.g. commercial, industrial) service types by a Field Engineering Manager when the known customer load at the time of installation is 1,000 cubic feet per hour ("CFH") or greater. If an exception is granted, a curb valve shall be installed in accordance with the applicable Columbia Gas Standard (GS 3020.020 "Service Lines Valves Requirements and Locations") and also documented on the service line record as to why an EFV was not installed. Note EFVs are currently available up to 10,000 CFH capacity. This means that for the majority of new and replaced service lines on systems with an MAOP greater than 10 psig, the service line will have an EFV installed.

system, we expect to see a reduction in Type 1 and Type 2 leakage repair necessitated by corrosion. However, this impact is expected to be gradual over the period of the program. The remaining wrought iron and bare steel pipe to be replaced continues to degrade, which continues to drive Type 1 and Type 2 leakage repair activities. Entering 2024, as a result of Columbia's aggressive pipe replacements, together with Columbia's aggressive leak repair program, Columbia had a total number of 729 Type-2 outstanding leaks in its system.

Q. How does the public benefit from Columbia's ongoing replacement of its aging facilities?

A. Columbia is removing deteriorating portions of its system and enhancing the safety of its system by ensuring replacement of facilities with new, durable and safer materials. Its system will continue to be able to provide deliverability at its maximum allowable operating pressure ("MAOP"), thus the public will receive better service, with fewer interruptions. Customers currently experience the benefits of the investments being made to enhance the safe and reliable delivery of their natural gas service. During the "Polar Vortex" events of both 2014 and 2015, Columbia's distribution system performed well and experienced no significant issues with service interruptions or curtailments of firm customers. The same has held true through the other cold weather events of the 2017-2018 winter heating season, as well as this past 2022-2023 winter heating season. Further, Columbia's comprehensive system replacement program is adding jobs throughout Columbia's service territory, both in the ranks of full-time Columbia employees (these include engineers and engineering technicians, land agents, and construction coordinators and construction

specialists), as well as the contractors who perform the actual pipe replacement (which includes laborers, equipment operators, crew leaders, and support staff) and associated support services such as: paving, traffic control, trucking, sand and gravel, and a myriad of other material purchases and support activities that are needed to execute this type of strategic replacement program. Finally, to emphasize the magnitude of this program, on average during 2023, Columbia had approximately 112 crews, which employed approximately 1,120 contractor employees and subcontractors (e.g. restoration, flaggers, drillers, plumbers, etc.). For 2024, Columbia will have approximately 105 crews with approximately 1,050 contractor employees and subcontractors (e.g. restoration, flaggers, drillers, plumbers, etc.).

Q. Is there anything else that you would like to say about Columbia's pipeline replacement efforts?

A. Yes. Taken in total, Columbia has made enormous progress since 2006 in delivering and maintaining a safe and reliable distribution system for its customers. The progress that I refer to is defined in more detail throughout Columbia witness McCaul's testimony, but includes identification and mitigation of system cross bores, reducing the number of inactive services in the system, improving the locating process to reduce third-party damage, improving emergency response rates and on-time appointments for customers, and dramatically increasing the amount of bare steel and first generation plastic pipe that it removes from the system annually compared to pre-2007 levels. Having said all of that, however, the system data is clear that as first generation bare steel pipe continues to age, Columbia will have to continue to focus on the accelerated replacement of bare steel and first generation

plastic to address the problems associated with aging infrastructure. Therefore, it is essential that Columbia continue to direct management effort and incremental capital resources toward this ongoing need. The synchronization of these replacement efforts with the enhanced focus on pipeline safety that Columbia has demonstrated over the last 17 years are integral parts of Columbia's DIMP Plan, and are essential planks of Columbia's ongoing efforts to enhance natural gas pipeline integrity management and, thus, provide a safe, reliable distribution system for our customers and the general public.

IV. Replacement Costs & Restoration Issues

Q. How have replacement costs trended and what are the primary cost drivers?

A. Columbia has experienced upward cost pressure for replacement projects over the past several years. The average cost of main replacement in 2008 was $81.25 per foot, while the current average cost of main replacement, using 2023 actuals, is $289 per foot. The following factors create the upward cost pressure:

- The location of projects has a significant impact on cost. Hard surface projects in urban areas normally have a higher replacement cost per foot than soft surface replacement in rural areas, given that similar size and material of pipe are being installed. The increased cost of urban areas can be due in part to the need to coordinate replacement of Columbia's facilities with facilities of other utilities or municipalities. These higher cost urban areas often experience higher risk and are increasingly being prioritized for replacement, contributing to the increasing average cost per foot.

- Changes in hard surface restoration requirements are a key component of the upward cost pressures. Municipalities are expanding restoration requirements on utilities. For example, ten years ago it was typical that trench restoration would consist of simply paving the trench that was excavated for the main installation. Today, that same project frequently requires curb to curb milling and overlay. On other projects, Columbia is required to locate its facilities under sidewalks. On these projects, Columbia is required to replace the entire sidewalk, and to the extent that the sidewalk does not meet Americans with Disabilities Act ("ADA") standards, Columbia is required to make them compliant with current ADA standards. This means that Columbia may need to install wheelchair ramps and curb realignment or replacement work.
- Contractor cost is another key component of increased costs. Contractor cost increases are driven by competition for resources as more natural gas distribution companies in Pennsylvania and across the country undertake main replacement programs, increase training and qualification requirements, and compete for the availability of construction work with other businesses inside and outside of the industry.

Q. What is Columbia doing to manage cost increases?

A. Columbia is focused on managing costs and making prudent capital investments that benefit our customers. As one of six gas distribution companies within the NiSource family making infrastructure capital investments, we are able to negotiate at scale with contractors and suppliers, delivering competitive pricing for materials and

services provided to Columbia.

Further, Columbia has initiated significant efforts regarding the management of permitting and restoration costs, which I will describe later in my testimony. Columbia's service territory spans over 450 municipalities in the Commonwealth of Pennsylvania, each of whom are authorized to set their own municipal ordinances related to street openings. Columbia incurs restoration costs on pipeline replacement projects in compliance with the ordinance of the municipality in which the pipeline is replaced.

Since November of 2020, we have added nine Construction Project Management positions across the state to provide more project management rigor to our larger, more complex projects. The responsibilities of these positions include, but are not limited to, assisting in the project design, permitting process, job readiness, maintaining job scope, costs, safety, productivity, and constant communication with internal and external stakeholders. They maintain a working relationship with municipal leaders during the job while delivering job updates.

Q. Do municipal standards continue to impact Columbia's aggressive pipeline replacement program?

A. Yes. Columbia serves approximately 445,000 customers within 26 counties and roughly 450 municipalities throughout the Commonwealth. Because of the size of our footprint, the number of municipalities we operate in and the lack of standard ordinances and restoration requirements across those communities, as a Company, we continue to face challenges related to local municipal oversight, fees, permitting processes and project restoration requirements related to our pipeline replacement

program. Local municipalities struggling with budgetary issues continue to look to shift costs and road maintenance responsibilities to utilities working (cutting into their streets) in their communities. Increased local municipal requirements or fees have and will continue to delay our pipeline replacement work and new business efforts, as well as cost the Company and our customers additional money.

Q. What is Columbia's plan to address these ongoing municipal challenges?

A. Columbia continues to implement a comprehensive plan to address municipal issues. The Company's Public Affairs team (in addition to select local operations, construction, engineering and new business employees) developed and executed a proactive municipal outreach program to establish, improve and maintain relationships with municipal officials in communities where we are, and will be, conducting significant pipeline replacement or new business projects. The program continues to focus on educating identified local staff/officials and elected representatives of boroughs, townships and cities/towns about:

- Columbia;
- Our pipeline replacement and new business efforts in general;
- Specific planned pipeline replacement or new business projects in their community;
- The benefits of our pipeline replacement or new business projects in their community; and
- The need for reasonable permit fees and restoration requirements.

The Public Affairs team works directly with municipalities to review proposed or

passed local public policies that may impact Columbia's proposed work. Specifically, the Public Affairs team is tasked with monitoring municipal ordinances and proposed amendments that may unreasonably increase paving restoration requirements, unreasonably increase permitting fees or place additional unreasonable fees for inspections, road openings or road degradation on Columbia's work.

The Company's Government Affairs team also educates State Representatives and State Senators in our service territory about the ongoing cost increases municipal governments are charging utility ratepayers through increased permitting and engineering fees as well as restoration requirements for Columbia's work in their municipalities. As a result, HB 1655 was introduced on September 5, 2023, which if adopted would prohibit local municipal governments from implementing permit fees and restoration standards that exceed Pennsylvania Department of Transportation permit fees and restoration standards. On September 6, 2023, Columbia testified in strong support of HB 1655 at a House Consumer Protection, Technology & Utilities Committee hearing on the legislation.

Q. Please provide further detail on the outreach focus of the municipal outreach program.

A. The outreach program focuses on, but is not limited to, the following groups:

- Local boroughs, townships and cities/towns in which we have not replaced significant mainline pipe or had new business projects, but have planned upcoming projects.
- Local boroughs, townships and cities/towns in which we need to improve and

enhance relationships due to past issues or new ordinances adversely affecting our operations or our customers.

- The district offices and staff of identified state legislators to educate them on planned pipeline replacement/new business projects in their districts and to gain a better understanding about local governments and their leadership. These offices may also be able to assist Columbia with relationship building and communications with local governments when appropriate.

Q. Do you have some examples of how Columbia was proactively engaged in addressing municipal issues in the most recent calendar year, 2023?

A. Yes. In 2023, the Public Affairs team participated in the following proactive outreach discussions:

- **Adams County** – Columbia conducted proactive outreach to Hamilton Township on a pipeline replacement project.
- **Allegheny County - City of Pittsburgh Utility Coordination:** Throughout the year, Columbia participated with the City of Pittsburgh in its utility coordination meetings to coordinate utility projects between the City and utilities working in the right of way, as well as road restoration and repaving efforts.
- **Allegheny County –** Columbia conducted proactive outreach with Avalon Borough, Baldwin Borough, Bellevue Borough, Bethel Park Borough, Castle Shannon Borough, Coraopolis Borough, Dormont Borough, Greentree Borough, Kennedy Township, Leet Township, Leetsdale Borough, Marshall Township, McDonald Borough, McKees Rocks Borough, Moon Township,

Mount Lebanon Township, Mount Oliver Borough, North Fayette Township, Oakdale Borough, Pine Township, City of Pittsburgh, Pleasant Hills Borough, Robinson Township, Scott Township, Sewickley Borough, Stowe Township, South Fayette Township, Upper Saint Clair Township, and Whitehall Borough regarding pipeline replacement projects or operational work in those communities.

- **Armstrong County –** Columbia conducted proactive outreach with the City of Parker.
- **Beaver County –** Columbia conducted proactive outreach with the City of Alliquippa, Ambridge Borough, Baden Borough, Beaver Borough, the City of Beaver Falls, Brighton Township, Economy Borough, Harmony Township, Monaca Borough, New Gallilee Borough, and Rochester Borough on pipeline replacement projects.
- **Butler County –** Columbia conducted a proactive meeting with Cranberry Township, Mars and Slippery Rock Township on a pipeline replacement project.
- **Centre County –** Columbia conducted proactive outreach with Bellefonte Borough regarding a pipeline replacement project.
- **Clarion County –** Columbia conducted proactive outreach with Beaver Township and Rimersburg Borough on a pipeline replacement project.
- **Fayette County –** Columbia conducted proactive outreach with Brownsville Borough, Dunbar Township, Newell Borough, Redstone Township, Springfield Township and the City of Uniontown on pipeline

replacement projects.

- **Franklin County –** Columbia conducted proactive outreach to Greencastle and Mont Alto Boroughs on pipeline replacement projects.
- **Lawrence County –** Columbia conducted proactive outreach with Bessemer Borough, Ellport Borough, Ellwood City Borough, the City of New Castle, Shenango Township, and Wampum Borough on pipeline replacement projects.
- **Somerset County –** Columbia conducted proactive outreach to Somerset Borough on a pipeline replacement project.
- **Washington County –** Columbia conducted proactive outreach with Canonsburg Borough, California Borough, Centerville Borough, Charleroi Borough, Donora Borough, Dunlevy Borough, Fredericktown Borough, Luzerne Township, North Franklin Township, North Strabane Township, Peters Township, South Strabane Township and the City of Washington on pipeline replacement projects.
- **Westmoreland County –** Columbia conducted proactive outreach with the City of Jeannette and Sewickley Township regarding pipeline replacement projects.
- **York County –** Columbia conducted proactive outreach to Dover Township, Manchester Township, Spring Garden Township, Springettsbury Township, West Manchester Township, West York Borough, and the City of York on pipeline replacement projects.

Q. When a municipality requests restoration beyond the area in which Columbia's pipeline replacement activity occurs, what does Columbia do to resolve the issue?

A. When the Company encounters a situation in which a municipality requests atypical or non-PennDOT standard restoration requirements, Columbia tries to negotiate with the municipality, in order to reach a compromise. This approach helps Columbia maintain good rapport with townships and municipalities. Maintaining relationships with municipalities and townships is very important, especially in the unforeseen event of an emergency. Thus, negotiation is the initial starting point and preferred resolution method.

Further, while negotiation is the preferred method for resolution, sometimes a compromise cannot be reached. When a compromise cannot be reached, the Company further analyzes the situation to determine the best path to move forward. The Company can opt to pursue litigation or evaluate whether to move forward with the project. Whether or not to move forward with a project is evaluated on an individual project basis, as each situation presents unique circumstances.

Q. Outside of the examples provided above, has Columbia been successful in challenging restoration requirements that Columbia considers to be atypical?

A. Yes. Some examples of Columbia's success are as follows:

- **City of Pittsburgh, Allegheny County:** In November and December of 2023, Columbia raised concerns to members of Pittsburgh City Council regarding a City of Pittsburgh Department of Mobility and Infrastructure

proposal to create a new $110 per service line fee on top of right-of-way opening fees on utility pipeline replacement projects in the city. The new fee was part of the 2024 proposed city budget and needed to be approved by Pittsburgh City Council. As a result of Columbia's education and advocacy against the proposal, the fee was reduced to $30 per service line and will save ratepayers approximately $30,000 in fees in 2024.

- **Ambridge Borough, Beaver County:** The borough had a restoration requirement to tie together any utility road cuts within 700 feet (over 1/10th of a mile) of each other. The PennDOT standard is to tie in multiple road cuts within 100 feet of each other. Columbia advocated for the borough council to change that ordinance. The borough council did amend the ordinance with a "multiple cuts within a block formula" and agreed to work with Columbia on a reasonable approach to restoration.
- **Canonsburg Borough, Washington County:** Columbia has engaged the borough since 2020 regarding a permit fee and road restoration ordinance put into effect in 2020 that significantly increases costs for Columbia's work. The ordinance requires curb to curb paving plus 25 feet on each side of a road cut and increased small project permit fees up to $950 per project. It also created a linear and square foot fee for larger projects resulting in permit fees for two pipeline replacement projects costing more than $12,000 and $13,000 for each project.

The paving restoration costs for the two pipeline replacement projects using the curb to curb plus 25 feet paving standard in the borough's

ordinance were significant. If Columbia restored to PennDOT standards, the cost was approximately $260,000. If Columbia restored to the borough's curb to curb plus 25 feet standard, the restoration cost increased to approximately $470,000 – an additional cost to ratepayers of $210,000.

In the Summer of 2023, Columbia refused to pave to the curb to curb plus 25 feet standard and threatened litigation against the borough. Columbia negotiated a PennDOT-like paving restoration plan with the borough saving ratepayers additional costs. Columbia is currently negotiating changes to the ordinance with borough council regarding permit fee costs and restoration standards.

- **Charleroi Borough, Washington County**: The borough has an ordinance requiring curb to curb paving if more than ten percent of the square area of any 50-foot length of roadway is opened and a permit fee formula of $8 per linear foot up to 100 feet; plus $2 per linear foot after that. Columbia negotiated a 50 cents per linear foot fee and PennDOT restoration standards for two 2023 pipeline replacement projects.
- **Dunbar Township, Fayette County**: The township's permit fee formula is a $250 application fee plus $5 per square foot of opening. Columbia has three proposed pipeline replacement projects in the township for 2024 and 2025. The estimated permit fees for the three proposed projects under the ordinance is approximately $262,000. The estimated PennDOT permit fee for identical projects in their right-of-way is $4,892.

Columbia is currently working with the township's solicitor and council on a more reasonable permit fee for the three projects.

- **Menallen Township, Fayette County:** In January of 2022, Columbia was planning two proposed pipeline replacement projects and had been approached by a potential new customer to provide service to their home in Menallen Township. Columbia's engineering department analyzed the township's fee ordinances to conduct work in the right-of-way on the proposed projects. The township's ordinance contains a permit fee formula of a $150 application fee; an inspection and supervision fee for the township engineer of $75 per hour with a minimum of four hours or a $300 fee; and a $3.67 per square foot fee for an opening or excavation.

  Columbia engineers estimated the township's fees for the proposed projects would be approximately $48,105 and exceeded fees charged by the PennDOT for similar work in its right-of-way by more than $45,000.

  After months of negotiations that did not produce results, on October 26, 2022, Columbia filed a petition in the Commonwealth Court of Pennsylvania challenging certain provisions of Menallen Township's ordinance regarding permitting fees and right-of-way fees as excessive. The case is currently pending in Commonwealth Court.

- **Neville Township, Allegheny County:** The township has given all authority for permitting to LSSE Engineering. For initial discussions on one pipeline replacement project, LSSE sent an invoice to Columbia for more than $7,400 with multiple employees allegedly needing to review our

information. On a second proposed pipeline replacement project, LSSE is demanding an escrow account be set up of more than $120,000 so they may charge the account to provide inspections on the proposed pipeline replacement project. This is in addition to a permit fee of more than $12,700. Columbia is attempting to negotiate reasonable permit fees, engineering fees and appropriate inspections for our upcoming projects in the township.

- **Redstone Township, Fayette County:** The township has a permit fee formula of $150 application fee, plus $75 per hour with four-hour minimum engineering inspection and supervision fee, plus $36.70 per square foot permit fee. Columbia has engaged the township's council regarding pipeline replacement projects in 2025 and 2026 that would replace approximately 9,600 linear feet of pipe. Those projects have estimated permit fees of more than $700,000. Columbia is working to arrive at a reasonable permit fee formula for the projects.

- **West Brownsville Borough, Washington County:** Since the Spring of 2021, Columbia has engaged in discussions with the borough's council regarding the Company's concerns with the borough's road restoration ordinance, Ordinance No. 2019-347. The restoration requirements of the ordinance demand paving for any opening no less than ten (10) feet in each direction from either edge of original excavation for the entire street width. (curb to curb/edge to edge)

Columbia restored operational project work areas in the borough to PennDOT restoration standards outlined in 67 PA Code Section 459.8 and PennDOT Publication 408. For those work projects, the total disturbed area is approximately 730 square feet. The cumulative required restoration under Ordinance 2019-347 is 5,970 square feet.

If comparing restoration costs for the Columbia work projects, the cost of restoration of the locations to PennDOT standards was approximately $4,522. Restoration in accordance with the Ordinance would increase costs to ratepayers by approximately $32,236. The borough's code enforcement officer, solicitor and council members threatened citations against Columbia for violations of Ordinance 2019-347. Discussions continued in the Fall of 2023 and were not productive. The borough's ordinance also has a permit fee formula for larger projects that is $10 per linear foot resulting in a $43,000 permit fee plus the potential payment of engineering costs for a proposed 2025 pipeline replacement project. Columbia is considering its available options, including litigation to challenge the borough's ordinance.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Statement No. 8

COLUMBIA GAS OF PENNSYLVANIA, INC.

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity and
Fair Rate of Return

DOCKET NO. R-2024-3046519

March 15, 2024

Columbia Gas of Pennsylvania, Inc.
Direct Testimony of Paul R. Moul
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Appendix A - Educational Background, Business Experience and Qualifications

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CPA	Columbia Gas of Pennsylvania, Inc.
DCF	Discounted Cash Flow
FOMC	Federal Open Market Committee
FPFTY	Fully Projected Future Test Year
g	Growth rate
IGF	Internally Generated Funds
LDC	Local Distribution Companies
Lev	Leverage modification
LT	Long Term
M&M	Modigliani & Miller
P-E	Price-earnings
PPUC	Pennsylvania Public Utility Commission
PUHCA	Public Utility Holding Company Act of 2005
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a Firm
SBBI	Stocks, Bonds, Bills and Inflation
s x v	Represents external growth

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
WNA	Weather Normalization Adjustment Mechanism

Introduction and Summary of Recommendations

Q. Please state your name, occupation and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your direct testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission (“PPUC” or the “Commission”) should recognize in the determination of the revenues that Columbia Gas of Pennsylvania, Inc. ("CPA" or the "Company") should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit No. 400, which is a multi-page document divided into fourteen (14) schedules.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company in this case?

A. Based upon my analysis of the Company, it is my opinion that the rate of return on common equity should be set at 11.75%. My return on equity includes a provision of 0.25% in recognition of management effectiveness. That is to say, the cost of equity that I am proposing is comprised of an 11.50% market-determined rate plus 0.25% for management performance. In this regard, I have not made an independent evaluation of the Company’s management effectiveness. Company witness Mark Kempic, President of the Company, describes the superior performance of its management in his testimony

((Columbia Statement No. 1). Witness Kempic has shown that the Company ranks high in customer service and management efficiency. My cost of equity determination should be viewed in the context of the need for supportive regulation at a time of increased infrastructure improvements now underway for the Company. As shown on page 1 of Schedule 1, I have presented the weighted average cost of capital for the Company, which is calculated with the December 31, 2025 Fully Projected Future Test Year ("FPFTY"). The Company's proposed rate of return is shown below:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	43.12%	5.07%	2.19%
Short-Term Debt	2.48%	5.25%	0.13%
Total Debt	45.60%		2.32%
Common Equity	54.40%	11.75%	6.39%
Total	100.00%		8.71%

The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The Company is a wholly-owned subsidiary of NiSource Gas Distribution Group, which is a wholly-owned subsidiary of NiSource Inc. ("NiSource"). NiSource is a holding company under the Public Utility Holding Company Act of 2005 ("PUHCA") and also owns Northern Indiana Public Service Company (a combination gas and electric utility), and other energy investments.

The Company provides natural gas distribution service to approximately 445,000 customers located in south-central and western Pennsylvania. Throughput to its customers for the twelve-months ended November 30, 2023, was represented by approximately 47% to sales customers and approximately 53% to transportation customers. CPA obtains its gas supplies from producers and marketers and has transportation arrangements through connections with six interstate pipelines. The Company has storage arrangements with three suppliers to supplement flowing gas.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a gas distribution utility, such as the Company. In this regard, I have considered four (4) well-recognized models. These methods include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's rate of return on common equity is 11.50% to which 0.25% is added in recognition of the exemplary performance of the Company's management.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark

Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. How have you measured the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of eight (8) gas companies. I will refer to these companies as the "Gas Group" throughout my testimony. I began with all of the gas utilities contained in The Value Line Investment Survey, which consists of nine companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. I eliminated one company from the Value Line group. UGI Corporation was removed due to its diversified businesses consisting of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and gas generation. The companies in the Gas Group are identified on page 2 of Schedule 3. These are the same companies that were used to apply the cost of equity models in the recent Quarterly Earnings Report (Docket No. M-2023-3041106) approved by the Commission on July 13, 2023.

Q. What noteworthy factors have influenced your cost of equity analysis?

A. My cost of equity analysis reflects the impact of high levels of inflation, which have not been seen for four decades. Indeed, the rate of inflation spiked upward to 9.1% in June 2022, and by January 2024 it had fallen to 3.1%. High levels of inflation, i.e., those above the Federal Open Market Committee ("FOMC") policy goal of 2%, have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt, and the need for more cautious financial practices, such as a prudent level of borrowing. While short-term interest rates were at historically low levels during much of the Pandemic,

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

longer-term interest rates began to rise in February 2021 and have continued at higher levels throughout 2022 and 2023. Following the Pandemic, the accommodative policy by the FOMC has ended, and higher interest rates have occurred. The FOMC uses its open market operations to control the Fed Funds rate as a means of implementing its dual mandate of healthy employment and price stability. This was revealed by the Fed Funds rate, which increased 525 basis points since the beginning of 2022 through 11 increases in 21 months. The FOMC paused its rate increases and held rates steady at its meeting on June 14, 2023. Thereafter, another rate increase occurred on July 26, 2023. The FOMC paused again at its meetings on September 20, November 1, and December 13, 2023, and January 31, 2024. It appears that we are at the end of the current interest rate tightening cycle. Some discussion suggests that reductions in the Fed Funds rate could occur later in 2024.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity. The specific application of these

methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Gas Group
DCF	12.05%
Risk Premium	11.50%
CAPM	13.86%
Comparable Earnings	13.10%

The range of equity cost rates is 11.50% to 13.86%. By focusing on the lower part of the range, the Company's cost of equity is at least 11.50%. As I will discuss later, CPA has more risk than the Gas Group. To the 11.50% minimum cost of equity, twenty-five (25) basis points has been added in recognition of the exemplary performance of the Company's management. The exemplary performance of the Company's management is described in the direct testimony of Mr. Kempic. Mr. Kempic describes the many initiatives that the Company has undertaken, which have produced high quality service at reasonable prices. The combined 11.75% (11.50% + 0.25%) rate of return on common equity is reasonable and cost based because it is within the range of returns (i.e., 11.50% to 13.86%) and recognizes the Company's greater risk as compared to the Gas Group. My recommended rate of return on common equity of 11.75% is likewise conservative because it makes no provision for the prospect that the rate of return may not be achieved due to unforeseen events, such as unexpected spikes in the cost of purchased products and other expenses. To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. From these measures, I recommend a cost of equity of 11.75%, which includes recognition of the exemplary performance of the Company's management.

Natural Gas Risk Factors

Q. What factors currently affect the business risk of natural gas utilities?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a complex environment with time frames for decision-making considerably shortened. Their business profiles are influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers. In addition, the natural gas business is being influenced by changing attitudes concerning its regulation and political risks that include efforts to reduce or eliminate the use of natural gas.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation, and the reduction of greenhouse gas emissions. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues. The testimony of witness Kempic and other Company witnesses discuss the investments that the Company has made and will continue to make to address these issues.

The Company also faces a series of risks that impact its cost of equity. In the western area of Pennsylvania, the Company operates in a unique situation with overlapping service territories, which enable other gas utilities to compete with one another for customers. Notably, one customer departed the Company's system in the Spring of 2019 and switched to another LDC that provides service in an overlapping service territory to the Company. This clearly presents a unique risk faced by the Company. Further, there are six interstate pipelines that traverse the Company's service territory. This situation exposes the Company to bypass for certain large volume customers. Finally, the existence of local gas production provides a bypass threat to the

Company, especially with production from the Marcellus Shale formation. Overall, the Company's risk of competition is considerably higher than that faced by many LDCs, including the members of the Gas Group that I used to measure the Company's cost of equity.

Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. Most of the Company's residential and commercial customers use natural gas for space heating purposes. This indicates that a large proportion of the Company's residential and commercial customers present a low load factor profile, and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. To deal with this issue, CPA has a weather normalization adjustment mechanism ("WNA") as part of its tariff. I also understand that the Company is proposing a second mechanism, called a RNA, that is a revenue normalization adjustment applicable only to residential customers. Description of the Company's WNA is contained in the testimony of Company witness Girata.

Q. Does your cost of equity analysis and recommendation take into account the WNA as discussed in the testimony of Company witness Girata?

A. Yes. All of my Gas Group companies have some form of WNA mechanism, and in some cases, other forms of revenue decoupling. Therefore, the market prices of all companies in my Gas Group reflect the expectations of investors that these companies' revenues are stabilized to some extent by a normalization mechanism. Therefore, my analysis reflects the impacts of normalization adjustment mechanisms on investor expectations through the use of market-determined models. If the Company is unable to obtain the RNA mechanism, its risk will increase above that of the Gas Group that serves as a basis

to measure the Company's cost of equity, i.e., the Gas Group's cost of equity will then understate the return that is appropriate for the Company.

Q. Are you aware that there is a Distribution System Improvement Charge ("DSIC") available to natural gas and electric utilities in Pennsylvania, and does the DSIC affect the Company's cost of capital?

A. I am aware that the Company had utilized the DSIC for short periods of time in the past. The cost of capital for CPA, however, is not affected by the DSIC. I say this because all of the proxy group companies whose data has been used to develop the cost of equity for CPA in this proceeding have at least some form of a DSIC or similar infrastructure rehabilitation mechanisms. Hence, whatever the benefit of a DSIC, or other regulatory mechanisms, that impact is already reflected in the market evidence of the cost of equity for the proxy group.

Q. How does the Company's throughput to large volume users or those with competitive alternatives affect its risk profile?

A. The Company's risk profile is influenced by natural gas delivered to its large industrial and commercial customers and those customers with competitive alternatives, as demonstrated by the bypass threat posed to 52 of the Company's major account customers, i.e., those with large volume usage and/or those with competitive alternatives. This throughput to these 52 customers represents approximately 22% (17,780,269 Dth ÷ 79,723,548 Dth) of the Company's total throughput. Of course, the number that CPA has identified is only a subset of the total load at risk since it is almost certain that the Company has not identified all customers who have competitive alternatives.

Generally speaking, there are four primary threats to throughput to the Company's largest volume users. First, the Company can and has experienced attrition in this large customer group. Second, the Company's largest customers, which have traditionally used

transportation service, have the ability to bypass the Company's system to other gas supply sources such as interstate pipelines, other local distribution companies, and/or nonregulated pipeline contractors providing access to local supplies. This was the risk to the Company noted above. Third, in addition to the bypass threat, a material portion of the large customer throughput can be exposed to alternative energy sources depending on the fluctuating costs of these different fuels in comparison with natural gas. Finally, in its effort to retain load, the Company is vulnerable to the impacts of business cycles, competition within its customers' industries, and other external factors that can result in shifts of production to customer facilities that are not served by the Company. All of these risks put fixed cost recovery for this class of customers at risk.

Q. Please indicate how the Company's construction program affects its risk profile.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents capital expenditures that do not increase the Company's customer base. Although the Company has made significant strides in reducing its percentage of cast iron and unprotected steel pipe, these facilities still represent 936.8 miles (or approximately 12%) of its distribution mains as of year-end 2022. Further, more recently, the Company is also focusing on the replacement of first generation plastic pipe in its necessary investments to upgrade infrastructure. The Company also has 35,336 (or approximately 8%) of its services constructed of unprotected steel. For the future, the Company expects its net capital expenditures to be:

Year	Capital Expenditures
2024	$ 425,029,516
2025	$ 413,815,909
2026	$ 474,937,896
2027	$ 477,753,722
2028	$ 497,451,344
Total	$ 2,288,988,387

The Company's total capital expenditures over the next five years will represent approximately 73% ($2,288,988,387 ÷ $3,122,961,249) of the net utility plant in service at December 31, 2022.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular CPA?

A. The Commission should recognize and take into account the need to replace infrastructure and the competitive environment in the natural gas business in determining the cost of capital for the Company, and provide a reasonable opportunity for the Company to actually achieve its cost of capital. A fair rate of return also represents a key to a financial profile that will provide the Company with the ability to raise the significant amount of capital necessary to meet its capital needs on reasonable terms. The Company has been proactive in dealing with its capital requirements for infrastructure needs by not making dividend payments in any of the years 2014 through 2022. By foregoing dividend payments, the Company is committed to reinvestment in Pennsylvania. The Commission should recognize and reward this commitment with a reasonable return on equity.

Fundamental Risk Analysis

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes, it is. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed previously. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared the Company to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. What companies comprise the Gas Group?

A. My Gas Group consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corporation, New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., Southwest Gas Holdings, and Spire, Inc.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost

of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the credit quality ratings compare for the Company, the Gas Group, and the S&P Public Utilities?

A. The Company obtains its external capital from NiSource Inc. Presently, the NiSource credit quality ratings are Baa2 from Moody's Investors Service ("Moody's") and BBB+ from Standard & Poor's Corporation ("S&P"). These ratings for NiSource represent the Long Term ("LT") issuer rating by Moody's and the corporate credit rating ("CCR") designation by S&P, which focuses upon the credit quality of the issuer of the debt rather than upon the debt obligation itself.

For the Gas Group, the average LT issuer rating is A3 by Moody's and the average CCR is A- by S&P, as displayed on page 2 of Schedule 3. For the S&P Public Utilities, the average credit quality rating is A3 by Moody's and BBB+ by S&P, as displayed on page 3 of Schedule 4. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for the Company, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2018-2022. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, the Company is smaller than the average size of the Gas Group, and smaller still than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity.

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

There are no market ratios available for the Company because its stock is owned by NiSource. The five-year average price-earnings multiple was equivalent for the Gas Group and the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio was somewhat lower for the Gas Group as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 55.9% for CPA, 49.0% for the Gas Group, and 40.5% for the S&P Public Utilities. The Company's common equity ratio was higher historically than the average for the Gas Group. However, for this case, the Company's common equity ratio is within the range of other gas distribution utilities thereby making it reasonable for setting rates in this case.

[2]For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.183 (1.9% ÷ 10.4%) for the Company, 0.113 (1.1% ÷ 9.7%) for the Gas Group, and 0.040 (0.4% ÷ 10.0%) for the S&P Public Utilities. The variability of the Company's rates of return was higher than the Gas Group and the S&P Public Utilities, thereby signifying higher risk for the Company.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[3] The five-year average operating ratios were 72.2% for the Company, 82.7% for the Gas Group, and 81.0% for the S&P Public Utilities. The Company's operating ratios were lower than the Gas Group, thereby indicating lower risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 4.27 times for the Company, 4.33 times for the Gas Group, and 2.94 times for the S&P Public Utilities. The interest coverages were fairly similar for the Company and the Gas Group, thereby indicating similar risk.

[3]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for the Company, the Gas Group and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 62.0% for the Company, 56.3% for the Gas Group and 62.3% for the S&P Public Utilities. Had the Company paid dividends in recent years, its IGF would have been weaker. The Company's average IGF to construction percentage has been slightly stronger than the Gas Group, which can be traced to the lack of dividend payments by the Company. The Company's IGF to construction expenditures will be under pressure in future years as its construction expenditures continue to increase.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.87 as the average for the

[4]Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

Gas Group (see page 2 of Schedule 3) and 0.90 as the average for the S&P Public Utilities (see page 3 of Schedule 4). The systematic risk for the Gas Group as measured by the Value Line beta is fairly similar to the S&P Public Utilities.

Q. Please summarize your risk evaluation.

A. In several aspects, principally related to its smaller size, its more variable equity returns, competitive pressures, and new capital needs to fund construction, CPA's risk is higher than the Gas Group. Its operating ratios and common equity ratio indicate lower risk for CPA. Its interest coverage, quality of earnings, and IGF to construction, point to similar risk for CPA and the Gas Group. On balance, the cost of equity measured with the Gas Group data will provide a reasonable representation of the Company's cost of equity.

Capital Structure Ratios

Q. Please explain the selection of capital structure ratios for CPA.

A. In this case, the capital structure ratios of CPA have been proposed to calculate the rate of return. Furthermore, consistency requires that the embedded cost rate of the Company's senior securities also be employed.

Q. Does Schedule 5 provide the Company's capitalization and capital structure ratios?

A. Yes. Schedule 5 presents the Company's capitalization and related capital structure ratios. The November 30, 2023 capitalization corresponds with the end of the HTY in this case. The November 30, 2024 capital structure is estimated at the end of the FTY, and the December 31, 2025 capital structure is estimated at the end of the FPFTY. The Company expects to issue $40 million of new long-term debt in the FTY, $105 million of new long-term debt between the FTY and the FPFTY and $150 million of new long-term debt in the FPFTY. A debt maturity of $54.515 million will also occur in the FPFTY. A

projection on retained earnings has been reflected in the FTY and FPFTY including an assumption of no dividend payments in either test year.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since rate-setting is prospective, the rate of return should, at a minimum, reflect known or reasonably foreseeable changes which will occur during the course of the FPFTY. As a result, I will adopt the Company's FPFTY capital structure ratios of 43.12% long-term debt, 2.48% short-term debt, and 54.40% common equity at December 31, 2025. The common equity ratio projected for the FPFTY is consistent with the actual common equity ratio for the Company at November 30, 2023. For short-term debt, I have used a twelve-month average for the FPFTY. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

Costs of Senior Capital

Q. What cost rate have you assigned to the debt portion of CPA's capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of debt at November 30, 2023. On page 2 of Schedule 6, I have shown the embedded cost rate of debt estimated at November 30, 2024. In the FTY, the debt issue placed in December 2021 reflects the estimated interest rate of 6.25% on this issue. This rate is similar to the actual rate of 6.2618% that the Company paid on its issue of $110 million placed on September 29, 2023. And on page 3 of Schedule 6, the embedded cost of debt is shown at December 31, 2025. For the

new issues of long-term debt, I have used cost rates of 6.25% in December 2024 and 6.00% in December 2025. In each instance of new debt, the interest costs were determined from the Bloomberg forward yield curve on 30-year Treasury bonds plus the spread that represents the NiSource credit quality of BBB+.

I will adopt the 5.07% embedded cost of long-term debt at December 31, 2025, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 43.12% long-term debt ratio.

Q. What cost rate have you assigned to the short-term debt?

A. I have used a cost of short-term debt of 5.25%, which represents the Company's estimate for the FPFTY. I should note that the actual short-term debt interest rate in the HTY was 5.6758%. The Company obtains its short-term debt from the NiSource money pool, which has commercial paper as its source. The interest rate for this case is established as the forecast of the Fed Funds rate of 4.38% rate, plus an additional 0.50%, which reflects the recent historical yield differential between the Fed Funds rate and commercial paper borrowing rate for a 75-day duration, plus a 0.25% risk premium to reflect the credit quality of NiSource.

Q. What overall debt cost rate have you determined for rate of return purposes?

A. As shown on page 3 of Schedule 6, the combined cost of long- and short-term debt is 5.08% for the FPFTY.

Cost of Equity – General Approach

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among CPA, the Gas Group and the S&P Public Utilities, the cost of equity must be measured by standard financial models I identified above. Differences in

risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage and bond ratings, must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of 11.75% for CPA including an increment for management performance.

Discounted Cash Flow

Q. Please describe the DCF model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k= D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon"

model.[5] My DCF results are provided on page 2 of Schedule1 for the Gas Group. The DCF return is 12.05% with the leverage adjustment and 10.74% without the leverage adjustment for the Gas Group. The leverage adjustment is discussed more fully below.

Among the limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility. Other limitations of the DCF include the constant P-E multiple assertion that does not conform with actual stock market performance. And, indeed, the FERC has moved to using multiple methods for measuring the cost of equity due to the limitations of the DCF.

Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the 12 months ended December 2023, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

[5] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950s, J.B. Williams exposited the DCF model in its present form nearly two decades earlier.

For the 12 months ended December 2023, the average dividend yield was 3.61% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.85% and 4.00%, respectively. In applying the DCF model, I have used the six-month average dividend yield of 3.85% for the Gas Group. The use of this dividend yield will reflect current capital costs while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different but generally accepted manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7.[6] This adjustment adds 14 basis points to the six-month average historical yield, thus producing the 3.99% adjusted dividend yield for the Gas Group.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the P-E multiple remains constant, the price per share of stock will grow at the same rate

[6] These adjustments are the 1/2 growth approach, the discrete approach, and the quarterly approach. Under the 1/2 approach, the procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, which assumes that half of the dividend payments will be at the expected higher rate during the initial investment period. Under the discrete approach, the "*g*" in the DCF model reflects the discrete growth in the quarterly dividend, which is required for the periodic form of the DCF to properly recognize that dividends are expected to grow on a discrete basis. The quarterly approach takes into account that investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments (D_0) results in this third DCF formulation. This DCF equation provides no further recognition of growth in the quarterly dividend. A compounding of the quarterly dividend yield recognizes the necessity for an adjusted dividend yield.

as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus on prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth ("b x r"), where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares that the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage during which a firm enjoys rapidly expanding markets, high profit margins and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage during which fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" stage, investment opportunities begin to mature, capital requirements decline and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated.

That is to say, the stages can be repeated where growth for a firm ramps up and ramps down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle but rather to rely upon analysts' growth forecasts used by investors when pricing common stocks.

Q. What factor should be considered in the determination of an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

Q. What data for the Gas Group have you considered in your growth rate analysis?

A. I considered the growth in the financial variables shown on Schedule 8 and Schedule 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth in earnings per share, dividends per share, book value per share and cash flow per share for the Gas Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and with the constant P-E multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates, which were also reviewed to gain a perspective on the industry, were obtained from the Value Line publication that provides this data. While historical data cannot be ignored, they are much less significant when applying the DCF model than projections of future

growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double-counted because they are already factored into analysts' forecasts of earnings growth.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the P-E multiple. As such, my company-specific growth analysis, which focuses principally on five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research also focuses on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points to make informed decisions to purchase and sell stocks.

Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The Value Line forecasts are also widely available to investors and can be obtained by subscription or free of charge at most public and collegiate libraries. The IBES/First Call and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Gas Group are also included on Schedule 9.

Q. What are the projected growth rates published by the sources you discussed?

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Gas Group by IBES/First Call (5.87%), Zacks (5.69%) and Value Line (7.31%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While various factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of

dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[7] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks and Value Line, provide the best indication of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts shown on Schedule 9 for the Gas Group exhibit a range of average earnings per share growth rates from 5.69% to 7.31%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.75% is a reasonable estimate of investor-expected growth for the Gas Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates. The reasonableness of this growth rate is also supported by the expected continuation of gas utility infrastructure spending.

Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Gas Group, average capital structure ratios are 37.01% long-term debt, 1.37% preferred

[7] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

stock, and 61.62% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate-setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book

capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations using well-recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M,"[8] provide a return of 9.09% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book value are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market

[8] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance, and the Theory of Investments," American Economic Review, June 1958, at 261-97. Franco Modigliani and Merton H. Miller, "Taxes and the Cost of Capital: A Correction," American Economic Review, June 1963, at 433-43.

prices. Stock prices above book value are common for utility stocks, and indeed, the stock prices of non-regulated companies exceed book values by even greater margins. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they actually exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true: when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I were to express my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 9.09%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 2.85% to compensate investors for the risk of

51.40% debt ratio and 0.11% for a 1.59% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts add up to 12.05% (9.09% + 2.85% + 0.11%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I added the 3.99% dividend yield, the 6.75% growth rate, and 1.31% for the leverage adjustment to arrive at the same 12.05% return computed directly with the M&M formula. I know of no means to mathematically solve for the 1.31% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.31% adjustment is merely a convenient way to compare the 12.05% return computed using the Modigliani & Miller formulas to the 10.74% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF shown on Schedule 7) based on a market-value capital structure. A 10.74% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield (D_1/P_0) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (Lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the

market value equity ratio related to the price of stock. The resulting DCF cost rate is 12.05%, computed as follows:

	D_1/P_0	+	g	+	*lev.*	=	k
Gas Group	3.99%	+	6.75%	+	1.31%	=	12.05%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the P-E multiple. An assumption that there will be no change in the P-E multiple is not supported by the realities of the equity market because P-E multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

Risk Premium Analysis

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule1. That result is 11.50%.

Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 5.00% yield represents a reasonable estimate of the prospective yield on long-term, public utility bonds. The 5.00% public utility bond yield I used in the Risk Premium method is very conservative

given current interest rates.

Q. What historical data are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule 11, page 1. For the 12 months ended December 2023 the average monthly yield on Moody's index A-rated public utility bonds was 5.54%. For the six- and three-month periods ended December 2023, the yields were 5.78% and 5.91%, respectively. During the 12 months ended December 2023, the range of the yields on A-rated public utility bonds were 5.13% to 6.34%. Page 2 of Schedule11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.45% on a twelve-month average basis, 1.37% on a six-month average basis, and 1.32% on a three-month average basis. With these data, 1.25% represents a reasonable, albeit conservative, spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe above. Blue Chip is a reliable authority and contains consensus forecasts of various interest rates compiled from a panel of banking, brokerage and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on December 28, 2023, and a yield spread of 1.25%, derived from recent historical data.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I have also shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2024	First	5.1%	6.1%	4.3%	1.25%	5.55%
2024	Second	5.0%	6.0%	4.3%	1.25%	5.55%
2024	Third	4.9%	6.0%	4.2%	1.25%	5.45%
2024	Fourth	4.8%	5.9%	4.1%	1.25%	5.35%
2025	First	4.8%	5.8%	4.0%	1.25%	5.25%
2025	Second	4.7%	5.8%	4.0%	1.25%	5.25%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2023 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2025-2029	4.9%	6.0%	4.1%
2030-2034	5.0%	6.0%	4.2%

The longer-term forecasts by Blue Chip suggest that interest rates will continue to be above pre-Pandemic levels. A 5.00% yield on A-rated public utility bonds represents a reasonably conservative benchmark for measuring the cost of equity in this case. All the data I used to

formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon such data to make investment decisions.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2022 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline, and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on Schedule12, page 1.

Common Equity Risk Premiums

Low Interest Rates	7.13%
Average Across All Interest Rates	5.96%
High Interest Rates	4.76%

Based on my analysis of the historical data, the equity risk premium was 7.13% when the marginal cost of long-term government bonds was low (i.e., 2.83%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.03% on average during periods of high interest rates), the spread narrowed to 4.76%. Over the entire spectrum of interest rates, the equity risk premium was 5.96% when the average government bond yield was 4.91%. From these data, I have utilized a 6.50% equity risk premium. The equity risk premium of 6.50% is between the premiums associated with low interest rates (i.e., 7.13%) and average for the entire historical period interest rates (i.e., 5.96%).

Q. What common equity cost rate did you determine based on your Risk Premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

	i	**+**	***RP***	**=**	***k***
Gas Group	5.00%	+	6.50%	=	11.50%

Capital Asset Pricing Model

Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 13.86% for the Gas Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 11.96% (13.86% - (0.23 x 8.26%)) through use of the Value Line beta excluding the leverage adjustment (i.e., 1.10 - 0.87 = 0.23). To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β") and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.87 for the Gas Group.

Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage-adjusted betas that I used in the CAPM. The Value Line betas are measured over a five-year period. The betas must be reflective of the financial risk associated with the ratemaking capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. Since we used book values in this case, the Value Line betas must be adjusted for the higher financial risk associated with the book value capital structure. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[9] as follows:

$$\beta l = \beta u \, [1 + (1 - t) \, D/E + P/E]$$

ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.58 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled “Hamada,” who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.10 for the book value capital structure of the Gas Group.

[9] Robert S. Hamada, “The Effects of the Firm’s Capital Structure on the Systematic Risk of Common Stocks;” The Journal of Finance, Vol. 27, No. 2; Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, Dec. 27-29, 1971. (May 1972), pp. 435-52.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the 12 months ended December 2023, the average yield on 30-year Treasury bonds was 4.09%. For the six- and three-months ended December 2023, the yields on 30-year Treasury bonds were 4.41% and 4.58%, respectively. During the 12 months ended December 2023, the range of the yields on 30-year Treasury bonds was 3.66% to 4.95%.

Due to high inflation rates above the policy goal of the FOMC, the accommodative policy was ended by the FOMC in the first quarter of 2022. A tighter monetary policy exists today and has caused higher interest rates that have already occurred. After the FOMC ended its bond-buying program (i.e., quantitative easing) in March 2022, it is in the process of running off its $9 trillion asset portfolio, which will keep interest rates at elevated levels.

Following the extraordinary events associated with the Pandemic that jolted the capital markets, much higher rates have been in place. Higher inflation was a contributing factor that prompted the FOMC to raise the Fed Funds rate I described previously. High interest rates clearly point to high capital costs as indicated by recent bond yields. The yield on 10-year Treasury bonds moved above the 3% level on May 2, 2022, for the first time since late 2018. By December 2023, the yield on 30-year Treasury bonds moved to 4.14%, or an increase of 2.47% (or 148%) since December 2020.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on December 28, 2023, indicate that the yields on long-term Treasury bonds are expected to be in the range of 4.0% to 4.3% during the next six quarters. This means that elevated interest rates will continue near current levels into 2024. The longer-term forecasts show that the yields on 30-year Treasury bonds will average 4.1% from 2025 through 2029 and 4.2% from 2030 to 2034. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have

used a conservative 3.75% risk-free rate of return for CAPM purposes, which considers the possibility of some moderation of rates prospectively.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 12.21% (12.40% + 12.02% = 24.42% ÷ 2) as the midpoint of the "low" and "average" interest rate environments. During those periods, the yield on long-term government bonds was 3.87% (2.83% + 4.91% = 7.74% ÷ 2). The resulting market premium is 8.34% (12.21% - 3.87%) based on historical data, as shown on page 2 of Schedule 13. As also shown on page 2 of Schedule 13, I calculated the forecast returns, which show a 11.93% total market return based on the Value Line forecasts. With these data, I calculated a market premium of 8.18% (11.93% - 3.75%) using the forecast data by Value Line. The resulting market premium applicable to the CAPM derived from these sources equals 8.26% (8.18% + 8.34% = 16.52% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Eugene F. Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms. Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could

significantly understate the cost of equity according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. To recognize this fact, I used the mid-cap adjustment of 1.02%, as revealed on page 3 of Schedule 13, for the CAPM calculation. The adjustment here is related to the size of the Gas Group.

Q. What does your CAPM analysis show?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 1.10 for the Gas Group, the 8.26% market premium, and the 1.02% size adjustment, and the flotation cost adjustment, the following result is indicated.

	Rf	**+**	***ß***	***x (Rm-Rf)***	**+**	***size***	**=**	***k***
Gas Group	3.75%	+	1.10	x (8.26%)	+	1.02%	=	13.86%

Comparable Earnings Approach

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risk characteristics would need to realize to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve

as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works v. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on page 3 of Schedule 14. The identities of the companies

comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used

20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.6% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return, as published by Value Line, is 13.6% also using values less than 20%, as provided on page 2 of Schedule 14. Using the average of these data, my Comparable Earnings result is 13.10%, as shown on page 2 of Schedule1.

Conclusion on Cost of Equity

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of various methods and models described previously, it is my opinion that the reasonable cost of common equity is 11.75% for the Company. My proposed cost of equity will accommodate the Company's small size and its business risk characteristics. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-two years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in

its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida. I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

Statement No. 8-R

COLUMBIA GAS OF PENNSYLVANIA, INC.

Rebuttal Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity and
Fair Rate of Return

DOCKET NO. R-2024-3046519

July 11, 2024

Introduction

Q. Please state your name and business address.

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm.

Q. Did you previously submit testimony in this proceeding on behalf of Columbia Gas of Pennsylvania, Inc. ("CPA", "Columbia" or the "Company")?

A. Yes. I submitted my direct testimony, Columbia Statement No. 8, on March 15, 2024.

Q. What is the purpose of your rebuttal testimony?

A. My rebuttal testimony responds to the direct testimony submitted by D. C. Patel, a witness appearing on behalf of the Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E"), and Christopher C. Walters, a witness appearing on behalf of the Office of the Consumer Advocate ("OCA"). If I fail to address each and every issue in the testimony of each of these witnesses, it does not imply agreement with those issues.

Q. What rate of return issues have been disputed in this case?

A. The Company's capital structure has been challenged by Mr. Walters. Mr. Patel has accepted the Company's proposed capital structure. Each of the opposing witnesses have accepted the Company's proposed cost of debt in this case. The cost of equity has been disputed by both Messrs. Walters and Patel. The equity returns proposed by the I&E and OCA witnesses are entirely too low to reflect the risks of Columbia and the prospective cost of equity. After analyzing their testimony, I found nothing that would cause me to change the 11.75% equity return that I have found to be reasonable and fair for the Company.

There are three key factors that bear on the rate of return issue in this case. Aside from technical issues that I will discuss later in my rebuttal testimony, the Commission should take into consideration the following:

1) A rate of return that will be reflective of the current capital cost rates, which is today higher than at any time since the financial crisis of 2007-08.
2) A rate of return that will reflect and be supportive of the Company's financial and risk profile.
3) The management effectiveness displayed by Columbia.

As I explain below, the opposing party recommendations fail to adequately consider these points and thereby, understate the required cost of common equity in this proceeding.

Q. Please summarize the key points of your cost of equity rebuttal testimony.

A. My key points are:

- Comparable Companies - Mr. Patel has made one deletion to the members of my Gas Group. Mr. Walters has made two deletions and other additions to my Gas Group that I proposed in this case.
- Discounted Cash Flow (DCF) - A variety of DCF results derived by the opposing witnesses are too close to the cost of debt to provide a reliable measure of the cost of equity. As such, alternative models for determining the cost of equity should be considered as has been Commission practice in other recent proceedings.
- Mr. Walter's application of the two-stage DCF model and the use of "sustainable" (i.e., book value) growth DCF model is inappropriate.
- DCF Leverage Adjustment - The I&E and OCA witnesses have not refuted the accuracy of my leverage adjustments to the DCF and beta component of the CAPM.

- Capital Asset Pricing Model - A reasonable application of the CAPM mandates using prospective yields on 30-year Treasury bonds, leverage adjusted betas, and size adjustment and produces a higher equity cost rate than the DCF method.
- Risk Premium Analysis - The Risk Premium approach has previously been considered by the Commission, and the results presented by the Company substantiate the Company's proposed return in this case.
- Comparable Earnings Approach - This approach verifies the Company's proposed return in this case.
- Management effectiveness of Columbia warrants an equity return above the midpoint of the indicated returns shown by the standard models of the cost of equity.

Q. What are the key aspects of the rate of return issue that the Commission should consider when deciding this issue in this case?

A. The issues involve the Company's cost of equity and the capital structure. OCA's witness, Mr. Walters, has opposed the actual capital structure and instead proposed a hypothetical capital structure, which is not warranted in this matter, based upon the Commission's policy. Mr. Walters's use of a hypothetical capital structure, rather than the Company's projected actual capital structure for the FPFTY, is factually wrong and contrary to long-standing Commission practice and precedent. I will detail the Commission recent findings on capital structure below.

My key points on the cost of equity are:

- The recommended equity returns proposed by Messrs. Patel and Walters fail to adequately reflect higher interest rates that have transpired since the end of the COVID Pandemic. Today, the return should be higher for reasons I will

explain below. Instead, Messrs. Patel and Walters are erroneously moving in the other direction. Some of the flawed analyses by opposing witnesses can be traced to the failure by Mr. Patel to give any weight to CAPM and Mr. Walters' defective CAPM analysis. These omissions by the opposing witnesses rest with their failure to follow the Commission's lead established in the Aqua and Columbia Water rate case decisions.

- The Commission has recognized that additional methods should be considered when establishing the cost of equity. This is especially important because of monetary policy by the Federal Open Market Committee ("FOMC") and relatively high inflation points to a higher cost of equity. Moreover, the DCF model is slow to respond to changes in bond yields, mandating use of alternative methods, such as CAPM and Risk Premium. Both the I&E and OCA witnesses have inadequately addressed this issue.
- Discounted Cash Flow ("DCF") – many of the DCF results by the opposing parties are clearly too low to provide a reliable measure of the cost of equity. This can be traced to the formulaic approach taken by Mr. Patel in applying this model (see pages 29-30 of I&E Statement No. 2). It is troublesome that Mr. Patel only devotes about two pages out of 76 pages of his direct testimony to substantiate his recommended cost of equity. Regarding Mr. Walters, he fails to adequately reflect investor expectations of growth. He errs when he gives insufficient weight to analysts' growth rate forecasts of earnings per share that are consistently used by Mr. Patel, me, and the Commission.
- The DCF proposal by Mr. Walters provides an inappropriate measure of investor expected returns. Analysts' projections of future growth are the only reasonable evidence of the DCF growth rate and the sustainable growth rate

and multistage models that he used are entirely inappropriate and have never been adopted in Pennsylvania.

- DCF Leverage Adjustment – Mr. Patel has not refuted the accuracy of my leverage adjustments to the DCF and beta component of the Capital Asset Pricing Model ("CAPM"). Mr. Walters draws erroneous conclusions concerning my leverage adjustment.
- CAPM – A reasonable application of the CAPM mandates using 30-year Treasury bond yields, leverage adjusted betas, and size adjustment. With these elements the CAPM indicates an equity cost rate that is 11.96% following the approach used by Mr. Patel. Indeed, Mr. Patel has proposed an 10.86% CAPM result in this case, even without these considerations. Significantly, he fails to reflect his CAPM result in his cost of equity recommendation. Without the results of the CAPM, Mr. Patel fails to adequately incorporate the current level of high interest rates. And, Mr. Patel fails to consider his CAPM results in his cost of equity recommendation even though the Commission has considered the CAPM results in its recent Aqua and Columbia Water rate case decisions.

Q. How should the rate of return set by the Commission support the Company's financial profile?

A. The Commission should set the Company's return on equity at a level that will attract investment in the Company to ensure the Company's financial ability to render safe and reliable service. Applying this principle, the Commission should reject the proposals by Messrs. Patel and Walters to lower the Company's return on common equity to 9.93% and 9.45%, respectively. These proposed equity returns would be viewed by investors as unsupportive of the Company's financial condition. The I&E and OCA witnesses provide

no explanation why 9.93% or 9.45% would be reasonable. Indeed, the Commission approved 10.24% in the last PECO gas rate case in 2021, and the Aqua Pennsylvania rate case where 10.00% was approved in 2022. Columbia Water received a 9.75% equity return without any recognition of management performance. It is noteworthy that the returns on equity are typically higher for natural gas LDCs as revealed by the Commission's Quarterly Earnings Report. Recently, the gas utility return on equity has been 50 basis points (i.e., 0.50%) higher than the water utilities and a higher return for the gas utilities has prevailed for a number of years. There have been dramatic increases in inflation, prompting the FOMC to increase the federal funds ("Fed Funds") rate to combat inflation. While the May 2024 rate of inflation was 3.3%, a meaningful decline from the peak of 9.1% that occurred in June 2022, it is still above the policy goal of 2% set by the FOMC. Indeed, to combat inflation, the Fed Funds rate has been increased by the FOMC eleven times since March 16, 2022, amounting to a 5.25% increase. This has been the fastest rate of increase in 40 years. This fact has not been adequately incorporated into the cost of equity proposals of Messrs. Walters and Patel. Indeed, with the upward move in interest rates, an equity return well above 10% is clearly warranted today. Based on the factors listed in by direct testimony and below, and for technical reasons set forth later in my rebuttal testimony, the Commission should adopt a substantially higher equity return today for Columbia.

Q. Are there additional issues that the Commission should consider when setting the Company's return?

A. Yes. The investment community would be very concerned if the Commission were to adopt the position of the opposing parties in this case. If it were to do so, investors would view Pennsylvania regulation as less supportive of the Company at a time of high levels of capital investment and increasing capital cost rates. Over the next five years, Columbia

expects capital expenditures to be approximately $2.3 billion, which represents 73% of the Company's existing Utility Plant In Service. If the Commission were to adopt the returns proposed by the OCA, Pennsylvania's regulatory support would certainly be placed into question by the investment community, particularly in the context of higher capital costs. Although cost allocations, rate design issues, and regulatory policies relative to the cost of service are important considerations, the return on equity used by the Commission to set rates embodies in a single numerical value a clear signal of regulatory support (or lack thereof) for the financial strength of the utilities that it regulates. In a single figure, the return on equity utilized to set rates provides a common and widely understood benchmark that can be compared from one company to another and is the basis by which returns on all financial assets (stocks – both utility and non-regulated, bonds, money market instruments, and so forth) can be measured. So, while varying degrees of sophistication are required to interpret the meaning of specific Commission policies on technical matters, the return on equity figure is universally understood and communicates to investors the types of returns that they can reasonably expect from an investment in utilities operating in Pennsylvania.

Q. Should the Commission consider the current high level of capital costs when deciding the return on equity in this case?

A. Yes. The Commission should recognize that accommodative policy by the FOMC has ended, and higher interest rates have occurred and will prevail in the future. Indeed, Value Line recently noted the FOMC remains on its "high for longer" interest-rate course. High inflation also has been a driving factor. As noted previously, the rate of inflation spiked upward to 9.1% in June 2022, and as of May 2024, it stood at 3.3%. High levels of inflation have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt – and the need for more cautious financial practices, such as a

prudent level of borrowing. Today's inflation is substantially higher than the target rate of 2%, which is the FOMC policy goal. One reason that explains the higher long-term interest rates can be traced to investor expectations of high inflation noted above. Higher interest rates clearly point to higher capital costs prospectively. The yield on 30-year Treasury bonds moved above the 2% level beginning in February 2021. In comparison, those yields closed out 2020 at 1.67% for December. By May 2024, the yield on 30-year Treasury bonds had moved to 4.62%, or an increase of 2.95% (or 177%). Likewise, the yield on A-rated public utility bonds has increased to 5.74% in May 2024 up from 2.77% in December 2020 -- a 297 basis point (or 107%) increase. I will describe the Blue Chip forecast of interest rates and the continuation of this level. Indeed, the reality of high interest rates demands higher, not lower capital costs.

Q. Is there additional evidence that suggests that the cost of capital will continue at high levels?

A. Yes. To gain a consensus view of future interest rates, I tabulated the forecasts of yields on 10-year Treasury notes published by a variety of well recognized and investor-influencing sources. I chose the 10-year Treasury note because it is available on a consistent basis for each source. The comparisons are:

	2025	2026	2027	2028	2029	2030
Blue Chip	4.00%	4.00%	4.00%	4.00%	4.20%	4.20%
CBO	4.10%	3.70%	3.60%	3.70%	3.80%	3.90%

The Blue Chip (June 1, 2024) and CBO (June 2024) reflect the general consensus that interest rates will remain at elevated levels in the future. The high levels of interest rates represent one key factor that adds to the risk of common equity. And for comparison purposes, the yield on public utility bonds always exceeds Treasury yields. As noted in my direct testimony (see page 33 of Statement No. 8), the spread in those yields is at least

1.25%, and historically higher than that through most of the year 2023. Page 2 of Schedule 11 in Exhibit 400 (see Columbia's standard filing requirements in this case) shows a spread of 1.45% on average for 2023. The Commission should take into account the forecast of interest rates when it sets the cost of equity for Columbia.

Q. How is the remainder of your testimony organized?

A. I will cover the issues of (i) capital structure, (ii) the composition of the proxy (i.e., barometer) group, (iii) the weight to be given to the DCF method, (iv) the DCF growth rate, (v) the leverage adjustment to the DCF and CAPM methods, (vi) the CAPM method, (vii) the Risk Premium analysis, (viii) Comparable Earnings, and (ix) management performance as part of the return on equity consideration.

Capital Structure Ratios

Q. Are there differences in the proposed capital structures utilized by the rate of return witnesses in this case?

A. Yes. Mr. Walters has erroneously proposed a lower hypothetical common equity ratio in place of Columbia's actual capital structure. Mr. Patel has accepted the Company's actual capital structure, because it falls within the range of capital structures of the proxy group.

Q. How does the Company's capital structure proposal differ from that advocated by Mr. Walters?

A. Mr. Walters's proposal is based on his view that the Company's proposed common equity ratio exceeds the average of his proxy group. In reaching his conclusion on capital structure ratios, Mr. Walters cites to another state regulatory agency, but he never establishes that the reasoning of the Arkansas Public Service Commission is applicable here.

Q. Is there any basis to deviate from the Company's actual capital structure to set the rate of return in this case?

A. No. The Company's actual capital structure ratios are entirely reasonable and acceptable. That alone is sufficient to support the use of the Company's actual capital structure in this case. Mr. Walters might have been led to a different conclusion if he had considered the most recently approved common equity ratio by this Commission rather than rely on the actions of another commission. Indeed, as an example, in its Order Entered on October 25, 2018, in Docket No. R-2017-2640058, the Commission adopted a 54.02% common equity ratio for UGI Utilities, Inc. – Electric Division. Furthermore, the Commission rejected the OCA's proposal to utilize a hypothetical capital structure in Columbia's 2020 base rate case (R-2020-3018835) and accepted Columbia's actual capital structure with 54.19% common equity. Indeed, the Company's proposal to utilize its actual common equity ratio of 54.40% in the present case is entirely reasonable based on prior Commission decisions. Moreover, the reasonableness of the Company's actual capital structure containing a common equity ratio of 54.40% is revealed by the data provided by Mr. Patel. His data shows that the Company's common equity ratio is within the range employed by his barometer group and, therefore, supports the level of common equity proposed by the Company. Mr. Patel's Barometer Group has a range of common equity ratios from 34.74% to 59.95%. This comparison supports the actual 54.40% common equity ratio for Columbia. Here, the Company's actual common equity ratio falls within that range that extends up to a 59.95% common equity ratio. Hence, the Company's actual common equity ratio conforms with Commission policy that states that the actual, not hypothetical, common equity ratio will be employed when it falls within the Barometer Group's range. Moreover, the hypothetical capital structure proposed by Mr. Walters is inconsistent with the higher risk profile of Columbia regarding it more competitive, which mandates a much more conservative capital structure that contains more common equity and less debt.

Q. Is there another issue that should be considered regarding Mr. Walters's hypothetical capital structure?

A. Yes. Another problem with Mr. Walters's approach is that when proposing a hypothetical debt ratio, he creates a mismatch between the cost of long-term debt that he accepts and his hypothetical debt ratio that he advocates. This mismatch arises because the hypothetical long-term debt ratio contains more debt than the amount of long-term debt that is actually outstanding for Columbia. That is to say, with more debt in the hypothetical capital structure, a higher cost of debt would be related to the higher hypothetical debt ratio. Mr. Walters never addresses this inconsistency in his proposal, and hence, it should be rejected.

Proxy Group

Q. Are there differences in the proxy groups utilized by the rate of return witnesses in this case?

A. Yes. Mr. Patel includes only seven companies from my Gas Group in his barometer group. A list of my companies is provided on page 13 of my rebuttal testimony. Mr. Patel drops Southwest Gas Holdings from my group. Mr. Walters accepts only six of the companies in my Gas Group and drops Chesapeake and NiSource. I disagree with those eliminations to my Gas Group because Chesapeake and NiSource, as well as Southwest Gas, fairly reflect the risks for the typical natural gas distribution utility. The acquisition Mr. Walters noted as the reason for not including Chesapeake in his Gas Groups has been completed, and the financing for that acquisition has already taken place. As to NiSource, only a minority interest in NIPSCO was sold and NiSource maintains a controlling interest in it. The transaction can be thought of as a financing activity. Further, Mr. Walters added additional companies that are completely inappropriate for inclusion in a proxy group that

is comparable to Columbia. There is no justification for including six water utility holding companies in the group because they are not comparable to Columbia. Eversource is also inappropriate, because while having LDC operations, it is mostly an electric utility. The Commission has no history of mixing utility types in a barometer group.

Q. Mr. Patel used the percentage of revenues devoted to utility operations as a criterion for screening companies to assemble his barometer group. Is this a correct criterion?

A. No. For utilities, the percentage of regulated revenues cannot be used as the criteria to select members of the Barometer Group. This is because the margins on other business segments within Barometer Group companies are generally dissimilar to the utility business. Energy trading is a case in point, which would make revenue comparisons incompatible because of the large revenues and small margins associated with that business. That is to say, energy trading generates large amount of revenues, but little profits because the margins on such trades are very small.

Q. How do the percentages of utility income and assets compare to the companies contained in your Gas Group?

A. Those results are shown below:

		Percent Regulated Operations		
		Revenues	Income	Assets
ATO	Atmos Energy Corp	96%	67%	97%
CPK	Chesapeake Utilities Corp.	62%	81%	77%
NJR	New Jersey Resources Corp.	39%	58%	64%
NI	NiSource, Inc.	100%	101%	93%
NWN	Northwest Natural Gas	95%	92%	93%
OGS	One Gas, Inc.	100%	100%	100%
SWX	Southwest Gas Corp.	39%	99%	67%
SR	Spire, Inc.	88%	83%	80%
	Average	77%	85%	84%

As shown above, the percentage of utility assets is above 64% for all members of my Gas Group. As such, these data show that no elimination to my Gas Group is appropriate in this case.

Q. Has the Commission used your Gas Group?

A. Yes. The Commission has recently used my Gas Group in its Quarterly Earnings Report (Docket Number U-2023-3044811) for the year ended September 30, 2023, which was adopted at the Public Meeting on January 18, 2024.

Q. Is there any basis to deviate from the proxy group that you proposed in this case for the Company?

A. No. My group of companies provides the best group that is comparable to the Company.

Cost of Equity

Q. The DCF model has been used by Mr. Patel, Mr. Walters and you as one method to measure the cost of equity. What is your position concerning the usefulness of the DCF method?

A. While the results of a DCF analysis should certainly be given weight, the use of more than

one method provides a superior foundation for the cost of equity determination. Since all cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing). I am aware that the Commission usually expresses its cost of equity determination in the context of the DCF model. But the Commission also considers other methods as well. In its order entered on December 28, 2012, in Docket No. R-2012-2290597, the Commission stated:

> Sole reliance on one methodology without checking the validity of the results of that methodology with other cost of equity analyses does not always lend itself to responsible ratemaking. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived equity return calculation.[1]

Similarly, in the Aqua Pennsylvania decision, the Commission observed:

> In the 2012 PPL Order, the Commission considered PPL's CAPM and RP methods, tempered by informed judgment, instead of DCF-only results. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. Historically, we have relied primarily upon the DCF methodology in arriving at ROE determinations and have utilized the results of the CAPM as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our equity return determination.[2]

Again, the Commission recognized the need for additional methods in its decision for Columbia Water.

[1] Pennsylvania Public Utility Commission v. PPL Electric Utilities, R-2012-2290597, order entered December 12, 2012, at 80.

[2] Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc., R-2021-3027385, order entered May 16, 2022, at 154-55.

> In *Aqua 2022*, the Commission determined the ROE by using informed judgement based on I&E's DCF and CAPM methodologies. We conclude that methodologies other than the DCF can be used as a check upon the reasonableness of the DCF derived ROE calculation. We historically have primarily relied upon the DCF methodology in arriving at ROE determinations and utilized the results of the CAPM, as a check upon the reasonableness of the DCF derived equity return. As such, where evidence based on other methods suggests that the DCF-only results may understate the utility's ROE, we will consider those other methods, to some degree, in determining the appropriate range of reasonableness for our ROE determination.[3]

The Commission has acknowledged the usefulness of other methods, such as CAPM, as a means of establishing a range of reasonable returns. Indeed, it is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return. The Commission's selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone.

Indeed, the influence of other methods must have an impact on the Commission's attitude toward the DCF model because the Commission's selection of the rate of return on equity for use in the DSIC is usually set well above the cost of equity indicated by the DCF model alone. For example, in the Quarterly Earnings Report at Docket No. M-2024-3048688, the Commission set the DSIC return at 10.15% for the Gas Companies, while the DCF returns were 9.79% using current stock prices and 9.53% using 52-week average stock prices. It is clear that the Commission has been guided by the results of other models and other factors aside from DCF when setting the DSIC return.

Q. What has Mr. Patel done with the results of models other than DCF?

A. Nothing. In this case, Mr. Patel essentially ignores the results of the CAPM, calling his

[3] Pennsylvania Public Utility Commission v. Columbia Water Company, R-2023-3040258, order entered January 18, 2024, at 108.

CAPM results a basis for comparison purposes only (see page 18, 19, 20, 25, 28, 33 and 37 of I&E Statement No. 2). Unlike Mr. Patel, Mr. Walters acknowledges (see page 3 of OCA Statement No. 3) that he used several methods, along with DCF to measure the cost of equity for Columbia. The use of multiple methods provides a more comprehensive and reliable basis to establish a reasonable equity return for Columbia. In his testimony, Mr. Patel shows that the average DCF result is too low by reference to his CAPM results. In this situation, the Commission should consider moving to within the top half of the range of DCF returns submitted in this case due to this understatement. This process would preserve use of DCF, but also accommodate the tendency of the DCF model to understate the required return in this market. Mr. Patel's DCF return range is from 8.76% for Chesapeake to 11.82% for NiSource. Since Mr. Patel's CAPM result is 10.86%, then it stands to reason that the top half of the range of DCF results should be emphasized in this case, because the average DCF by itself is too low. Hence if DCF is to be used exclusively, as argued by Mr. Patel, then the proper DCF return should be 10.88% which is within the top half of the range, i.e., 9.93% + 11.82% = 21.75% ÷ 2, and is without regard to management performance.

Indeed, the CAPM and RP methods reflect directly the changes in interest rates and are an important indicator of higher equity cost rates. Although Mr. Patel claims (see pages 25-26 of I&E Statement No. 2) that DCF sufficiently considers economic factors, including inflation, there is no input in the DCF that Mr. Patel can point to that substantiates his position. We know that CAPM and RP reflect directly changes in interest rates and those models are more responsive to inflation in this regard than DCF.

Q. Has the National Association of Regulatory Utility Commissioners ("NARUC") taken a position on the use of multiple methods to measure the cost of equity?

A. Yes. The NARUC has published a paper entitled "Cost of Capital and Capital Markets

Primer for Utility Regulators." In it, the NARUC said:

> The goal of all cost of equity models is to capture the realities of the capital marketplace and each model does so from a different perspective. Because these financial models are simplifications of the real world, the ROE results are estimates rather than exact discernments of ultimate truth. Ideally, the model results will corroborate each other but may not in practice. Different estimates resulting from different models can usefully frame, bracket, or define a range or zone of estimates. [4]

Investors, investment bankers, and corporate financial professionals use multiple models when evaluating the cost of equity. Likewise, it is desirable for regulators to also use multiple models when evaluating the cost of equity.

DCF Application by I&E

Q. What form of the DCF model has been employed in this case?

A. The constant growth form of the DCF model has been used by Mr. Walters, Mr. Patel, and me. Mr. Walters has also performed a "two step" DCF analysis and a sustainable growth DCF analysis, which, in reality, is a retention growth analysis. He also conducted a multi-stage growth DCF model. It must be recognized, however, that each of these methods employs assumptions which are simply not realistic. For example, according to the theory of the constant growth form of the DCF, future earnings per share, dividends per share, book value per share, and price per share will all appreciate at the same constant rate absent any change in dividend payout and price-earnings multiple. There is no evidence that these conditions actually prevail in the equity markets.

Q. Are there limitations to the application of the DCF that indicates that it should not be used alone to establish the equity return, which Mr. Patel seems to support especially in times of rising or falling interest rates?

[4] John D. Quackenbush, CFA, "Cost of Capital and Capital Markets Primer for Utility Regulators," National Association of Regulatory Utility Commissioners, December 2019, page 16.

A. My point is that all models have their strengths and weaknesses, and it is important to rely on more than one model in determining the cost of common equity. There are many assumptions associated with the specification of the DCF. These are:

- The form of the model. A choice must be made whether to employ the continuous or discrete form of the model.
- Whether a finite or infinite form of the model realistically represents investor's horizon.
- Whether compounding of the quarterly dividend should be employed.
- The timing of the dividend payments regarding the interval from the ex-dividend date and the stock measurement date needs to be addressed.
- A choice is necessary relative to a representative price that would reasonably represent the rate effective period, e.g., 12-month average, 6-month average, 13-week average, spot, etc.
- Assumptions concerning the structure of returns which under the DCF assumes that the price-earnings multiple, dividend payout ratio, and earned return will be constant.
- Whether single or multiple growth rates better reflect investor expectations.
- Choices concerning the use of historical or forecast growth rates.
- From a historical perspective, whether 10-years, 5-years, or some other historical period is representative of investor expectations.
- Choice among variables to measure growth, e.g., earnings per share, dividends per share, book value per share, cash flow per share, retention growth, price growth, etc.
- Choice of investor influencing growth rates that are available from I/B/E/S First Call, Zacks, and Value Line.

- Whether the growth rate if measured by the formula "b x r" should be modified for external growth, i.e., "sv."
- The potential misspecification of the rate of return applicable to book value when taken directly from DCF if the market price diverges from book value.

Many of the assumptions, especially the constant price-earnings multiple, constant payout rate, and constant earned return, are particularly unrealistic.

Q. Do the DCF results proposed by Mr. Patel provide a reasonable representation of the cost of equity?

A. Not in my opinion. I&E Witness Patel concludes that the DCF cost of equity is 9.93%, while the CAPM cost rate is 10.86% (I&E Statement No. 2, pages 28 and 32). As noted above, the Commission has stated that it would consider other methods when the other methods showed that the DCF method understated the cost of equity. It should be noted that I&E's DCF result in this case is also too low for two reasons. First, there have been significant increases in interest rates and inflation since the Pandemic, indicating a higher cost of equity today. Second, I&E's own CAPM result of 10.86% illustrates its DCF result is too low.

Focusing on the DCF approach, the principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any abnormalities. That said, when some of the DCF results for companies in the I&E barometer group are unreasonable on their face, the reliability of the method being used, or the witness' application of that method, must be questioned. As indicated below, the DCF results shown below fall into this category:

Company	Average: 52 wk & Spot Yield	+	Growth	=	Total
Chesapeake Utilities Corp.	2.46%	+	6.30%	=	8.76%
ONE Gas, Inc.	4.03%	+	4.67%	=	8.69%

It is a fundamental tenet of finance that the cost of equity must be higher than the cost of debt by a meaningful margin to compensate for the higher risk associated with a common equity investment. As noted above, the DCF return for these companies fails to provide a sufficient spread over the yield of on A-rated public utility bonds, which currently stands at 5.74% in May 2024.

Q. Please summarize the DCF growth rate analysis performed by Mr. Patel.

A. As shown on page 29 of I&E Statement No. 2, Mr. Patel proposes a growth rate based on his review of analysts' projected earnings growth rates. His growth rate (i.e., 5.95%) is below the 6.75% growth rate that I determined. Referring to Mr. Patel's growth rates, the 4.65% growth rate for Northwest Natural and 4.67% for ONE Gas appear to be outliers. The range of growth rates for other companies is 5.29% (i.e., Spire) to 7.60% (i.e., NiSource).

Q. What DCF return is indicated from the data presented by Mr. Patel after removing the unduly low results for Chesapeake and ONE Gas?

A. Those results are revealed below:

Company	Average: 52 wk & Spot Yield	+	Growth	=	Total
Atmos Energy Corp.	3.02%	+	7.17%	=	10.19%
NiSource Inc.	4.22%	+	7.60%	=	11.82%
New Jersey Resources Corp.	3.91%	+	5.50%	=	9.41%
Northwest Natural Gas Co.	5.02%	+	4.65%	=	9.67%
Spire Inc.	5.18%	+	5.29%	=	10.47%
Average					**10.31%**

The DCF returns shown above are calculated without regard to the leverage adjustment that is necessary to align the market-determined cost of equity with the book value capital structure used for ratesetting.

DCF Application by OCA

Q. Please summarize Mr. Walters's DCF methodology.

A. Mr. Walter's mechanical approach to the DCF produces wholly unrealistic results. In particular, for his sustainable growth and multi-stage forms of DCF, the calculations show returns in the range of 8.12% to 8.36%. In addition to being far too low, these results do not adequately compensate equity investors for the higher risk they assume, given that the yield on A-rated public utility debt was 5.74% in May 2024.

Q. Are there other aspects of Mr. Walters's testimony where his analysis is deficient?

A. Yes. The "multi-step" DCF model, which the FERC uses for interstate natural gas pipelines, is appropriate only under very limited situations. More specifically, the FERC has indicated that the two-step model is warranted where the analysts' growth estimates are two to three times greater than growth in the gross domestic product ("GDP") and when a company is expected to have a low dividend payout ratio that is similar to industrial companies. These considerations do not apply to natural gas distribution utilities, which makes the two-step (i.e., multi-stage) model inapplicable in this case.

Q. Do you have any comments regarding Mr. Walter's proposed dividend yields?

A. Yes. My primary objection to the dividend yields employed by Mr. Walters involves his use of a 13-week period in the stock price/dividend yield. Due to the volatility of the stock market, a 90-day (i.e., three-month) period is too short to reasonably measure dividend yields. As indicated in my direct testimony, I believe that a 6-month average better captures investor sentiment and market conditions. This is because a 6-month average more closely reflects the long-term horizon of public utility ratesetting.

Q. In his direct testimony, Mr. Walters relies on retention growth in his sustainable growth DCF analysis. Please discuss the limitations of this approach.

A. Retention growth, along with external financing growth, is another means of describing book value per share growth. Other factors also contribute to earnings growth that are not accounted for by the retention growth formula, such as reacquisition of common stock previously issued, changes in financial leverage, acquisition of new business opportunities, profitable liquidation of assets, and repositioning of existing assets. In my view, book value per share growth, or its surrogate retention growth, does not represent the proper financial variable to be considered when selecting the DCF growth component. The following shows how the return expected by investors of 9.47% for the Gas Group and 10.05% for the Total group that he calculates on his Exhibit CCW-6, page 1 translates into a much lower DCF result that Mr. Walters shows on Exhibit CCW-7.

	Average Gas	Average Total
Return on Equity	9.47%	10.05%
Dividend Yield on Book Value	-5.50%	-5.86%
Dividend Yield on Market Value	4.37%	3.67%
Result	8.34%	7.86%
New financing growth	0.95%	0.50%
Average DCF return	9.29%	8.36%

The new financing growth shown as the difference between Columns 6 and 7 on page 2 of Exhibit CCW-6 has been altered to reflect the elimination of the negative values that were not carried forward by Mr. Walters in Exhibit CCW-6.

As shown above (with a few basis points variation due to rounding), the retention approach advocated by Mr. Walters is clearly inconsistent with the traditional form of the DCF model used by the Commission. A key component of retention growth is the Value Line assumed return on book common equity. Mr. Walters does not and cannot explain why an investor expected returns of 9.47% and 10.09%, even if that were correct, should be reduced to 9.29% or 8.36% in this case, particularly since rates are set on book value (net original cost). Importantly, Mr. Walters has not demonstrated that retention growth determines investor expected return rates.

Q. What DCF results would be obtained by relying on forecasts of earnings per share growth stated by Mr. Walters that is typically considered by the Commission?

A. Mr. Walters himself relied on forecasts by analysts published by Value Line, and shows DCF returns of 9.73% and 10.17%. As I described in my pre-filed direct testimony, forecasts of the earnings growth rate are widely used by investors to set utility stock prices and are the only valid measure of growth for DCF purposes.

Q. What DCF return did Mr. Walters calculate with the multi-stage DCF?

A. As shown on Exhibit CCW-8, Mr. Walters' multi-stage DCF provides a DCF return of 8.84% for the Gas Group and 8.20% for the total group. The most obvious problem with Mr. Walters' approach concerns his use of GDP growth in the third stage. In this regard, he advances the proposition that the growth rate for a utility can never exceed the long-term GDP of the country. To the contrary, gas utilities are in a long-term growth phase due to the adoption of 20-to-30-year plans for accelerated replacement of mains and services. As I have explained in my direct testimony, companies, including utilities, can cycle through the growth phases. While Mr. Walters lists other lower criteria for determining the long-term growth rate, he states in his testimony that he is being generous by using his long-term estimate of GDP growth of 4.14%. This growth rate is well below analysts' projections of earnings growth used by Mr. Patel and me, and it produces a nonsensical DCF cost rate of just 8.84% for the Gas Group and 8.20% for the total group.

Q. Do the "sustainable" DCF growth rates proposed by Mr. Walters provide a reasonable input in the cost of equity analysis using the DCF model?

A. No. Mr. Walters indicates that his method for analyzing sustainable growth rate rests on components of the GDP. There are several problems with his approach. It should be noted that the combination of the real GDP growth and inflation equals nominal GDP, i.e. (1.018) * (1.022) = (1.0403 -1) = 4.14%. Mr. Walters is essentially developing a generic growth rate based on GDP growth that would apply to any, or all, companies, whether they are regulated or non-regulated companies. However, each company has a unique company-specific growth rate. His approach is simply incompatible with the basic concept of the DCF, where future cash flows for each company are systematically related to one another by a constant growth rate that represents a basic tenant of the single-stage DCF. It is also incompatible with the use of the growth rates of a comparable barometer group

of companies to meet the requirement that a utility is to be permitted to earn a return equal to comparable companies. The DCF equation is P = D / (k-g). Mr. Walter's growth rate does not fit within this equation.

Q. How does Mr. Walters' multi-stage DCF calculation compare to the DCF model using analysts' growth rate?

A. It is much lower. Analysts' forecasts have been demonstrated to be a superior growth rate measure in the DCF[5]. In his multi-stage DCF, Mr. Walters erroneously used the GDP forecast growth rate and dividends per share growth rather than earnings per share growth. Correcting for this error is shown in my Exhibit PRM-1R, attached to my rebuttal testimony. There, the terminal cash flow is represented by the Value Line forecast earnings per share and price-earnings multiple. Investors value all stocks as a multiple of earnings. Had he used this approach, he would have then produced a DCF return of 10.26% for the Gas Group and 10.91% for the total group. This shows that his multi-stage DCF return is completely inadequate for the reasons explained above.

Leverage Adjustment

Q. At pages 51-59 of I&E Statement No. 2, Mr. Patel responds to your leverage adjustment and argues that it should be rejected. Do you agree?

A. No. Mr. Patel states that he opposes the leverage adjustment. In his discussion of my leverage adjustment, Mr. Patel mentions market-to-book ratios ("M/B") (see page 52 of

[5] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould. "We have compared the accuracy of four methods for estimating the growth component of the discounted cash flow yield on a share: past growth rate in earnings (KEGR), past growth rate in dividends (KDGR), past retention growth rate (KBRG), and forecasts of growth by security analysts (KFRG)…we have three observations to make. First, the superior performance by KFRG should come as no surprise. All four estimates of growth rely upon past data, but in the case of KFRG a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth."

I&E Statement No. 2). I need to be clear that my leverage adjustment is not designed to produce any particular M/B ratio.

Q. Please respond to Mr. Patel's criticism of your leverage adjustment.

A. Mr. Patel offers three reasons for not making a leverage adjustment. First, Mr. Patel notes that the credit rating agencies assess financial risk in terms of a company's booked debt obligations in their analysis of the creditworthiness of a company (see I&E Statement No. 2 page 54). I agree. But this has nothing to do with my leverage adjustment. The credit rating agencies do not measure the market required cost of equity for a company. The credit rating agencies are only concerned with the interests of lenders. They are judging risk associated with a company's ability to make timely payments of principal and interest. Hence, they are not concerned with the cost of equity or how it is applied in the rate-setting context. While Mr. Patel's observation is correct, it has no relevance to my leverage adjustment.

Q. Second, Mr. Patel also questions your leverage adjustment by reference to prior Commission orders. Please comment.

A. Mr. Patel points to several decisions where the Commission declined to make a leverage adjustment (see I&E Statement No. 2 pages 55-56). The fact that the Commission declined to use the leverage adjustment in the 2008 Aqua Pennsylvania case cited by Mr. Patel does not invalidate its use. Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance. Just like an increment for management performance is not recognized in all rate cases, so too the Commission seems to be taking a similar approach to the leverage adjustment. As to the City of Lancaster decision, the situation there was quite different than the leverage adjustment that I propose in this case. Lancaster proposed a leverage adjustment to the

cost of equity measured with the Hamada formula and applied it to the DCF result, the Risk Premium result, and the CAPM. While the Hamada formula plays a role in the CAPM, it is not applicable to the DCF or the Risk Premium measures of the cost of equity. Hence, this distinguishes the City of Lancaster approach to the leverage adjustment from mine in this case. As to the UGI Utilities – Electric Division case, there the Commission granted a management performance increment rather than a leverage adjustment when arriving at a 9.85% equity return. And for the 2020 Columbia case, the Company accepted the I&E's recommendation of the allowed return, which was 9.86%, in a case litigated at the height of the COVID-19 Pandemic. Thus, Columbia chose not to argue the leverage adjustment in Exceptions to the Commission. However, based upon the current inputs to the DCF that indicated a low result, the Commission should now consider using the leverage adjustment, just as it did previously when the DCF was suggesting unusual results. In the PECO - Gas rate case, the Commission arrived at a 10.24% return without the leverage adjustment, because that return was already deemed to be on the higher side and no additional adjustment was warranted. Finally, the Commission set the equity return at 10.00% for Aqua Pennsylvania in its 2021 rate case without a leverage adjustment, but with an adjustment for management performance.

Q. Third, Mr. Patel argues that information provided investors is book values according to Value Line. Is this correct?

A. No. Mr. Patel contends that information presented to investors (see page 58 of I&E Statement No. 3), such as that included in the Value Line reports, argues against my leverage adjustment because investors base their investment decisions on book value. However, the Value Line reports clearly show the market capitalization of each company in his barometer group. This means that investors are well aware of the market capitalization of the gas utility stocks that Mr. Patel relies upon for his analysis of the cost

of equity. More importantly, I fundamentally disagree that investors base their decisions on book values. To the contrary, it is the future cash flows that investors expect to realize that determines the price they are willing to pay for a share of common equity. Stated differently, investors are concerned with the return that will be earned on the dollars they invest (i.e., their market price) and not some accounting value of little relevance to them. The financial risk associated with the book value capital structure is different from the market value of the capitalization. I clearly demonstrate this point on Schedule 10 of Columbia Exhibit No. 400. Hence, the observation of Mr. Patel is misplaced because I have clearly shown the difference in financial risk and that risk difference must be taken into account when arriving at an equity return that is applicable to the weighted average cost of capital using book value weights.

Further, Mr. Patel asserts that the leverage adjustment is not required because investors are aware that market values are above book value. This has nothing to do with my adjustment. The purpose of the adjustment is to synchronize the financial risk associated with the ratesetting capital structure in order to provide a utility with the return that accommodates the leverage used in setting rates. Investors are only concerned with the returns that they can realize on market values, not the values used to set rates.

Q. Please respond to Mr. Walters' criticisms of your leverage adjustment.

A. Mr. Walters asserts that my leverage adjustment is "nothing more than a market-to-book ratio adjustment to the DCF return." This is completely incorrect. I need to be clear that my leverage adjustment is not designed to produce any particular market-to-book ratio. Rather, as I derive it, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus a term(s) reflecting the increase in financial risk resulting from the use of leverage in the capital structure. For my Gas Group, the return is 9.09% for those companies if their capital structure contained 100% common

equity plus 2.85% for the actual debt in the capital structure plus 0.11% for the actual preferred stock in the capital structure. A market-to-book ratio plays no role in these calculations. Perhaps it is worthwhile to recap the procedure used in making my adjustment, which, as previously explained, entails a three step process. In step one, the DCF cost of equity is calculated using the market price of stock and the capital structure ratios computed from the market capitalization of both the debt and equity of a firm. In step two, a completely unleveraged cost of equity is calculated, as if the firm were 100% equity financed. In the third step, a releveraged cost of equity is calculated with the capital structure determined from the book value of debt and equity capitalization as noted above. I must reiterate that my leverage adjustment contains no factor for a particular market-to-book ratio. It merely expresses the cost of equity as the unleveraged return plus compensation for the additional risk of introducing debt and/or preferred stock into the capital structure.

Cost of Common Equity - Capital Asset Pricing Model

Q. At page 21 of I&E Statement No. 2, Mr. Patel argues that the CAPM is less responsive than DCF to changes in the capital markets, because the CAPM uses historical betas and measures the return on equity indirectly. Do these observations defeat the usefulness of the results of the CAPM?

A. Absolutely not. The CAPM is just as responsive to changes in capital costs as is the DCF. Indeed, the CAPM is more responsive to the current level and trend in interest rates because the risk-free rate of return reflects those factors directly. The market risk premium is also forward-looking, as it is based on a DCF type calculation for the market total return, as proposed by Mr. Patel. And while the beta calculation is based on historical data, Value Line adjusts its historical betas for the tendency of betas to move toward 1.00 on a forward-

looking basis. The bottom line is the CAPM is just as responsive to changes in capital costs as any other method.

Q. Mr. Patel presents a revenue requirement calculation showing the difference associated with using the DCF and CAPM results (see page 35 of I&E Statement No. 2.). What does this comparison reveal?

A. This comparison is not relevant to this case. If any insight can be made with these inputs, it would be between the midpoint of the range, i.e., 10.40% (10.86% + 9.93% = 20.79% ÷ 2) and the lower end of the range, i.e., 9.93%. That gap is 47 basis points. That produces a $12.170 million difference in revenue requirement, not the $24.339 million Mr. Patel reports.

Q. Do you have concerns regarding Mr. Patel's application of the CAPM?

A. Yes. Mr. Patel's CAPM analysis understates the cost of equity for a number of reasons: (i) his use of the yield on 10-year Treasury notes, (ii) his failure to use leveraged adjusted betas, and (iii) his failure to make a size adjustment. With regard to Mr. Patel's CAPM analysis, which produces a 10.86% cost rate, it can be argued that he has understated the risk-free rate. On Schedule 12 of I&E Exhibit No. 2, he uses a projected 10-year treasury note yield from Blue Chip on April 1, 2024 and December 1, 2023, producing a 3.88% risk-free rate.

Q. How does the use of the yield on 10-year treasury notes compare with yields on longer-term treasury bonds?

A. The Blue Chip report shows this comparison. For the first quarter of 2024, the gap was 0.17% (4.33% - 4.16%) between the yields on 30-year and 10-year Treasury obligations. For the period 2026-2030, that gap is projected to increase to 0.20% (4.3% - 4.1%) according to the June 1, 2024 Blue Chip. This shows a systematic understatement of Mr. Patel's CAPM returns. Shorter-term rates, such as 10-year notes, respond more to the

policy initiatives of monetary officials, while long-term rates, such as 30-year bonds, are more a reflection of investor sentiment of their required returns. For this reason, long-term rates, such as those revealed by 30-year Treasury bonds, should be used to measure the risk-free rate of return.

Q. How has Mr. Patel understated the risk-free rate of return?

A. The support for his risk-free rate of return is shown on his Schedule 9 of I&E Exhibit No. 2. There, he incorrectly gives the same weight to the yield on 10-year Treasury notes for the third and fourth quarter of 2024 as he does for the entire five-year period from 2025 through 2029. This approach leads to an understated risk-free rate of return. Even if 10-year rates are used, it is necessary to correct the weights assigned to the forecast data presented by Mr. Patel. The resulting risk-free rate of return is 4.1% using the yield on 10-year Treasury Notes and 4.3% using the yield on 30-year Treasury Bonds.

Year	10-Year Treasury Yield	30-Year Treasury Yield
2025	4.00%	4.20%
2026	4.00%	4.20%
2027	4.00%	4.20%
2028	4.00%	4.30%
2029	4.20%	4.40%
2030	4.20%	4.40%
Average	4.07%	4.28%

Q. How should these results be used in the CAPM?

A. The risk-free rate of return should be calculated with the data that I present above. The size adjustment of 1.02% must also be incorporated into the CAPM. I have corrected Mr. Patel's CAPM as indicated below using those inputs and the forecast yield on 30-year Treasury bond shown above:

	Rf	+	*β*	(	*Rm*	-	*Rf*	) +	*size*	=	*K*
Gas Group	4.28%	+	0.86	(	12.05%	-	4.28%	) +	1.02%	=	11.98%

Q. Mr. Patel questions the need to adjust the CAPM results for size differences. Please comment.

A. As a preliminary matter, it is noteworthy that CAPM provides compensation solely for systematic risk, and that the size of the Gas Group must be considered separately. Just as investors have choices concerning large cap, midcap, and small cap equity investments offered by many mutual funds and ETFs, size is clearly on important investment criteria for investors. It is well recognized that the return for small cap investments outperform large cap investments. Indeed, the Ibbotson Yearbook shows that small cap stocks have outperformed large cap stocks by four percentage points (4.00%) over the past ninety-seven (97) years. As I indicated with the data presented on Schedules 2, 3 and 4 of Exhibit PRM-1, the gas utilities are small as they are just 19% of the size of the electric and gas utilities that comprise the S&P Public Utilities. Indeed, recent FERC orders specifically prescribe an adjustment to the CAPM due to the size of an enterprise.[6] Mr. Patel's arguments revolve around the purported distinction between regulated utilities and unregulated industrial companies described by Dr. Annie Wong. However, the Wong article that he relies upon was authored nearly thirty (30) years ago and employed data going back into the 1960s. Enormous changes have occurred in the industry since the 1960s that have fundamentally changed the utility business. The Wong article also noted that betas for the non-regulated companies were larger than the betas of the utilities. This, however, is not a revelation, because utilities continue to have lower betas than many

[6] *See, e.g.*, Association of Businesses Advocating Tariff Equity, 171 FERC ¶61,154 (May 21, 2020).

other companies. This fact does not invalidate the additional risk associated with small size.

The Wong article further concludes that size cannot be explained in terms of beta. Again, this should not be a surprise. Beta is not the tool that should be employed to make that determination. Indeed, beta is a measure of systematic risk, and it does not provide the means to identify the return necessary to compensate for the additional risk of small size. In contrast, the famous Fama/French study (see "The Cross-Section of Expected Stock Returns," The Journal of Finance, June 1992) identified size as a separate factor that helps explain returns.

Q. How does size affect the financial performance of a small company?

A. Examples of the financial consequences of external factors that can influence the financial performance of a small company include loss of a large customer and the effect of unexpected changes in expense.

Q. Do you have concerns regarding the application of the CAPM by Mr. Walters?

A. Mr. Walters' CAPM analysis understates the cost of equity for a number of reasons: (i) his use of the undefined "Kroll normalized" market premium, (ii) his use of S&P betas, and (iiiv) the failure to make a financial leverage and size adjustments. Mr. Walters uses a beta that is not leverage adjusted, an unrealistic market risk premium, and ignores the size adjustment. He therefore proposes some totally unrealistic CAPM result of 8.65% to 8.71%. This compares with my CAPM of 10.94% (excluding leverage and size), Mr. Patel's CAPM of 10.86%, and the Quarterly Earnings Report's CAPM of 10.87%.

Q. What are your observations concerning Mr. Walters' calculation of the total market return using the S&P Composite Index data?

A. Mr. Walters' analysis is deficient because of his reliance on the "Kroll" market premium that does not conform with investors expectations. This deficiency is shown by recent

Value Line reports, the total return on the entire market as measured by Value Line is 13.78% ((2.2% + (1.55$^{.25}$) – 1) as of April 24, 2024. This return exceeds the returns of 11.27% and 7.44% presented by Mr. Walters on page 17 of his testimony. This would increase his CAPM result to 12.13% (13.78% - 4.10% = 9.68% x 0.83 = 8.03% + 4.10%). The Commission has not employed S&P betas in the CAPM, and should not begin now.

Q. Mr. Walters also questions the need to further adjust the CAPM results for size differences. Please comment.

A. Mr. Walters' argument essentially rests with his objection that the adjustment for small size does not extend to regulated utilities. My reading of Mr. Walters' testimony indicates that he does not dispute the effect of size on the cost of equity, but that it applies only to non-regulated companies. As the famous Fama/French study demonstrated, the size adjustment applies to both regulated and non-regulated companies because the Fama/French study considered both types of companies.

Q. At pages 97-98 of OCA Statement No. 3, Mr. Walters also challenges the adjustment that you made to the results of the CAPM for the size of the Gas Group. Please respond.

A. A size adjustment is necessary because the financial impact of changes in specific dollar amounts of revenues and costs have a magnified influence on a small company because there are fewer dollars over which those revenues or costs can be spread. The SBBI/Morningstar Yearbook clearly demonstrates that the simple CAPM does not reflect the return that is associated with small size. As Ibbotson has stated:

> The security market line is based on the pure CAPM without adjusting for the size premium. Based on the risk (or beta) of a security, the expected return should fluctuate along the security market line. However, the expected returns for the smaller deciles of the NYSE/AMEX/NASDAQ lie above the

line, indicating that these deciles have had returns in excess of those appropriate for their systematic risk.[7]

Cost of Common Equity - Risk Premium Analysis

Q. Do you believe the risk premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity, which must be higher than the cost of debt in recognition of the higher risk of equity (see Statement No. 8 pages 41-42). So, while Mr. Patel declines to use the Risk Premium approach to measure the Company's cost of equity, it is an approach that provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk. It is particularly useful when investors expect changes in the cost of debt prospectively, which is currently the expectation of investors, as I have explained above and in Statement No. 8, page 35. Indeed, the Risk Premium approach provides for direct reflection of prospective interest rates in the model and therefore, should be given weight in determining the equity cost rate in this case.

Q. What does Mr. Patel say about your risk premium analysis?

A. Mr. Patel makes the unfounded assertion that the Risk Premium and CAPM methods should only be used as a comparison to the results of the DCF method because they do not carry over from the investment decision-making process to the utility rate setting process (see page 21 of I&E Statement 2). In fact, it is precisely because investors

[7] 2016 SBBI Yearbook (Stocks, Bonds, Bills and Inflation), page 7-15.

consider the results of other methods that they too should be used in addition to the DCF in the development of the cost of equity in this proceeding. Mr. Patel's assertion that the Risk Premium method does not measure the current cost of equity as directly as the DCF is similarly without foundation. As I explained in my direct testimony and earlier in this rebuttal testimony, we are facing the prospect of increased interest rates for the foreseeable future. I incorporated the trend toward higher interest rates when I developed my Risk Premium cost of equity of 11.50% although, as noted above, actual interest rates on A-rated public utility bonds have already exceeded the projection I used for my Risk Premium cost of equity (see page 34 of Statement No. 8, where the forecasts show 5.25% to 5.55% yields on A-rated public utility bonds, yet I used just 5.00%). Hence, my Risk Premium cost rate is fully responsive to changing market fundamentals and the credit quality of the Electric Group.

The Risk Premium approach is solid as acknowledged by Mr. Walters who has used this model to measure the Company's cost of equity. It is an approach which provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk.

Q. Please comment on the Risk Premium analysis presented by Mr. Walters?

A. The Risk Premium result of 9.63% to 10.14% developed by Mr. Walters for a utility with Baa rated credit quality clearly shows that the results of the DCF analysis are unrealistic. Even his analysis is defective because I have shown that the Risk Premium approach yields an 11.50% return.

Mr. Walters claims that Kroll supply-side equity risk premium is much lower than the risk premium that I established using historical data (see page 54 of Statement No. 3). His claim is unsupported because he has not shown that his risk premium is related to the level of interest rates, i.e., it expands when interest rates decline and contracts as

interest rates increase, and it is not based on actual measurable returns that are revealed by historical data.

Cost of Common Equity - Comparable Earnings Approach

Q. Please respond to the criticism of the Comparable Earnings approach.

A. The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Further, given the 10-year time frame (i.e., five years historical and five years projected) considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital.

The Comparable Earnings approach satisfies the comparability standard established in the Hope case. In addition, the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets. Moreover, in a 1994 study that addressed the ROE issue, John Olson (then with Merrill Lynch) established that equity returns from non-regulated companies provide better assessment of investor requirements than those available for regulated utilities.[8]

Management Performance and Other Matters

Q. Both Mr. Patel and Mr. Walters oppose any recognition for management

[8] "Natural Gas: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

performance in the determination of the return on equity. Mr. Patel and Mr. Walters assert that Columbia has not done anything other than what it is required. How do you respond?

A. As I stated in my direct testimony, I believe Columbia has performed in an exemplary manner, as explained by Columbia Witness Kempic in his direct testimony, and that performance should be recognized in this case. Mr. Patel simply disagrees, without addressing or refuting any of the items highlighted by Columbia's witnesses as examples of Columbia's excellent performance. Mr. Walters's position regarding management performance is that the models of the cost of equity already incorporate management effectiveness. In each case, neither Messrs. Patel nor Walters have shown that Columbia is not entitled to some form of management performance recognition by the Commission. Mr. Kempic's direct and rebuttal testimonies establish that the Company's management performance warrants recognition by the Commission.

Q. A change in depreciation method is another issue that has been raised in this proceeding. Do you have an observation concerning this matter?

A. OCA witness Andrews recommends a change to Columbia's depreciation method in his direst testimony. A change in depreciation method could have a negative impact on Columbia's cash flow. While that is a concern to the Company, it will have no impact on its return because the Company will book depreciation expense using whatever method the Commission selects to set rates. The real question is: Is it preferable for the Company to obtain return of capital previously provided by investors in a timely manner as relates to retirements, or is it better for the Company to raise additional investor-provided capital that carries an 8.71% return. The other alternative for reduced cash flow is to cut-back on capital expenditures to match the diminished cash flow. That alternative would stretch out the time for Columbia's accelerated infrastructure improvement program, possibly by an

extensive amount of time.

Q. Some OCA witnesses argue that if the Commission approves the RNA, the Company's risk will be reduced and the equity return should be lower. Please respond.

A. The OCA witnesses are incorrect on this point. As I fully documented on pages 8 and 9 of Statement No. 8, no adjustment to the cost of equity is warranted for the RNA because just like the WNA the risk attributes of the both mechanisms are fully reflected in the cost of equity determination with market data derived from the Gas Group. I am also advised that the WNA and proposed RNA for CPA only applies to residential usage.

Summary

Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. Patel and Mr. Walters seriously understate the cost of common equity for Columbia and, in Mr. Walters's case, inappropriately uses a hypothetical capital structure. This is also particularly true for Mr. Walters' cost of equity proposal. In an environment of high interest rates and Company-specific risk factors, an opportunity to earn a cost of equity of 11.75% is reasonable for Columbia.

Q. Does this conclude your rebuttal testimony at this time?

A. Yes. I reserve the right to supplement my testimony as additional issues arise during the course of this proceeding. Thank you.

Columbia Gas of Pennsylvania

Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1] (1)	Annualized Dividend[2] (2)	First Stage Growth[3] (3)	Cash Flows Year1 (4)	Year2 (5)	Year3 (6)	Year4 (7)	Year5 (8)	Multi-Stage Growth DCF (10)
1	Atmos Energy Corporation	$114.80	$3.22	7.17%	$ 3.45	$ 3.70	$ 3.96	$ 4.25	$ 137.78	6.27%
2	New Jersey Resources Corporation	$41.96	$1.68	5.93%	$ 1.78	$ 1.89	$ 2.00	$ 2.12	$ 59.50	10.62%
3	Northwest Natural Holding Company	$36.81	$1.95	4.05%	$ 2.02	$ 2.10	$ 2.17	$ 2.25	$ 64.00	15.76%
4	ONE Gas, Inc.	$61.82	$2.64	4.33%	$ 2.75	$ 2.87	$ 3.00	$ 3.13	$ 90.00	11.25%
5	Southwest Gas Holdings, Inc.	$68.47	$2.48	5.43%	$ 2.61	$ 2.76	$ 2.91	$ 3.06	$ 75.60	5.26%
6	Spire Inc.	$59.53	$3.02	5.95%	$ 3.20	$ 3.39	$ 3.59	$ 3.81	$ 88.00	12.39%
7	Eversource Energy	$57.99	$2.70	4.17%	$ 2.98	$ 3.11	$ 3.24	$ 3.38	$ 92.80	13.51%
8	American States Water Company	$72.04	$1.72	8.23%	$ 1.83	$ 1.94	$ 2.06	$ 2.19	$ 105.30	9.99%
9	American Water Works Company, Inc.	$119.97	$2.83	7.75%	$ 3.05	$ 3.28	$ 3.54	$ 3.81	$ 182.00	10.72%
10	California Water Service Group	$46.15	$1.12	9.40%	$ 1.23	$ 1.35	$ 1.49	$ 1.63	$ 66.00	9.62%
11	Middlesex Water Company	$51.75	$1.30	2.70%	$ 1.34	$ 1.37	$ 1.41	$ 1.45	$ 84.00	12.05%
12	SJW Group	$56.61	$1.60	7.33%	$ 1.72	$ 1.85	$ 1.99	$ 2.14	$ 79.35	9.45%
13	Essential Utilities, Inc.	$35.69	$1.23	5.78%	$ 1.30	$ 1.37	$ 1.45	$ 1.54	$ 63.60	14.96%
14	**Gas Average**	**$63.90**	**$2.50**	**5.48%**	**263.71%**	**278.35%**	**293.85%**	**310.24%**	**8581.25%**	**10.26%**
15	**Gas Median**									**10.94%**
16	**Total Average**	**$63.35**	**$2.11**	**6.02%**	**225.12%**	**238.32%**	**252.37%**	**267.30%**	**9137.88%**	**10.91%**
17	**Total Median**									**10.72%**

Sources:
The Value Line Investment Survey, April 5, May 10, and May 24, 2024.

	VL EPS	VL E/P	Price
Atmos Energy Corporation	$8.35	16.5	137.78
New Jersey Resources Corporation	$3.50	17.0	59.50
Northwest Natural Holding Company	$3.20	20.0	64.00
ONE Gas, Inc.	$5.00	18.0	90.00
Southwest Gas Holdings, Inc.	$4.20	18.0	75.60
Spire Inc.	$5.50	16.0	88.00
Eversource Energy	$5.80	16.0	92.80
American States Water Company	$3.90	27.0	105.30
American Water Works Company, Inc.	$7.00	26.0	182.00
California Water Service Group	$2.75	24.0	66.00
Middlesex Water Company	$3.00	28.0	84.00
SJW Group	$3.45	23.0	79.35
Essential Utilities, Inc.	$2.65	24.0	63.60

COLUMBIA STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
NICOLE M. PALONEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

I. Introduction

Q. Please state your name and business address.

A. Nicole Paloney, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as Director of Rates and Regulatory Affairs.

Q. What are your responsibilities as Director of Rates and Regulatory Affairs?

A. I am responsible for developing and directing rate activity on behalf of the Company before the Pennsylvania Public Utility Commission ("Commission") as well as coordinating and representing the Company's position in a variety of regulatory matters and proceedings.

Q. What is your educational and professional background?

A. I have a Bachelor of Science in Business and Administration with an emphasis in Accounting and Finance from The Ohio State University. In 1998, I was hired as a staff auditor for Deloitte, primarily serving middle market clients in a variety of industries, including manufacturing, public pension systems and not for profit clients. I was promoted to manager in 2004 and served in that capacity until I left Deloitte in July 2005. From August 2005 until August 2008, I was employed by Cardinal Health in Dublin, Ohio. Cardinal Health provides pharmaceutical and medical products to the Health Care industry and is also a manufacturer of medical

and surgical products. I was a manager in Internal Audit during my tenure at Cardinal, with responsibility over internal audits that took place in the manufacturing and corporate segments of the company.

In August 2008, I joined NiSource Corporate Services Company ("NCSC") as an Internal Audit manager, with responsibility for internal audits that took place in NiSource Inc.'s ("NiSource") Gas Distribution segment. In September 2011, I transitioned to the Regulatory Strategy and Support group in the role of Project Manager, providing support to the state regulatory teams in Pennsylvania and Maryland. In May 2014, I began my role as Director of Rates and Regulatory Affairs for the Company.

Q. Have you previously testified before this Commission or any other Commission?

A. Yes. I have testified before the Commission on behalf of Columbia in its 2015, 2016, 2018, 2021, and 2022 base rate cases at Docket Nos. R-2015-2468056, R-2016-2529660, R-2018-2647577. R-2021-3024296 and R-2022-3031211, respectively. In addition to base rate proceedings in Pennsylvania, I also have submitted testimony in support of Columbia's request to increase the cap on its Distribution System Improvement Charge (Docket No. P-2015-2521993) and in an abandonment proceeding (Docket No. A-2015-2513395), as well is in the Company's Purchased Gas Cost proceedings at Docket Nos. R-2020-3018993, R-2021-3024349 and R-2022-3031172, respectively. I also have testified before the Public Service Commission of

Maryland in Columbia Gas of Maryland base rate cases as a cost-of-service witness in Case No. 9316 and as a policy witness in Case Nos. 9354 and 9480.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide background on the budgeting process for Columbia's Gas Utility Segment departments, which include Field Operations, Construction, Customer Programs, President, and Safety Compliance and Risk Management, and how the Company's budget is determined. My testimony supports projected Operations and Maintenance ("O&M") expenses for the Fully Projected Future Test Year ("FPFTY") (through December 31, 2025), that have been incorporated in Columbia witness Komenda's cost of service analysis (Columbia Statement No. 4) for Columbia. Company witness Nicholas Bly will be supporting the budgeting process for corporate O&M functions, overhead expenses, and NCSC at Columbia Statement No. 15. The following chart illustrates the cost elements in Exhibit 104, Schedule 1 pages 5 and 6 supported by myself and witness Bly.

Cost Element Category	Company Witness
Labor	Bly/Paloney
Incentive Compensation	Bly
Pension	Bly
Pension Deferral Amortization	Bly
OPEB	Bly
Other Employee Benefits	Bly
Outside Services	Bly/Paloney
Building Leases	Bly/Paloney
Other Rent and Leases	Bly/Paloney
Corporate Insurance	Bly
Injuries and Damages	Bly
Employee Expenses	Bly/Paloney
Company Memberships	Paloney
Utilities and Fuel Used in Company Operations	Bly/Paloney
Advertising	Bly/Paloney
Fleet & Other Clearing	Bly/Paloney
Materials & Supplies	Bly/Paloney
Other O&M	Bly/Paloney
PUC, OCA, OSBA Fees	Paloney
NCSC	Bly

In addition to the information I will be supporting above, I will also be supporting the hydrogen adjustment made by Company Witness Komenda at Exhibit 104, Schedule 2, Sheet 18 and the calculation of the Municipal Levelization Charge discussed by Company witness Kempic in Columbia Statement No. 1. I will also address Bill Ready Billing.

II. FULLY PROJECTED FUTURE TEST YEAR – O&M EXPENSE

Q. What is the basis for the forecasted O&M expense included in the Fully

Projected Future Test Year?

A. The forecasted O&M expense included in the FPFTY test period is derived from the Company's most recent O&M budget.

Q. How is the O&M budget developed?

A. The O&M budget for Columbia is developed by 3 distinct groups within the organization.

(1) Operations Planning: Operations Planning is responsible for developing a Field Operations budget planned at the cost element level. This budget includes expected cost increases for the current year (merit increases, supplier increases, etc), along with continuous improvement initiatives and other cost savings initiatives throughout the organization. This budget is compared to the prior year spend to ensure it is reasonable compared to actual costs incurred in the prior year and aligns with current expectations.

(2) State Financial Planning and Analysis (State FP&A): State FP&A reviews and verifies that the Field Operations budget is entered correctly in the budget system, develops the O&M budget for the other Gas Utility Segment departments, and verifies the budget is appropriately spread by department, by cost element, and by month. The budgeting process described above is for all expenses charged directly to each subsidiary.

(3) Corporate Financial Planning & Analysis (Corporate FP&A): Corporate FP&A is responsible for budgeting the Company's NCSC allocation. In addition,

Corporate FP&A budgets corporate O&M functions and overhead expenses charged to the Company outside of the Gas Utility Segment (primarily non-utility work). Company Witness Nicholas Bly will address the budgeting process for corporate O&M functions, overhead expenses, and NCSC in his testimony at Columbia Statement 15.

Q. Does that conclude the development of the O&M expense budgeting process?

A. No. There are a series of reviews throughout the budget process with various business partners along with Company Leadership to discuss the upcoming budget and answer questions. After everything is complete, the final budget is reviewed and approved by the Company President and Senior VP of Financial Planning and Analysis. This review includes a comparison of a series of data points based on most recent experience. Specifically, the proposed O&M budget is compared to the most recent year's O&M budget as well as compared to the prior year's actual, experienced amounts. These comparisons help identify trends and allow for measurement against the Company and parent company management's expectations. Once finalized, the departmental O&M expense budget is incorporated into the Company's operating plan.

Q. Have you excluded certain cost categories from your comparison?

A. Yes. O&M expenses that are designed to match, or track against, revenues related to specific programs or costs such as gas costs and low-income programs have been

excluded. Such revenue matching mechanisms have been previously approved by this Commission and ensure that there is no impact on net operating income. The accounting treatment generally allows such expenses to be deferred as incurred and reclassified to expense when the recovery of program costs is recorded in revenue. While these O&M expense variances may be material, there is a corresponding offsetting revenue variance. For that reason, I have excluded these expenses from the comparison so as not to distort the accuracy of the budget.

Forecasted Labor Expense

Q. What are the principal assumptions used in the development of the labor cost element for specific department budgets included in the forecasted test period O&M expenses?

A. Labor expense is based on projected headcount and wage increase assumptions for the FPFTY. More detailed labor budgets are developed by projecting Future Test Year ("FTY") labor based on a trend analysis. This results in a sub-total for total labor dollars available by month, which will then be allocated among O&M accounts, capital, and charges to other departments where work is performed. That allocation involves developing an estimate for the following year's O&M labor budget based on the projected work by activity and using the estimate to determine how much of the labor budget should be allocated to O&M accounts. The remaining labor resources are then allocated to capital or charged out to other departments where work may be performed. A final reasonableness check is done to compare the budgeted amount

for capital labor against prior year actual capital charges to ensure the numbers are in line with the most recent results.

The starting point for forecasting labor costs for Gas Utility Segment departments, excluding Field Operations, is the current organizational chart, which is then reviewed with each functional leader to properly reflect their organization for the upcoming year, including any terminations, additions, or transfers. The labor planning module calculates annual salary increases for merit. Additionally, the planning system reduces labor expense by a capitalization rate. The labor expense values by department are compared to the prior year for reasonableness before the plan is finalized.

Q. Does your budgeting analysis include any projections regarding Columbia headcount?

A. Yes, Columbia is projecting 728 active full-time employees for 2024 and 2025, and an overall wage increase guideline of 4% for 2024 and 3% for 2025 for exempt and non-exempt employees. Labor costs for bargaining unit employees are based on the contracts currently in place.

Forecasted Non-Labor Expenses

Q. Please explain how non-labor activities or events are taken into account in the development of the O&M expense budget.

A. Non-labor expenses start with the assumption that amounts are to be held relatively flat year to year, beginning with 2023 actuals, reflecting normal, ongoing level of

expenses and further adjusted for incremental activities or events that are reasonably expected to occur, or adjusted for expenses that are not expected to recur.

The FTY and the FPFTY Outside Services budgets reflect planned work activities and work volume.

O&M Expense Levels

Q. What are the O&M expense levels for the Historic Test Year, Future Test Year, and Fully Projected Future Test Year?

A. Per Exhibit 104, Schedule 1, Pages 3 & 4, Row 21, O&M expense is $176,764,272 for the Historic Test Year ended November 30, 2023, $172,708,000 for the Future Test Year ending November 30, 2024, and $167,493,000 for the Fully Projected Future Test Year ending December 31, 2025, which are decreases of $4,056,272 and $5,215,000, respectively, before pro forma ratemaking adjustments for the FTY and the FPFTY.[1]

Bill Ready Billing

Q. Please explain Columbia's settlement obligation relating to Bill Ready Billing from Docket R-2022-2023011.

A. As part of the settlement in Docket R-2022-3031211, Columbia agreed the initial filing of the next base rate case will include testimony regarding the costs to implement Bill Ready Billing and a timeline associated with such implementation.

[1] This testimony compares O&M expenses independent of expense items specifically tracked against revenues as discussed earlier in this testimony.

The settlement stated that all parties reserved their rights to support or oppose Bill Ready Billing.

Q. What is Bill Ready Billing?

A. With Bill Ready Billing, a utility such as Columbia provides a customer's usage data to the customer's Natural Gas Supplier ("NGS") and, based on that usage, the NGS then calculates the total charge for gas supplied to that customer. The NGS then provides the utility with the total charge for gas supply to be included on the customer's bill along with the customer's distribution charges. In other words, Bill Ready means that the NGS calculates its portion of the customer's bill instead of the utility doing so on behalf of the supplier. In terms of how this would work in practice, on the day after Columbia reads the customer's meter, a 3-day bill preparation period would begin. For every customer receiving gas supply from an NGS, in each of the 21-unit billing cycles, Columbia would provide the customer's consumption data to the NGS and, in turn, the supplier would provide to Columbia a total gas supply charge for inclusion on the customer's bill. Columbia would then bill the customer using the supplier-provided gas supply charge and Columbia's distribution charges. If an NGS fails to provide the charge and rate by the deadline, a gas supply charge of zero would be presented on the customer bill for the current revenue billing cycle.

Q. Have you estimated the cost and timeline for implementation of Bill Ready Billing by the Company?

A. Yes. The estimated cost of implementing Bill Ready Billing by Columbia is between $780,000 and $820,000. The estimated time of implementation is a minimum of 12 months from a Commission order directing that Bill Ready Billing be made available.

Q. Please explain why Columbia does not offer Bill Ready Billing as a billing option.

A. Bill Ready Billing is not necessary, nor is it in the customers' best interests. There are disadvantages to customers associated with Bill Ready Billing. When a total charge is presented without the rate, as it may be with Bill Ready, customers could have issues with understanding how the commodity costs were calculated. Also, if commodity charges are not received from suppliers within the 3-day bill preparation period, a customer could receive a bill with gas commodity charges in the amount of zero for that billing month. If this were to occur, the gas commodity charge would need to be added to the customer's next bill, resulting in the customer being billed for two months of gas commodity charges in a single billing statement.

Q. Does Columbia have an overall position on implementing Bill Ready Billing as an additional billing option for suppliers in Pennsylvania?

A. Yes, it is Columbia's position that Bill Ready Billing is not necessary for suppliers to serve their customers, offers no additional advantages to customers, and any costs incurred to implement this billing option would not be prudent. Further, Columbia has a history of implementing enhancements aimed at supporting NGSs in the

Company's service territory, but often these enhancements have not been utilized by NGSs after implementation. For example, Columbia eliminated the NGS logo set-up fee, included space on the customer bill for an NGS message and a shopping information box. Columbia also implemented a mechanism for NGSs to access customer account numbers in a public venue, when the account number is not available from the customer or Eligible Customer List. Comments submitted to the Commission by interested parties (including the Retail Energy Supply Association ("RESA")) stated that these changes would result in greater customer awareness of the supplier through the inclusion of NGS logos and other pertinent product information. RESA also advocated for the implementation of password-protected portals on the basis that the tool would streamline the CHOICE enrollment process and alleviate the need for a customer to take additional steps later to complete the transaction. These enhancements were implemented in August 2016. Only 11 out of 39 NGSs have submitted their logos to be included on customer bills, which represents 8% of customers currently enrolled in the Company's Customer CHOICE® Program. There has not been significant engagement of the NGS bill messaging option after its deployment. To date, no NGS has utilized the Account Access portal. The costs associated with these changes were more than $900,000, recovered from distribution customers. It is unreasonable to continue to promote enhancements as an option for suppliers that are not used once instituted, especially

when they are not necessary for the supplier to serve its customers and offer no additional benefit to the customer.

Hydrogen Pilot: Hydrogen Purchase Expense

Q. Please summarize the Company's request for the purchase of hydrogen.

A. The Company seeks recovery of $54,000 in O&M expense for the purchase of hydrogen for its Hydrogen Blending Skid at Columbia's training center in Monaca, Pennsylvania. In 2022, the Company built and installed a hydrogen blending skid that is connected to part of the training distribution system at its Monaca training center (referred to as "Safety Town") to blend up to 20% (by volume) hydrogen into Safety Town. The blending skid was connected to the Company's Safety Town in the spring of 2023 for the purpose of better understanding hydrogen safety. The goal of installing the blending skid is to advance hydrogen technology and demonstrate that blending hydrogen with natural gas can contribute to a reduction in carbon emissions. I emphasize that no hydrogen is currently being blended into Columbia's operating system serving customers.

Q. Are any costs associated with the construction of the blending skid included in the Company's rate base?

A. No, there are not.

Q: What is the benefit of doing this work?

A: This work provides many benefits. Having access to hydrogen in a controlled environment allows company employees to become familiar with hydrogen blends

and allows for long term and extensive trials in working with hydrogen blends. This type of work is necessary for the Company to understand what changes would be needed to any current standards should hydrogen be blended into the system in the future.

Q: How does this work benefit Columbia's customers?

A: Hydrogen blending is one option to help decarbonize the gas system and reduce greenhouse gas emissions. As more and more of Columbia's customers are interested in low carbon solutions, the interest in hydrogen is expected to grow. It is expected that customers will begin to request or want to purchase hydrogen-blended natural gas. The insights gained from Columbia's project educates Columbia's employees and provides valuable information on how to operate a hydrogen blended system.

Q: Are Columbia's employees able to gain this knowledge from other sources?

A: Research on hydrogen blending is taking place sporadically across the country, however that work is complementary to the work being done by the Company and does not replace the opportunity that direct access to and hands on training on an actual blending skid provides Columbia's employees. Access to a fully functioning hydrogen blending skid is rare as only a few exist in the country. In addition, Columbia's blending skid is more robust than others.

Q: What advantages does Columbia's blending system offer over others?

A: Columbia's system can blend hydrogen from 0% up to 20%, by volume, into Safety

Town. Other blending systems are only blending up to 5%. By working with higher percentages, Columbia can more fully assess what percentage of hydrogen will most benefit customers. Columbia's blending system is connected to a tiny model home, as well as the rest of Safety Town. This allows Columbia's employees to work with hydrogen blends in a real home setting, with all modern natural gas appliances, as well as all of the advantages of Safety Town.

Q: What is the current status of the Company's blending skid?

A: The blending skid is currently up and running. It was installed in the Spring of 2023 and Safety Town was modified for that blending skid to be able to blend hydrogen into parts of Safety Town. Hydrogen was purchased for this work.

Q: What is Columbia requesting for the blending skid?

A: Columbia is requesting to recover the small cost of hydrogen to be able to continue its work with hydrogen for a longer term. This will allow the Company to continue to learn about hydrogen blending. The monthly cost of hydrogen for the skid is approximately $4,500 and, as such, the Company is requesting recovery of $54,000 per year.

<u>Municipal Levelization Charge ("MLC")</u>

Q. Please explain the Company's rate design proposal regarding Municipal Levelization Charge.

A. As noted in Columbia witness Kempic's testimony (Columbia Statement No. 1), the

Company is seeking to recover costs from customers who reside in certain municipalities where paving and restoration requirements exceed, and are more costly than, standards established by the Pennsylvania Department of Transportation ("PennDOT"). By the same token, Columbia seeks to provide billing credits to customers who reside in municipalities where paving and restoration requirements are less costly than PennDOT standards.

Q. Does the Company track ordinances in the municipalities where pipeline replacement projects and operational work is performed?

A. Yes. As noted in Exhibit NP-1, the Company's construction organization tracks both asphalt and concrete paving requirements by municipality. As part of this tracking process, existing paving standards are compared to PennDOT standards to determine if the differences between municipal ordinances and PennDOT Standards are going to impact costs.

Q. For the municipalities that are identified in Exhibit NP-1 as having differences in existing ordinances compared to PennDOT Standards, are some municipalities willing to negotiate the level of paving to a level deemed comparable to the Penn DOT standard?

A. Yes. Here are some examples of successful negotiations to reduce paving requirements:

- **Bethel Park:** Existing municipality ordinance of 3.5-inch mill and overlay ("M&O") paving requirement. For 2023 project work in Bethel Park, the

Company was able to negotiate down to 1.5-inch M&O which is in line with the PennDOT Standard of 1.5-inch M&O. M&O paving requirements will need to be negotiated on an individual project basis as existing municipality standard remains at 3.5 inches.

- **Charleroi Borough, Washington County:** Existing municipality ordinance: Curb to curb paving required if more than ten percent of the square area of any 50-foot length of roadway is opened. The PennDOT standard is one foot cut back and patching the hole. Columbia has negotiated a PennDOT restoration standard for two upcoming pipeline replacement projects in Charleroi Borough, Washington County.
- **Canton Township, Washington County:** Existing municipality ordinance: a "Road Maintenance Agreement" is necessary to receive a permit and requires 100 feet of paving restoration on each side of a cut in a lane. The PennDOT standard is one foot cut back and patching the hole. The township ordinance is currently not being enforced. Columbia project restoration is negotiated on a per project basis, which then requires Township Supervisor approval.

Q. Do successful negotiations in reducing paving requirements on one project carry forward to the next project performed in any given municipality?

A. No. As long as ordinances have paving requirements that are different than PennDOT standards, every project's paving requirements need to be negotiated

individually. The inherent risk of strict application of the municipality ordinance in place always exists.

Q. How did the Company determine which customers would be subject to the MLC?

A. First, the Company reviewed all construction projects for the calendar years of 2021, 2022 and 2023 for the municipalities that had ordinances that were beyond the requirements of the PennDOT standard and determined whether those municipalities agreed to lower restoration requirements. Two municipalities had ordinances that exceeded PennDOT standards and did not agree to negotiate lower standards, which resulted in costs in excess of PennDOT standards being incurred during these time periods – the City of Pittsburgh and the Borough of Perryopolis. Second, the Company reviewed which municipalities permit restoration back to original condition, which is less than the PennDOT standards. They are New Sewickley Township and Roscoe Borough.

Q. How did the Company calculate the additional charges to be recovered from, and credits to be provided to, customers in the municipalities identified?

A. Please see Exhibit NP 1. To determine the costs above PennDOT standards for the City of Pittsburgh, the average cost of 1.5 inches of M&O was compared to the average costs of M&O of 3.5 and 4 inches for City of Pittsburgh projects. The difference was applied to the number of yards paved for the period of 2021-2023, resulting in costs

of $1,349,423 above the PennDOT standards for the City of Pittsburgh. For the Borough of Perryopolis, the two-inch M&O requirement resulted in costs of $53,752 in excess of PennDOT standards. The annual revenue requirement associated with the costs for the two municipalities above the PennDOT standards was totaled and divided by the total number of annual bills of customers in the two municipalities to determine the charge. The same amount was divided by the total number of annual bills of customers in the municipalities with restoration requirements below PennDOT standards to determine the credit. As such, the MLC is revenue neutral.

Q. What is the impact of these costs to customers in the individual municipalities?

A. The impact is a monthly charge of $0.70 per bill to Columbia customers who are located in the City of Pittsburgh and the Borough of Perryopolis and is a monthly credit of $7.44 per bill to customers located in Roscoe Borough and New Sewickley Township.

Q. Does the Company plan on continuing to track municipal costs in this manner going forward?

A. Yes. The Company plans to continue tracking the cost impact of municipal restoration requirements and associated fees and will continue to negotiate with municipalities whose ordinances exceed PennDOT standards, as described in Company witnesses Kempic's (Columbia Statement No. 1) and Brumley's (Columbia Statement No. 7) testimony.

Q. Does this complete your direct testimony?

A. Yes, it does.

Mill & Overlay Costs	City of Pittsburgh								
	2023			2022			2021	Perryopolis	
	2023	2023	Total - 2023	2022	2022	Total - 2022	2021	2023	Total
CPA Average SY Cost of 1.5" M/O (PennDOT Spec)	$23.85	$23.85		$23.85	$23.85		$23.85	$23.85	
Paving Contract Costs	$70.47	$81.80		$70.47	$81.80		$81.80	$25.61	
Yards Paved	2,666	5,994	8,660	11,461	4,579	16,040	1,348	30,541	
Paving Contract Costs	$187,873.02	$490,309.20	$678,182.22	$807,656.67	$374,562.20	$1,182,218.87	$110,266.40	$782,155.01	
Cost to M/O to PennDOT Specs 1.5" M/O	$63,584.10	$142,956.90	$206,541.00	$273,344.85	$109,209.15	$382,554.00	$32,149.80	$728,402.85	
Difference	$124,288.92	$347,352.30	$471,641.22	$534,311.82	$265,353.05	$799,664.87	$78,116.60	$53,752.16	**$1,403,174.85**
% Difference	295.47%	342.98%	328.35%	295.47%	342.98%	309.03%	342.98%	107.38%	
M / O Requirement of Municipality	4 inches	3.5 Inches		4 inches	3.5 Inches		3.5 Inches	2 Inches	

Revenue Requirement							Municipal Levelization Charge	Municipal Levelization Credit
			2021	2022	2023			
1	Annual Incremental Capital Costs		$78,117	$799,665	$525,393	Total Annual Revenue	$188,825	($188,825)
2	Total Incremental Capital Costs		$78,117	$877,781	$1,403,175	0030298PITTSBURGH	21,876	
3	Accumulated Depreciation				($29,424)	0511365PERRYOPOLIS	728	
4	**Net Incremental Capital Costs**				**$1,373,751**			
5	Pre-Tax Rate to Determine Revenue	Ln. 15			11.11%	1252876ROSCOE		356
6	Revenue Impact of Incremental Capital	Ln. 4 times Ln. 5			$152,623	0070417NEW SEWICKLEY		1,760
7	Depreciation Expense	Ln. 2 times Ln. 8			$36,202	Total Customers	22,604	2,116
	Total Annual Revenue Impact	**Ln. 6 + Ln.7**			**$188,825**		12	12
						Number of Bills	271,248	25,392
8	Composite Depreciation Rate	Exh. 105, Page 9	2.58%	2.58%	2.58%	**Per Month**	**$ 0.70**	**$ (7.44)**

Rate of Return						
9		Type of Capital	Ratios	Cost Rate	Weighted Cost Rate	Weighted Cost Rate
10		Long-Term Debt	43.12%	5.07%	2.19%	2.19%
11		Short-Term Debt	2.48%	5.25%	0.13%	0.13%
12		Total Debt	45.60%		2.32%	2.32%
13						
14		Common Equity	54.40%	11.75%	6.39%	8.79%
15	Pre-Tax Rate to Determine Revenue	Total	100.00%		8.71%	**11.11%**

16	Gross-up Rate Calculation	1 Federal		21.00%
17		2 State		7.99%
18		3 Fed. Benefit of SIT	Ln 1 x Ln 2	1.68%
19		4 Effective Rate	Ln 1 + Ln 2 - Ln 3	27.31%
20		5 Gross up Rate	1 - Ln 4	72.69%

PA	TCC - LOCATION	Permit Type	Restoration Requirements - Asphalt	Restoration Requirements - Concrete	Restoration Requirements Above Penn Dot (Mill & Overlay ("M&O "), Base, Concrete, Etc)	Restoration Requirements Not Above PennDOT Standards
PA	2231	Ambridge Borough	Base repair 1' cutback to match existing depth - M&O 1.5" with 20' cubacks - if two or more openings are within a city block, M&O entire block between intersecting streets on any age street	Replace entire width of concrete slab @ minimum of 8" - 1' cutbacks not to create any slab less then 6' in length - Install 3/4" dowels every 12"	M&O exceeds PennDOT standards - Borough is negotiable on restoration	N/A
PA	2231	City of New Castle	1' cutback to match existing depth - M&O 1.5" curb to curb - Connect any excavation upto 300 LF apart on any age street	Replace joint to joint matching existing depth - Install dowels every 12"	M&O exceeds PennDOT standards - City is negotiable on restoration	N/A
PA	2231	Leet Township	Base repair is 1' cutback @ a minimum of 8.5" - M&O 1.5" curb to curb with a 50' cut back - Must connect 4 or more patches within a 100' on any age street	Replace joint to joint matching existing depth - Install dowels every 12"	M&O exceeds PennDOT standards, Concrete S/W Depth, Permitting (Engineering Costs)	N/A
PA	2231	Harmony Township	Base repair 1' cutback to match existing depth - Mill & Pave 1.5" curb to curb 15' each side of excavation - Must connect excavations if within 100 LF - Must replace curb if trench is within 1.5' from curb gutter on any age street	Replace entire width of concrete slab @ minimum of 8" - 1' cutbacks not to create any slab less then 6' in length - Install 3/4" dowels every 12"	M&O exceeds PennDOT standards - Permitting (Engineering Costs)	N/A
PA	2231	Neville Township	1' cutback to match existing depth - M&O 2" centerline to curb unless opening is within 2' of centerline then M&O must be curb to curb - Connect any openings that are within 100 LF on any age street	Joint to joint to include concrete curbs @ existing concrete depth or 10" minimum- Install geotextile plus 8" 2A limestone & 3/4" dowels 18" apart	M&O exceeds PennDOT standards, Concrete Pavement, Permitting (Engineering Costs)	N/A
PA	2231	Edgeworth Borough	Base repair is 1" cuback @ 10" minimum - M&O 1.5" curb to curb with 50" cutback on streets less than 5 years old	Replace joint to joint matching existing depth - Install dowels every 12"	M&O exceeds PennDOT standards	N/A
PA	2231	Leetsdale Borough	Base repair is 1' cutback @ a minimum of 8.5" - M&O 1.5" curb to curb with a 50' cut back - Must connect 4 or more patches within a 100'	Replace joint to joint matching existing depth - Install dowels every 12" - Concrete sidewalk to be at 6" depth with window frame finish	M&O exceeds PennDOT standards, Concrete S/W Depth, Permitting (Engineering Costs)	N/A
PA	2231	Conway Borough	PennDOT	PennDOT	Permiting (Enginnering Costs)	Falls in line with PennDOT standards - restoration only
PA	2231	Emsworth Borough	Base repair is 1' cutback to match existing depth - M&O is to be at 3" depth curb to curb	PennDOT	M&O exceeds PennDOT standards	N/A
PA	2231	City of Pittsburgh	1' cutbacks on ditchline; 1.5" Curb to curb for roads paved within 5 years. --If older than 5 years -4" M/O on primary roads (bus routes); -3.5" M/O on secondary roads	Match existing depth/width to nearest joint. seal joints with caulking PennDOT	M&O exceeds PennDOT standards, Permitting Fees	N/A
PA	2231	New Sewickly Township	1' cuback to match existing depth	PennDOT	N/A	Return to original condition
PA	2231	Ellwood City Borough	Base repair is 1' cuback to match existing depth - M/O is 2.5" curb to curb	PennDOT	M&O exceeds PennDOT standards - Negotiable on Restoration	N/A
PA	2321	City of Brownsville	The permittee shall replace (asphalt, concrete, or brick topcoat or combination thereof) the roadway, including a 1' cutback, from curb to seam or curb to curb (if the seam is ?d) and 10'- beyond the opening in both directions except at an intersction or historical roadway. In the absence of curbs and for all single-lane road, the paved surface must be replaced the entire width of the paved surface to berm. Full lane restoration includes milling 1.5" off the existing roadway and placing 1.5" of 9.5 mm asphalt on the full lane of the roadway	Same	M&O exceeds PennDOT standards	N/A
PA	2321	California	1' cutback and 1 lane restoration for linear trenches 100' and greater. Curb to curb for any transverse crossing within 100'	Must replace same thickness from seam to seam.	Overlay from curb to curb on single tranverse cut is above PennDOT standards.	Falls in line with PennDOT standards
PA	2321	Redstone TWP	1'cutback and 1 lane restoration for linear trenches 100' and greater. Curb to curb for 2 or more transverse crossings within 100'		N/A	Falls in line with PennDOT standards
PA	2321	Centerville Borough	1' cutback and 1 lane restoration for linear trenches 100' and greater. Curb to curb for 2 or more transverse crossings within 100'		N/A	Falls in line with PennDOT standards

PA	TCC - LOCATION	Permit Type	Restoration Requirements - Asphalt	Restoration Requirements - Concrete	Restoration Requirements Above Penn Dot (Mill & Overlay ("M&O "), Base, Concrete, Etc)	Restoration Requirements Not Above PennDOT Standards
PA	2321	Charleroi	1' cut back and If at anytime, more than ten (10) percent of the square area, of any fifty (50) foot length of roadway in Charleroi Borough is opened, that whole fifty (50) foot length of road curb to curb shall be milled and resurfaced to the Borough's specifications.		M&O exceeds PennDOT standards	N/A
PA	2321	Connellsville TWP	Any Trench over 5 feet is curb to curb	Same	Asphalt M&O exceeds PennDOT standards	N/A
PA	2321	Connellsville City	1' cut back and 1 lane restoration for linear trenches 100' and greater. Curb to curb for 2 or more transverse crossings within 100'	8" of concrete joint to joint full lane width	N/A	Falls in line with PennDOT standards
PA	2321	South Connellsville	1' cutback and 1 lane restoration for any trenches over 10 ' and curb to curb for any crossings for length of excavation. Any trenches/Openings within 6' must be included.	same	Asphalt M&O exceeds PennDOT standards	N/A
PA	2321	South Union TWP	1' cut back and 1 lane restoration for linear trenches 10' and greater. Curb to curb for any 2 or more transverse crossing within 100'. 4 or more openings 100' apart will required curb to curb. Any patch within 5' of trench need to be inluded in work	Any cut over 4 feet - dowel required. 12" of concrete Joint to Joint	N/A	Falls in line with PennDOT standards
PA	2321	Uniontown City	1' cutback and 1 lane restoration for linear trenches 10' and greater. Curb to curb for any 2 or more transverse crossing within 100'. 4 or more openings 100' apart will required curb to curb. Any patch within 5' of trench need to be inluded in work	Any cut over 4 feet - dowel required. 12" of concrete Joint to Joint	N/A	Falls in line with PennDOT standards
PA	2321	North Union Twp	1' cutback and 1 lane restoration for linear trenches 10' and greater. Curb to curb for any 2 or more transverse crossing within 100'. 4 or more openings 100' apart will required curb to curb. Any patch within 5' of trench need to be inluded in work	Any cut over 4 feet - dowel required. 12" of concrete Joint to Joint	N/A	Falls in line with PennDOT standards
PA	2321	Luzerne	Any Excavation over 50' is curb to curb paving	Same	M&O exceeds PennDOT standards	N/A
PA	2321	Donora	1' cutback and 1 lane restoration for linear trenches 100' and greater. Curb to curb for 2 or more transverse crossings within 100' . 4 or more openings within 100' will require curb to curb.		N/A	Falls in line with PennDOT standards
PA	2321	Dunbar	Any excavation over 10 feet is curb to centerline then curb to centerline paving for length of excavation. Any excavation over 10' and on both sides of street is curb to curb for length of excavation.		N/A	Falls in line with PennDOT standards
PA	2321	Dunbar TWP	1' cutback and 1 lane restoration for linear trenches 100' and greater. Curb to curb for 2 or more transverse crossings within 100' . 4 or more openings within 100' will require curb to curb.	On concrete based streets, such base shall be replaced with concrete and the minimum size of the opening or excavation shall be sixteen (l 6) square feet.	N/A	Falls in line with PennDOT standards
PA	2321	East Bethlehem	1' cutback and curb to curb for length of distrubed area		M&O exceeds PennDOT standards	N/A
PA	2321	West Brownsville	1' cutback and curb to curb plus 10 feet for any opening	curb to curb plus 10 feet for any opening	M&O exceeds PennDOT standards	N/A
PA	2321	Menallen	1' cutback and 1 lane restoration for linear trenches 100' and greater. Curb to curb for 2 or more transverse crossings within 100' . 4 or more openings within 100' will require curb to curb.		N/A	Falls in line with PennDOT standards
PA	2321	Youngwood	If 10 excavations occur in one block within a three-year period, the applicant must mill and pave to Borough specifications the entire road surface within that block, during its required restoration. For purposes of this section, a "block" is defined as an area of roadway between cross streets or nearest intersections. Large projects of over 100 linear feet will be discussed during permit process (Typically PennDOT Standards)		M&O exceeds PennDOT standards	N/A

PA	TCC - LOCATION	Permit Type	Restoration Requirements - Asphalt	Restoration Requirements - Concrete	Restoration Requirements Above Penn Dot (Mill & Overlay ("M&O "), Base, Concrete, Etc)	Restoration Requirements Not Above PennDOT Standards
PA	2321	West Newton	overlay of the street with a I ½" wearing course from the centerline of the roadway to the curb for a minimum of 15-feet in each direction on either side of any street opening. In the event that a street opening would disturb on both sides of the centerline of a street the restoration will be required from curb to curb for a minimum of 15-feet in each direction on either side of any street opening.	The restoration of the concrete paved area shall include repairing the roadway from the centerline of the roadway to the curb for a minimum of 5-feet in each direction on either side of any street opening. In the event that a street opening would disturb on both sides of the centerline of a street the restoration will be required from curb to curb for a minimum of 5-feet in each direction on either side of any street opening.	N/A	Falls in line with PennDOT standards
PA	2321	Stockdale	1' cutback and 15' M/O on each side of excavation. Any street newer than 5 years must be curb to curb for length of excavation. Any street less than 18' is curb to curb.	8" -12" with Dowel joint to joint	M&O exceeds PennDOT standards	N/A
PA	2321	Somerset	1' cut back and any cut in single lane is M/O curb to centerline and any road cut in 2 lanes is curb to curb. 3 or more cuts within 150' for entire section of roadway for all openings		M&O exceeds PennDOT standards	N/A
PA	2321	Sewickley TWP	1' cut back and When a longitudinal opening is made in the pavement, the entire roadway width (curb to curb) shall be milled and overlaid with pavement approved by the Sewickley Township Public Works Department. When one or more transverse openings are made within 25 linear feet of pavement, the entire roadway width (curb to curb) shall be milled and overlaid with approved pavement within the total opening length, including those areas unexcavated. Whenever any utility or contractor shall make cuts in new pavement for purposes of replacing a main line on a street or part thereof or for purposes of making any capital improvements or improving or upgrading an existing system, or when any utility or contractor shall for any purposes, except emergency purposes, make a cut or cuts in new pavement totaling 90 square feet or more within any block in the Township, then the utility shall be required to backfill and permanently restore, refinish, mill and re-pave the entire width of sale street from curb to curb for the entire length of the block or blocks of said street or streets where there is located	Replace original wearing course joint to joint	M&O is excessive when compared to PennDOT requirements	N/A
PA	2321	Roscoe	1' cutback and bring roadway back to orginal condition	replace to exisiting condition	N/A	Return to original condition
PA	2321	Rices Landing	1' cutback and 1 lane restoration for linear trenches 100' and greater. Curb to curb for 2 or more transverse crossings within 100' . 4 or more openings within 100' will require curb to curb.	NA	N/A	Falls in line with PennDOT standards
PA	2321	Perryopolis	1' cutback and 2" of Overlay for the entire surface of asphalt roadways will be overlayed on all longitudinal cuts. Where numerous random utility cuts are made, the street or lane shall be resurfaced for its entire width, if so determined by the Borough Engineer. Work shall be completed by a Borough-approved paving contractor.	10" of concrete joint to joint	M&O exceeds PennDOT standards	N/A
PA	2321	North Huntington	1' cutback and 1 lane restoration for linear trenches 100' and greater. Curb to curb for 2 or more transverse crossings within 100' . 4 or more openings within 100' will require curb to curb.	10" of concrete joint to joint	N/A	Falls in line with PennDOT standards
PA	2321	Newell	2" of asphalt and he entire surface of asphalt roadways will be overlayed on all longitudinal cuts. Where numerous random utility cuts are made, the street or lane shall be resurfaced for its entire width, if so determined by the Borough Engineer	10" of concrete joint to joint	M&O exceeds PennDOT standards scope and thickness requirements	N/A
PA	2321	Masontown	3" of 19mm and 1.5'" M/o for any cuts or trenchs to restore roadway to orginal condition		M&O exceeds PennDOT standards	N/A
PA	2321	Point Marion	Curb to curb for any trench over 100'	Original Condition	M&O exceeds PennDOT standards	N/A
PA	2391	Canonsburg Borough	1' cutbacks on ditchline --1.5" M/O plus 30 ft on each end of base repair.	match exisitng	M&O exceeds PennDOT standards	N/A

PA	TCC - LOCATION	Permit Type	Restoration Requirements - Asphalt	Restoration Requirements - Concrete	Restoration Requirements Above Penn Dot (Mill & Overlay ("M&O "), Base, Concrete, Etc)	Restoration Requirements Not Above PennDOT Standards
PA	2221	Borough of Pleasant hills	1' cutbacks on ditchline 1.5" M/O curb to curb	match existing	M&O exceeds PennDOT standards	N/A
PA	2221	Bethel Park	1' cutbacks on ditchline 3.5" M/O one lane plus 30'	match existing	M&O exceeds PennDOT standards scope and thickness requirements	N/A
PA	2421	Spring Garden Twp	openings 10'L by 3' wide,2 transverse cuts in 100' less ,4 or more openings in 100' require overlay, roads 14'or less full overlay. 1' cutbacks ,3' or closer to curb ,go to edge ,patches within 5' include patch.	match existing	M&O exceeds PennDOT standards. New ordinance requires all permanent restoration within 90 days of opening	N/A
PA	2421	Red Lion Boro	openings 10 x 3' ,2 transverse or more in 100' 4 or more openings in100' require overlay,1' cut back,3' from edge ,go to edge,within 5' existing patch include patch	4" concrete side walk,6" driveways,5' joints.ada,every street corner.	M&O exceeds PennDOT standards and concrete requirements	N/A
PA	2421	North Codorus Twp	any openingrequires 100' overlay in either direction	match existing	M&O exceeds PennDOT standards requirements	N/A
PA	2421	Mt.Wolf	string line with 1' cutback' .remove material to 10 1/2" below finished street regardless of depth,4"crusher,5"base,1 1/2" Id wearing	meet existing	Asphalt/Base requirements exceed PennDOT standards	N/A
PA	2421	Manchester Twp	Compaction test required,1 test per street or every 100',Flowable fill may be required.1'cutback	meet existing	High level of compaction testing required.	Falls in line with PennDOT standards
PA	2421	York City	1' cut back,opening a road 5 years or newer,curb to curb overlay.	meet existing	N/A	Falls in line with PennDOT standards
PA	2421	Hanover Boro	1' cutback,longitude opening 100',2 transverse cuts in 100' require overlay	4" sidewalks,6" driveways	N/A	Falls in line with PennDOT standards
PA	2221	Brentwood	1' cutback, petromat layer before M/O. 1.5" M/O curb to curb plus 30' for roads less than 10 years old	match existing	M&O exceeds PennDOT standards	N/A
PA	2221	Dormont	1' cutbacks 1.5" M/O curb to curb. 60' minimum	match existing	M&O exceeds PennDOT standards	N/A
PA	2421	York Townsip	1' cutbacks,5 years or newer,longitudinal 100' ,2 or more transverse in 100' 4 or more in 100'overlay.regardless of age 2 or more in 100'longitudinal or transverse,overlay	match existing	N/A	Falls in line with PennDOT standards
PA	2221	Mt. Lebanon	1' cutbacks 1.5" M/O curb to curb plus 10' on each side	match existing	N/A	Falls in line with PennDOT standards
PA	2391	Canton Township	1' cutbacks on ditchline 1.5" M/O curb to curb plus 100' on each side. ** only additional 1' aroud on singular spot holes	match existing	M&O exceeds PennDOT standards	N/A
PA	2391	Oakdale	1' cutbacks on ditchline 1.5" M/O curb to curb plus 25 ft each side	match existing	M&O exceeds PennDOT standards	N/A
PA	2391	North Fayette	1' cutbcks on ditchline 1.5" M/O curb to curb plus 20'	match existing	M&O exceeds PennDOT standards	N/A
PA	2421	Gettysbury Boro	1' cut back,10 x 3 opening,2 or more transverse cutsin less than 100', 4 or more openings in less than 100' require overlay,25 mm superpave,9.5 superpave weAR 1 1/2"	match existing	N/A	Falls in line with PennDOT standards
PA	2451	Bellefonte	1' cut back,10x 3,2 or more transverse cuts in 100' ,4 or more in less than 100' require overlay.	match existing,portland cement-specific color in historic district.	N/A	Falls in line with PennDOT standards
PA	2451	Spring TWP	1' cut back, within 5' c/l require full overlay,2 or more cuts in 18 months require overlay	alter crosswalkor within row,required to upgrade ramp.not limited to that crosswalk, crosswalks in all intersection with letter of agreement.	M&O exceeds PennDOT standards	N/A
PA	2391	City of Washington	1' cutbacks on base repairs, 1.5" M/O the disturbed lane 10' on each side of base repair, M/O curb to curb if both lanes are disturbed	match existing	M&O exceeds PennDOT standards	N/A
PA	2221	Upper St Clair Twp	1' cutbacks on base repairs, 1.5" M/O the disturbed lane 30' on each side of base repair, any patches within 100' feet of each other must be connected in M/O plus 30' on each side	match existing	M&O exceeds PennDOT standards	N/A
PA	2391	North Strabane Twp	1' cutbacks on base repairs, 1.5" M/O the disturbed lane 15' on each side of base repair, any patches within 75' of each other must be connected in M/O plus 15' on each side	match existing	M&O exceeds PennDOT standards	N/A

PA	TCC - LOCATION	Permit Type	Restoration Requirements - Asphalt	Restoration Requirements - Concrete	Restoration Requirements Above Penn Dot (Mill & Overlay ("M&O "), Base, Concrete, Etc)	Restoration Requirements Not Above PennDOT Standards
PA	2391	Peters Twp	1' cutbacks on base repairs, 1.5" M/O the disturbed lane 30' on each side of base repair, any patches within 100' of each other must be connected in M/O	match existing	M&O exceeds PennDOT standards	N/A
PA	2221	County of Allegheny	1' cut backs on base repairs, 2" M/O the disturbed lane 10' on each side of base repair, any trench opening across the full width of the roadway must be M/O 2" deep curb to curb 30' on each side	match existing	M&O thickness and opening requirments exceed PennDOT standards	N/A
PA	2221	Stowe Twp	1' cut backs on base repairs, 1.5" M/O the disturbed lane 25' on each side of base repair	match existing	25' on each side of base repair is above PennDOT standards	Falls in line with PennDOT standards
PA	2221	Greentree Borough	1' cut backs on base repairs, 1.5" M/O 5' on each side of base repair full width of the roadway	match existing	N/A	Falls in line with PennDOT standards
PA	2391	Cecil Twp	1' cut backs on base repairs, 1.5 " M/O full width of the street, length determined by authorized township representative with 60 lineal feet being the minimum	match existing	M&O exceeds PennDOT standards	N/A

COLUMBIA STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
JENNIFER HARDING
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

Q. Please state your name and business address.

A. My name is Jennifer Harding. My business address is 290 W. Nationwide Blvd, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is VP Tax at NCSC.

Q. What are your responsibilities as Income Tax Manager?

A. In my current position as VP Tax, I am responsible for all tax matters for NiSource, Inc., and its subsidiaries, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"). My responsibilities include oversight of the income and indirect tax accounting and reporting, forecasting income and indirect taxes, preparation and filing income and indirect tax returns, technical income tax research, tax planning, income and indirect tax audits and review and implementation of federal and state tax legislation.

Q. What is your educational and professional background?

A. I earned a B.A. in Business Administration with a concentration in Accounting in 2007 from the Notre Dame of Maryland University in Baltimore, Maryland. I began my career with KPMG in Baltimore, Maryland in 2005. In 2009, I joined Constellation Energy as a Tax Manager responsible for all aspects of income tax and non-income tax for the generation segment and managed the IRS Federal tax audit Compliance Assurance Process program. Constellation was acquired by Exelon Corporation in 2012 and I served as the Tax Manager of the regulated

electric utility in Chicago, Illinois responsible for income tax accounting, forecasting income taxes, and income tax and non-income tax return filings. In 2014, I worked as the Tax Manager for Mead Johnson Nutrition BV for the European region with responsibility for all aspects of income tax and non-income tax accounting, tax research and tax return filings. In 2016, I worked for Cardinal Health in Columbus, Ohio as the Director of International Tax Operations with a responsibility for income tax accounting, forecasting, mergers & acquisitions, tax research, and tax return filings in Cardinal Health's foreign jurisdictions. In 2018, I worked as the Head of Tax for Hyperion Materials & Technologies with full responsibility for all global income and non-income tax accounting, tax return filings, research, mergers & acquisitions, and forecasting. In January 2020, I joined NiSource as the Director of Income Tax Operations and was promoted to VP Tax in February 2023.

Q. Have you previously testified before this or any other regulatory commission?

A. Yes, I previously testified before the Pennsylvania Public Utility Commission ("Commission") in Columbia's most recent rate case at Docket No. R-2022-3031211. I have also previously testified in proceedings before the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Maryland Public Service Commission, the Public Utilities Commission of Ohio, and the Virginia State Corporation Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to present and support Columbia's income

tax and other tax expense included in the cost of service. The filing includes federal and state income tax recovery, reduction of rate base for deferred income taxes and incorporation of the effects of the enacted Tax Cuts and Jobs Act of 2017. The income tax calculations are included in Exhibit 7 for the Historic Test Year (the twelve-month period ending November 30, 2023) and Exhibit 107 for the Future Test Year (the twelve-month period ending November 30, 2024) and Fully Projected Future Test Year (the twelve-month period ending December 31, 2025). Taxes other than income tax are included in Exhibit 6 for the Historic Test Year and Exhibit 106 for the Future Test and Fully Projected Future Test Year.

Q. Will you explain the basis for the income tax calculations for the Historic Test Year?

A. The tax calculations were made in accordance with federal and state laws. The federal tax rate in effect for the Historic Test Year is 21%. The federal tax rate of 21% has also been reflected for the Future Test Year and the Fully Projected Future Test Year. The Historic Test Year tax calculations have been impacted by certain items that have been historically treated as flow-through or deferred in rate making proceedings.

Q. Has the Company recognized the reduction of Pennsylvania corporate net income tax rate in the state income tax expense?

A. Yes, H.B. 1342 was signed into law on July 8, 2022. The legislation decreases the corporate income tax rate from 9.99% to 8.99% in 2023, 8.49% in 2024 and 7.99% in 2025.

Q. Can you explain the deficient accumulated deferred income taxes

recognized and flow-through items included in the tax provision and impacts of the Pennsylvania H.B. 1342?

A. Yes, the Company also has non-property related deferred taxes on customer advances and inventory that have been normalized in rate base for federal and state purposes. The Company remeasured the accumulated deferred state taxes from 9.99% over the 9-year reduction to 4.99% in 2031 and recognized the deficient deferred tax of $1,782,085 (before gross-up) recorded to a regulatory asset. The Company proposes to recognize the flow-through impact to tax expense over a ten-year amortization in the Fully Projected Future Test Year, which represents deficient deferred tax expense of $178,209 per year (See Exhibit 107, Pg 16, Column 4, Line 30 for the flow back of net Excess Deferred Taxes of ($2,370,454) which represents this amount, plus TJCA excess deferred taxes for plant/property of ($3,747,017) and deficient deferred taxes for the Federal NOL of $571,394 and inventory/customer advances of $626,961 discussed below).

Q. Can you explain the flow-through items included in the tax provision and impacts of the TCJA of 2017?

A. Prior to 1981, federal tax statutes did not require full normalization of accelerated tax depreciation versus book straight line depreciation recovered in rates. Beginning in 1981, the normalization method of accounting prevents utilities from recognizing a reduction in current taxes resulting from the application of accelerated tax depreciation to be immediately recognized as flow-through to utility ratepayers under the Internal Revenue Code. Such benefits must be provided for in a deferred tax reserve, and that reserve may be allowed as a rate base reduction. Prior to 1984,

the Company flowed-through the benefits of accelerated depreciation for vintage years prior to 1981. Beginning in 1984, the Company began to normalize the remaining book versus tax differences on Asset Depreciation Range vintages (1971 through 1980) based upon the Commission's order in Docket No. R-832493. For the Historic Test Year, the Company has very little in terms of tax depreciation remaining on pre-1981 assets. Thus, Columbia is in a turnaround position, since book depreciation is now higher than tax depreciation. In addition, the Company has excess accumulated deferred income taxes that were originally computed at higher federal tax rates (namely 46% federal tax rate for asset vintages 1981-1987 and 35% federal tax rate for asset vintages 1988-2017) compared to the current corporate income tax rate of 21%, a result of the enactment of TCJA of 2017, that are being refunded in rates under the Average Rate Assumption Method ("ARAM"). ARAM is the method under which the excess in the reserve for deferred income taxes is reduced over the remaining lives of the property as used in its books of account that gave rise to the reserve for deferred income taxes and flow-through the amortization of the excess accumulated deferred income taxes. Because most of the book versus tax differences related to assets that were 15- or 20-year property for federal tax purposes and there were multiple years of bonus depreciation since 2001, the excess is in a turnaround situation. There is a variable nature inherent in ARAM, which does not result in an amount that is fixed in every period due to factors such as changes in capital additions, depreciation rates, future retirements, and the vintages of those retirements. The Company projects to record lower tax expense of $3,747,017 in its federal tax provision related to the excess accumulated deferred

income taxes on asset vintages 1981-2017 for the Fully Projected Future Test Year.

Q. Are there any other deferred taxes that are impacted by the TCJA?

A. Yes, the Company also has deferred taxes for the Federal net operating loss ("NOL"), customer advances, inventory, and other book vs. tax timing differences. The federal rate reduction creates net deficient deferred taxes that were originally computed at a 35% federal tax rate for these assets that are reversing at a 21% federal tax rate. For the Federal NOL, the Company includes the recovery of the deficient deferred taxes over the estimated remaining life of the assets of 42 years based on a composite book depreciation rate of 2.4% as included in the last base rate case and projects to record higher tax expense in the amount of $571,394 for the Fully Projected Future Test Year. For the non-property related deferred taxes on customer advances and inventory that are included in the calculation of rate base, the Company projects to record higher tax expense in its federal tax provision by $626,961, using a ten-year amortization period for the Fully Projected Future Test Year. The remaining non-property deferred taxes on book vs. tax timing differences are a net deferred tax asset which results in net deficient deferred taxes because of TCJA. It is the Company's position that because those deferred taxes were not included in the calculation of rate base, the Company is not seeking recovery of the deficient deferred taxes resulting from the decrease in the federal income tax rate.

Q. Does the Company intend to recognize a change in accounting method to adopt the natural gas safe harbor ("NGSH") method issued under Revenue Procedure 2023-15 consistent with the 2008 change in method of accounting for repairs impact Columbia's taxable income in the rate-

making process?

A. Yes, the Company is in the process of reviewing and quantifying the provisions of the safe harbor method for taxpayers with natural gas transmission and distribution property and expects to adopt the method on the 2023 tax return due on or before the extended due date of October 15, 2024. The federal repairs deduction will be normalized under deferred tax accounting, so there will be no impact on total federal tax expense. However, the repairs deduction has not been normalized for state income tax purposes, based on prior Commission orders, and is expected to be recognized as flow-through for state tax purposes and is reflected in the state tax expense. Since the Columbia recognized a method change in 2008 to deduct qualified costs as deductible repairs, the Company does not expect material impact to adopt the NGSM method.

Q. Are there any other items treated as flow-through in the rate-making process?

A. Yes. The Company continues to reduce its income tax allowance for the net cost of retirements, which is allowed as a deduction on its tax return. In addition, there are three permanent differences included in the tax provision. A permanent difference results when revenue (gain) or expense (loss) is recognized in book accounting but not recognized under the rules of the Internal Revenue Code, or vice versa. Permanent items increasing tax expense are non-deductible expenses for business meals and employee stock purchase plan compensation included in the total flow-through adjustments on Exhibit 107, Page 16, Line 11.

Q. How has the Company handled Pennsylvania Corporate Net Income

Taxes in its calculation of deferred income taxes for property?

A. The Company, based on prior Commission orders, has not normalized deferred state income taxes. The Company continues to flow-through the state income tax benefits of accelerated depreciation on its book depreciable assets. The Company was not permitted to claim the benefit of Federal bonus depreciation deductions that have been taken in years prior to 2018 in the Pennsylvania corporate tax and recognizes a state modification for accelerated tax deductions in future years for previously-disallowed bonus depreciation.

Q. Does the Company expect to fully utilize the Pennsylvania net operating loss carryforward in the Fully Projected Future Test Year?

A. Yes. The Company had a $144,975,996 net operating loss for 2008 that was carried forward to future years. In October 2017, the Pennsylvania Supreme Court held that the flat-dollar cap on the NOL deduction violated the Uniformity Clause of the Pennsylvania Constitution[1] thereby affirming the Commonwealth Court of Pennsylvania decision in 2015[2]. The Pennsylvania Supreme Court ordered that the flat-dollar cap of $5 million be removed. In anticipation of the Pennsylvania Supreme Court ruling, the Pennsylvania House of Representatives passed House Bill ("HB") 542, which included a provision that removed the $5 million cap on NOL deductions and increases the then-current cap of 30% of taxable income to 35% for tax year 2018 and 40% for tax year 2019 and future years. On October 30, 2017, Pennsylvania Governor Tom Wolf signed HB542 into law. In response to the

[1] *Nextel Communications of the Mid-Atlantic, Inc. v. Commonwealth*, 171 A.3d 682 (Pa. 2017).
[2] *Nextel Communications of the Mid-Atlantic, Inc., v. Commonwealth*, 129 A.3d 1 (Pa. Commw. 2015).

decision, the Pennsylvania Department of Revenue has revised its forms and procedures to eliminate the $5 million flat-dollar cap. The Company's computed state tax expense considers the NOL limitation of 40% of state taxable income in the Historic Test Year and Future Test Year. However, the remaining Pennsylvania net operating loss is less than 40% of state taxable income in the Fully Projected Future Test Year (Exhibit 107, Page 17, Line 6). The Pennsylvania NOL carryforward is reflected on Exhibit 7, Page 23 depicting the Pennsylvania NOL carryforward is fully utilized in the Fully Projected Future Test Year.

Q. How does the utilization of the Pennsylvania NOL carryforward impact the revenue gross-up factor computed on Exhibit 102, Schedule 3 for the fully projected future test year ending December 31, 2025?

A. The benefit of the Pennsylvania NOL has been included in the revenue gross up factor presented on Exhibit 102, Schedule 3, Page 5, Line 12 by reducing the Pennsylvania state income tax rate of 7.99% to 6.85% (7.99% multiplied by 85.79%).

Q. Does the Company's proposed revenue requirement reflect a consolidated tax adjustment?

A. No. The passage of Act 40, 66 Pa. C.S. § 1301.1, which became effective August 10, 2016, eliminated the consolidated tax adjustment in ratemaking. Title 66 of the Pennsylvania Consolidated Statues Section 1301.1 states that 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 computation of income tax expense to reduce rates. However, Section 1301.1(b) requires a public utility seeking

to change rates to demonstrate that it shall use at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent shall be used for general corporate purposes. The Company prepared Exhibit No. 7, Pages 2 through 4 for the computation of the Section 1301.1 differential and details of the income and losses of affiliated companies for the periods 2020 to 2022. The Company computed what the consolidated tax expense adjustment would have been by dividing the 3-year average of Columbia's Federal taxable income of $74.7 million by the 3-year average of the Federal taxable income of the consolidated group members with taxable income of $643.7 million to determine the percentage of Columbia's income of 12%. This percentage was multiplied by the 3-year average of Federal taxable loss of the adjusted consolidated group members with taxable loss of $280.5 million. Columbia's allocation of Federal taxable loss companies is $32.5 million tax effected at 21% resulting in a Section 1301.1(b) differential of $6.8 million.

Q. Does the Company's rate case claim support the conclusion that it is using at least 50 percent of the amount that would have been a consolidated tax adjustment prior to Act 40 to support reliability or infrastructure related capital investment?

A. Yes, as depicted in GAS-RR-014, Attachment A and discussed in the direct testimony of Columbia Witness Covert (Columbia St. No. 11), Columbia's pro forma capital additions for reliability or infrastructure projects (Replacement Age & Condition) are $330.1 million in the FTY and $308.6 million in the FPFTY. This expenditure

level is greater than $3.4 million (50% of the $6.8 million Section 13.01.1(b) differential) that would have been a consolidated tax adjustment prior to Act 40 of 2016.

Q. Does the Company's rate case claim support the conclusion that it is using at least 50 percent the amount that would have been a consolidated tax adjustment prior to Act 40 to support the amount of the revenue requirement attributed to general corporate purposes?

A. Yes, as depicted in Exhibit 102, Schedule 3, Page 3, Line 19 and discussed in direct testimony of Columbia Witness Komenda (Columbia St. No. 4), Columbia's pro forma operating and maintenance budget is $223.4 million in the FTY and $219.5 million in the FPFTY. This expenditure level is greater than $3.4 million (50% of the $6.8 million 13.01.1(b) differential) that would have been a consolidated tax adjustment prior to Act 40 of 2016.

Q. Can you summarize the impact of your testimony on historic and proposed income tax expense?

A. Yes, for the Historic Test Year, Exhibit 7, Page 19, Line 34 delineates total pro forma tax expense of $53,171,452. This total includes $7,046,156 of state income taxes (Exhibit 7, Page 19, Line 33), which is based on $305,366,636 of operating income (Exhibit 7, Page 19, Line 1) less $67,234,278 of interest expense on debt (Exhibit 7, Page 19, Line 5) for total pre-tax income of $238,132,358 resulting in an effective state income tax rate of 2.96%. The reduced state effective tax rate, as compared to the Pennsylvania statutory rate of 8.99%, is a result of the flow through treatment of repairs deductions and Pennsylvania net operating loss carryforward deductions for

state income tax purposes. The expense for federal income taxes is $46,125,296 (Exhibit 7, Page 19, Line 32) resulting in an effective tax rate of 19.37%. The decreased federal effective tax rate, as compared to the federal statutory rate of 21%, is largely attributable to the flow-through of the amortization of excess accumulated deferred income taxes related to the reduction of the corporation federal income tax rate from 35% to 21% as a result of the enactment of TCJA of 2017.

Q. Please continue with respect to the Fully Projected Future Test Year.

A. For the Fully Projected Future Test Year, Exhibit 107, Page 16, Line 34 delineates total income tax expense of $65,154,238. This total includes $8,798,541 of state income taxes (Exhibit 107, Page 16, Line 33), which is based on $368,932,554 of operating income (Exhibit 107, Page 16, Line 1) less $80,946,832 of interest expense on debt (Exhibit 107, Page 16, Line 5) for total pre-tax income of $287,985,722 resulting in an effective state income tax rate of 3.06%. The reduced state effective tax rate, as compared to the Pennsylvania statutory rate of 7.99%, is a result of the flow through treatment of the repairs deductions and flow through deductions for bonus depreciation that was disallowed in prior years for state income tax purposes. The Company notes that the remaining Pennsylvania net operating loss carryforward of $17,381,305 (Exhibit 107, Page 17, Line 6 and Exhibit 7, Page 23) is fully utilized in the Fully Projected Future Test Year. The expense for federal income taxes is $56,355,697 (Exhibit 107, Page 16, Line 32) resulting in an effective tax rate of 19.57%. The decreased federal effective tax rate, as compared to the federal statutory rate of 21%, is largely attributable to the flow-through of the amortization of excess accumulated deferred income taxes related to the reduction of the

corporation federal income tax rate from 35% to 21% as a result of the enactment of TCJA of 2017.

Q. How have taxes impacted the Company's rate base?

A. Exhibit 107, Page 5, delineates the reduction in rate base for Federal deferred income taxes and federal excess deferred income taxes. The amounts include deferred taxes on net utility plant that have or will be normalized by the end of the Fully Projected Future Test Year, as well as federal and state deferred taxes on inventory and customer advances.

Q. How has the deduction for 263A mixed service costs impacted deferred taxes in rate base?

A. As agreed in the Commission-approved settlement of Columbia's 2012 rate case (R-2012-2321748), the Company is authorized to normalize this deduction for federal income taxes and treat the deferred taxes as a reduction to rate base. The adjustment can be found on Exhibit 107, Page 16, Line 16.

Q. Is there an inclusion of deferred taxes for the Federal Net Operating Loss in rate base?

A. In the Historic Test Year, the deferred tax asset for the Federal NOL, which represents the remaining balance of un-utilized net operating loss, is $ 38,402,447 as shown in Exhibit 7, Page 9, Line 6 and deficient deferred taxes of $24,304,286 as shown in Exhibit 7, Page 9, Line 46 attributed to the remeasurement of the federal income tax rate to 21% under TCJA. The Company has incurred a tax loss for federal purposes in tax years 2008, 2010, 2011, 2012, 2013, 2016, and 2017, as a result of taking deductions for 50-100% bonus depreciation, resulting in the deferred tax

asset being recorded for the un-utilized net operating losses. The deferred tax asset represents the cash benefits the Company has not received because of the net operating losses. The deferred tax asset is included in rate base because the Company cannot reflect an increase in deferred taxes for tax depreciation deductions that have not been realized. To do so would violate the principles of the normalization requirements under the Internal Revenue Code. Past IRS rulings addressing this issue have made it clear that companies cannot reduce rate base for benefits that have not been realized. The deferred tax asset for the un-utilized net operating losses for the Fully Projected Future Test Year is primarily due to repairs and accelerated depreciation deductions. Due to the net operating losses generated by bonus depreciation deductions in the aforementioned years and the modifications to the Federal NOL under the TCJA, the expectation is that the Company will not utilize all of its net operating losses until beyond the Fully Projected Future Test Year. Therefore, there is an increase to rate base on Exhibit 107, Page 5a.2, Line 6 of $33,332,857 as a deferred tax asset for the unutilized Federal net operating loss carryforward and deficient deferred taxes of $21,807,713 as shown in Exhibit 107, Page 5a.2, Line 46 attributed to the remeasurement of the federal income tax rate to 21% under TCJA for the Fully Projected Future Test Year.

Q. Please explain the adjustment to deferred taxes for the Fully Projected Future Test Year on Exhibit 107, Page 5.

A. Whenever there are estimated changes in the deferred taxes that occur in a future rate period, the Normalization requirements of the Internal Revenue Code require that the deferred taxes be reflected on a pro rata basis as provided under Reg. Section

1.167(l)-1(h)(6)(ii). A future test period is defined as that portion of the test period after the effective date of the rate order. Under the pro rata basis, the change in the deferred taxes is determined by multiplying the change by a fraction of the number of days remaining in the period at the time such change is to be accrued over the total number of days in the future period. Applying this calculation resulted in a decrease to deferred taxes of $17,044,074 computed on Exhibit 107, Page 5b.

Q. Are you sponsoring any other expense adjustments?

A. Yes. I am also sponsoring adjustments for Federal Insurance Contribution Act ("FICA") Tax, Property Tax, and License and Franchise Tax. These adjustments are delineated on Exhibits 6 for the Historic Test Year and 106 for the Future Test Year and Fully Projected Future Test Year.

Q. Please explain the FICA adjustment.

A. The adjustment represents an increase in FICA taxes as they apply to the labor charged to O&M (See Exhibit No. 4, Schedule 1, Page 2 Lines 1 and 2). A decrease in payroll taxes of $88,063 is reflected in the annualized Historic Test Year presented on Exhibit No. 6, Schedule 2, Page 3 for the calculation. For the Fully Projected Future Test Year, the Company is projecting a higher payroll base, thus increasing payroll taxes by $53,671 as reflected on Exhibit No. 106, Schedule 2, Page 3 for the calculation.

Q. Please explain the property tax adjustment.

A. The PURTA tax and the locally assessed property tax on Pennsylvania property are both consistent with the most recent year-end tax levels as of December 31, 2022. The West Virginia tax for gas stored underground was developed using the

December 31, 2023 assessed value and the 2022 tax rate. This annualized level is increased compared to the Historic Test Year level of $692,641, as shown on Exhibit 6, Schedule 2, Page 4, Line 6. The detail supporting this calculation for the Fully Projected Future Test Year is provided on Exhibit 106, Schedule 2, Page 4. The pro forma Fully Projected Future Test Year reflects an upward adjustment of $289,680 from the annualized level primarily as a result of the increased West Virginia stored gas December 31, 2023 assessed value and the 2023 tax rate which is the latest available at this time.

Q. Please explain the Other Tax adjustment on Exhibit 106, Schedule 2, Page 2.

A. Other taxes are primarily comprised of excise tax. The annualized level of $3,019 was not adjusted for the Historic Test Year. The pro forma Fully Projected Future Test Year was also not adjusted from this level.

Q. Does this conclude your testimony?

A. Yes.

COLUMBIA STATEMENT NO. 10-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
JENNIFER HARDING
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

I. Introduction

Q. Please state your name and business address.

A. My name is Jennifer Harding. My business address is 290 W. Nationwide Blvd, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is VP Tax at NCSC.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the direct testimony of Witness Greg R. Meyer, submitted on behalf of the Office of Consumer Advocate ("OCA") concerning exclusion of a correlating reduction in Accumulated Deferred Income Tax ("ADIT") adjustment related to his proposed reduction in the Company's Plant in Service served in this proceeding. Additionally, I will respond to Witness Meyer's proposed increase to synchronized interest, the exclusion of the impact on rate base for OCA Witness Brian C. Andrews' proposed reduction of depreciation expense and the statutory tax rate Witness Meyer used to compute the tax effect of changes to operating earnings before tax.

Q. Do you agree with OCA Witness Meyer's exclusion of a corresponding reduction in ADIT related to the proposed Plant in Service adjustment?

A. No, Mr. Meyer proposes to reduce Plant in Service by $41 million based on the Company's budget to actual data from January 2024 to March 2024. (OCA Statement No. 2, Exhibit No. 1, p. 2). However, he does not include a corresponding adjustment to ADIT. The Company notes that tax deductions are normalized, resulting in current deduction offset by a future taxable temporary difference creating a deferred tax liability and net zero tax expense. The proposed reduction of plant additions results in the reversal of the current deduction, and reversal of the offsetting future taxable temporary difference. Any adjustment, or reduction in ADIT, associated with a change to the plant in service claimed by the Company should represent the adjusted book/tax difference tax effected at the Federal income tax rate of 21%. To the extent that the Company's forecasted plant additions are reduced, the Company has prepared a computation to determine the correlating reduction in ADIT of $1,123,725 as seen in Schedule JH-10R, pages 1 and 2. Columbia Witness Spanos' rebuttal testimony depicted that OCA Witness Andrews ignored the impact of the reduction of depreciation expense of $44,493,909 million (OCA Statement No. 2, Exhibit No. 1, p. 7) as an increase to rate base, which would result in a corresponding increase of ADIT of ($9,343,721) depicted on Schedule JH-10R, Page 4.

Q. Do you agree with OCA Witness Meyer's adjustment to increase synchronized tax-deductible interest expense and decrease Federal and state income taxes?

A. No, I do not. OCA computed an increase of synchronized tax-deductible interest expense of approximately $6.6 million as a result of a proposed decrease in rate

base of approximately $41 million and an increased weighted cost of debt rate of 2.54% (OCA Statement No. 2, Exhibit No. 1, p. 8). The increased weighted cost of debt results from OCA's proposal to adopt a hypothetical capital structure with 50% debt, rather than the Company's actual capital structure proposed by Mr. Moul. As indicated in Columbia Witness Covert's rebuttal testimony, the Company disputes the reduction to rate base attributed to reduced capital additions and materials & supplies proposed by OCA Witness Meyer. As indicated above, Columbia Witness Spanos' rebuttal testimony depicted that OCA Witness Andrews ignored the impact of the reduction of depreciation expense on rate base. Furthermore, Columbia Witness Moul's rebuttal testimony disputes the proposed hypothetical capital structure as proposed by OCA Witness Walters. Therefore, the weighted cost of debt should remain at 2.54%. Consequently, the Company disputes the resulting decrease of Federal and state income tax proposed by OCA Witness Meyer of approximately $1.81 million, respectively.

Q. Do you agree with the tax rate OCA Witness Meyer's used to tax effect his adjustments to Federal and state income taxes?

A. No, I do not. The Company disputes the tax rate of 27.48% that Witness Meyer used to compute the interest and tax effect for the Fully Projected Future Test Year. (OCA Statement No. 2, Exhibit No. 1, p. 8). The Federal and Pennsylvania tax rate for the twelve months ending December 31, 2025 are presented below.

Federal tax rate	21.00%
Pennsylvania tax rate	7.99%
Federal benefit	(1.68%)

Total Statutory rate 27.31%

Furthermore, the tax effect of the proposed decrease in book depreciation is a temporary difference that is subject to normalization for Federal tax purposes but is treated as flow-through for state tax purposes as depicted in Schedule JH-10R, Page 3.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.
PLANT ADDITIONS
COMPUTATION OF ADIT ADUSTMENT
($000)

Line No.	Description	Ref	FPFTY at Current Rates
			(1)
	Computation by OCA		
1	Plant Additions, per OCA		$ 3,908,164,462
2	Plant Additions, per Company		3,949,617,853
3	Adjustment to Plant in Service	OCA GM Exh 1, Pg 2	(41,453,391)
4	Adjustment to Depreciation Reserve	OCA GM Exh 1, Pg 2	-
5	Adjustment to ADIT	OCA GM Exh 1, Pg 2	-
	Computation of ADIT by Columbia		
6	Reduction in Plant in Service	= Line 3	$ (41,453,391)
7	Bonus Depre	= Line 28	-
8	Plant in Service Basis after Bonus		(41,453,391)
9	Repairs Deduction	= Line 27	1,004,393
10	Plant in Service Basis after Repairs		(40,448,998)
11	MSC Deduction	= Line 29	21,645
12	Plant in Service Basis after MSC		(40,427,353)
13	MACRS Depreciation (20yr) - 1st Year	3.75%	1,516,026
14	Plant in Service Basis after MSC		(38,911,327)
15	MACRS Depreciation (20yr) - 2nd Year	7.22%	2,809,009
16	Remaining Plant in Service Basis		(36,102,318)
17	Total Tax Deduction	= Sum Lines 8, 10, 12, 14, 16	5,351,073
18	Total Book Depreciation Addback	= Line 4	-
19	Net Book/Tax Difference	= Sum Line 18 and 19	5,351,073
20	Federal Tax Rate		21.00%
21	Reduction in ADIT	= Line 21 * Line 22	$ 1,123,725
22	Difference between OCA Proposed Adjustment and the Company		
	Computation of Repairs and MCS % by Columbia		
23	Repairs on Gas Pipeline	Exhibit 107, Page 16, Line 14	(95,697,121)
24	Bonus Depreciation	Exhibit 107, Page 16, Line 15	-
25	Sec 263A Mixed Service Costs	Exhibit 107, Page 16, Line 16	(2,113,494)
26	Repairs on Gas Pipeline	= Line 24 / Line 2	2.42%
27	Bonus Depreciation	= Line 25 / Line 2	0.00%
28	Sec 263A Mixed Service Costs	= Line 26 / Line 2	0.05%

COLUMBIA GAS OF PENNSYLVANIA, INC.
PLANT ADDITIONS
TAX DEPRECIATION MACRS TABLE
($000)

Table A-1 3-, 5-, 7-, 10-, 15-, and 20-year Property Half Year Convention

Line No.	Year	Depreciation rate for recovery period					
		3-year	**5-year**	**7-year**	**10-year**	**15-year**	**20-year**
		(1)	(2)	(3)	(4)	(5)	(6)
1	1	33.33%	20.00%	14.29%	10.00%	5.00%	3.750%
2	2	44.45%	32.00%	24.49%	18.00%	9.50%	7.219%
3	3	14.81%	19.20%	17.49%	14.40%	8.55%	6.677%
4	4	7.41%	11.52%	12.49%	11.52%	7.70%	6.177%
5	5		11.52%	8.93%	9.22%	6.93%	5.713%
6	6		5.76%	8.92%	7.37%	6.23%	5.285%
7	7			8.93%	6.55%	5.90%	4.888%
8	8			4.46%	6.55%	5.90%	4.522%
9	9				6.56%	5.91%	4.462%
10	10				6.55%	5.90%	4.461%
11	11				3.28%	5.91%	4.462%
12	12					5.90%	4.461%
13	13					5.91%	4.462%
14	14					5.90%	4.461%
15	15					5.91%	4.462%
16	16					2.95%	4.461%
17	17						4.462%
18	18						4.461%
19	19						4.462%
20	20						4.461%
21	21						2.231%
22		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

COLUMBIA GAS OF PENNSYLVANIA, INC.
COMPUTATION OF INCOME TAXES

Line No.	Description	Ref	FPFTY at Present Rates	Ref	Adjustment	FPFTY at Present Rates
			(1)		(2)	(3) = (1 + 2)
1	Operating Income Before Income Taxes	Exh 102, Sch 3, Pg 3	246,582,180	OCA GM Exh 1, Pg 4	62,891,805	$ 309,473,985
2	Pennsylvania Corporate Net Income Tax Deductible (Below)	Exh 107, Pg 16	(411,513)		0	0
3	***Statutory Adjustments***					
4	Flow-Through Adjustments					
5	Interest on Debt (1)	Exh 107, Pg 16	(80,946,832)	OCA GM Exh 1, Pg 8	(6,595,281)	(87,542,112)
6	Employee Business Expense Disallowance	Exh 107, Pg 16	392,636		-	392,636
7	AFUDC Equity	Exh 107, Pg 16	0		-	0
8	Employee Stock Purchase Plan	Exh 107, Pg 16	45,029		-	45,029
9	NCS Allocation- Perm Taxes	Exh 107, Pg 16	0		-	0
10	Parking	Exh 107, Pg 16	23,493		-	23,493
11	Total Flow Through Adjustments	Exh 107, Pg 16	(80,485,674)		(6,595,281)	(87,080,954)
12	***Deferred Adjustments***					
13	Excess Tax Depreciation Over Book	Exh 107, Pg 16	(60,579,196)	OCA GM Exh 1, Pg 7	(44,493,909)	(105,073,105)
14	Repairs on Gas Pipeline	Exh 107, Pg 16	(86,559,688)		-	(86,559,688)
15	Bonus Depreciation	Exh 107, Pg 16	-		-	-
16	Sec 263A Mixed Service Costs	Exh 107, Pg 16	(1,977,361)		-	(1,977,361)
17	Loss on Retirement - ACRS/MACRS Property Basis	Exh 107, Pg 16	-		-	-
18	Avoided Cost Interest	Exh 107, Pg 16	-		-	-
19	Builder Incentives Capitalized	Exh 107, Pg 16	-		-	-
20	Stored Gas Losses	Exh 107, Pg 16	-		-	-
21	Contributions In Aid of Construction	Exh 107, Pg 16	-		-	-
22	Tax Inventory Adj	Exh 107, Pg 16	-		-	-
23	Capitalized Inventory	Exh 107, Pg 16	-		-	-
24	Customer Advances	Exh 107, Pg 16	-		-	-
25	Total Deferred Adjustments	Exh 107, Pg 16	(149,116,245)		(44,493,909)	(193,610,154)
26	Taxable Income	Exh 107, Pg 16	16,568,749		11,802,615	28,782,877
27	Federal Income Tax Payable @ 21%	Exh 107, Pg 16	3,479,437		2,478,549	6,044,404
28	Deferred Income Taxes	Exh 107, Pg 16	31,314,411		9,343,721	40,658,132
29	Tax Refund Amortization	Exh 107, Pg 16	-		-	-
30	Flow Back Of Excess Deferred Taxes	Exh 107, Pg 16	(2,370,454)		-	(2,370,454)
31	Effect of CNIT Deferred Tax on FIT	Exh 107, Pg 16	-		-	-
32	Net Federal Income Tax Expense	Exh 107, Pg 16	32,423,394		11,822,270	44,332,082
33	State Income Tax Expense (Below)	Exh 107, Pg 16	411,513		943,029	1,354,542
34	Income Tax Expense (Before Investment Tax Credit)	Exh 107, Pg 16	32,834,907		12,765,299	45,686,624
35	Investment Tax Credit	Exh 102, Sch 3, Pg 3	(121,211)			(121,211)
36	**Total Income Tax Expense**	Exh 102, Sch 3, Pg 3	**32,713,696**		**12,765,299**	**45,565,413**
37	**Operating Income**	Exh 102, Sch 3, Pg 3	**213,868,484**		**50,126,506**	**263,908,572**
38	Rate Base	Exh 107, Pg 16	3,489,087,567		(42,547,711)	3,446,539,856
39	Weighted cost of LT Debt	Exh 107, Pg 16	2.32%			2.54%
40	Syncronized Interest	Exh 107, Pg 16	80,946,832		6,595,281	87,542,112
41	**Calculation of Pennsylvania Corporate Net Income Tax**					
42	Operating Income Before Income Taxes	Exh 107, Pg 17	246,582,180		62,891,805	309,473,985
43	Statutory Adjustments (Page 16, Lines 14 & 28)	Exh 107, Pg 17	(229,601,919)		(51,089,190)	(280,691,108)
44	Pennsylvania Bonus Depreciation Adj	Exh 107, Pg 17	(11,829,916)		-	(11,829,916)
45	State Taxable Income	Exh 107, Pg 17	5,150,345		11,802,615	16,952,961
46	Net Operating Loss Deduction	Exh 107, Pg 17	-		-	-
47	PA Taxable Income	Exh 107, Pg 17	5,150,345		11,802,615	16,952,961
48	PA State Rate	Exh 107, Pg 17	7.99%		7.99%	7.99%
49	Current State Income Tax Expense	Exh 107, Pg 17	411,513		943,029	1,354,542
50	Deferred Tax On Net Operating Loss Deduction	Exh 107, Pg 17	-		-	-
51	Deferred Tax on Inventory Adj	Exh 107, Pg 17	-		-	-
52	Deferred Tax on Capitalized Inventory	Exh 107, Pg 17	-		-	-
53	Deferred Tax on Customer Advances	Exh 107, Pg 17	-		-	-
54	Pennsylvania Corporate Income Tax Expense	Exh 107, Pg 17	411,513		943,029	1,354,542

Columbia Gas of Pennsylvania, Inc.
Rate Base ADIT
December 31, 2025

Line No.	Acct. No.	Description	Ref	Pro Forma December 31, 2025	Adjustment	Pro Forma December 31, 2025
				(1)	(2)	(3)
1		**Deferred Income Taxes**				
2	190	Income Taxes	Exh 108, Schedule 8	34,655,652	0	34,655,652
3	282	Depreciation	Exh 108, Schedule 8	(403,584,837)	(9,343,721)	(412,928,558)
4	283	Other	Exh 108, Schedule 8	0	0	0
5	254	Excess ADIT	Exh 108, Schedule 8	(129,894,952)	0	(129,894,952)
6	182	Regulatory Liability Excess ADIT (Before Gross Up)	Exh 108, Schedule 8	1,596,451	0	1,596,451
7		Total Deferred Income Taxes	Exh 108, Schedule 8	(497,227,686)	(9,343,721)	(506,571,407)

Decrease in book depreciation	OCA GM Exh 1, Pg 7	(44,493,909)
Federal Tax Rate		21%
Accumulated deferred income tax (ADIT)		(9,343,721)

COLUMBIA STATEMENT NO. 10-RJ

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REJOINDER TESTIMONY OF
JENNIFER HARDING
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 30, 2024

I. Introduction

Q. Please state your name and business address.

A. My name is Jennifer Harding. My business address is 290 W. Nationwide Blvd, Columbus, Ohio 43215.

Q. Have you previously filed testimony in this matter?

A. Yes, I have provided Direct and Rebuttal Testimony.

Q. What is the purpose of your Rejoinder testimony?

A. I will respond to the surrebuttal testimony served in this proceeding by Pennsylvania Office of Consumer Advocate ("OCA") witness Greg R. Meyer concerning adjustments to Rate Base for Accumulated Deferred Income Taxes ("ADIT").

Q. Do you agree with the ADIT computed by Witness Meyer included in his corrected surrebuttal testimony on Exhibit GRM-SR-1 Page 3.5?

A. No, I do not. Witness Meyer has captured the computation of ADIT on the difference between book depreciation and the computed tax depreciation tax effected at 21%. However, he has omitted a correlated adjustment for the tax repairs deduction attributed to Account 376 Mains and Account 380 Services, as well as the mixed service cost ("MSC") deduction on all Account classes. Columbia applies the qualifying repairs and MSC percentage based on that latest tax filed return, which represents 23.28% and .51% for the 2022 tax return, respectively. The total book basis is reduced by these deductions to compute the applicable MACRS tax depreciation resulting in a decrease in ADIT of $2,365,213 ($1,958,926 in 2024 and $406,288 in 2025) as depicted in Exhibit JH-10-RJ Page 1 of 1.

Q. Do you agree with Witness Meyer's ADIT adjustment of ($8,970,874) presented in his corrected surrebuttal testimony on Exhibit GRM-SR-1 Page 3?

A. No, I do not. Based on the presentation of the adjustments to Rate Base by Witness Meyer, the ADIT Adjustment associated with the change in the accumulated reserve adjustment should be ($4,787,374) which represents $22,797,020 ($1,447,796 and $21,359,224 presented on Exhibit GRM-SR-1, Page 3, Lines 3 and Lines 6, respectively) tax effected at the federal income tax rate of 21%. However, Columbia notes discrepancies with the Accumulated Reserve Adjustment of $21,359,224 presented in Witness Meyer's Exhibit GRM-SR-1, page 2, Line 6 compared to the Deprecation Expense Adjustment of $42,718,447 presented Witness Meyer's Exhibit GRM-SR-1, page 2, Line 7.

Q. Do you agree with Witness Meyer's computation of income tax expense presented in his corrected surrebuttal testimony on Exhibit GRM-SR-1 Page 8?

A. No, I do not. The amount of Sales Revenues presented on Witness Meyer's Exhibit GRM-SR-1, Page 8, Line 1 of $4,445,605 does not agree to Exhibit GRM-SR-1, Page 4, Line 1 Total Operating Revenues of $5,331,455. Additionally, the computation of Interest Sync presented on Witness Meyer's Exhibit GRM-SR-1, page 8, Line 9 should be updated based on the discrepancies with the Accumulated Reserve Adjustment of $21,359,224 presented in Witness Meyer's Exhibit GRM-SR-1, page 2, Line 6 compared to the Deprecation Expense Adjustment of $42,718,447 presented on Witness Meyer's Exhibit GRM-SR-1, page 2, Line 7.

Q. Does this complete your Prepared Rejoinder Testimony?

A. Yes, it does.

		Jan-24	Feb-24	Mar-24			Jan-24	Feb-24	Mar-24		23.28% 2024	0.51% 2024		2024	2024	2024	2025	2025	2025	2025	
Line	Account	Net Addition Disallowance	Net Addition Disallowance	Net Addition Disallowance	Total Disallowance	Depreciation Rate	Book Depreciation	Book Depreciation	Book Depreciation	Total Book Depreciation	Tax Repairs Deduction (Mains & Services)	Tax Mixed Service Cost (MSC) Deduction	Tax Basis (After Repairs & MSC)	Tax Rate	Tax Depreciation	ADIT	Book Depreciation	Tax Rate	Tax Depreciation	ADIT	Total ADIT
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
1	303.30	1,623,198	128,389	(6,165,851)	(4,414,264)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
2	303.99	(144,682)	23,913	(81,289)	(202,058)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
3	374.20	-	-	2	2	1.32%	-	-	0	0		0	2	3.75%	0	(0)	0.03	7.22%	0	(0)	(0)
4	374.40	(72,086)	14,895	(26,086)	(83,277)	1.32%	(912)	172	(273)	(1,012)		(425)	(82,852)	3.75%	(3,107)	529	(1,099.26)	7.22%	(5,981)	1,025	1,554
5	374.50	(289)	-	-	(289)	1.02%	(3)	-	-	(3)		(1)	(288)	3.75%	(11)	2	(2.95)	7.22%	(21)	4	6
6	375.40	46,505	31,287	28,538	106,330	1.46%	651	400	330	1,380		542	105,788	3.75%	3,967	(657)	1,552.42	7.22%	7,637	(1,278)	(1,935)
7	375.70	(98,472)	120,113	(3,562)	18,079	2.40%	(2,265)	2,522	(68)	190		92	17,987	3.75%	675	(121)	433.90	7.22%	1,298	(182)	(303)
8	375.71	(3,339)	(3,339)	(3,339)	(10,017)	2.41%	(77)	(70)	(64)	(211)		(51)	(9,966)	3.75%	(374)	45	(241.41)	7.22%	(719)	100	145
9	376.00	9,433,057	10,662,004	7,596,532	27,691,593	1.49%	134,696	139,006	89,607	363,309	6,445,612	108,355	21,137,627	3.75%	792,661	(1,466,497)	412,604.74	7.22%	1,525,925	(233,797)	(1,700,294)
10	376.30	(531,305)	(654,471)	(801,372)	(1,987,148)	3.53%	(17,974)	(20,215)	(22,395)	(60,584)		(10,134)	(1,977,014)	3.75%	(74,138)	4,975	(70,146.32)	7.22%	(142,721)	15,241	20,215
11	376.80	(136,775)	-	-	(136,775)	1.47%	(1,927)	-	-	(1,927)		(698)	(136,077)	3.75%	(5,103)	813	(2,010.59)	7.22%	(9,823)	1,641	2,454
12	378.20	3,766,351	3,391,484	4,254,034	11,411,869	2.08%	75,076	61,725	70,050	206,851		58,201	11,353,668	3.75%	425,763	(58,194)	237,366.88	7.22%	819,621	(122,273)	(180,467)
13	378.30	-	457	-	457	2.08%	-	8	-	8		2	455	3.75%	17	(2)	9.51	7.22%	33	(5)	(7)
14	380.00	3,399,617	2,159,979	2,872,889	8,432,485	2.02%	65,811	38,178	45,942	149,931	1,962,781	32,995	6,436,709	3.75%	241,377	(438,317)	170,336.20	7.22%	464,666	(61,809)	(500,126)
15	381.00	160,747	12,457	(1,552)	171,652	1.92%	2,958	209	(24)	3,143		875	170,777	3.75%	6,404	(869)	3,295.72	7.22%	12,328	(1,897)	(2,765)
16	381.10	16,720	16,705	19,812	53,237	2.16%	346	316	339	1,001		272	52,965	3.75%	1,986	(264)	1,149.92	7.22%	3,824	(561)	(825)
17	382.00	(145,899)	36,473	84,620	(24,805)	1.66%	(2,321)	530	1,112	(679)		(127)	(24,678)	3.75%	(925)	78	(411.76)	7.22%	(1,782)	288	366
18	383.00	(22,932)	(54,542)	4,636	(72,838)	1.77%	(389)	(845)	65	(1,169)		(371)	(72,467)	3.75%	(2,717)	403	(1,289.23)	7.22%	(5,231)	828	1,231
19	384.00	1,814	1,812	2,141	5,767	1.21%	21	19	21	61		29	5,738	3.75%	215	(39)	69.78	7.22%	414	(72)	(111)
20	385.00	73,085	68,279	72,740	214,105	2.94%	2,059	1,756	1,693	5,509		1,092	213,013	3.75%	7,988	(750)	6,294.69	7.22%	15,377	(1,907)	(2,657)
21	385.10	899	392	-	1,291	2.94%	25	10	-	35		7	1,284	3.75%	48	(4)	37.96	7.22%	93	(12)	(16)
22	387.45	(3,525)	(106,467)	(280,486)	(390,478)	3.92%	(132)	(3,652)	(8,704)	(12,489)		(1,991)	(388,487)	3.75%	(14,568)	855	(15,306.74)	7.22%	(28,045)	2,675	3,530
23	394.30	151,287	145,103	80,609	376,999	3.92%	5,683	4,977	2,502	13,162		1,923	375,076	3.75%	14,065	(593)	14,778.36	7.22%	27,077	(2,583)	(3,176)
24	394.31	(55,566)	-	-	(55,566)	3.92%	(2,087)	-	-	(2,087)		(283)	(55,283)	3.75%	(2,073)	57	(2,178.19)	7.22%	(3,991)	381	437
25	397.50	117,805	116,948	142,288	377,041	4.46%	5,035	4,564	5,024	14,623		1,923	375,118	3.75%	14,067	(287)	16,816.03	7.22%	27,080	(2,155)	(2,442)
26	398.00	(22,000)	-	(8,000)	(30,000)	6.19%	(1,305)	-	(392)	(1,697)		(153)	(29,847)	3.75%	(1,119)	(89)	(1,857.00)	7.22%	(2,155)	63	(27)
27	Total	17,554,215	16,111,871	7,787,304	41,453,392		262,970	229,610	184,765	677,345	8,408,392	192,073	37,469,249		1,405,097	(1,958,926)	770,203		2,704,905	(406,288)	(2,365,213)
Reference		DR OCA-9-014 Attachment A.	DR OCA-9-014 Attachment A.	DR OCA-9-014 Attachment A.	= Sum (Column 3,4 and 5)	Exhibit BCA-1	= Column 2 x Column 6 x 11.5/12	= Column 3 x Column 6 x 10.5/12	= Column 4 x Column 6 x 9.5/12	Line 8 + Line 9 + Line 10	= Column 5 * Repairs % for Mains (376) and Services (380)	= Column 5 Less Column 11 X MSC %	= Column 5 Less Column 11 Less Column 12	MACRS Table	= Column 13 * 14	= (Column 10 Less Column 11 Less Column 12 Less Column 15) x 21%	= Column 5 x Column 6	MACRS Table	= Column 13 x Column 18	= (Column 17 Less Column 19) x 21%	= Column 16 + Column 20

COLUMBIA STATEMENT NO. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
JULIE COVERT
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

I. Introduction

Q. Please state your name and business address.

A. My name is Julie E. Covert and my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), as Lead Regulatory Analyst.

Q. What are your responsibilities as Lead Regulatory Analyst?

A. I am responsible for supporting the NiSource Inc. ("NiSource") operating companies in a variety of informational and rate filings, general rate case preparation and support, and other duties as assigned.

Q. What is your educational and professional background?

A. I have a Bachelor of Science in Business Administration from Franklin University. My career began at NiSource in 2007 providing general accounting support for Columbia Gas of Virginia, Inc. Since 2007, I have worked on Asset Accounting matters for the Columbia Distribution Companies, which includes Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"), before transferring into my current Lead Regulatory Analyst role in 2015.

Q. Have you ever testified before a regulatory Commission?

A. Yes, I was the Rate Base witness for Columbia in Docket No. R-2018-2647577, R-2022-3031211 and for Columbia Gas of Virginia in Docket No. PUR-2018-00131.

II. Statement of Purpose

Q. Please describe the purpose of your testimony in this proceeding.

A. I will present schedules that demonstrate Columbia's rate base as of December 31, 2025, which reflects the Fully Projected Future Test Year ("FPFTY") investment level that is utilized within the revenue requirement supported by Witness Komenda (Columbia Statement No. 4). My testimony will support and detail the various components included in rate base. I am also sponsoring the following exhibits:

Exhibit No.	Description
Exhibit No. 8	Historic Test Year rate base
Exhibit No. 13, Schedule 6 (27)	Schedule of gas producing units retired or scheduled for retirement
Exhibit No. 108	Future Test Year and Fully Projected Future Test Year rate base
Exhibit No. 113, Schedule 4 (27)	Schedule of gas producing units retired or scheduled for retirement
Exhibit No. 408, Page 1 (11)	AFUDC and method of rate calculation
Exhibit JEC-1 (Attached hereto)	Update of Exhibit 108, Schedule 1 from Docket No. R-2022-3031211 (Updated through December 31, 2023)
Exhibit JEC-2 (Attached hereto)	Comparison of actual rate base additions for the twelve months ended December 31, 2023

Q. What test years will you be addressing in your testimony?

A. I will be addressing the twelve-month period ending November 30, 2023 as the Historic Test Year (Exhibit 8), the twelve-month period ended November 30, 2024 as the Future Test Year (Exhibit 108), and the twelve-month period ended December 31, 2025 as the FPFTY (Exhibit 108).

III. Rate Base

Q. Is the FPFTY utilized by Columbia in this case similar to that used in its prior base rate cases?

A. Yes. Columbia elected to use the FPFTY provided in Act 11 of 2012 in Docket Nos. R-2012-2321748, R-2014-2406274, R-2015-2468056, R-2016-2529660, R-2018-2647577, R-2020-3018835, R-2021-3024296 and R-2022-3031211. The Company has made the same election in the current case. Also note, the presentation of rate base in this case is the same as the prior cases.

Q. Are there any requirements from prior cases arising from the Company's use of a FPFTY?

A. Yes. Pursuant to Paragraph 33 of the approved settlement in the Company's prior rate case, at Docket No. R-2022-3031211, Columbia is required to provide the Commission and the statutory parties, on or before April 1, 2024, an update to Columbia Exhibit 108, Schedule 1, which is to include actual capital expenditures, plant additions and retirements by month for the twelve months ending December 31, 2023. This update is attached to my testimony as Exhibit JEC-1.

In addition, Columbia is required to provide a comparison of rate base additions for the twelve months ended December 31, 2023. This update is attached to my testimony as Exhibit JEC-2.

Q. Please comment on how the Company's actual capital additions for the 12-month period ending December 31, 2023 compares to the projections made in Columbia's prior rate case at Docket No. R-2022-3031211.

A. The Company's actual capital additions for the twelve-month period ending December 31, 2023 exceeded projections filed, as shown in the table below.

Budget per 2022 Rate Case, 2022-3031211 Exhibit 108, Schedule 1				
	Budget	Actual	Over/(Under)	%
Additions	$887,663,291	$888,164,586	$501,295	0.06%

Q. Please explain the development of rate base at November 30, 2023 for the Historic Test Year, November 30, 2024 for the Future Test Year and December 31, 2025 for the FPFTY.

A. Rate base is summarized on Exhibit 8, Page 3, and further detailed by the various components in Exhibit 8, Schedules 1-10, for the Historic Test Year. Rate base for the Future Test Year and the FPFTY are summarized on Exhibit 108, Page 3, and further detailed by various components in Exhibit 108, Schedules 1-10.

Q. Please discuss the amounts included in Property, Plant and Equipment for the Historic Test Year as illustrated on Exhibit 8, Page 3 Lines 1-9.

A. The Company's Plant in Service includes plant in service per books as of November 30, 2023. Accounts 101 and 106 are detailed in Lines 2 through 4. Note, the plant detail for Leases (Line 4) is separately provided as Leases are removed from rate base. The Company is not making a claim for Construction Work in Progress ("CWIP") as of the end of the Historic Test Year as noted in Line 5. The Historic Test Year also includes per books Gas Stored Underground – Non-Current, Account 117 on Exhibit 8, Page 3, Line 6. Reductions are included for the reserve for depreciation, per

Company witness Spanos (Columbia Statement No. 5) on Line 7. Finally, gas lost in underground storage is on Line 8.

Q. Please explain how the Company's Future Test Year and FPFTY Property, Plant and Equipment were developed.

A. The Company's Plant in Service as of December 31, 2025, as shown on Exhibit 108, Schedule 1, Pages 1-13 was developed beginning with Plant in Service at November 30, 2023 (Column 2). Forecasted Plant additions based on the Company's current capital plan were added in columns 3 and 6 while forecasted retirements supported by Company witness Spanos (Columbia Statement No. 5) were subtracted in columns 4 and 7. Exhibit 108, Schedule 1, Page 14, Column 6 reflects the net forecasted plant in service included in rate base as of December 31, 2025. Additional details surrounding the budget is discussed by Company witness Brumley (Columbia Statement No. 7).

Q. Please explain Exhibit 8, Schedule 2.

A. This Exhibit reflects the balance in construction work in progress ("CWIP"). The Company is not making a claim for CWIP in the Historic Test Year.

Q. Please explain Exhibit 108, Schedule 2.

A. Exhibit 108, Schedule 2 shows that forecasted CWIP, Account 107, is expected to remain at the same level for the FPFTY as it was at November 30, 2023. The Company is making no claim for CWIP in the FPFTY.

Q. Please explain the credits to Gas Plant in Service on Exhibit 8, Page 3, Lines 7-8 and Exhibit 108, Page 3, Lines 6-7.

A. Line 7, Depreciation Reserve, Accounts 108-111 in Exhibit 8, Page 3 for the Historic Test Year and Line 6, Exhibit 108, Page 3 for the FPFTY are detailed and supplied by Company witness Spanos, by plant account, in Exhibit 5 for the Historic Test Year and Exhibit 105 in the FPFTY. Exhibit 8, Page 3, Line 8 and Exhibit 108, Page 3, Line 7 Accumulated Provision for Gas Lost – Underground Storage, Account 117, is per books as of November 30, 2023 for the Historic Test Year and December 31, 2025 for the FPFTY.

Q. Did you include Materials and Supplies inventory balances in rate base?

A. Yes. As shown on Exhibit 8, Schedule 5, Materials and Supplies included in the Historic Test Year rate base is a 13-month average of the historical monthly balances in Plant Materials, Account 154. Materials and Supplies in the Future Test Year rate base as shown on the Exhibit 108, Schedule 5 begins with November and December 2023 actual balances (most recently available), with January 2024 through November 2024 balances calculated by applying the Gross Domestic Product ("GDP") deflator supported by Company witness Komenda (Columbia Statement No. 4) in Exhibit 104, Schedule 2, Page 20, to the actual balances of January 2023 through November 2023. The GDP deflator is further applied to the Future Test Year balances to arrive at the FPFTY balances.

Q. Did you include Prepayment balances in rate base?

A. Yes. Exhibit 8, Schedule 6 for the Historic Test Year shows prepayments for: Prepaid Leases, Account 16500000; Corporate Insurance, Account 16521000; Prepaid Insurance I/C, Account 1652000; Regulatory Commission Fees, Office of Consumer

Advocate ("OCA") fees, and Office of Small Business Advocate ("OSBA") fees, Account 16503600; and Prepaid Permits, Account 16503700. The amount in the Historic Test Year rate base is based on a 13-month average of historic monthly balances per the Company's books. Exhibit 108, Schedule 6 for the FPFTY shows prepayments for: Prepaid Leases, Account 16500000; Corporate Insurance, Account 16521000; Prepaid Insurance I/C, Account 1652000; Regulatory Commission Fees, OCA, and OSBA fees, Account 16503600; and Prepaid Permits, Account 16503700. The amounts for the FPFTY rate base were determined by incrementally applying the GDP deflators supported by Company witness Komenda in Exhibit 104, Schedule 2, Page 20 to the January 2023 through November 2023 actual balances to reflect expected new prepayments as of December 2025.

Q. Did you include Gas Stored Underground in rate base?

A. Yes, I did.

Q. What valuation methodology is applied to Gas Stored Underground?

A. As per the Commission's March 31, 2001 Order at Docket No. P-2010-2209925, Columbia uses the Weighted Average Cost of Gas ("WACOG") methodology to value Storage Gas.

Q. Please describe the WACOG accounting methodology you applied to value the FPFTY storage balance.

A. Under the WACOG accounting methodology, the actual cost and volume of the current month's injections are added to the inventory value calculated at the end of the previous month, and a new average cost per Dth is calculated for the current

month. The current month's withdrawals are deducted from the balance at the new average cost per Dth. When storage gas is being injected (April – October), the inventory cost for the current month is added to the inventory cost from the previous month(s). At the end of injection season, the storage cost for the winter is well established. During the withdrawal season (November – March), withdrawals are made at the average price primarily resulting from the injection season.

Q. Did you include an adjustment to Gas Stored Underground in rate base?

A. Yes. I have calculated a twelve-month average cost of gas to be included in rate base.

Q. Do you provide exhibits supporting this storage adjustment?

A. Yes, I do.

Q. Please identify and explain those exhibits.

A. The supporting exhibits are Exhibit 8, Schedule 7 and Exhibit 108, Schedule 7. The actual December 2022 through November 2023 injections and withdrawals are reflected on Exhibit 8, Schedule 7 in columns A and E, respectively. A projected Monthly Average Cost of Gas is detailed in Column B of Exhibit 8, Schedule 7. Therefore, under the WACOG accounting methodology, the current month's injections (Column A) are multiplied by the Monthly Average Cost of Gas (Column B). The result is added to the inventory value calculated at the end of the previous month (Column G), and a new WACOG per Dth is calculated (Column D) for the current month. The current month's withdrawals (Column E) are multiplied by the new WACOG per Dth (Column D) and the result is deducted from the cumulative balance (Column G). This method is continued every month through November

2023, as shown in Exhibit 8, Schedule 7. Exhibit 8, Schedule 7, Line 14 calculates a twelve-month average storage balance to be included in the Pro Forma Rate Base.

Exhibit 108, Schedule 7 repeats this process from November 2023 through December 2025. Injection rates are based on NYMEX Natural Gas Futures. Lines 27 and 28 calculate a twelve-month average storage balance for the Future Test Year rate base and FPFTY rate base, respectively.

Q. Did you include Deferred Income Taxes in rate base?

A. Yes, I did. Balances as of November 30, 2023 pertaining to Deferred Income Taxes included in rate base are shown on Exhibit 8, Schedule 8. The balances were supplied by Company witness Harding (Columbia Statement No. 10) on Exhibit 7, Page 9. Forecasted balances as of November 30, 2024 and December 31, 2025 pertaining to Deferred Income Taxes included in rate base are shown on Exhibit 108, Schedule 8. These were supplied by Company witness Harding on Exhibit 107, Page 5.

Q. How did you determine the Customer Deposits in rate base?

A. Customer Deposits, Account 235, is a 13-month historic average, as detailed on Exhibit 8, Schedule 9 for the Historic Test Year. The 13-month average for the forecasted rate base, detailed on Exhibit 108, Schedule 9, reflects projected balances for November 2024 through December 2025, with entries for November and December of each year based on actual data for November and December of 2023. The balances for January 2024 – December 2025 are based on Historic Test Year balances.

Q. Please explain the Company's accounting for Contributions in Aid of Construction and Customer Advances.

A. Customer Advances for Construction are classified to the 252 and 186 accounts. This includes advances by customers for construction which are to be refunded either wholly or in part. Once the customer advance is received, it is journaled as a credit to the 252 account and a debit to Cash (account 131). The next month a journal entry is made to debit the 186 account and credit the Capital asset (Account 101).

The calculation of rate base includes the Customer Advance 252 and 186 accounts as well as the Capital Asset (Account 101). Therefore, rate base has appropriately reduced amounts paid by Customers.

If the advance is refunded, then a debit is made against the Capital asset (Account 101) and the customer is issued a refund. Additionally, an entry is made to reduce the balances in Account 186 and 252. However, if the customer advance is deemed non-refundable, it becomes a Contribution in Aid of Construction and remains as a credit to the Capital asset.

Customer Advances for Construction are reflected on Exhibit 8 Page 3, line 25 for the HTY and Exhibit 108 Page 3, line 25 for the FTY and FPFTY.

IV. <u>Distribution Service Improvement Charge</u>

Q. Please describe the Distribution Service Improvement Charge ("DSIC").

A. The DSIC was designed to allow for recovery of reasonable and prudent costs incurred to repair, improve or replace eligible property which has been completed and placed in service, but which is not being recovered through base rates.

Q. Is Columbia currently charging a DSIC?

A. No. Columbia has not charged a DSIC since September 30, 2021.

Q. When will the Company be eligible to include plant additions in the DSIC?

A. Consistent with the Tariff, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC. Pursuant to the Commission-approved Settlement of the 2022 base rate case in Docket No. R-2022-3031211, the Company would be eligible to include plant additions in the DSIC upon attaining total FPFTY plant in service of $4,061,081498 as projected by Columbia at December 31, 2023, per Exhibit No. 108, Schedule 1.

Columbia exceeded these projected additions in January 2024.

V. <u>Other Exhibits</u>

Q. Please explain the purpose of Page 2 of Exhibit 8.

A. This page satisfies 52 Pennsylvania Code Section 53.53 I.A, item 2 of the Commission's standard filing requirements, which provides that Exhibit 8, Page 4, shows the Company's rate base claim from its last base rate proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated for Actuals Through December 31, 2023
R-2022-3031211

Line No.	Description	Account No. (1)	Plant Beginning Balance 12/31/2022 (2) $	Additions (3) $	Retirements (4) $	Balance as of 1/31/2023 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 2/28/2023 (8)=(5+6+7) $
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	44,485,237	360,951	(459,808)	44,386,381	3,333,603	(129,277)	47,590,707
6	Cloud Software	303.99	6,573,354	22,464	0	6,595,818	103,650	0	6,699,468
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,177	0	0	948,177	0	0	948,177
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,091	0	(48)	3,361,043	0	(0)	3,361,043
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	6,052,167	138,630	(20,407)	6,170,390	175,222	0	6,345,612
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,286,116	1,674	(5,062)	6,282,728	13,340	(1,142)	6,294,926
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	41,720,888	0	0	41,720,888	247,278	0	41,968,165
30	Structures, Other Distribution System, Leased	375.71	4,795,351	0	0	4,795,351	0	0	4,795,351
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,380,456,440	8,727,496	(331,919)	2,388,852,017	13,434,545	(2,316,389)	2,399,970,173
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Mains - Bare Steel	376.30	61,567,559	0	(32,951)	61,534,608	0	(1,413)	61,533,195
35	Mains - Cast Iron	376.80	148,787	0	0	148,787	0	0	148,787
36	Measuring & Regulating Equipment General	378.10	1,443,154	0	0	1,443,154	0	0	1,443,154
37	Measuring & Regulating Equipment Regulating	378.20	135,582,449	457,200	(116,058)	135,923,591	1,066,482	(138,394)	136,851,679
38	Measuring & Regulating Equipment Local Gas	378.30	411,206	0	0	411,206	0	0	411,206
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	752,775,069	3,718,674	(1,214,404)	755,279,340	4,082,549	(596,197)	758,765,692
42	Meters	381.00	44,144,210	24,815	(41,198)	44,127,827	80,643	0	44,208,471
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	44,117,833	271,610	(31,219)	44,358,224	134,987	(29,759)	44,463,453
45	House Regulators	383.00	16,729,466	87,534	(6,633)	16,810,367	101,288	(8,005)	16,903,649
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	5,985,309	76,407	(11,978)	6,049,738	3,853	303	6,053,893
48	Industrial M&R Equipment. Large Volume	385.10	1,004,345	0	(461)	1,003,883	0	0	1,003,883
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	586,338	0	0	586,338	0	(3,377)	582,961
53	Other Equipment, Telemetering	387.45	12,317,842	9,242	(32,690)	12,294,394	4,887	(43,794)	12,255,487
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,481,127	3,608	0	3,484,735	11,588	(600)	3,495,724
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	719,027	8,893	0	727,920	0	0	727,920
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	309,612	20,979	0	330,592	0	0	330,592
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	19,923,634	0	(48,068)	19,875,566	128,115	(13,916)	19,989,765
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	780,221	0	0	780,221	0	0	780,221
78	Miscellaneous Equipment	398.00	950,814	0	0	950,814	3,547	0	954,361
79	**Total Gas Plant in Service**		**3,668,192,368**	**13,930,177**	**(2,352,902)**	**3,679,769,643**	**22,925,577**	**(3,281,959)**	**3,699,413,261**

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated for Actuals Through December 31, 2023
R-2022-3031211

Line No.	Description	Account No.	Plant Beginning Balance 2/28/2023	Additions	Retirements	Balance as of 3/31/2023	Additions	Retirements	Balance as of 4/30/2023
		(1)	(2)	(3)	(4)	(5 = 2+3+4)	(6)	(7)	(8)=(5+6+7)
			$	$	$	$	$	$	$
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	47,590,707	15,636	(21,137)	47,585,206	353,829	(320,718)	47,618,317
6	Cloud Software	303.99	6,699,468	135,111	0	6,834,579	(2,792)	0	6,831,788
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,177	0	0	948,177	0	0	948,177
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,043	0	0	3,361,043	0	0	3,361,043
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	6,345,612	10,175	(1)	6,355,786	15,754	0	6,371,540
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,294,926	81,213	(2,190)	6,373,949	(3,640)	0	6,370,309
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	41,968,165	358,097	0	42,326,262	229,311	0	42,555,573
30	Structures, Other Distribution System, Leased	375.71	4,795,351	328,244	0	5,123,595	(61,097)	(11,941)	5,050,557
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,399,970,173	12,766,792	(552,796)	2,412,184,169	11,290,824	(695,278)	2,422,779,715
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Mains - Bare Steel	376.30	61,533,195	0	(31,228)	61,501,968	0	(57,804)	61,444,164
35	Mains - Cast Iron	376.80	148,787	0	0	148,787	0	0	148,787
36	Measuring & Regulating Equipment General	378.10	1,443,154	0	0	1,443,154	0	0	1,443,154
37	Measuring & Regulating Equipment Regulating	378.20	136,851,679	120,383	(69,899)	136,902,163	47,656	(10,130)	136,939,689
38	Measuring & Regulating Equipment Local Gas	378.30	411,206	297	(3,171)	408,331	4,001	0	412,332
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	758,765,692	7,303,828	(731,175)	765,338,345	4,381,892	(1,233,054)	768,487,183
42	Meters	381.00	44,208,471	322,657	(164,894)	44,366,234	358,929	0	44,725,162
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	44,463,453	253,283	(84,739)	44,631,997	172,329	(60,797)	44,743,528
45	House Regulators	383.00	16,903,649	108,625	(10,049)	17,002,225	102,880	(10,252)	17,094,853
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,053,893	0	(2,862)	6,051,031	318	(840)	6,050,509
48	Industrial M&R Equipment. Large Volume	385.10	1,003,883	0	(940)	1,002,943	0	0	1,002,943
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	582,961	0	0	582,961	0	0	582,961
53	Other Equipment, Telemetering	387.45	12,255,487	764,629	(3,311)	13,016,805	85,823	(42,979)	13,059,649
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,495,724	174,378	(694)	3,669,407	(165,556)	(1,441)	3,502,410
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	727,920	0	0	727,920	0	0	727,920
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	330,592	14,952	0	345,544	0	0	345,544
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	19,989,765	53,455	0	20,043,220	36,914	(27,555)	20,052,579
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	780,221	0	0	780,221	0	0	780,221
78	Miscellaneous Equipment	398.00	954,361	0	0	954,361	0	0	954,361
79	**Total Gas Plant in Service**		**3,699,413,261**	**22,811,753**	**(1,679,086)**	**3,720,545,928**	**16,847,373**	**(2,472,788)**	**3,734,920,514**

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated for Actuals Through December 31, 2023
R-2022-3031211

Line No.	Description	Account No. (1)	Plant Beginning Balance 4/30/2023 (2) $	Additions (3) $	Retirements (4) $	Balance as of 5/31/2023 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 6/30/2023 (8)=(5+6+7) $
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	47,618,317	2,014,964	0	49,633,281	156,164	0	49,789,445
6	Cloud Software	303.99	6,831,788	(2,038)	0	6,829,750	216	0	6,829,966
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,177	0	0	948,177	0	0	948,177
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,043	0	0	3,361,043	0	0	3,361,043
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	6,371,540	(1,100)	0	6,370,440	1,123	0	6,371,562
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,370,309	12,353	0	6,382,662	15,972	0	6,398,634
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	42,555,573	0	(3,509)	42,552,064	0	0	42,552,064
30	Structures, Other Distribution System, Leased	375.71	5,050,557	0	0	5,050,557	0	0	5,050,557
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,422,779,715	17,243,633	(562,816)	2,439,460,532	26,530,127	(1,044,487)	2,464,946,172
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Mains - Bare Steel	376.30	61,444,164	0	(44,723)	61,399,441	0	(91,106)	61,308,335
35	Mains - Cast Iron	376.80	148,787	0	0	148,787	0	0	148,787
36	Measuring & Regulating Equipment General	378.10	1,443,154	0	(189)	1,442,966	0	0	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	136,939,689	124,359	(47,658)	137,016,390	1,650,387	(47,711)	138,619,066
38	Measuring & Regulating Equipment Local Gas	378.30	412,332	0	(57)	412,275	0	(933)	411,342
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	768,487,183	5,254,162	(1,016,508)	772,724,837	7,004,729	(1,176,358)	778,553,208
42	Meters	381.00	44,725,162	107,265	(136,184)	44,696,244	150,441	(104,229)	44,742,455
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	44,743,528	215,852	(48,765)	44,910,615	216,569	(42,051)	45,085,133
45	House Regulators	383.00	17,094,853	102,833	(6,488)	17,191,197	99,278	(7,330)	17,283,145
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,050,509	8,250	(7,811)	6,050,948	16,619	(31,686)	6,035,881
48	Industrial M&R Equipment. Large Volume	385.10	1,002,943	0	(1,243)	1,001,701	0	(3,740)	997,961
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	582,961	0	0	582,961	0	(2,557)	580,404
53	Other Equipment, Telemetering	387.45	13,059,649	(131,165)	(19,540)	12,908,944	34,268	(46,940)	12,896,273
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,502,410	3,026	0	3,505,436	3,432	0	3,508,868
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	727,920	0	0	727,920	0	(79,944)	647,976
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	345,544	0	(1,506)	344,037	0	0	344,037
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	20,052,579	45,062	(39,432)	20,058,209	86,696	(12,877)	20,132,028
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	780,221	0	0	780,221	0	0	780,221
78	Miscellaneous Equipment	398.00	954,361	0	0	954,361	0	0	954,361
79	**Total Gas Plant in Service**		**3,734,920,514**	**24,997,456**	**(1,936,429)**	**3,757,981,540**	**35,966,020**	**(2,691,949)**	**3,791,255,612**

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
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Line No.	Description	Account No. (1)	Plant Beginning Balance 6/30/2023 (2) $	Additions (3) $	Retirements (4) $	Balance as of 7/31/2023 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 8/31/2023 (8)=(5+6+7) $
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	49,789,445	193,018	0	49,982,464	1,384,845	0	51,367,309
6	Cloud Software	303.99	6,829,966	36,224	0	6,866,190	238,097	0	7,104,287
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,177	0	0	948,177	0	0	948,177
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,043	0	0	3,361,043	0	0	3,361,043
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	6,371,562	157,258	(57)	6,528,763	106,803	(0)	6,635,566
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,398,634	51,784	(11,571)	6,438,847	50,373	(3,831)	6,485,389
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	42,552,064	21,436	0	42,573,499	299,849	0	42,873,348
30	Structures, Other Distribution System, Leased	375.71	5,050,557	27,138	0	5,077,695	59,060	0	5,136,755
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,464,946,172	31,418,004	(1,033,919)	2,495,330,256	33,218,146	(801,009)	2,527,747,393
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Mains - Bare Steel	376.30	61,308,335	1,139	(49,683)	61,259,791	210	(44,512)	61,215,489
35	Mains - Cast Iron	376.80	148,787	0	0	148,787	0	0	148,787
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	0	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	138,619,066	2,278,265	(158,136)	140,739,195	207,323	(118,964)	140,827,554
38	Measuring & Regulating Equipment Local Gas	378.30	411,342	0	0	411,342	0	(4,584)	406,758
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	(453)	(903)
41	Services	380.00	778,553,208	3,852,384	(1,068,932)	781,336,661	7,844,288	(877,593)	788,303,356
42	Meters	381.00	44,742,455	8,844	(36,184)	44,715,115	318,801	(112,296)	44,921,621
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	45,085,133	169,802	(42,632)	45,212,303	370,823	(63,206)	45,519,920
45	House Regulators	383.00	17,283,145	99,404	(8,512)	17,374,036	125,571	(9,905)	17,489,702
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,035,881	2,123	(1,369)	6,036,635	84,351	(2,026)	6,118,960
48	Industrial M&R Equipment. Large Volume	385.10	997,961	0	(335)	997,626	0	(259)	997,367
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	580,404	0	(2,574)	577,830	0	0	577,830
53	Other Equipment, Telemetering	387.45	12,896,273	127,640	(43,967)	12,979,946	208,817	(83,316)	13,105,447
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,508,868	1,227	0	3,510,095	0	0	3,510,095
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	647,976	0	(34,573)	613,403	0	(13,743)	599,660
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	344,037	55,623	0	399,660	0	0	399,660
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	20,132,028	0	(13,577)	20,118,451	63,296	(36,306)	20,145,441
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	780,221	0	0	780,221	0	0	780,221
78	Miscellaneous Equipment	398.00	954,361	9,594	0	963,954	0	0	963,954
79	**Total Gas Plant in Service**		**3,791,255,612**	**38,510,906**	**(2,506,021)**	**3,827,260,497**	**44,580,652**	**(2,172,002)**	**3,869,669,147**

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated for Actuals Through December 31, 2023
R-2022-3031211

Line No.	Description	Account No. (1)	Plant Beginning Balance 8/31/2023 (2) $	Additions (3) $	Retirements (4) $	Balance as of 9/30/2023 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 10/31/2023 (8)=(5+6+7) $
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	51,367,309	368,287	(386,187)	51,349,409	469,092	(201,376)	51,617,125
6	Cloud Software	303.99	7,104,287	3,474	0	7,107,761	54,154	0	7,161,914
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	0	389,345
16	Compressor Station Equipment	354.00	948,177	0	0	948,177	0	0	948,177
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,043	0	0	3,361,043	0	(2)	3,361,041
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	6,635,566	256,774	0	6,892,340	0	0	6,892,340
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	0	3,233,171
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,485,389	39,874	(15,524)	6,509,739	28,289	(1,641)	6,536,387
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	42,873,348	98,541	0	42,971,889	6,491,959	0	49,463,848
30	Structures, Other Distribution System, Leased	375.71	5,136,755	0	0	5,136,755	0	0	5,136,755
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,527,747,393	17,182,603	(683,809)	2,544,246,187	31,716,547	(931,477)	2,575,031,258
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Mains - Bare Steel	376.30	61,215,489	3	(70,258)	61,145,234	0	0	61,145,234
35	Mains - Cast Iron	376.80	148,787	0	0	148,787	(371)	(74,278)	74,139
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	0	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	140,827,554	89,856	(57,605)	140,859,806	43,320	(35,871)	140,867,254
38	Measuring & Regulating Equipment Local Gas	378.30	406,758	0	0	406,758	0	0	406,758
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0	0	(903)	0	0	(903)
41	Services	380.00	788,303,356	4,097,804	(1,599,344)	790,801,816	15,108,203	(1,426,179)	804,483,840
42	Meters	381.00	44,921,621	416,738	(85,714)	45,252,645	225,108	(38,737)	45,439,017
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	45,519,920	129,673	(77,394)	45,572,199	308,807	(45,309)	45,835,697
45	House Regulators	383.00	17,489,702	108,876	(14,872)	17,583,706	139,440	(6,427)	17,716,719
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,118,960	55,388	(9,025)	6,165,323	405,576	(19,121)	6,551,778
48	Industrial M&R Equipment. Large Volume	385.10	997,367	0	(158)	997,209	0	(508)	996,701
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	577,830	0	0	577,830	0	0	577,830
53	Other Equipment, Telemetering	387.45	13,105,447	794,174	(19,677)	13,879,943	155,979	(13,421)	14,022,501
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,510,095	0	0	3,510,095	0	0	3,510,095
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	599,660	0	0	599,660	0	(28,262)	571,398
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	399,660	0	0	399,660	0	0	399,660
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	20,145,441	30,256	(36,000)	20,139,697	22,110	(35,012)	20,126,795
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	780,221	0	0	780,221	0	0	780,221
78	Miscellaneous Equipment	398.00	963,954	0	0	963,954	8,547	0	972,501
79	**Total Gas Plant in Service**		**3,869,669,147**	**23,672,320**	**(3,055,567)**	**3,890,285,900**	**55,176,759**	**(2,857,621)**	**3,942,605,038**

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated for Actuals Through December 31, 2023
R-2022-3031211

	Description	Account No. (1)	Plant Beginning Balance 10/31/2023 (2) $	Additions (3) $	Retirements (4) $	Balance as of 11/30/2023 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 12/31/2023 (8)=(5+6+7) $
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	51,617,125	591,901	(234,667)	51,974,359	1,485,708	(880,885)	52,579,183
6	Cloud Software	303.99	7,161,914	127,776	0	7,289,690	393,974	0	7,683,664
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	389,345	0	0	389,345	0	(1,820)	387,525
16	Compressor Station Equipment	354.00	948,177	0	(539)	947,638	0	0	947,638
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,041	0	(1)	3,361,040	0	(6)	3,361,034
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	6,892,340	40,979	0	6,933,319	1,087,897	(8,797)	8,012,420
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171	0	(146)	3,233,025
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,536,387	7,714	(50,131)	6,493,970	52,232	(38,197)	6,508,005
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	49,463,848	(24,378)	0	49,439,470	112,302	(14,889)	49,536,882
30	Structures, Other Distribution System, Leased	375.71	5,136,755	0	0	5,136,755	241,483	(55,968)	5,322,270
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,575,031,258	27,264,507	(1,703,169)	2,600,592,596	72,829,477	(6,450,069)	2,666,972,004
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Mains - Bare Steel	376.30	61,145,234	25	(129,817)	61,015,442	1,425	(651,400)	60,365,467
35	Mains - Cast Iron	376.80	74,139	0	0	74,139	0	0	74,139
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	0	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	140,867,254	125,165	(215,028)	140,777,391	3,373,676	(392,583)	143,758,484
38	Measuring & Regulating Equipment Local Gas	378.30	406,758	0	0	406,758	0	0	406,758
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0	0	(903)	0	0	(903)
41	Services	380.00	804,483,840	7,146,516	(1,561,558)	810,068,798	5,998,090	(961,648)	815,105,240
42	Meters	381.00	45,439,017	281,082	(71,764)	45,648,335	199,678	0	45,848,012
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	45,835,697	161,110	(35,629)	45,961,179	232,554	(25,521)	46,168,212
45	House Regulators	383.00	17,716,719	128,435	(5,740)	17,839,414	188,945	(3,344)	18,025,015
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,551,778	24,754	(6,093)	6,570,439	314,687	(21,101)	6,864,025
48	Industrial M&R Equipment. Large Volume	385.10	996,701	0	(555)	996,145	0	(245)	995,901
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	577,830	0	(11,293)	566,537	0	0	566,537
53	Other Equipment, Telemetering	387.45	14,022,501	230,080	(130,284)	14,122,296	1,123,866	(141,348)	15,104,814
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,510,095	0	478	3,510,573	209,937	0	3,720,511
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	571,398	0	0	571,398	0	(17,214)	554,184
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	399,660	0	0	399,660	0	(4,544)	395,117
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	20,126,795	107,909	(19,434)	20,215,270	258,230	(95,478)	20,378,022
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	780,221	0	(9,818)	770,403	0	0	770,403
78	Miscellaneous Equipment	398.00	972,501	0	(2,264)	970,237	57,156	0	1,027,393
79	**Total Gas Plant in Service**		**3,942,605,038**	**36,213,575**	**(4,187,306)**	**3,974,631,308**	**88,161,317**	**(9,765,200)**	**4,053,027,426**

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated for Actuals Through December 31, 2023
R-2022-3031211

SUMMARY

Line No.	Description	Account No. (1)	Plant Beginning Balance 12/31/2022 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2023 (5 = 2+3+4) $
1	**Intangible Plant**					
2	Organization Costs	301.00	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	44,485,237	10,728,000	(2,634,054)	52,579,183
6	Cloud Software	303.99	6,573,354	1,110,309	0	7,683,664
7	**Underground Storage Plant**					
8	Land	350.10	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498
15	Lines	353.00	389,345	0	(1,820)	387,525
16	Compressor Station Equipment	354.00	948,177	0	(539)	947,638
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477
18	**Distribution Plant**					
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,091	0	(57)	3,361,034
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	6,052,167	1,989,515	(29,262)	8,012,420
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	(146)	3,233,025
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,286,116	351,177	(129,288)	6,508,005
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	41,720,888	7,834,393	(18,399)	49,536,882
30	Structures, Other Distribution System, Leased	375.71	4,795,351	594,828	(67,909)	5,322,270
31	Structures, Communication	375.80	16,515	0	0	16,515
32	Mains	376.00	2,380,456,440	303,622,700	(17,107,136)	2,666,972,004
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481
34	Mains - Bare Steel	376.30	61,567,559	2,802	(1,204,894)	60,365,467
35	Mains - Cast Iron	376.80	148,787	(371)	(74,278)	74,139
36	Measuring & Regulating Equipment General	378.10	1,443,154	0	(189)	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	135,582,449	9,584,072	(1,408,036)	143,758,484
38	Measuring & Regulating Equipment Local Gas	378.30	411,206	4,298	(8,746)	406,758
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	(453)	(903)
41	Services	380.00	752,775,069	75,793,119	(13,462,948)	815,105,240
42	Meters	381.00	44,144,210	2,495,001	(791,199)	45,848,012
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	44,117,833	2,637,399	(587,019)	46,168,212
45	House Regulators	383.00	16,729,466	1,393,107	(97,557)	18,025,015
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	5,985,309	992,325	(113,609)	6,864,025
48	Industrial M&R Equipment. Large Volume	385.10	1,004,345	0	(8,444)	995,901
49	Other Equipment	387.10	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	586,338	0	(19,801)	566,537
53	Other Equipment, Telemetering	387.45	12,317,842	3,408,238	(621,266)	15,104,814
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372
56	**General Plant**					
57	Structures, Communications	390.10	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,481,127	241,640	(2,257)	3,720,511
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	719,027	8,893	(173,736)	554,184
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	309,612	91,554	(6,050)	395,117
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0
69	Tools, Tools and Other	394.30	19,923,634	832,042	(377,654)	20,378,022
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0
77	Communication Equipment, Telemetering	397.50	780,221	0	(9,818)	770,403
78	Miscellaneous Equipment	398.00	950,814	78,843	(2,264)	1,027,393
79	**Total Gas Plant in Service**		**3,668,192,368**	**423,793,886**	**(38,958,829)**	**4,053,027,426**

Columbia Gas of Pennsylvania, Inc.
Property, Plant & Equipment - Budget to Actual Comparison
2022 Rate Case at Docket R-2022-3031211

		Additions						
		Budget		Actuals		Month Over (Under)	Cumulative Spend Over (Under)	Over
Ln. No.	Month	Month	Cumulative	Month	Cumulative	Budget	Budget	(Under)
	(1)	(2)	(3)	(4)	(5)	(6)=(4-2)	(7)=(5-3)	(8)=(7/3)
		($)	($)	($)	($)	($)	($)	(%)
1	1/31/2023	17,275,769	481,810,436	13,930,177	478,300,877	(3,345,592)	(3,509,559)	-0.73%
2	2/28/2023	24,723,736	506,534,172	22,925,577	501,226,454	(1,798,158)	(5,307,718)	-1.05%
3	3/31/2023	21,653,917	528,188,089	22,811,753	524,038,207	1,157,836	(4,149,882)	-0.79%
4	4/30/2023	19,076,840	547,264,930	16,847,373	540,885,580	(2,229,467)	(6,379,349)	-1.17%
5	5/31/2023	23,467,404	570,732,333	24,997,456	565,883,036	1,530,052	(4,849,297)	-0.85%
6	6/30/2023	39,583,219	610,315,553	35,966,020	601,849,057	(3,617,199)	(8,466,496)	-1.39%
7	7/31/2023	27,878,837	638,194,390	38,510,906	640,359,962	10,632,069	2,165,573	0.34%
8	8/31/2023	45,232,477	683,426,867	44,580,652	684,940,614	(651,825)	1,513,748	0.22%
9	9/30/2023	45,354,264	728,781,130	23,672,320	708,612,934	(21,681,944)	(20,168,196)	-2.77%
10	10/31/2023	51,038,879	779,820,009	55,176,759	763,789,694	4,137,880	(16,030,316)	-2.06%
11	11/30/2023	40,638,288	820,458,297	36,213,575	800,003,269	(4,424,713)	(20,455,029)	-2.49%
12	12/31/2023	67,204,994	887,663,291	88,161,317	888,164,586	20,956,323	501,295	0.06%

COLUMBIA STATEMENT NO. 11-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
JULIE E. COVERT
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

I. Introduction

Q. Please state your name and business address.

A. My name is Julie E. Covert, and my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the direct testimony of Witness Greg Meyer, submitted on behalf of the Office of Consumer Advocate ("OCA") concerning recommended adjustments to the Company's Plant in Service and Materials and Supplies. I will also address the recommendation of Witness Esyan Sakaya, submitted on behalf of the Bureau of Investigation and Enforcement ("I&E"), that the Company provide future updates to Columbia Exhibit No. 108, Schedule 1.

Q. Please summarize Mr. Meyer's adjustment to Plant in Service.

A. Mr. Meyer recommends reducing Plant in Service based on his theory that the Company has experienced a historic pattern where the value of actual capital additions is less than budgeted amounts. As such, Mr. Meyer proposes to reduce Plant in Service by $41 million based on the Company's budget to actual data from January 2024 to March 2024.

Q. What evidence did Mr. Meyer provide to support the proposed adjustment to Plant in Service?

A. Mr. Meyer uses data from the Company's discovery responses to OCA Set 5, Question 2, Docket No. R-2022-3031211 for years 2018 – 2021, and OCA Set 9, Question 10, R-2024-3046519 for years 2022 and 2023, as well as Exhibit No. 108, Schedule No. 1 for years 2024 and 2025 to support his proposed adjustment to Plant in Service.

Q. Do you agree with Mr. Meyer's recommended adjustment to Plant in Service? Please explain.

A. No. First, the data Mr. Meyer uses to support his adjustment to Plant in Service was taken from the discovery response OCA Set 5, Question 2 from Columbia's 2022 base rate case at Docket No. R-2022-3031211, which was relied upon by OCA's witness to make a proposed rate base adjustment in the 2022 rate case. This information was revised in my rebuttal testimony (Statement No, 11-R, Page 2 and 3) in the 2022 base rate case.

Q. Why was it necessary to revise the information presented in the 2022 rate case?

A. There were several flaws in OCA's use of that data in the 2022 rate case. First, the data presented in that discovery response was plant additions, and not net plant additions. It is necessary to reflect retirements in an analysis of rate base additions because additions and retirements combined make up net plant additions. Second, the analysis was substantially flawed in presenting 2018 data and skipping 2019 data, because the Company substantially made up its underspending in 2018 by overspending its budget in 2019. There was also a substantial overstatement in the presentation of the 2021 budgeted and actual data, Table JEC-1R shown below

provides a budget to actual comparison of net plant additions for years 2016 through 2021 and the first five months of 2022, that was provided in my rebuttal testimony in the 2022 case.

Table JEC-1R

Columbia Gas of Pennsylvania, Inc.
Net Plant Additions - Budget to Actual Comparison
2016 - 2022

Year	Net Plant Additions Projections	Net Plant Additions Actuals	Over/Under	% Over/Under
2016	201,484,582	212,091,161	10,606,580	5.2642%
2017	241,193,780	246,180,352	4,986,572	2.0675%
2018	256,289,120	209,983,896	(46,305,224)	-18.0676%
2019	258,343,265	294,610,057	36,266,792	14.0382%
2020	288,945,858	277,795,194	(11,150,663)	-3.8591%
2021	338,558,967	322,821,714	(15,737,253)	-4.6483%
2022	65,010,868	95,266,763	30,255,895	46.5397%
			Average Over/Under	**5.9050%**

Table JEC-1R shows the Company was overbudget in 2016, 2017, 2019 and the first five months of 2022.

Q. Are there errors in Mr. Meyer's Table GRM-2 in addition to the errors identified above that he carried over from the 2022 rate case?

A. Yes. Like the errors for prior years identified above, Table GRM-2 in Mr. Meyer's testimony is titled Net Plant – Budget to Actual (OCA Statement 2, Page 5). However, data for the Years 2022 and 2023 reflect additions not net additions. Once retirements are factored into the analysis, the Company is under-budget $5.7 million or 1.66% in 2022 and $2.4 million or .61% in 2023. Table JEC-2R below

shows the percentage of net plant additions over/under budget for the last five years. The Company was over-budget in 2019 and minimally under-budget in 2022 and 2023.

Table JEC-2R

Year	Over/Under	% Over/Under-Budget
2019	36,266,792	14.0%
2020	(11,150,663)	-3.9%
2021	(15,737,253)	-4.6%
2022	(5,675,457)	-1.7%
2023	(2,378,616)	-0.6%

Q. Does Mr. Meyer use the foregoing data in deriving his adjustment?

A. No. Rather than basing his adjustment on historic experience, Mr. Meyer proposes to adjust rate base by the under-budget amount for the first three months of 2024, which is contrary to OCA's position in the 2022 base rate case, Docket No. R-2022-3031211 (see OCA Statement 1-SR (Morgan), Page 5). In the 2022 base rate case, the OCA's position was that only a full year's activity should be considered, not a partial year's activity.

Mr. Meyer believes his adjustment is conservative, but he uses a different methodology than OCA proposed in the Company's last rate case. If Mr. Meyer had used an average of correct data for the past five years, as shown above, there would be no basis for an adjustment in this case.

Q. What methodology should be used to calculate a Plant in Service adjustment?

A. I have no reason to believe the Company will not meet its budgeted Plant in Service for 2024 or 2025. A reduction to Plant in Service is inappropriate given the Company's record in meeting its projections and because the Company has until December 2025 to meet its Plant in Service projections filed in this case.

Q. Can Columbia explain the reasons why actual net plant additions were below projections during January – May 2024?

A. Yes, Columbia Witness Kempic will provide an explanation in his rebuttal.

Q. What is the amount and status of the Company's Construction Work in Progress ("CWIP") as of May 2024?

A. The following table provides the status and amount of CWIP as of May 31, 2024.

Table JEC-3R

CWIP Status	May-24
Cancelled	3,061,764
Completed	1,662,511
In Service	8,056,308
Open	109,987,751
Posted to CPR	2,846,684
Suspended	5,507,663
Total	**131,122,681**
CWIP In Service	**12,565,503**

A status of Completed, In Service, or Posted to CPR (Continuing Property Records) represents costs that should be considered Plant in Service. Thirteen million dollars ($13 million) of CWIP is Plant in Service and will be reclassed accordingly, thereby reducing the Company's current under-budget position.

Q. Did Mr. Meyer make any other adjustments to rate base in relation to the proposed Plant in Service adjustment?

A. No, he did not. Witness Meyer proposes a $41 million adjustment to Plant in Service, but he did not propose the required corresponding adjustments to Accumulated Depreciation or Accumulated Deferred Income Tax ("ADIT") in relation to the proposed Plant in Service adjustment. This is an error, because if there is a change to projected net plant additions, there would be changes to projected accumulated depreciation and projected ADIT. Please refer to Witness Spanos' and Witness Harding's rebuttal testimonies.

Q. Please explain Mr. Meyer's adjustment to Materials and Supplies.

A. Mr. Meyer proposes a total disallowance of Materials and Supplies based on his belief that selling Company accounts receivables would result in a negative cash working capital and therefore, overstate rate base.

Q. Do you agree with Mr. Meyer's adjustment to Materials and Supplies?

A. No, I do not. The Commission's regulations at 52 Pa. Code § 53.53 do not require the Company to file a claim for Cash Working Capital. In addition, Mr. Meyer arbitrarily chooses a total disallowance of Materials and Supplies based solely on his experience, not any actual data provided in this case.

Q. Why did the Company not make a claim for cash working capital?

A. Not only is a claim for cash working capital not required under Commission regulations, but I have also been advised by counsel that the Commission has rejected negative cash working capital claims in past cases.

Q. Are there any other issues with OCA's proposed rate base?

A. Yes. Witness Andrews proposes a $43 million decrease in depreciation expense which would impact the amount of Accumulated Depreciation and Accumulated Deferred Income Taxes included in rate base. Also, OCA Witness Meyer's revenue requirement adjustments in Table GRM-1 do not include the required adjustments to Accumulated Depreciation or Accumulated Deferred Income Taxes associated with OCA's proposed change to depreciation expense.

Q. Earlier you stated that you will address I&E witness Sakaya's recommendation that the Company update Columbia Exhibit No. 108, Schedule 1. What is your position regarding I&E witness Sakaya's recommendation?

A. Witness Sakaya recommends that the Company update Exhibit 108, Schedule 1 no later than April 1, 2025, to include actual capital expenditures, plant additions, and retirements by month for twelve months ending November 30, 2024, as well as provide an additional update for actuals through December 31, 2025, by April 1, 2026. The Company is agreeable to providing such updates to Exhibit 108, same as it has in prior rate cases.

Q. Does this complete your prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 12

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
RIBEKA DANHIRES
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

I. Introduction

Q. Please state your name and business address.

A. Ribeka Danhires, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc., ("Columbia" or "the Company") as Manager, Rates & Regulatory Service.

Q. What are your responsibilities as Manager, Regulatory Policy?

A. I am responsible for managing Columbia's rates and regulatory activity before the Pennsylvania Public Utility Commission ("Commission"). This responsibility includes ensuring timely, accurate rate and regulatory filings before the Commission as well as compliance with Columbia's Rates and Rules for Furnishing Gas Service, known as Tariff Gas Pa. P.U.C. No. 9 ("Tariff").

Q. Please describe your professional experience.

A. I hold a Bachelor of Arts degree in Accounting from the University of Pittsburgh and a Master's of Business Administration degree from Seton Hill University. After graduating from college, I was employed by Duquesne Light Company for ten years. I started in the Rates & Tariff Services Department as a Rates Analyst and concluded my time at Duquesne Light Company in the Regulatory Affairs Department as the Pennsylvania State Regulatory Coordinator. I joined Columbia in December 2015 as a Senior Rate Analyst and moved into my current role as Manager, Rates & Regulatory Service in December 2018.

Q. Have you previously testified before this or any other utility Commission?

A. Yes. In Pennsylvania, I submitted direct testimony on behalf of Columbia in its 2021 and 2022 rate cases, at Docket Nos. R-2021-3024296 and R-2022-3031211, as the Tariff Witness. Additionally, I testified at several rate complaint hearings, most recently regarding the Company's Weather Normalization Adjustment ("WNA") at Docket Nos. C-2023-3039555 and C-2023-3040138. I also provided direct testimony as the Tariff Witness in Columbia Gas of Maryland's ("CMD's") 2018, 2021, and 2022 rate cases in Case Nos. 9480, 9664, and 9680, respectively, before the Maryland Public Service Commission. In addition, I submitted direct testimony and testified in support of CMD's 2016, 2017, 2018, 2019, and 2020 Purchased Gas Adjustment ("PGA") filings in Case Nos. 9510(j), 9510(k), 9510(l), 9510(m), and 9510(n), respectively as well as provided direct testimony in support of the settlement in CMD's 2019-2023 Strategic Infrastructure Development and Enhancement Plan ("STRIDE") in Case No. 9479 and direct testimony formally requesting approval for a new 5-year STRIDE Plan at Case No. 9709.

Q. Please explain the purpose of your Direct Testimony in this proceeding.

A. My purpose in this proceeding is to present and sponsor Columbia's proposed tariff changes. My testimony lists the exhibits that I am sponsoring as well as a high-level explanation of the proposed tariff revisions. The details of those proposed tariff changes can be found in Exhibit 14, Schedule 2, Attachments B and C.

Q. What exhibits are you sponsoring?

A. I am sponsoring the following exhibits:

Exhibit No.:	Description:
Exhibit No. 10, Schedule 4 (39)	Company policy with respect to relationship with potential customers.
Exhibit No. 14, Schedule 1 (26)	List of information provided to the Commission.
Exhibit No. 14, Schedule 2 (6)	Present and proposed tariff pages.
Exhibit No. 15, Schedule 1 (01)	Corporate history, list of counties and municipalities served, and total population in areas served.
Exhibit No. 15, Schedule 2 (02)	System map.
Exhibit No. 114, Schedule 1 (26) (6)	List of information provided to the Commission and tariffs, both present and proposed.
Exhibit No. 115 (01) (02) (24)	Corporate history, system map, and affiliate relationships.

II. Tariff Changes Summary

Q. Please provide a brief description of Columbia's proposed tariff changes.

A. There are several proposed tariff changes. The substantive tariff changes proposed in Supplement No. 374 include base rate revisions and the State Tax Adjustment Surcharge ("STAS") reset to zero with the implementation of new base rates which has been reflected on page 165 of the Company's tariff. In addition to those revisions,

Columbia is proposing a Municipal Levelization Charge, a new rate rider - the Revenue Normalization Adjustment ("Rider RNA") and a modification to the Company's Rider WNA – Weather Normalization Adjustment ("Rider WNA"). All substantive changes reflect a "(C)" in the right margin of the page. Several non-substantive changes, such as formatting and updates to text, also are included.

Q. Please provide a listing of all the tariff changes available.

A. Tariff pages 2 through 2a within Exhibit 14, Schedule 2, Attachments B and C, present the List of Changes to the Tariff proposed in this base rate case.

III. Substantive Tariff Changes

Q. Please explain the changes to rates within Supplement No. 374 as shown on the "Rate Summary" pages.

A. The "Rate Summary" pages are shown as pages 16 through 19. These pages contain the rate components and the total effective rate for each of the Company's rate schedules. The changes to each rate schedule, by page, will be described below.

Page 16, which details the rates for residential sales service and Choice service (Rate Schedules RSS and RDS), reflects increases to the Customer Charge, Distribution Charge, Gas Supply Charge, and Pass-through Charge. A new column was added to page 16 for the proposed Rider RNA and the STAS rate was reset to zero.

Commercial and industrial accounts using less than or equal to 64,400 therms per year normally fall into one of three rate schedules depending on their choice of service. Rate Small General Sales Service ("SGSS") reflects the rates for customers purchasing their gas supply from the Company, while Rate Small Commercial Distribution ("SCD") and Rate Small General Distribution Service ("SGDS") are tariffed rate schedules for the mandatory firm capacity Choice program and the Gas Distribution Service program respectively, which are for customers choosing to purchase their gas from a natural gas supplier. Rate Summary page 17, which contains the rates for these rate schedules, reflects an increase to the Customer Charge, Distribution Charge, and Gas Supply Charge. Additionally, the STAS rate was reset to zero.

Rate Summary page 18 contains customer and distribution charge rates for commercial and industrial customers using more than 64,400 therms per year. Rate Schedule Large General Sales Service ("LGSS") is for those customers who purchase their gas supply from Columbia. Rate Schedules Small Distribution Service ("SDS") and Large Distribution Service ("LDS") are rates for customers purchasing gas from suppliers. This page reflects increases to the Customer Charge and Distribution Charge. Additionally, the STAS rate was reset to zero.

Rate Schedules Main Line Sales Service ("MLSS") and Main Line Distribution Service ("MLDS") are for customers who receive either sales service or distribution service, respectively, and are within two (2) miles of an interstate pipeline or are

served directly from an interstate pipeline through a "dual purpose" meter. Columbia is proposing a slight decrease to the MLDS Distribution Charges and to reset the STAS rate to zero, as reflected on page 19.

Q. Where do the rate changes contained in your testimony originate?

A. The rate changes affecting the Customer Charge and Distribution Charge for each rate schedule can be found within Exhibit No. 103, Schedule No. 8 pages 5 through 9. The rate change to the Universal Service Plan – Rider USP ("Rider USP") can be found on page 5 within that same exhibit and schedule and Rider MFC – Merchant Function Charge ("Rider MFC") and Municipal Levelization Charge rate changes are shown in Exhibit No. 103, Schedule No. 7, pages 7 and 8 and page 12, respectively. The rate design contained in Exhibit No. 103 is also discussed in Company Witness Johnson's testimony (Columbia Statement No. 6). The STAS rate is reflected at 0% on Exhibit 3, Schedule 1. The percentages for Rider MFC are identified in Exhibit MLB-1 attached to Company witness Battig's testimony (Columbia Statement No. 3).

Q. The Company's tariff includes a proposal for the Municipal Levelization Charge. Please explain.

A. Company witness Paloney's testimony, Statement No. 9, discusses the Municipal Levelization Charge proposed to be applicable to customers in the following locations: City of Pittsburgh, Perryopolis Borough, Roscoe Borough, and New Sewickley Township. The Municipal Levelization Charge has been added to the Company's tariff on page 144.

Q. The Company's tariff includes a proposal for Rider RNA. Please explain.

A. Company witness Johnson's testimony, Statement No. 6, discusses the proposal for Rider RNA. Rider RNA has been added to the Company's tariff on pages 145 and 145a to be applicable to non-CAP residential customers under Rate Schedules RSS and RDS.

Q. Pages 16 and 21 of the tariff designate a location for Rider RNA, however, a rate is not included. Please explain.

A. As indicated in the description of Rider RNA on pages 145 and 145a of the Tariff, the Company is not proposing to bill Rider RNA until the October 2025 billing cycle. Columbia has filed the proposed Tariff with an effective date of May 14, 2024 and, at that time, a rate for Rider RNA will not yet be billed. Therefore, it is appropriate that Rider RNA rate is not specified in the Tariff at this time.

Q. The Company's tariff includes a modification to the Company's Rider WNA. Please explain.

A. Company witness Johnson's testimony, Statement No. 6, discusses the proposal to remove the 3% deadband from the Company's current Rider WNA mechanism. The changes to reflect the removal of the deadband are reflected within the Company's tariff on pages 162 and 163.

IV. Non-Substantive Tariff Changes

Q. Please explain the formatting changes.

A. The headers on each Tariff page have been updated to reflect Supplement No. 374 and the sequence of each page number has increased by one from the previously filed supplement number for each individual page. The "Issued" date and the "Effective" date in the footer on each Tariff page now reflect "March 15, 2024" and "May 14, 2024", respectively. Tariff pages 137 and 163 also reflect changes in the footer to include the current President's name. Additionally, the following has been added to the Table of Contents, page 4: Municipal Levelization Charge, Rider RNA, and the previous page 163 has been combined with page 162 and is now blank to be held for future use.

Q. There are several text changes included. Please explain.

A. There are four (4) tariff pages that include changes to the text. The four (4) pages are as follows: page no. 21, page no. 48, page no. 137 and page no. 164a.

Q. Please explain the text change to page no. 21.

A. To be consistent with the presentation of the other riders shown on page 21, the phrase "Rider EE" has been added to the description of the Energy Efficiency Rider line item.

Q. Please explain the text change to page no. 48.

A. Subsection 8.1, under Section 8. Extensions, is applicable to residential customers. To avoid confusion on the applicability, the word 'Residential' has been added to now read "8.1 Residential Service Connections".

Q. Please explain the text change to page no. 137.

A. Within the first sentence under the 'Rate' section of Rate Schedule Rate DGDS – Distributive Generation Distribution Service – there is a missing word. The text change adds the word 'and' to the sentence to correct for the missing word.

Q. Please explain the text change to page no. 164a.

A. Per recent conversations with the Commission's Bureau of Audits, the Company is including tariff revisions to better clarify the timing around the Company's filings.

V. Other Tariff Changes

Q. Please explain the changes on the remaining "Summary" pages.

A. The remaining "Summary" pages include pages 20 through 21c.

The "Other Rates Summary", page 20, shows an increase to the Price-to-Compare for residential gas supply and commercial gas supply. The changes are a direct result of the change in Rider MFC rates. The "Gas Supply Charge Summary" on page 21a and the "Price-to-Compare Summary" on page 21c includes these changes too. The "Other Rates Summary" page also includes two new lines for the proposed Municipal Levelization Charge and an increase to the STAS rate.

Page 21, which is the "Rider Summary", reflects an increase to Rider USP, Rider MFC, and STAS rates. This "Rider Summary" page also includes new line for the proposed Rider RNA.

The residential rates included on the "Pass-through Charge Summary" on page 21b are impacted by the Rider USP increase which causes the rate in the "Total Pass-through" column to increase for Rate Schedules RSS and RDS.

The rate change for the Rider MFC percentages is included on Tariff page 161 which is the tariff page that describes the rider.

Q. Does this complete your Prepared Direct Testimony?

A. Yes.

COLUMBIA STATEMENT NO.12-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
RIBEKA DANHIRES
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

Introduction

Q. Please state your name and business address.

A. My name is Ribeka Danhires. My business address is 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as the Manager of Rates and Regulatory.

Q. Have you previously filed testimony in this matter?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I prepared a redline and clean tariff page in response to a tariff change addressed in the rebuttal testimony of Columbia witness Davis. Additionally, I address the tariff implications of the Company's withdrawal of its proposal to eliminate the three (3) percent deadband for the Weather Normalization Adjustment ("WNA").

Q. What tariff change does Witness Colton propose?

A. Columbia witness Davis testifies regarding a modification to the Company's Tariff, Page No. 44 relating to security deposits. The modifications to Tariff Page No. 44 at Section 6.2 are attached to my rebuttal testimony as Attachment A – redline and clean versions. The Company's modification to Section 6.2 Deposits is in response to Office of Consumer Advocate Witness Colton's proposal.

Q. Do you have anything additional you would like to address regarding the Tariff?

A. Yes. As discussed in Witness Johnson's rebuttal testimony, the Company is withdrawing its request to eliminate the three (3) percent deadband to the WNA as proposed in its initial filing. The current WNA in the Company's tariff – Twelfth Revised Page No. 162 of Supplement No. 334 – including the 3% deadband, will remain in effect until May 31, 2026, as provided in the 2021 rate case settlement (R-2021-3024296).

Q. Does this complete your prepared Rebuttal Testimony?

A. Yes, it does.

RULES AND REGULATIONS GOVERNING THE DISTRIBUTION AND SALE OF GAS (Continued)

6. Credit - continued

6.2 Deposits

Deposits may be required from customers taking service for a period of less than thirty (30) days, in an amount equal to the estimated gross bill for such temporary period. The estimated annual bill shall be calculated on the basis of the annual bill to the premises at which service is being requested for the prior 12 months, or, if unavailable, a similar premises in close proximity. Deposits required by the Company for Tariff regulated charges shall be based on only those regulated charges. Any customer having secured the return of a deposit shall not be required to make a new deposit unless the service has been discontinued or the customer's credit standing impaired through failure to comply with Tariff provisions.

(1) Residential Deposits

The Company uses a generally accepted credit scoring methodology, in the range of general industry practice, based on an Applicant or Customer's utility payment history. The Company will access one of three major credit reporting agencies that use a commercially recognized credit scoring methodology. The payment history of the applicant or customer that is available to the credit reporting agency determines the credit score.

Deposits for residential service will equal one sixth of the estimated annual bill of the property for which the residential utility service is requested.

A Customer or Applicant that self declares or provides income documentation that household income is at or below 150% of poverty or less shall not be asked to provide a cash deposit. (C)

(A) When applicable, a deposit for residential service may be required from the following:

1. An Applicant who previously received utility distribution services and was a customer of the Company and whose service was terminated for any of the following reasons:

(a) Nonpayment of an undisputed delinquent account.
(b) Failure to complete payment of a deposit, provide a guarantee or establish credit.
(c) Failure to permit access to meters, service connections or other property of the Company for the purpose of replacement, maintenance, repair or meter reading.
(d) Unauthorized use of the utility service delivered on or about the affected dwelling.
(e) Failure to comply with the material terms of a settlement or payment arrangement.
(f) Fraud or material misrepresentation of identity for the purpose of obtaining utility service.
(g) Tampering with meters, including, but not limited to, bypassing a meter or removal of an automatic meter reading device or other public utility equipment.
(h) Violating tariff provisions on file with the commission so as to endanger the safety of a person or the integrity of the delivery system of the public utility.

2. Any residential Applicant or Customer who is unable to establish creditworthiness to the satisfaction of the Company through the use of a generally accepted credit scoring methodology which employs standards for using the methodology that fall within the range of general industry practice. The Company may use other means to determine credit worthiness for commercial and industrial customers.

(C) Indicates Change

RULES AND REGULATIONS GOVERNING THE DISTRIBUTION AND SALE OF GAS (Continued)

6. Credit - continued

6.2 Deposits

Deposits may be required from customers taking service for a period of less than thirty (30) days, in an amount equal to the estimated gross bill for such temporary period. The estimated annual bill shall be calculated on the basis of the annual bill to the premises at which service is being requested for the prior 12 months, or, if unavailable, a similar premises in close proximity. Deposits required by the Company for Tariff regulated charges shall be based on only those regulated charges. Any customer having secured the return of a deposit shall not be required to make a new deposit unless the service has been discontinued or the customer's credit standing impaired through failure to comply with Tariff provisions.

(1) Residential Deposits

The Company uses a generally accepted credit scoring methodology, in the range of general industry practice, based on an Applicant or Customer's utility payment history. The Company will access one of three major credit reporting agencies that use a commercially recognized credit scoring methodology. The payment history of the applicant or customer that is available to the credit reporting agency determines the credit score.

Deposits for residential service will equal one sixth of the estimated annual bill of the property for which the residential utility service is requested.

A Customer or Applicant ~~who is confirmed to be eligible for the Customer Assistance Program~~that self declares or provides income documentation that household income is at or below 150% of poverty or less shall not be asked to provide a cash deposit. (C)

(A) When applicable, a deposit for residential service may be required from the following:

1. An Applicant who previously received utility distribution services and was a customer of the Company and whose service was terminated for any of the following reasons:

(a) Nonpayment of an undisputed delinquent account.
(b) Failure to complete payment of a deposit, provide a guarantee or establish credit.
(c) Failure to permit access to meters, service connections or other property of the Company for the purpose of replacement, maintenance, repair or meter reading.
(d) Unauthorized use of the utility service delivered on or about the affected dwelling.
(e) Failure to comply with the material terms of a settlement or payment arrangement.
(f) Fraud or material misrepresentation of identity for the purpose of obtaining utility service.
(g) Tampering with meters, including, but not limited to, bypassing a meter or removal of an automatic meter reading device or other public utility equipment.
(h) Violating tariff provisions on file with the commission so as to endanger the safety of a person or the integrity of the delivery system of the public utility.

2. Any residential Applicant or Customer who is unable to establish creditworthiness to the satisfaction of the Company through the use of a generally accepted credit scoring methodology which employs standards for using the methodology that fall within the range of general industry practice. The Company may use other means to determine credit worthiness for commercial and industrial customers.

(C) Indicates Change

COLUMBIA STATEMENT NO. 13

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
THEODORE M. LOVE
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

1 Introduction

Q. Please state your name, occupation, and business address.

A. My name is Theodore M. Love, and I am a Partner at Green Energy Economics Group, Inc. ("GEEG"), an energy consulting firm founded in 2005. My business address is 2534 Downingsville Road, Lincoln, Vermont 05443.

Q. On whose behalf are you testifying?

A. My testimony is submitted on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia Gas" or the "Company").

Q. Please briefly describe your professional experience.

A. I have been involved in the review and preparation of natural gas and electric energy efficiency plans, as well as potential studies and cost-effectiveness analyses, in nearly a dozen states, three Canadian Provinces, and China, since I began working with GEEG in 2007. Most relevant to this proceeding, I have advised Columbia Gas on their 2022 Energy Efficiency Plan filings as part of the 2022 Company Rate Case. I have advised UGI Utilities, Inc. – Gas Division ("UGI Gas") on its Energy Efficiency and Conservation ("EE&C") Plan since 2015 and Philadelphia Gas Works ("PGW") on its energy efficiency activities since August 2008. I also advised Peoples Natural Gas ("Peoples") on its EE&C filing in 2017. My full resume is attached as Exhibit TML-1.

Q. Have you previously testified before this or any other regulatory agency?

A. Yes. I have previously provided testimony to the Pennsylvania Public Utility Commission ("Commission") in ten dockets. I have also provided written testimony in California, Ontario, and Nova Scotia and participated in the preparation and

development of testimony or evidence in British Columbia, Vermont, Connecticut, Maryland, Oklahoma, Texas, Illinois, and Louisiana. Please see Exhibit TML-1 for a complete list of the proceedings in which I have testified and their docket numbers.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will identify and describe Columbia Gas's proposed updates to their current Three-Year Energy Efficiency Plan ("Plan" or "EE Plan").

Q. Please summarize your testimony.

A. I will provide some background on the EE Plan, an overview of the updated Plan's projected cost, savings, and cost effectiveness under the Total Resource Cost ("TRC") test. Finally, I will provide a summary of the updates made to each program followed by my recommendations and conclusions.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following exhibits:

- Exhibit TML-1 – Resume of Theodore M. Love
- Exhibit TML-2 – Three-Year Energy Efficiency Plan (Clean)
- Exhibit TML-3 – Three-Year Energy Efficiency Plan (Red-line)

2 Background

Q. Does Columbia Gas currently operate an EE Plan?

A. Yes. As part of its 2022 Rate Case (Docket No. R-2022-3031211), Columbia Gas filed for approval of a voluntary 3-year natural gas energy efficiency plan ("EE Plan"). The EE Plan was approved under the Order adopted December 8, 2022 with a budget of $4 million for the years 2023 to 2025 and the final EE Plan was filed in compliance with the Order on December 19, 2022. The EE Plan projects savings to Columbia

Gas's residential customers of 1.3 million Dth of natural gas over the lifetime of the measures installed. From a total resource perspective, the EE Plan is projected to provide a present value of net benefits of $5.7 million (in 2022 dollars), with a Total Resource Cost test benefit-cost ratio ("BCR") of 2.12, more than twice the value of every dollar invested. Additionally, the EE Plan is projected to avoid the emission of CO2 equivalent to over 2,900 cars being removed from the road over the lifetime of installed measures.

The EE Plan has two programs; the Residential Prescriptive ("RP") Program, which provides incentives for high-efficiency natural gas fired equipment, and the Online Audit Kit ("OAK") Program, which provides customers with customized online audit that then allows them to receive a space heating and/or water heating kit at no cost. The EE Plan launched August 1, 2023, and the Company plans to file its first Annual Report by April 1, 2024.

Q. Why is Columbia Gas proposing an Updated EE Plan?

A. The Company is filing an updated EE Plan ("Updated EE Plan") to address the successes and challenges encountered in the first year of its EE Plan's operations. Specifically, Columbia Gas saw extremely robust demand in its OAK Program and a slower than projected uptake in RP Program. The OAK Program had very strong customer participation as the programs launched, with 6,277 kits being requests by customers via the online audit within the first five months of program launch.[1] This initial surge of interest nearly reached the 6,920 kits projected for the entirety of the

[1] 3,794 of the 6,277 were paid for and delivered in 2023.

three-year plan.

The RP Program had a slower, but still steady, ramp-up in customer participation, with rebates going to 697 measures. This represents slightly less than half of the projected measures for the year as shown in the following table.

Table 1. Residential Prescriptive Rebates (2023 Projected vs. Actual)

Measure	2023 Original EE Plan Projections	2023 Actual Rebates	%
Furnace	520	237	46%
Boiler	20	19	95%
Combi-boiler	80	33	41%
Smart Thermostat	900	345	38%
Tankless Water Heater	120	63	53%
Total	**1,640**	**697**	**43%**

The slowest uptake for the program was for smart thermostats, most of the other equipment was around half of the initial projections.

The Company is providing an Updated EE Plan that will allow the continuation of its OAK Program for the three years by shifting funds from the underspending of its RP Program in 2023. Columbia Gas is also proposing the addition of insulation with air sealing and natural gas fired heat pumps to its RP Program to provide its customers with a wider range of measures and assist in meeting the Company's savings goals.

Q. How was the Updated EE Plan developed?

A. The Updated EE Plan was developed with the goal of maintaining the budget commitment of $4 million over three years, while recognizing the pent-up demand for the OAK Program and expanding the offerings in the RP Program. The Company

is still finalizing savings and cost accounting for 2023 so the Updated EE Plan includes participation rates from 2023, preliminary spending and savings figures from 2023, updated participation rates for 2024-2025 based on 2023 experience, and the addition of more measures in the RP Program.

In addition, the need to make such adjustments was anticipated in the Original EE Plan. Specifically:

> "This plan document provides the principles and three-year goals that Columbia Gas is seeking, but certain adjustments, such as providing incentives for new measures or moving budgets between years and programs, may be required to meet these goals. " (p. 11)

It is normal for programs to adjust to market demands, and this flexibility is key to running a successful energy efficiency portfolio.

3 Overview of Updated Plan

Q. Would you please describe the updates to the Three-Year Energy Efficiency Plan?

A. Columbia is proposing a few updates in the Updated EE Plan. To begin, 2023 rebate participation was updated to actual participation values after the first program year. The savings and spending values were adjusted to preliminary figures, as they are still being finalized for inclusion in the 2023 Annual Report. Secondly, participation numbers in both the Residential Prescriptive (RP) and Online Assessment Kit (OAK) programs have been adjusted based on the 2023 program year trends. Lastly, the addition of new rebate availability is proposed for insulation with air sealing and natural gas-powered heat pumps for the RP program. These updates are being made

without increasing the overall approved $4 Million spending level, including Portfolio-Wide (PW) expenses.

Q. What gas savings are projected for the Updated EE Plan?

A. The Updated EE Plan is projected to have annual natural gas savings of 81,567 Dth and 1,229,978 Dth of natural gas savings over the lifetime of the measures installed.

Q. What additional benefits are projected to occur from the updated EE Plan?

A. The Plan is projected to save 3,467 MWh of electricity and 478.5 million gallons of water over the lifetime of the measures installed. Additionally, reduced emissions of over 75,120 short tons of CO2 are expected to occur from program activity, which is equivalent to removing over 2,869 cars from the road permanently. Section 1.5 of Exhibit TML-2 contains additional details on savings projected for the plan.

Q. What are the lifetime TRC test benefits and costs projected for the updated Plan?

A. Under the TRC test, the Plan is projected to provide present value benefits in 2022 dollars of $14.45 million with corresponding present value costs of $5.07 million. This comes out to $9.38 million in net benefits from the proposed plan with an overall BCR of 2.85. In addition, both the RP and OAK programs are cost effective on their own.

Q. Does this plan update result in increased spending?

A. No. With the adjustments made to the participation rates per program based on 2023 actual performance, the plan update is still projected to not exceed the current approved $4 Million budget. The underspending in the RP Program and portfolio

wide costs have been shifted to the OAK program as shown in the following table.

Table 2. Comparison of Updated EE Plan and Original EE Plan Budgets

Program	Updated EE Plan	Original EE Plan	Diff ($)
RP Program	$1,992,800	$2,417,000	($424,200)
OAK Program	$1,410,200	$771,000	$639,200
Portfolio Wide Costs	$597,000	$812,000	($215,000)
Total	**$4,000,000**	**$4,000,000**	$0

Q. How have projections for benefits changed between the Original EE Plan and the Updated EE Plan?

A. The Updated EE Plan projects 11% higher first year gas savings, with a $3.6 million jump in net benefits to customers under the TRC test as shown in the following table.

Table 3. Comparison of Updated EE Plan and Original EE Plan Benefits

Metric	Updated EE Plan	Original EE Plan	Diff (%)
Gas Savings			
Annual Gas (Dth)	81,567	73,552	11%
Lifetime Gas (Dth)	1,229,978	1,264,342	-3%
TRC Test Results			
TRC Net Benefits (2022$)	$9,378,905	$5,731,291	64%
TRC BCR	2.85	2.12	35%

The savings in the OAK Program are not as long lived as the savings in the RP Program, which is why lifetime gas savings are slightly lower between the two plans. However, the OAK Program is able to achieve significantly more TRC benefits per dollar spent than the RP Program. This, along with the reduction in portfolio wide spending, increases net benefits under the TRC test.

Q. When does Columbia Gas anticipate implementing the proposed

updates?

A. The Company plans to continue offering its current programs without interruption, while reducing or eliminating marketing of its OAK Program to dial back participation and maintain budgets. Columbia Gas then plans to make the new heat pump and insulation measures available to customers starting January 1st, 2025, pending approval of the updated Plan.

4 Specific Plan Updates

Q. Please describe the updates to the RP Program.

A. The RP Program has been updated in two ways. First, the rebate participation, costs, and savings were updated for 2023. The rebate participation figures represent actual participation. The costs and savings figures for 2023 are currently being finalized and preliminary figures are being used in the updated Plan. Final cost and savings figures will be provided in the Regulatory Annual Report filing by April 1st, 2024. Secondly, Columbia is seeking approval for the addition of rebate offerings to customers who install natural gas-powered heat pumps and for customers who install insulation and air sealing in their home. The updated program is expected to cost $2.0 million in nominal dollars over three years and save 798 thousand Dth of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $3.1 million with a BCR of 1.95. The program will also save 3,467 MWh of electricity and approximately 50 thousand tons of CO2 over the lifetime of the installed measures, which is equivalent to permanently removing over 1,905 cars from the road.

Q. Please describe the new rebate for insulation and air sealing.

A. Columbia Gas will offer customers a rebate of 25% of the cost of insulation and air sealing, up to $2,500. This measure will help customers improve the comfort of their homes, save significant energy over a long period of time, and aligns with rebates that may be made available through the Inflation Reduction Act ("IRA") of 2022 via the Pennsylvania Department of Environmental Protection. In addition, this offering provides customers who are not ready to replace existing natural gas equipment the opportunity to use the least amount of natural gas possible in their home. When they are then ready to replace their existing natural gas equipment, their building shell will be improved, leading to further savings and the ability to likely downsize their new equipment. The Company anticipates rebates for 164 air sealing and insulation jobs in 2025.

Q. Please describe the new rebate for natural gas heat pumps.

A. The Company plans to provide an incentive of $2,000 to customers who switch from a natural gas-powered furnace or boiler to a natural gas-powered heat pump. Natural gas heat pumps can provide efficiency levels of over 140%, compared to a maximum of approximately 98% for furnaces and boilers. This technology will provide a way for Columbia Gas's customers to have access to the most efficient natural gas heating equipment available. The Company projects rebates for four natural gas heat pumps in 2025.

Q. Will there be any changes to how the RP program is administered?

A. No. The same third-party administrator resources that are currently administering the program and the same internal staff at Columbia will administer the updated RP program.

Q. Please describe the updates to the OAK program.

A. The updates to the OAK Program solely include updated projections based on 2023 program participation and costs. The overwhelming demand from Columbia customers for the OAK program led to participation rates in 2023 that nearly eclipsed the total phase projection in just five months of availability to customers. Due to this customer demand, Columbia ceased marketing the program and updated the projections for the phase. Costs were re-allocated from underspent projections in RP to account for the increased OAK participation. Even with no marketing activity in the program, the customer demand is still outpacing initial phase projections. The updated program is expected to cost $1.4 million in nominal dollars over three years and save 431 thousand Dth of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $6.8 million with a BCR of 6.38. The program will also save 478.5 million gallons of water and approximately 25 thousand tons of CO2 over the lifetime of the installed measures, which is equivalent to permanently removing over 964 cars from the road.

Q. Will there be any changes to how the OAK program is administered?

A. No. Columbia will utilize the existing program administrator and internal staff to administer the OAK program.

Q. Are there any changes to the portfolio-wide costs associated with the updated Plan.

A. Yes. The 2023 figures have been updated with preliminary costs, while no changes have been made to portfolio-wide costs in 2024 or 2025. Finalized costs will be

provided in the Regulatory Annual Report Filing by April 1, 2024.

5 Conclusion and Recommendation

Q. Will the Updated EE Plan, if implemented, benefit the Company's residential customers?

A. Yes, it will. Columbia is proposing an updated plan investment that will return a present value of TRC net benefits of $9.4 million, in 2022 dollars, with a TRC benefit-cost ratio ("BCR") of 2.85. Not only does the Plan provide significant energy savings and economic benefits for customers, but it also helps customers increase the comfort of their home, especially with the new insulation and air sealing measure, and reduce the emission of greenhouse gases. Reduced spending on energy also shifts spending to other parts of the economy which can have both an economic multiplier effect and help with regional job creation.

Q. What conclusions do you reach about the proposed updated Plan?

A. I find that the Plan is based on the successful first year of implementation by the Company and will continue to provide important natural gas and other resource savings. Furthermore, the updated Plan more accurately reflects the demand of the Company's customer base and will continue to provide substantial economic benefits to the Company's residential ratepayers, the economy within the Company's territory, and Pennsylvania as a whole.

Q. Does this conclude your testimony?

A. Yes. I reserve the right to submit supplemental testimony during the course of the proceeding. Thank you.

Theodore Love

2534 Downingsville Rd. | Lincoln, VT 05443
tel: (919) 949 – 5906
tlove@greenenergyeconomics.com

Professional Experience

Green Energy Economics Group, Inc. – Cuttingsville, VT

Partner	2017 to Present
Senior Associate and Data Scientist	2013 to 2017
Associate	2010 to 2013
Analyst	2007 to 2010

For over 15 years, Theodore "Theo" Love has been providing insights into the design, analysis, and implementation of energy efficiency and distributed energy resource programs and portfolios in twelve states, three Canadian provinces, and China. He has a particular focus on EE/DER policy analysis, program design and implementation, cost-effectiveness testing, financing, and building scalable tools to analyze everything from individual projects to programs to portfolios. Some recent project experience includes:

- Providing regulatory and policy analysis assistance to the Small business Utility Advocate in California and Ontario on various energy efficiency dockets.
- Ongoing review and analysis of EfficiencyOne's energy efficiency portfolio in Nova Scotia on behalf of the Consumer Advocate of Nova Scotia.
- Design, regulatory, and implementation support for voluntary electric and gas energy efficiency programs in Pennsylvania for UGI, PGW, and Columbia Gas.
- Working with PSE&G in New Jersey on forecasting and scaling their internally managed commercial and industrial programs.

2007 – 2010
Consultant, **Alter & Rosen, LLP**, New York, NY

2006 – 2007
Client Reporting Analyst, **AllianceBernstein LP**, White Plains, NY

Affiliations

Association of Energy Service Professionals (AESP) - Business Issues and Regulatory Models Topic Committee Co-Chair 2023 - present
AESP Gas Topic Committee Co-Chair 2019-2023
AESP National Conference Planning Committee 2021, 2022, 2023
Energy Efficiency Alliance (EEA) of Pennsylvania / New Jersey - Policy Conference Planning Committee 2022, 2023

Recent Project Experience

Green Energy Economics Group, Inc.

Economic and Policy Analysis
Small Business Utility Advocate - California *(June 2020 – Present)*

- Reviewed plans and provided testimony on codes and standards, program budgets, and non-energy benefits (Docket No. A22-02-005)
- Provided assistance on comments and testimony regarding phase out of gas incentives (Docket No. A22-02-005)
- Reviewed plans and provided testimony on cost-effectiveness test and application of Automated Response Technology (ART) Program. (Docket No. A22-05-002)
- Assisted SBUA with analysis of claims and provided feedback on potential areas of mismanagement of funds (Docket No. A22-06-003)
- Reviewed plan and worked with SBUA to draft advice letter on program design related to small business, measures selection, and reporting requirements. (Docket No. R08-16-021)
- Participated in working group to examine the definition of underserved customers. Authored report on participation rates for small and microbusinesses in CA energy efficiency programs. (Docket No. R13-11-005)
- Provided comments on cost-effectiveness tools and reporting databases for Energy Efficiency programs (Docket No. R13-11-005)
- Reviewed third-party evaluation plans (Docket No. R13-11-005)
- Participated in workshops and developed comments and testimony supporting small business access to clean energy financing (Docket No. R20-08-022).
-

Economic and Policy Analysis
Small Business Utility Alliance – Ontario, CA *(June 2021 – Present)*

- Reviewed plan and participated in fully litigated proceeding, including providing testimony on bet practices and program design, coordination with electric programs, cost-effectiveness, shareholder incentives, and stake holder engagement. (Matter No. EB-2021-0002)

Economic and Policy Analysis
Consumer Advocate – Nova Scotia *(March 2019 – Present)*

- Member of DSM Advisory Group (DSMAG) on behalf of the Consumer Advocate of Nova Scotia to provide ongoing support for design and implementation of programs.
- Provided analysis and written testimony on Efficiency One's (E1) 2023 – 2025 DSM Plan (Matter No. M10473) as it relates to historical spending, affordability, underserved communities, and avoided costs.

- Provided analysis and written testimony on Efficiency One's (E1) 2020 – 2022 DSM Plan (Matter No. M09096) as it relates to spending and savings levels, affordability, and allocation of funds.
- Provided comments on the 2019 DSM Potential Study's economic analysis and projection assumptions and approach

Program Management and Benefit Cost Analysis Expert
Public Service Enterprise Group (PSE&G) – New Jersey (October 2021 – April 2023)

- Consulted on forecasting and management of PSE&G's internally run commercial Engineered Solutions and Direct Install programs.
- Assisted with rollout of tracking system for PSE&G DSM portfolio.
- Provided assistance with calculation of six economic tests for PSE&G's energy efficiency and conservation portfolio, including development of calculation engine and launch as a subcontractor to ANB Enterprises.

Development and Regulatory Support for DSM Portfolio
Columbia Gas of Pennsylvania - Pittsburgh, Pennsylvania (February 2022 – Present)

- Successfully developed, provided regulatory support for, and got approval of a three-year voluntary gas energy efficiency plan and provided supporting testimony under Docket No. P-2014-2459362.
- Ongoing assistance with the launch and implementation of the first three-year voluntary gas energy efficiency plan.

Development and Implementation of Energy Efficiency and Conservation Plans
UGI Utilities, Inc. – Pennsylvania (June 2015 – Present)
Assist UGI Utilities, Inc. and PNG with the development and approval of Energy Efficiency and Conservation (EE&C) Plans for their UGI Gas PNG Gas, and UGI Electric divisions, including:

- Ongoing evaluation and portfolio planning activities for both UGI Gas and UGI Electric energy efficiency portfolios.
- Developing an achievable efficiency scenarios for UGI Gas and PNG Gas.
- Designing a five-year, $27 million energy efficiency and conservation plan for UGI Gas. Submitting direct testimony on behalf of UGI Gas, Inc. on the design and implementation of the proposed plan (Docket No. R-2015-2518438)
- Designing a five-year $15 million energy efficiency and conservation plan for PNG Gas. Submitting direct testimony on behalf of PNG Gas, Inc. on the design and implementation of the proposed plan (Docket No. R-2016-2580030)
- Assisting with the design and implementation and reporting of the UGI Electric's voluntary EE programs. Designing and assisting with approval for a five-year $7.2 million electric energy efficiency and conservation plan (Docket No. M-2018-3004144)

Strategic Planning and Implementation of DSM Portfolio
Philadelphia Gas Work's (PGW) - Philadelphia, Pennsylvania (August 2008 – Present)

- Assisting with ongoing program planning and implementation of both the Low-Income Usage Reduction Plan (LIURP) and the market-rate DSM portfolio.

- Provided supporting testimony and analysis for the Phase III market-rate DSM plan under Docket No. P-2014-2459362.
- Designed Phase II plan with PGW and submitted direct testimony supporting the plan on behalf of PGW (Docket No. P-2014-2459362)
- Member of lead consulting team that aided in the design and approval of PGW's five-year, $54 million portfolio of DSM programs;
- Providing ongoing technical assistance in the development of PGW's $35 million Phase II five year plan.
- Providing ongoing technical support in program design and implementation, including the roll-out of six programs that, combined since inception, have saved 120,000 MMBtus at a cost of approximately $17 million;
- Developed specifications for and currently collaborating with internal PGW staff on database system to track weatherization projects, rebate applications, and other information pertaining to PGW's DSM portfolio;
- Developed multiple Excel-based tools used by contractors to perform field audits, provide QA/QC, and track ongoing progress for contractors, programs, and the portfolio as a whole;
- Provided research and analysis support for multiple rounds of expert testimony before the Pennsylvania Public Utility Commission (Docket R-2009—2149884);
- Aided in the issuance of RFPs and selection of candidates for over $40 million in contracts;
- Major contributor to PGW's ongoing formal reporting and evaluation process, including the issuance of five implementation plans, three annual reports, and two impact evaluations.

DSM Potential Studies in New York, New Jersey, and Pennsylvania
Optimal Energy, Inc. - Vermont *(December 2018 – December 2019)*

- Assisted Optimal Energy, Inc. with the development of measure assumptions and characterizations for statewide, electric and gas DSM potential studies.

Natural Gas Efficiency Options and EE&C Plan for Peoples Natural Gas
Peoples Natural Gas, Inc. – Pennsylvania *(September 2017 – February 2019)*

- Prepared report on program, sector, and portfolio-level cost and savings for 29 natural gas administrators in 11 States, and provided recommendations for potential natural gas DSM opportunities for Peoples Natural Gas
- Assist with stakeholder review process
- Developed five year $42 million Energy Efficiency and Conservation (EE&C) Plan, and provided testimony to support the adoption of the Plan (ongoing).

Research on Leading Energy Efficiency Portfolios
Green Energy Economics Group - Vermont *(November 2007 – Present)*

- Maintain research and proprietary analysis on actual and projected results from over a dozen electric and natural gas demand side management (DSM) portfolios throughout North America;

Analytic and Technical Support for DSM Tracking Systems
PECO Energy Company – Pennsylvania (September 2016 – December 2017)
Commonwealth Edison Company – Illinois (August 2017 – August 2018)
Companywide (September 2020 – present)

- Subcontractor to ANB Systems Inc. to provide domain expertise and analytic support to rollout of enhanced tracking system.
- Developed dashboards and internal reports used by PECO's EM&V team, business planning, and various program and portfolio managers.
- Guided automation of PECO's six-month and annual reporting process.
- Provided expert guidance on the development of cost effectiveness calculation modules for clients in Pennsylvania and New Jersey
- Oversaw project development of audit tool for ComEd's Carbon Free School Assessment Program.

Technical Assistance for Energy Efficiency Program Planning
Green Mountain Power - *Vermont (August 2012 – July 2017)*

- Developed multivariable regression model and framework to estimate the cost per kW to address a reliability gap in the St. Albans region with targeted energy efficiency.
- Reviewed and analyzed program proposals for the $20 million Community Energy & Efficiency Development Fund (CEED Fund), including the development of scoring and rebalancing mechanisms;
- Analyzed dataset of 5,000 custom business projects to establish models used for future planning exercises.
- Prepared report on uncounted benefits of renewable generation sources for Vermont.

Analysis of Energy Efficiency in British Columbia
BC Sustainable Energy Association & Sierra Club BC, *British Columbia (May 2011 – June 2014)*

- Provided comments and energy efficiency opportunities report for proceedings on FortisBC Gas and Electric's long-term DSM plans in December of 2013.
- Assisted on research for direct testimony on reasonableness of gas DSM Plan by Fortis Energy Utilities before the British Columbia Utilities Commission, BCUC Project No. 3698627;
- Technical support on assessment of FortisBC Electric's long-term DSM plan and corresponding expert testimony;
- Assistance with direct testimony and technical support on assessment of BC Hydro's long-term DSM plan, before the BCUC.

Energy Efficiency Potential in Oklahoma
Sierra Club, *Oklahoma (April 2011 – November 2011, December 2013 – January 2014)*

- Provided updated report for energy efficiency in Oklahoma and additional comments on PUC rulemaking for electric and gas utility programs.
- Preparation of report on energy efficiency potential for Oklahoma;
- Assistance with research and drafting comments on the US regional haze Federal Implementation Plan for the State of Oklahoma;

- Research and formulation of energy efficiency potential projections provided as part of expert testimony for Oklahoma Gas & Electric's rate case before the Corporation Commission of Oklahoma, Cause No. PUD 201100087.

Technical Assistance for Energy Efficiency Programs
Focus on Energy - *Wisconsin* *(June 2011 – August 2013)*

- Developed and customized cost-effectiveness calculators for Wisconsin's Focus on Energy portfolio of energy efficiency programs;
- Trained staff and other consultants on usage of tools and general economic analysis of energy efficiency programs;
- Provided QA/QC on cost-effectiveness analysis of 14 programs spending over $160 million in two years.

Chicagoland Energy Efficiency Portfolio
People's Gas - *Chicago, Illinois* *(September 2008 – January 2013)*

- Providing ongoing regulatory support;
- Provided cost-benefit analysis of various program scenarios and aided in the analysis of contractor bids;
- Customized excel-based portfolio and project cost-effectiveness tools to client's specifications.

Testimony Support for Expanding Gas Energy Efficiency in Pennsylvania
Citizens for Pennsylvania's Future, *Pennsylvania* *(July 2013 – September 2013)*

- Provided support on preparation of testimony regarding Peoples Gas of Pennsylvania's DSM plans, including preparation of benchmarking report and alternative scenario projections.

Energy Efficiency Potential in Texas
Sierra Club, *Texas* *(May 2012 – August 2012)*

- Research and development of alternative energy efficiency potential scenarios for the ten investor owned utilities (IOUs) in Texas;
- Development of comments for the Public Utility Commission of Texas;
- Development of presentation before the Energy Efficiency Incentive Program Committee.

Austin Energy's Energy Efficiency Potential
Austin City Council Consumer Advocate, *Austin, Texas* *(April 2012)*

- Research and development of alternative energy efficiency potential scenarios for Austin Energy.

Nevada Power's Energy Efficiency Potential
Sierra Club, *Nevada* *(November 2011 – June 2012)*

- Research on Nevada Power's Integrated Resource Plan (IRP) and development of alternative energy efficiency potential projections.

Comments on EmPower Maryland Programs
Sierra Club, *Maryland* *(September 2011 – October 2011)*

- Research for and development of comments on EmPower Maryland's energy efficiency programs, including the development of alternative energy efficiency potential projections.

Ontario Power Authority Field Audit Support Tool
Green Communities Canada - *Ontario, Canada* *(January 2011 – May 2011)*

- Collected and implemented specifications for updating the tool used by Ontario Power Authority's low-income program field agents to collect data and determine project net present values;
- Added custom features including customer input forms, saving and closing routines, and database file importing.

Energy Efficiency Potential in Arkansas
Sierra Club/Audubon Society, *Arkansas* *(September 2009 – March 2010)*

- Research and drafting assistance for expert testimony on energy efficiency' as an alternative to the White Bluff Steam Electric Station before the Public Service Commission of Arkansas, Docket No. 09-024-U.

Training for NGOs Working on Energy Efficiency Projects in China
ISC and NRDC – United States and China *(August 2008 – September 2010)*

- Developed training materials and provided remote and in-person training sessions on the economic and financial analysis of industrial retrofit projects for structuring and negotiating financial incentive offers to customers;
    - Worked with the Institute for Sustainable Communities (ISC) to aid its efforts to promote energy efficiency in the Guangdong and Jiangsu Provinces (February 2009 – September 2010);
    - Worked with the National Resource Defense Council (NRDC) to aid in its efforts in China, especially in conjunction with a $100 million revolving loan fund from the Asia Development Bank (August 2008- January 2009).

Incentive Calculations for the Project Cost-effectiveness Analysis Tool (CAT)
Efficiency Vermont – Burlington, Vermont *(November 2008 – June 2010)*

- Aided in the design of a new approach to calculating incentives for custom energy efficiency projects based on financing and reaching a desired rate of return;
- Modified CAT's cash-flow projection engine, an Excel VBA system, to accommodate the new approach to incentives.

Vermont's 20-year Forecast of Electricity Savings from Sustained Investment
Efficiency Vermont – Burlington, Vermont *(December 2008 – October 2009)*

- Provided components of final report relating to long-term trends for the environment (climate change, land-use, and water-use), population growth, and governmental regulation;

- Provided additional technical support on electric demand-side savings potential.

Connecticut's Long Term Acquisition Plan
Connecticut Office of the Consumer Council – Connecticut (August – October 2008)

- Provided research and support for expert testimony regarding long-range energy-efficiency procurement plan of the Energy Conservation Management Board, on behalf of the Connecticut Office of Consumer Counsel.

Energy Efficiency Plans of BC Hydro and Terasen Gas
BC Sustainable Energy Association and
The Sierra Club - British Columbia, Canada (October 2008 – March 2009)

- Provided research and support for expert testimony and technical support on assessment of BC Hydro's long-term DSM plan, before the BCUC, on behalf of the BC Sustainable Energy Association and Sierra Club Canada (November 2008 – March 2009);
- Provided research and support for expert testimony on assessment of Terasen Gas conservation plans before the BCUC, on behalf of the BC Sustainable Energy Association and Sierra Club Canada (October 2008).

Testimony and Proceeding Participation

Forum	On Behalf Of	Docket/Matter	Date	Issues Addressed
Pennsylvania Public Utility Commission	Philadelphia Gas Works	Docekt No. P-2014-2495362. Approval of Demand-Side Management Plan for FY 2024-2026	September-23	Historical performance. Plan design and cost-effectiveness.
Pennsylvania Public Utility Commission	UGI Utilites Inc. - Electric Division	Docket No.M-2023-3043230 . Petition of UGI Utilities, Inc. – Electric Division for Approval of Phase IV of its Energy Efficiency and Conservation Plan	September-23	Energy efficiency plan proposal, including projections for costs, savings, and cost-effectiveness.
California Public Utility Commission	Small Business Utility Advocates	R. 22-02-005. Application of Pacific Gas and Electric Company for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Portfolio Plan (U 39 M) and associated Matters.	October-22	Issues related to 3-year Energy Efficiency Business Plan

California Public Utility Commission	Small Business Utility Advocates	R. 22-02-005. Application of Pacific Gas and Electric Company for Approval of 2024-2031 Energy Efficiency Business Plan and 2024-2027 Portfolio Plan (U 39 M) and associated Matters.	September-22	Comments on the phase out of gas incentives.
Nova Scotia Utility and Review Board	The Consumer Advocate of Nova Scotia	Matter No. M10473 An Application by EfficiencyOne for Approval of a 2023 – 2025 Demand Side Management ("DSM") Resource Plan	May-22	Historical performance of portfolio, proposed scenarios, affordability, addressing underserved communities, program design, and avoided costs.
Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	Docket No. R-2022-3031211. Columbia Gas of Pennsylvania, Inc. 2022 Rate Case Proceeding	March-22	Three-year energy efficiency plan proposal, including projections for costs, savings, and cost-effectiveness.
Ontario Energy Board	Small Business utility Alliance	EB-2021-0002. Enbridge Gas Inc. – Multi Year Demand Side Management Plan (2022 – 2027)	December-21	Analysis of commercial program goals and program design
California Public Utility Commission	Small Business Utility Advocates	R. 21-02-014. Rulemaking to Address Energy Utility Customer Bill Debt Accumulated During the COVID-19 Pandemic.	April-21	Report on Analysis of Small Business Utility Bill Arrearages in California during COVID-19
Pennsylvania Public Utility Commission	Philadelphia Gas Works	P-2014-2459362, Petition of Philadelphia Gas Works for Approval of Demand-Side Management Plan for FY 2016-2020	October-20	Historical performance of PGW's DSM Phase II Plan and modifications to program design.
California Public Utility Commission	Small Business Utility Advocates	R. 20-08-022 to Investigate and Design Clean Energy Financing Options for Electricity and Natural Gas Customers	July-20	Comments to address options for small business customer
Nova Scotia Utility and Review Board	The Consumer Advocate of Nova Scotia	Matter No. M09096, Efficiency 1 (E1) Application for Approval of 2020 – 2022 Demand Side Management (DSM) Resource Plan	May-19	DSM Investment Levels and Affordability, Usage of Unspent Ratepayer Funding, Rate and Bill Impacts, Target Setting.

Pennsylvania Public Utility Commission	UGI Gas Utilities Inc. – Gas Division	R-2018-3006814, UGI Gas Utilities Inc. – Gas Division, Rate Case	January-19	Energy Efficiency & Conservation Plan and Total Resource Cost Implementation.
Pennsylvania Public Utility Commission	UGI Utilities, Inc. – Electric Division	M-2018-3004144, Petition of UGI Utilities, Inc. – Electric Division for Approval of Phase III of Its Energy Efficiency and Conservation Plan	August-18	Electric energy efficiency and conservation plan development, projections, implementation, and EM&V.
Pennsylvania Public Utility Commission	Peoples Natural Gas Company	M-2017-2640306, Petition of Peoples Natural Gas Company LLC for Approval of its Energy Efficiency and Conservation Plan	January-18	Energy efficiency study, energy efficiency & conservation plan, and total resource cost implementation.
Pennsylvania Public Utility Commission	UGI Penn Natural Gas, Inc	P-2016-2580030, UGI Penn Natural Gas, Inc. Rate Case	January-17	Energy efficiency & conservation plan and total resource cost implementation.
Pennsylvania Public Utility Commission	UGI Utilities, Inc.	P-2015-2518438, UGI Utilities, Inc.- Gas Division Rate Case	January-16	Energy efficiency & conservation plan and total resource cost implementation.
Pennsylvania Public Utility Commission	Philadelphia Gas Works	P-2014-2459362, Philadelphia Gas Works Demand-Side Management Plan for FY 2016-2021	May-15	Analysis of Phase I DSM Plan and design of Phase II DSM Plan.

Publications

Love, Theodore. J. Nunley. "Using Smart Thermostats to Engage Residential Customers and Drive Comprehensive Retrofit Projects" In *Proceedings of the ACEEE 2020 Summer Study on Energy Efficiency in Buildings*, Washington, D.C.: American Council for an Energy Efficient Economy.

Love, Theodore. "The Future for Residential Gas Efficiency is Combined". *Strategies*. Association of Energy Service Professionals. January 11, 2019.

Love, Theodore. "Using Open Data to Predict Energy Usage: What tax lot data can tell us about energy usage intensity in New York City". *Behavior Energy, and Climate Change Conference 2015*. Sacramento, CA

Plunkett, John, Theodore Love, Francis Wyatt. "An Empirical Model for Predicting Electric Energy Efficiency Acquisition Costs in North America: Analysis and Application". In *Proceedings of the ACEEE 2012 Summer Study on Energy Efficiency in Buildings*, #906, Washington, D.C.: American Council for an Energy Efficient Economy.

Gold, Elliott, Marie-Claire Munnelly, Theodore Love, John Plunkett, Francis Wyatt. "Comprehensive and Cost-Effective: A Natural Gas Utility's Approach to Deep Natural Gas Retrofits for Low Income Customers." In *Proceedings of the ACEEE 2012 Summer Study on Energy Efficiency in Buildings*, #442, Washington, D.C.: American Council for an Energy Efficient Economy.

Education

Clark University – Worcester, MA
B.A. Magna cum Laude, *Mathematics and Computer Science*, 2006.
Study Abroad Program, Spring Semester 2005 (Kansai Gaidai University: Osaka Japan)

General Assembly: New York City, NY
Data Science Intensive Course, 2015

Columbia Gas of Pennsylvania

Updated Three-Year Energy Efficiency Plan –
January 1, 2023 – December 31, 2025

March 15, 2024

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1 Introduction and Background

1.1 Plan Update

The updated plan outlined below is being proposed to meet two primary objectives. First, necessary updates were made to projections and costs based on the performance trends experienced in 2023. Secondly, new measures are being proposed to be added to the Residential Prescriptive (RP) program to address new technology and achieve alignment with federal efficiency initiatives that will be launching during the term of this filing. These two objectives and the benefits to the proposed updates are outlined in greater detail below.

Updated Costs and Projections

Participation trends in 2023 showed much greater than anticipated demand for the Online Audit Kit (OAK) program and lower than anticipated demand for the RP program. The updated tables throughout the plan show actual participation numbers from 2023 with preliminary cost and savings figures for each program, including Portfolio Wide (PW) administrative costs. The final cost and savings figures are still being finalized and will be filed in the required Annual Report, shortly after the date of this filing. In addition, participation, and spending projections for 2024 and 2025 were updated to match the trends shown in 2023. The result of this update is greater participation in the OAK program and slightly lower participation in the RP program.

Added RP Rebate Measures

To address newly available high efficiency natural gas heating technology, residential natural gas heat pumps are being added to the RP program. The efficiency of this measure can exceed 140% and provides the highest efficiency option available on the market for customers heating their home with natural gas. This measure is being proposed with two different baselines. A furnace baseline for forced air natural gas heat pumps and a boiler baseline for air to water natural gas heat pumps. In particular, the air to water natural gas heat pump provides a

much-needed higher efficiency alternative to customers that are looking to achieve the lowest natural gas usage possible while utilizing the existing infrastructure from their natural gas boiler.

In addition to natural gas heat pumps, a rebate is being added for customers who install insulation and air sealing in their home. This measure provides customers with long lasting energy savings by upgrading the performance of their building shell and aligns with the Federal Inflation Reduction Act (IRA) that is likely to be launched in Pennsylvania sometime toward the end of 2024 or beginning of 2025.

1.2 Plan Overview

This plan provides a detailed description of the design and implementation of the energy efficiency and conservation portfolio ("EE&C Portfolio" or "Portfolio") that Columbia Gas of Pennsylvania, Inc. ("Columbia Gas" or "the Company") is proposing to offer in its Three-Year Energy Efficiency ("EE Plan" or "Plan"). The Plan builds on other voluntary gas energy efficiency plans offered by natural gas distribution companies serving Pennsylvania, and specifically targets residential customers. This document provides an updated scenario that aligns with settlement conditions to maintain a budget of $4 million over the 3-year period. In this scenario, the Residential Prescriptive program's initial year participation was reduced and projected ramp up was taken down to minimal levels for 2024 and 2025, with associated reductions in variable administration and marketing costs. Similarly, the first year and ramp up for the Online Audit Kit Program was adjusted downward significantly for 2024 and 2025. Portfolio wide costs were maintained at current levels to maintain full oversight of the portfolio.

The Plan has a three-year duration, beginning January 1, 2023 and ending December 31, 2025. Over the three years of the Plan, Columbia Gas plans to spend $4.0 million on the administration and delivery of two residential energy efficiency programs. The programs are projected to save 1.2 million Dth of natural gas over the lifetime of the measures installed. From a total resource perspective, the portfolio present value of benefits is $14.4 million, with $5.1 million in present value of costs, leading to a present value of net benefits of $9.4 million and a TRC

BCR of 2.85. Furthermore, the energy efficiency programs are expected to save 3,467 MWh of electricity, 479 million gallons of water, create between 37 and 75 jobs, and avoid the emission of CO_2 equivalent to over 2,869 cars being removed from the road over the lifetime of installed measures.

1.3 Plan Development

The Plan was developed to help Columbia Gas' residential customers to address barriers to using natural gas more efficiently. It has two programs:

- Residential Prescriptive (RP) Program
- Online Audit Kit (OAK) Program

The RP Program is based on rebate programs run in Pennsylvania by other natural gas distribution companies. The OAK Program is based on a successful program run by Columbia Gas of Virginia for over the past decade.

Various market characteristics were gathered for Columbia Gas' territory, including avoided costs for natural gas and electricity, demographic, building stock, and equipment market characteristics. Next, measures were characterized and screened for cost effectiveness using the TRC test. Incentive levels were established for these measures and projects, generally set to be in-line with the other programs in Pennsylvania. The cost-effective measures and projects were then used to calculate savings and maximum participation levels. Programs were staged to account for the ramp-up required for new programs. Finally, non-incentive budgets were developed to address fixed and variable costs associated with each program and the portfolio. For the settlement scenario, budgets were constrained to a $4 million overall spend.

1.4 Portfolio Costs

The following table provides an overview of the spending by year and program for the total EE Plan. The maximum projected budget in a year is $1.9 million in FY 2025, approximately 0.34% of Columbia Gas' FY 2020 revenues.[1] Although Act

[1] $3.8 million is 0.7% of total 2020 revenues of $555 million from Columbia's Annual Report of Columbia Gas of Pennsylvania, Inc. Year Ended December 21, 2020 at p. 26.

129's requirements are not mandatory for voluntary natural gas distribution company energy efficiency programs, this level is well under the 2% cap that Act 129 imposes on electric efficiency programs in Pennsylvania.[2] Since only residential customers are eligible for the programs, it is anticipated that all costs will be recovered from the residential rate class, excluding Customer Assistance Program ("CAP") customers.

Table 1. Projected Spending for EE Plan by Program

Projected Costs (Nominal)	2023	2024	2025	2023 - 2025
Residential Prescriptive Program	$311,100	$626,000	$1,055,700	$1,992,800
Online Audit Kit Program	$222,900	$551,300	$636,000	$1,410,200
Portfolio Wide Costs	$125,000	$234,000	$238,000	$597,000
Total	**$659,000**	**$1,411,300**	**$1,929,700**	**$4,000,000**

The portfolio-wide cost lines from the previous table are costs that apply to all programs in the EE portfolio. They are costs incurred at the portfolio level for program development, design, tracking, reporting, and administrative overhead. Development costs for the portfolio occur in the first year as programs are designed and reporting infrastructure is put in place. These costs become a smaller percentage of the portfolio as the rest of the programs ramp up. In the final year, the portfolio wide costs represent 13% of the portfolio total cost, and, over the three-year period, they represent 16% of the portfolio's costs. The following table provides a portfolio-level look at costs by category.

Table 2. Projected Efficiency Portfolio Budgets by Category

Category	2023	2024	2025	2023 - 2025
Customer Incentives	$320,000	$714,300	$1,031,700	$2,066,000
Administration	$298,000	$581,000	$647,000	$1,526,000
Marketing	$38,000	$72,000	$107,000	$217,000
Inspections	$3,000	$24,000	$34,000	$61,000
Evaluation	$0	$20,000	$110,000	$130,000
Total	**$659,000**	**$1,411,300**	**$1,929,700**	**$4,000,000**

[2] *See* 66 Pa.C.S. § 2806.1(g) (limiting the total cost of an EDC's EE&C Plan to 2% of the EDC's total annual revenue as of December 31, 2006).

1.5 Portfolio Benefits

1.5.1 Natural Gas Savings

The following tables provide projected natural gas savings by program and sector for the EE Plan.

Table 3. Projected First Year Gas Savings by Program (Dth)

Program	2023	2024	2025	2023 - 2025
Residential Prescriptive Program	6,447	15,719	21,989	44,154
Online Audit Kit Program	7,446	14,024	15,943	37,413
Total	**13,893**	**29,742**	**37,932**	**81,567**

Table 4. Projected Lifetime Gas Savings by Program (Dth)

Program	2023	2024	2025	2023 - 2025
Residential Prescriptive Program	119,875	270,261	408,386	798,523
Online Audit Kit Program	90,326	156,820	184,309	431,455
Total	**210,201**	**427,082**	**592,695**	**1,229,978**

1.5.2 Other Resource Savings

The following table shows electric savings for measures installed under the energy efficiency programs in the EE&C Portfolio. The electric savings are secondary savings from measures that primarily save natural gas, such as air-conditioning savings from thermostats. This section contains ancillary water savings from gas efficiency measures that also save water, such as low-flow faucet aerators and showerheads.

Table 5. Projected Electric and Water Savings

	2023	2024	2025	2023 - 2025
First Year				
Energy (MWh)	25	95	145	**265**
Demand (kW)	4.5	16.9	43.1	**64.4**
Water (Million Gallons)	7.9	19.7	20.2	**47.9**
Lifetime				
Energy (MWh)	276	1,040	2,150	**3,467**
Water (Million Gallons)	78.8	197.4	202.3	**478.5**

1.5.3 Emission Reductions

This section contains projections for CO_2 emission reductions due to the energy efficiency programs. The total lifetime savings of 76 thousand tons of CO_2 is equivalent to removing over 2,897 cars off the road. The following table breaks out the emission reductions due to gas savings and electric savings. While the emissions reductions are projected below, the main TRC test for the portfolio does not include any monetized value for these emissions reductions.

Table 6. Projected Lifetime CO_2 Emission Reductions by Energy Source (Short Tons)

Savings Source	2023	2024	2025	2023 - 2025
Natural Gas	12,297	24,984	34,673	71,954
Electricity	252	950	1,964	3,167
Total	**12,549**	**25,935**	**36,637**	**75,120**

1.5.4 Job Creation

Investing in cost-effective energy efficiency creates jobs in two ways, one direct and the other indirect, as discussed in a 2012 white paper from the ACEEE.[3] Direct job creation results from hiring related to implementing the programs. Indirect job creation results from the substitution of capital spent on natural gas with capital spent in the local economy. Additional jobs are created by the indirect or income effect from cost-effective energy efficiency investment. Further, the net economic benefits from efficiency investment reduce household and business gas bills and raise household disposable incomes and business profitability. Customers will tend to spend most of this additional money and save the rest. This additional spending creates a "multiplier" effect through the cycle of re-spending of the initial cost savings, which stimulates aggregate demand for goods and services. Satisfying increased demand for goods and services requires more labor. While some of the jobs created leak into the broader U.S. and global economy, a good portion (possibly higher than 80%) of jobs created due to energy efficiency stay within the Commonwealth. The approach of looking at net job

[3] "Energy Efficiency Job Creation: Real World Experiences" Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.

creation through both direct means and with economic multiplier effects is endorsed in the 2012 white paper from ACEEE.[4]

The number of jobs created from investments in energy efficiency directly relates to the total resource value of the energy that these measures save. Studies of employment impacts of Demand Side Management ("DSM") use energy savings as a surrogate for total resource value. A meta-study of U.S. data found that estimates for the number of jobs created had a wide range, but that most studies estimate that between 30 and 60 net jobs are created by saving one TBtu.[5] In New York, New Jersey, and Pennsylvania, the ACEEE projected that 164,320 jobs, or 59 for every TBtu saved, could be attributed to EE in 1997 through 2010.[6]

As shown in the following table, Columbia Gas estimates that its gas energy efficiency programs portfolio will generate between 38 and 76 net additional jobs over the lifetime of the efficiency measures installed over the next five-years. This range is based on assuming that each TBtu of gas savings creates between 30 and 60 full-time equivalent jobs in Pennsylvania.

Table 7. Estimated Job Creation due to Energy Efficiency Programs

	JOB CREATION IMPACTS OF GAS EFFICIENCY PORTFOLIO		
	30 Jobs/TBtu	45 Jobs/TBtu	60 Jobs/TBtu
TOTAL PORTFOLIO			
2023	7	11	15
2024	13	19	25
2025	17	26	35
TOTAL	**37**	**56**	**75**

[4] Energy Efficiency Job Creation: Real World Experiences" Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.
[5] Laitner, Skip, and Vanessa McKinney. June 2008. *Positive Returns: State Energy Efficiency Analyses Can Inform U.S. Energy Policy Assessments*. Washington, D.C.: American Council for an Energy Efficiency Economy.
[6] Nadel, Steven, Skip Laitner, Marshall Goldberg, Neal Elliott, John DeCicco, Howard Geller, and Robert Mowris. 1997. *Energy Efficiency and Economic Development in New York, New Jersey, and Pennsylvania. Washington, D.C.*: American Council for an Energy Efficiency Economy.

1.6 Cost-Effectiveness Analysis

The following table provides Total Resource Cost (TRC) test cost-effectiveness projections for the EE Plan.

Table 8. TRC Cost-effectiveness Summary of Portfolio (2022$)

Program	Total Resource PV Benefits	Total Resource PV Costs	Total Resource PV Net Benefits	Total Resource B/C Ratio
Residential Prescriptive Program	$6,388,970	$3,270,996	$3,117,975	1.95
Online Audit Kit Program	$8,060,188	$1,262,372	$6,797,816	6.38
Portfolio Wide Costs	$0	$536,886	($536,886)	-
EE Programs	**$14,449,159**	**$5,070,254**	**$9,378,905**	**2.85**

While the portfolio is cost effective using the primary TRC Test, if the values for demand-response induced pricing effects ("DRIPE")[7] and internalized market prices for carbon dioxide ("CO_2") are included, the portfolio would show substantially more benefits.

1.6.1 Cost-Effectiveness Analysis Methodology

The cost-effectiveness results reported in the Plan followed standard industry practices for utilizing the TRC Test for cost effectiveness. The TRC Test methodology used is similar to that used by other natural gas distribution companies serving Pennsylvania that offer energy efficiency programs, and by the Act 129 Utilities. To calculate benefits, projected natural gas, electricity, and water savings are multiplied by avoided costs, and this stream of future values is discounted to the present. The cost side of the test consists of the present value of all incremental costs incurred by participants, including net operation and maintenance costs, and the non-incentive costs incurred by the portfolio administrator. If the benefits outweigh the costs (the benefit-cost ratio is above

[7] DRIPE accounts for the suppression effects on wholesale prices from reduced usage due to DSM.

one), then the total cost of energy services for an average customer within the territory will fall and the portfolio is considered cost effective

The analysis used a real discount rate (RDR) of 3%. The RDR was calculated using an assumption of a nominal discount rate ("NDR") of 5% and inflation rate of 2.0%, which comes from the Act 129 Phase IV TRC Test Order.[8]

1.6.2 Avoided Costs

The avoided cost of natural gas for Columbia Gas of Pennsylvania was developed in a similar manner to other Pennsylvania natural gas distribution companies offering energy efficiency programs and includes the costs of baseload and storage capacity, along with an estimate of avoidable local distribution costs. The avoided costs for baseload capacity were computed as the cost of Columbia Gas Transmission (TCO) FTS, Henry Hub commodity was priced using NYMEX futures from March 7, 2022 through 2027. The futures prices and the 2022 Annual Energy Outlook ("AEO") forecasts are very close to one another in 2027 and 2028, and differ by less than 10% on an annual basis through the end of the futures in 2034. The Annual Energy Outlook projections were used from 2028 onward. The avoided costs for heating load were computed from the Columbia Gas Transmission SST rate, plus refill from the Columbia FSS rate, adjusted for load factor over the heating season. Commodity costs include the commodity charge and gas retention from the TCO tariffs. The avoided costs also include an allowance for avoidable load-related distribution investments, borrowed from UGI's estimates in its 2018 EE&C filing, at Docket No. R-2018-3006814.

The Plan also uses avoided costs for electric energy and peak demand based on weighted average annual values from the electric utilities in Columbia Gas' territory, including Duquesne Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn. Values for the various electric utilities came from the respective Act 129 Phase IV filings for each utility.

[8] Act 129 Phase IV 2021 Total Resource Cost (TRC) Test (Case No. M-2019-3006868). Final Order dated December 19, 2019. P. 20

Avoided costs for water came from the Act 129 Phase IV TRC Test Order.

1.7 Implementation

1.7.1 Program Staging

The Company anticipates that it will require six to nine months post Plan approval to finalize implementation details, hire vendors, and begin the marketing and outreach for ramping up the programs. All programs are projected to begin operations by July 1, 2023. This will give the programs a short year of activity in 2023, with significantly more activity projected in 2024 with the anticipation of full participation levels in 2025.

1.7.2 Administration

The Portfolio will be managed by Columbia Gas, who will engage the services of various contractors to fulfill all the roles required to implement the Plan. The table below describes the main roles in the management of the Plan.

Table 9. Overview of Administration Roles

Role	Description
Plan Administrator	Primarily responsible for program and portfolio planning, management and reporting. Supervises and manages all other roles.
Implementation and Design Consultants	Provides assistance in the design and implementation on multiple aspects of the portfolio, including, but not limited to, program design, reporting, marketing, and training.
Implementation Contractor	Directly responsible for main aspects of program delivery, including but not limited to, customer engagement and retention, technical assistance, measure installation, rebate processing, program tracking, inspection, and reporting.
Evaluator	Performs independent program and portfolio evaluations that are used to verify savings and guide future plans.

1.7.3 Marketing

Columbia Gas will investigate the use of a branded micro-website for the programs, for which multiple streams of advertising will lead back to, such as print, online ads, social media, bill inserts, trade ally outreach and residential canvassing efforts. These efforts are anticipated to be particularly important for driving

participation in the Online Audit Kit program, which in turn may feed into the Residential Prescriptive Program.

Columbia Gas will also look to partner with local businesses and trade organizations (builders, contractors, electricians, plumbers, HVAC service providers, equipment suppliers, etc.) to familiarize them with program opportunities, energy efficiency practices and implementation requirements and to utilize them, where appropriate, as one of the program's service delivery channels.

- Targeting equipment manufacturers, distributors, installation contractors and retailers/vendors to make sure they offer high-efficiency equipment and can make customers aware of available incentives.
- Partnering with community-based organizations to develop outreach and program delivery strategies.
- Working with Act 129 electric administrators to combine marketing and delivery options and address all aspects of efficiency at the same time.

Additional details for each program are in the individual program plans, and Columbia Gas will develop a more detailed marketing strategy for each of the programs and for the entire portfolio as part of the program setup.

1.7.4 Reporting

Columbia Gas will submit an annual report on the EE Plan each April, three months after the close of the program year. This report will provide information on activity for the previous year and progress towards three-year goals, including, but not limited to:

- First year and lifetime savings;
- Participation;
- Spending;
- Cost effectiveness;
- Highlights of portfolio and program activity; and
- Updates to program delivery and design.

In-order to tie savings and costs together as effectively as possible, results will be reported based on commitments made. Any measures that have been

verified as installed within a program year along with any costs committed to these measures, including administration costs, will be counted for that year.

1.7.5 Program Flexibility

To make sure that the EE&C Portfolio is able to address changing market conditions and improve service delivery as quickly as possible, Columbia Gas requires flexibility in the allocation of budgets and implementation of program improvements. This plan document provides the principles and three-year goals that Columbia Gas is seeking, but certain adjustments, such as providing incentives for new measures or moving budgets between years and programs, may be required to meet these goals. Columbia Gas will include any such adjustments in its annual report but does not anticipate seeking initial approval for such updates, considering that all costs are anticipated to be collected from the same rate class. Columbia Gas will file an updated EE Plan in anticipation of material changes that may have a serious effect on goals, such as:

- The addition or removal of a program;
- A need for total funding levels above those approved for the plan term; and
- Significant changes to cost-effectiveness projections, such as an update to avoided costs or a large reduction in portfolio spending projections.

1.8 Evaluation, Measurement, and Verification

1.8.1 Technical Reference Manual

To maintain consistency with existing gas efficiency programs in Pennsylvania, Columbia Gas will utilize a Technical Reference Manual ("TRM") based on the most recent version of the UGI Gas, Inc. TRM and Columbia Gas VA's experience with its online audit program. The Columbia Gas TRM will only contain those measures relevant to the programs proposed in this plan, and will include updates to some measure assumptions to calibrate them to Columbia Gas' service territory (such as equivalent full load heating hours and heating degree days). In the future, any results from program evaluations that affect deemed savings calculations will

also be added to the TRM. The proposed TRM is included as Attachment A to this plan.

1.8.2 Tracking System

Columbia Gas will require that its coordinators collect all relevant customer, application, measure, and contractor information and that this data is provided in a timely fashion. Columbia Gas will regularly review this data, and will aggregate cost, savings, and participation data to a centralized database controlled by Columbia Gas that will be the source for program management and reporting.

1.8.3 Inspections

Inspections may be performed on a sub-set of applications before any incentive is paid. Inspectors will determine whether the measure is operational and matches the application, and they will solicit customer feedback on the programs. Inspection rates for prescriptive programs will be designed to gather a statistically significant sample of program activity. See individual program plans for additional details.

1.8.4 Evaluations

Columbia Gas will monitor the ongoing progress of the EE Plan to provide the highest possible service to customers, while maintaining controls to maximize the potential for savings and costs to be properly verified and counted. Columbia Gas will closely track program data, perform inspections of completed projects, and perform periodic evaluations for all the programs.

Columbia Gas will, at a minimum, evaluate each of its programs once adequate participation levels have been reached and a full 12 months of post-participation billing data has been collected. As part of the initial program development, Columbia Gas will work with the selected evaluator to establish the methodology and goals of the evaluation. Initial objectives include:

- Verifying energy savings and associated costs;
- Assessing market attitudes towards the program, including contractors, customers, and efficient equipment suppliers; and

- Measuring the effectiveness of current program design, marketing, and service delivery.

The evaluation section of the individual program descriptions includes additional details on evaluation schedules and goals unique to that program.

2 Program Plans

2.1 Residential Prescriptive

Objective

The Residential Prescriptive (RP) program is designed to overcome market barriers to energy efficient space and water heating equipment and building shell upgrades in the residential sector through rebates and customer awareness. The objective of the program is to avoid lost opportunities by encouraging consumers to install the most efficient gas heating technologies available when replacing older, less efficient equipment and make long lasting improvements to their building shell through insulation and air sealing. The program also aims to strengthen Columbia Gas' relationship with HVAC contractors, suppliers, and other trade allies.

Eligible Rate Class

RDS/RSS

Cost Effectiveness

Three-Year Cost-Effectiveness Results (2022$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC Test	$6,388,970	$3,270,996	$3,117,975	1.95
Gas Admin Test	$6,206,232	$1,776,040	$4,430,192	3.49

Savings Projections

Three-Year Savings Projections

First Year Savings	2023	2024	2025	2023 - 2025
Natural Gas (Dth)	6,447	15,719	21,989	**44,154**
Electric Energy (MWh)	25.1	94.6	145.4	**265.1**
Peak Demand (kW)	4.5	16.9	43.1	**64.4**

	Water (Million Gallons)	0.0	0.0	0.0	**0.0**
	Lifetime Savings	**2023**	**2024**	**2025**	**2023 - 2025**
	Natural Gas (Dth)	119,875	270,261	408,386	**798,523**
	Electric Energy (MWh)	276.1	1,040.5	2,150.2	**3,466.8**
	Water (Million Gallons)	0.0	0.0	0.0	**0.0**

Budget Projections

Three-Year Budgets (Nominal)

Costs by Category	**2023**	**2024**	**2025**	**2023 - 2025**
Customer Incentives	$213,100	$480,000	$779,700	**$1,472,800**
Administration	$75,000	$70,000	$107,000	**$252,000**
Marketing	$20,000	$52,000	$75,000	**$147,000**
Inspections	$3,000	$24,000	$34,000	**$61,000**
Evaluation	$0	$0	$60,000	**$60,000**
Total	**$311,100**	**$626,000**	**$1,055,700**	**$1,992,800**

Participation Projections

Three-Year Participation Projections

Projected Units	**2023**	**2024**	**2025**	**2023 - 2025**
Furnace - ENERGY STAR	237	500	600	**1,337**
Boiler - 94+ AFUE	19	30	40	**89**
Combi Boiler - 94+ AFUE	33	60	100	**193**
Wifi Thermostat - ENERGY STAR	345	1,300	1,600	**3,245**
Tankless Water Heater - ENERGY STAR	63	120	150	**333**
Gas Heat Pump (Furnace Baseline)	-	-	2	**2**
Gas Heat Pump (Boiler Baseline)	-	-	2	**2**
Insulation and Air Sealing	-	-	164	**164**

	Total	**697 2,010 2,658 5,199**
Program Rollout	*Jan 2023 – Jun 2023*	Finalize program process and implementation details, select vendors, and develop initial marketing push
	Jul 2023	Launch Program
	2023 - 2024	Continue engagement activities with customers and trade allies.
	2025	Reach full anticipated participation levels.
Program Design	The RP Program offers rebates for qualifying insulation and air sealing project, residential-sized space and water heating equipment and controls. For most measures, customers will have a contractor install the measure and receive a rebate to offset some of the incremental cost of the higher efficiency equipment. Smaller measures, such as Wi-Fi enabled thermostats, will only require a valid proof of purchase before a rebate is issued. Customers will be encouraged to process rebates through an online portal, but may also submit a paper application through the mail. Columbia Gas may also provide the option to purchase qualified smart thermostats via an online marketplace. If program funds begin to run low, incentive levels may be lowered, or equipment removed from the program if additional budget adjustments cannot be made. Columbia Gas will aim to provide as little interruption to customers as possible due to such adjustments. Columbia Gas will continue to examine other equipment for potential inclusion in the program, as well as the relative market adoption of equipment already receiving incentives.	
Target Market and End Uses	The RP targets residential consumers who use natural gas to heat their homes and/or generate hot water. In general, the program aims to incentivize only the highest levels of efficient equipment on the	

	market. The minimum level of efficiency for measures offered through the RP program will be ENERGY STAR®, when available, and in some cases may exceed ENERGY STAR®. On the space heating side, the program provides incentives for ENERGY STAR® labeled smart thermostats, furnaces, high efficiency boilers, combination boilers, and natural gas powered heat pumps. ENERGY STAR® smart thermostats offer the potential for deeper savings than traditional programmable thermostats due to the wide range of features and feedback they offer. ENERGY STAR® requirements for furnaces drive customers toward the highest efficiency tier of condensing units (95+ AFUE) and require efficient fans that save electricity. The program would also require boilers to go towards the highest efficiency tier with an AFUE of at least 94. Offering incentives for combination space and water heating boilers addresses two types of end-use with one piece of equipment. These "combi boilers" also address issues with orphaned water heaters having existing atmospheric venting systems that are no longer adequate, when switching to condensing heating equipment. Finally, offering incentives for the newly emerging technology of natural gas-powered heat pumps provides customers the ability to heat their homes with the highest efficiency available in natural gas space heating. The program addresses water heating savings by offering incentives for ENERGY STAR® tankless water heaters. The program also addresses long-term savings by offering incentives for customers to upgrade the performance of their building shell through insulation and air sealing.

Financial Incentives

Incentives were designed to be in line with other offerings in the region and/or cover approximately two-thirds of the incremental cost of the measure. The table below lists the proposed incentive schedule.

Proposed Residential Prescriptive Program Rebates (Nominal)

Equipment	Minimum Efficiency	Proposed Incentive	Maximum Incentive
Smart Thermostat	ENERGY STAR®	$100	$100
Furnace	ENERGY STAR®	$400	$500
Boiler	94+ AFUE	$1,000	$1,500
Combi Boiler	94+ AFUE	$1,200	$1,800
Tankless Water Heater	ENERGY STAR®	$400	$500
Gas Heat Pump (Furnace Baseline)	Gas Heat Pump Forced Air	$2,000	$5,000
Gas Heat Pump (Boiler Baseline)	Gas Heat Pump Air to Water	$2,000	$5,000
Insulation and Air Sealing	N/A	25% Cost ($2,500 Cap)	$2,500

All equipment besides the Wi-Fi thermostat must be powered by natural gas. Insulation and Air Sealing customers must have natural gas as their heat source.

Marketing Approach

The RP program may be marketed through inclusion on Columbia's website and through social media, as well as through bill inserts and other media messaging. The main way that many customers will hear about the RP Program is through HVAC contractors, weatherization contractors, and plumbers, and the

	program will be a key part of trade ally outreach efforts. Incentives will help these contractors sell jobs, and efforts such as cobranding and potentially assigning incentives to contractors will provide trade allies with even more tools to move customers to higher efficiency levels.
Evaluation, Measurement, and Verification	Quality Assurance All applications will require proof of purchase and a valid Columbia Gas account number. Rebates received as an instant rebate via a qualified participating contractor or equipment distributor will be accompanied by an invoice showing the point of sale discount passed on to the customer. The rebate processor will verify that the equipment is eligible for the rebate based on the model's Air-Conditioning Heating and Refrigeration Institute (AHRI) number before issuing any rebate. The program's rebate processor will maintain a real-time database of rebate activity, which will be periodically reviewed by Columbia Gas and stored separately for long-term purposes. There will be inspections of approximately five percent (5%) of non-thermostat equipment rebates and approximately one percent (1%) of Wi-Fi thermostat rebates to obtain a statistically significant sample of activity. The inspection will consist of verifying that the rebated equipment is installed and operational and conclude with a short informational interview with the participant. Virtual inspections will be explored to reduce program costs and increase inspection rates. Evaluations A third-party vendor will evaluate the program's process and impacts after sufficient participation has occurred in the third year of the Plan.

Program Administration	Rebate Processing and Inspection The rebate processor will accept customer applications, track and verify application information, notify the customer of any issues, maintain a call center, and report results to Columbia Gas. The rebate processor may also be responsible for other programs to streamline portfolio management. The rebate processor will also be responsible for inspections. Marketing and Outreach Columbia Gas and their vendors will handle marketing and outreach for the RP program. Evaluator A third-party evaluator will be retained to perform evaluations.

2.2 Online Audit Kit

Objective

The Online Audit Kit (OAK) Program is designed to provide residential customers with information on how to improve the efficiency of their homes along with free, targeted energy savings kits. The program also provides a way for customers to engage with Columbia Gas and learn about the RP Program.

Eligible Rate Class

RSD/RSS

Cost Effectiveness

Three-Year Cost-Effectiveness Results (2022$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC Test	$8,060,188	$1,262,372	$6,797,816	6.38
Gas Admin Test	$2,820,621	$1,262,372	$1,558,249	2.23

Savings Projections

Three-Year Savings Projections

First Year Savings	2023	2024	2025	2023 - 2025
Natural Gas (Dth)	7,446	14,024	15,943	**37,413**
Electric Energy (MWh)	0.0	0.0	0.0	**0.0**
Peak Demand (kW)	0.0	0.0	0.0	**0.0**
Water (Million Gallons)	7.9	19.7	20.2	**47.9**
Lifetime Savings	**2023**	**2024**	**2025**	**2023 - 2025**
Natural Gas (Dth)	90,326	156,820	184,309	**431,455**
Electric Energy (MWh)	0.0	0.0	0.0	**0.0**
Water (Million Gallons)	78.8	197.4	202.3	**478.5**

Budget Projections

Three-Year Budgets (Nominal)

Costs by Category	2023	2024	2025	2023 - 2025
Customer Incentives	$106,900	$234,300	$252,000	**$593,200**
Administration	$98,000	$277,000	$302,000	**$677,000**
Marketing	$18,000	$20,000	$32,000	**$70,000**
Inspections	$0	$0	$0	**$0**
Evaluation	$0	$20,000	$50,000	**$70,000**
Total	**$222,900**	**$551,300**	**$636,000**	**$1,410,200**

Participation Projections

Three-Year Participation Projections

Projected Kits	2023	2024	2025	2023 - 2025
Water Heating Kit	2,455	6,150	6,300	**14,905**
Space Heating Kit	1,339	1,400	2,100	**4,839**
Total	**3,794**	**7,550**	**8,400**	**19,744**

Program Rollout

Jan 2023 – Jun 2023	Finalize program process and implementation details, select vendors, and develop initial marketing push
Jul 2023	Launch Program
2023 - 2024	Continue engagement activities with customers and trade allies.
2025	Reach full anticipated participation levels.

Program Design

The OAK Program provides a way for customers to undergo an online audit of their home, which will result in a customized set of recommendations. The customer will then be eligible to receive up to

	two targeted energy saving kits, shipped to their home at no cost. The first kit is for customers who use natural gas for water heating, and the second kit is for customers who utilize natural gas to heat their homes. Participating customers will also be referred to the RP program incentives if appropriate. To reach customers who do not have easy access to the internet, a phone version of the audit will be made available.
Target Market and End Uses	There will be two kits available for customers. The water heating kit will include measures such as high-efficiency showerheads and low-flow faucet aerators. The space heating kit will include low-cost measures such as outlet and light switch gaskets, caulk, and foam sealant along with instructions on effective installation.
Financial Incentives	Kits will be provided at no cost to the customer.
Marketing Approach	The OAK program will be marketed through bill inserts, social media, and on Columbia Gas' website. Other outreach efforts may include email, radio, and print advertisements. The program will also act as a referral service for customers who may want to participate in the RP program.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> Columbia Gas will perform a survey of participants every year to determine installation rates for energy saving kits and assess customers satisfaction with program recommendations. <u>Evaluations</u>

	The program will undergo a process and impact evaluation in the third year once sufficient time has passed for the program to achieve meaningful participation.
Program Administration	Online Audit and Kit Provider Columbia Gas will hire a vendor to provide an online audit solution and package and send energy saving kits to customers. Marketing and Outreach Columbia Gas and their vendors will handle marketing and outreach for the program. Evaluator A third-party evaluator will be retained to perform annual participant surveys and regular program evaluations.

3 Appendices

3.1 Avoided Cost Tables

Gas Avoided Costs (2022$/Dth)

Year	Base	Space Heating	Domestic Hot Water
2023	$4.67	$10.49	$6.12
2024	$4.48	$10.42	$5.97
2025	$4.46	$10.47	$5.96
2026	$4.47	$10.57	$6.00
2027	$4.49	$10.67	$6.04
2028	$4.66	$10.90	$6.22
2029	$4.84	$11.14	$6.41
2030	$4.92	$11.30	$6.51
2031	$5.04	$11.49	$6.66
2032	$5.10	$11.62	$6.73
2033	$5.20	$11.79	$6.85
2034	$5.21	$11.87	$6.87
2035	$5.22	$11.96	$6.91
2036	$5.25	$12.06	$6.95
2037	$5.29	$12.17	$7.01
2038	$5.32	$12.28	$7.06
2039	$5.34	$12.38	$7.10
2040	$5.40	$12.52	$7.18
2041	$5.43	$12.63	$7.23
2042	$5.43	$12.70	$7.24
2043	$5.45	$12.81	$7.29
2044	$5.40	$12.85	$7.26
2045	$5.39	$12.93	$7.27
2046	$5.40	$13.03	$7.30
2047	$5.41	$13.13	$7.34
2048	$5.46	$13.27	$7.41
2049	$5.46	$13.37	$7.43
2050	$5.47	$13.48	$7.47

Developed by Resource Insight, Inc.

Other Resource Avoided Costs (2022$)

Year	All-Year Energy ($/kWh)	Generation Capacity ($/kW-yr)	T&D ($/kW-yr)	Water ($/gal)
2023	$0.0324	$54.63	$53.93	$0.013
2024	$0.0324	$54.63	$53.93	$0.013
2025	$0.0323	$54.63	$53.93	$0.013
2026	$0.0335	$54.64	$53.93	$0.013
2027	$0.0348	$54.64	$53.93	$0.013
2028	$0.0362	$54.64	$53.93	$0.013
2029	$0.0374	$54.63	$53.93	$0.013
2030	$0.0380	$54.63	$53.93	$0.013
2031	$0.0390	$54.63	$53.93	$0.013
2032	$0.0404	$54.63	$53.93	$0.013
2033	$0.0413	$54.63	$53.93	$0.013
2034	$0.0420	$54.63	$53.93	$0.013
2035	$0.0415	$54.64	$53.93	$0.013
2036	$0.0411	$54.63	$53.93	$0.013
2037	$0.0414	$54.63	$53.93	$0.013
2038	$0.0415	$54.63	$53.93	$0.013
2039	$0.0414	$54.63	$53.93	$0.013
2040	$0.0416	$54.63	$53.93	$0.013
2041	$0.0418	$54.63	$53.93	$0.013
2042	$0.0418	$54.63	$53.93	$0.013
2043	$0.0418	$54.63	$53.93	$0.013
2044	$0.0418	$54.63	$53.93	$0.013
2045	$0.0418	$54.63	$53.93	$0.013
2046	$0.0418	$54.63	$53.93	$0.013
2047	$0.0418	$54.63	$53.93	$0.013
2048	$0.0418	$54.63	$53.93	$0.013
2049	$0.0418	$54.63	$53.93	$0.013
2050	$0.0418	$54.63	$53.93	$0.013

3.2 Detailed Measure Assumptions

	Costs		Savings				
Measure Name	**Incentive**	**Incr. Cost**	**Lifetime (Yrs)**	**Dth**	**kWh**	**kW**	**Water (Gal)**
Residential Prescriptive Program							
Furnace - ENERGY STAR	$400.00	$758.40	20	13.99	0	0	0
Boiler - 94+ AFUE	$1,000.00	$1,785.00	25	12.83	0	0	0
Combi Boiler - 94+ AFUE	$1,200.00	$2,526.18	25	22.72	0	0	0
Wifi Thermostat - ENERGY STAR	$100.00	$150.00	11	4.52	73	0.01	0
Tankless Water Heater - ENERGY STAR	$400.00	$592.85	20	9.18	0	0	0
Gas Heat Pump (Furnace)	$2,000.00	$17,195.75	15	40.46	0	0	0
Gas Heat Pump (Boiler)	$2,000.00	$14,007.50	15	36.09	0	0	0
Insulation & Air Sealing	$925.00	$3,700.00	30	12.50	176.74	0.1361	0
Online Audit Kit Program							
Web Faucet Aerator - Kitchen	$2.00	$2.00	10	0.51	0	0	941
Web Faucet Aerator - Bathroom	$1.00	$1.00	10	0.11	0	0	201
Web High Efficiency Showerhead	$5.00	$5.00	10	0.51	0	0	934
Web Switch/Outlet Cover	$2.50	$2.50	15	1.64	0	0	-
Web Caulk	$3.00	$3.00	15	0.37	0	0	-
Web Foam Sealant	$6.00	$6.00	15	0.37	0	0	-
Water Heating Kit	$20.00	$20.00	1	-	0	0	-
Space Heating Kit	$6.50	$6.50	1	-	0	0	-

3.3 Detailed Program and Portfolio Cost-effectiveness

Energy Efficiency Programs' Cost Effectiveness over Three-Year Portfolio (2022$)

	Total Resource			Gas Energy System		
Program	Present Value Benefit	Cost	PV of Net Benefits	Present Value Benefit	Cost	PV of Net Benefits
Portfolio Total	$14,449,159	$5,070,254	$9,378,905	$9,026,852	$3,575,297	$5,451,555
Non-Measure Costs		$1,730,783			$1,730,783	
Total Measure Costs	$14,449,159	$3,339,471	$11,109,688	$9,026,852	$1,844,514	$7,182,338
Program						
Residential Prescriptive Program						
Program Total	$6,388,970	$3,270,996	$3,117,975	$6,206,232	$1,776,040	$4,430,192
Non-Measure Costs		$464,179			$464,179	
Total Measure Costs	$6,388,970	$2,806,817	$3,582,153	$6,206,232	$1,311,861	$4,894,371
Online Audit Kit Program						
Program Total	$8,060,188	$1,262,372	$6,797,816	$2,820,621	$1,262,372	$1,558,249
Non-Measure Costs		$729,718			$729,718	
Total Measure Costs	$8,060,188	$532,654	$7,527,535	$2,820,621	$532,654	$2,287,967
Portfolio Wide Costs						
Program Total	-	$536,886	$(536,886)	-	$536,886	$(536,886)
Non-Measure Costs		$536,886			$536,886	
Total Measure Costs	-	-	-	-	-	-

3.4 Technical Reference Manual (TRM)

Technical Reference Manual

Measure Savings Algorithms

Columbia Gas of Pennsylvania

February 19, 2024

Prepared by:

GreenEnergy EconomicsGroup

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Prepared by: Green Energy Economics Group, Inc.

1 Cross-Sector TRM Issues

3.5 Establishing Baselines

The savings methods and assumptions can differ substantially based on the program delivery mechanism for each measure type. Within each of the measure protocols in the TRM, there is a definition for the measure's baseline efficiency, a critical input into the savings calculations. Most measures will fall into one of two categories, each with a baseline that is most commonly used:

- One for market-driven choices – often called "lost opportunity" and either replacing equipment that has failed (replace on burnout) or new installations (new construction)
- One for discretionary installations – either early replacement or retrofit

For all new construction (NC) and replace on burnout (ROB) scenarios, the baseline is typically a jurisdictional code or a national standard; however, there may be cases where a market baseline is appropriate. In these scenarios, the Commission has a preference for codes and standards as it is too expensive and time consuming to conduct annual market baseline and characterization research. Additionally, the TRM provides estimates for gross energy savings only, whereas net savings "…include the effects of free-ridership, spillover, and induced market effects."

For discretionary installation scenarios, the baseline is typically the existing equipment efficiency, but in the case of early replacement (EREP), at some point the savings calculations must incorporate changes to the baseline for new installations (e.g., code or market changes) to account for eventual natural replacement of the equipment. This approach encourages residential and business consumers to replace working inefficient equipment and appliances with new high-efficiency products rather than taking no action to upgrade or only replacing them with new standard-efficiency products.

All baselines are designed to reflect current market practices that are updated periodically to reflect upgrades in federal equipment standards, building code, or information from evaluation results. Specifically for commercial and industrial measures, Pennsylvania has adopted the 2015 International Energy Conservation Code (IECC) per 34 Pa. Code Section 403.21, effective October 1, 2018. Per Section 401.2 of IECC 2015, commercial buildings must comply with either "[t]he requirements of ANSI/ASHRAE/IESNA Standard 90.1[-2013]" or comply with the requirements outlined in IECC 2015 Chapter 4. In accordance with IECC 2015, commercial protocols relying on code standards as the baseline condition may refer to either IECC 2015 or ASHRAE 90.1-2013 per the program design.

The baseline estimates used in the TRM are based on applicable federal standards, or are documented in baseline studies or other market information. This TRM reflects the most up-to-date codes, practices, and market transformation effects. The measures herein include, where appropriate, schedules for the implementation of Federal standards to coincide with the beginning of a program year. These implementation schedules apply to measures where the Federal standard is considered the baseline, as described herein or otherwise required by law. In cases where the ENERGY STAR criterion is considered the eligibility requirement and the existing ENERGY STAR Product Specification Version expires in a given year, the new ENERGY STAR Product Specification Version will become the eligibility requirement at the start of the next consecutive program year.

The combined effect of measure retention and persistence is the ability of installed measures to maintain the initial level of energy savings or generation over the measure life. If the measure is subject to a reduction in savings or generation over time, the reduction in retention or persistence is accounted for using factors in the calculation of resource savings.

4 Residential Time of Replacement Market

4.1 Space Heating End Use

4.1.1 Efficient Space Heating System

Unique Measure Code(s): TBD

Draft date: 2/19/24

Effective date: TBD

End date: TBD

Measure Description

This measure applies to residential-sized gas furnaces, boilers, and gas heat pumps purchased at the time of natural replacement. A qualifying furnace or boiler must meet minimum efficiency requirements (AFUE).

Definition of Baseline Condition

The efficiency levels of the gas-fired furnaces or boilers that would have been purchased absent this or another DSM program are shown in the following table. The baseline for a gas heat pump is the type of equipment currently in place and being replaced.

Equipment Type	Baseline AFUE
Gas Furnace	80%
Gas Boiler	84%

Definition of Efficient Condition

The installed gas furnace or boiler must have an AFUE greater than that shown in the table below. Efficient model minimum AFUE requirements are detailed below.

Equipment Type	Minimum AFUE
Gas Furnace	95%

Gas Boiler	94%
Gas Heat Pump	>100%

Gas Savings Algorithms

MMBtu savings are realized due to the increase in AFUE of the new equipment. MMBtu savings vary by equipment type due to differences in model specific baseline AFUE and high efficiency AFUE percentages. Savings are calculated from the baseline new unit to the installed efficient unit.

$$Annual\ Gas\ Savings\ (MMBtu) = \frac{Capacity_{Out}}{1{,}000} \times \left(\frac{1}{AFUE_{Base}} - \frac{1}{AFUE_{Eff}}\right) \times EFLH_{Heat}$$

Where:

Capacity $_{Out}$ = Output capacity of equipment to be installed (kBtu/hr)

1,000 = Conversion from kBtu to MMBtu

$AFUE_{Base}$ = Efficiency of new baseline equipment (Annual Fuel Utilization Efficiency)

$AFUE_{Eff}$ = Efficiency of new equipment

$EFLH_{Heat}$ = Equivalent Full Load Heating Hours (Refer to EFLH table by climate zone in References Section)

Electric Savings Algorithms

Energy Savings

∆kWh = 0 kWh

Demand Savings

∆kW = 0 kW

Where:

ΔkWh = Gross customer annual kWh savings for the measure.

ΔkW = Gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Gas Furnace	0%	0%
Gas Furnace with ECM Fan	0%	0%
Gas Boiler	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
Gas Furnaces	20
Gas Boilers	25
Gas Heat Pump	15

Sources: Lifetime estimates used by Efficiency Vermont, PGW and UGI for furnaces and boilers. Gas heat pump lifetime from Illinois TRM, Version 11.0, Volume 2, p 575.

Water Savings

There are no water savings for this measure.

4.1.2 WiFi Thermostat – ENERGY STAR®

Unique Measure Code(s): TBD

Draft date: 2/19/24

Effective date: TBD

End date: TBD

Measure Description

This is an ENERGY STAR® WiFi thermostat controlling a residential-sized gas furnace or boiler.

Definition of Baseline Condition

The baseline is a manual thermostat where each temperature setting change requires human intervention or a conventional programmable.

Definition of Efficient Condition

The efficient thermostat is one that is WiFi enabled, ENERGY STAR® certified and can be programmed to automatically increase or lower the temperature setting at different times of the day and week.

Gas Savings Algorithms

$$Annual\ Gas\ Savings\ (MMBtu) = SH_{pre} \times ESF$$

Where:

SH_{pre} = Space Heat MMBtu gas usage with manual thermostat = 70.6[9]

[9] Space-heat usage assumption from examination of Columbia Gas PA residential usage by month.

ESF = Percentage savings from WiFi thermostat compared to non-WiFi connected thermostat. See table below by installation method.

Heating Energy Savings Factors (ESF)

Program Type	Baseline	Air Source Heat Pump	Furnace/Boiler Heating (Electric or Fossil)
Upstream buy-down (Customer Self-Installation)	Unknown Mix Default	6.4%[a]	6.4%[a]
Customer Self-Installation with Education	Unknown Mix Default	7.9%[b]	7.9%[b]
Professional Installation	Manual	11.5%[c]	11.5%[c]
	Conventional programmable	7.9%[d]	7.9%[d]

[a] *Average of heating estimates from two studies.*

[b] *Heating savings are based on average of savings from unknown mix default with customer self-installation and average of professional installation savings from manual and programmable thermostats. In this case, 7.9%=((11.5%×0.42 + 7.9%×0.58) + 6.4%) / 2*

[c] *Average of four heating savings estimates from four studies.*

[d] *The ESF value for a is applied here as an estimate until information becomes available showing different savings incented through a direct install program.*

Source for table values: Act 129 Phase IV TRM.

Electric Savings Algorithms

If the type of air conditioning is known, then use the appropriate algorithm below. If the type or existence of air-conditioning is not known, then assume that 45% have central air-conditioning and estimate the cooling savings as 45% of a house with central air conditioning.[10]

Reduced furnace fan or boiler circulator pump usage is also likely to occur and provide electricity savings during both the heating and cooling seasons, but these auxiliary savings are not accounted for in the following algorithms.

[10] Percentage of houses with central air-conditioning from 2009 RECS data.

Energy Savings

$\Delta kWh = \Delta kWh_{Aux} + \Delta kWh_{Cool}$

ΔkWh_{Aux} = Furnace Fan kWh savings

ΔkWh_{Cool} = 0 kWh if house has no air conditioning
= ΔkWh_{CAC} if house has central air conditioning
= 0 if house has room air conditioning
= 45% × ΔkWh_{CAC} if no information about air conditioner

Deemed Savings ΔkWh

Program Type	Baseline	Fossil Fuel Furnace (Fan Only) ΔkWh_{Aux}	CAC Cooling ΔkWh_{CAC}
Upstream buy-down (Customer Self-Installation)	Unknown Mix Default	48	77
Customer Self-Installation with Education	Unknown Mix Default	60	120
Professional Installation	Manual	87	182
	Conventional programmable	60	150

Source: Act 129 Phase IV TRM.

Demand Savings

ΔkW = 0 kW if house has no air conditioning
= ΔkW_{CAC} if house has central air conditioning
= 0 if house has room air conditioning
= 45% × ΔkW_{CAC} if no information about air conditioner
= *0.0130 kW default*

Deemed Savings ΔkW

Program Type	Baseline	ASHP Cooling	CAC Cooling ΔkW_{CAC}
Upstream buy-down (Customer Self-Installation)	Unknown Mix Default	0.0269	0.0289
Customer Self-Installation with Education	Unknown Mix Default	0.0418	0.0450
Professional Installation	Manual	0.0633	0.0680
	Conventional programmable	0.0521	0.0560

Source: Act 129 Phase IV TRM.

Where:

ΔkWh = gross customer annual kWh savings for the measure.

ΔkW = gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
WiFi Thermostat	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
WiFi Thermostat	11

Source: August 2019 Act 129 TRM, Volume 2, p.47.

Water Savings

There are no water savings for this measure.

4.2 Water Heating End Use

4.2.1 Tankless Water Heater

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure is an on-demand gas water heater.

Definition of Baseline Condition

The efficiency levels of the gas-fired stand-alone storage water heater that would have been purchased absent this or another DSM program are shown in the following table.

Equipment Type	Usage Draw Pattern	Baseline UEF[11]
Gas Stand-alone Storage Water Heater	Very Small	0.27
Gas Stand-alone Storage Water Heater	Low	0.52
Gas Stand-alone Storage Water Heater	Medium	0.58
Gas Stand-alone Storage Water Heater	High	0.64

[11] Based on the federal standard for residential gas-fired water heater as of June 2017 and assumed typical 40 gallon storage. https://www.law.cornell.edu/cfr/text/10/430.32

Baseline usage draw pattern is established by the capacity of the installed tankless water heater, using the table below:

Usage Draw Pattern	Max GPM	Daily Volume in Gallons (*V*)
Very Small	0 ≤ GPM < 1.7	10
Low	1.7 ≤ GPM < 2.8	38
Medium	2.8 ≤ GPM < 4.0	55
High	4.0 ≤ GPM	84

If the tankless water heater capacity is not available, assume medium usage draw pattern.

Definition of Efficient Condition

The installed tankless water heater must have an UEF greater than that shown in the table below. Efficient model minimum UEF requirements are detailed below.

Equipment Type	Minimum UEF
Gas Tankless Water Heater	0.87

Gas Savings Algorithms

The following formula for gas savings is based on the DOE test procedure for water heaters[12].

$$Annual\ Gas\ Savings\ (MMBtu) = \frac{\left(\frac{1}{UEF_{Base}} - \frac{1}{UEF_{Eff}}\right) \times V \times \rho \times c_p \times 67 \times 365}{1{,}000{,}000}$$

Where:

UEF_{Base} = Uniform Energy Factor of baseline water heater based on usage draw pattern

UEF_{Eff} = Uniform Energy Factor of efficient water heater

[12] 10 CFR Appendix E to Subpart B of Part 430, Uniform Test Method for Measuring the Energy Consumption of Water Heaters

V	=	Daily volume of hot water usage in gallons. See table in baseline section. If usage draw pattern is unknown, assume medium (55 gallons/day).
ρ	=	Water density at 125°F (8.24 lb/gal)
c_p	=	Specific heat of water (1.00 Btu/lb °F)
67	=	°F temperature rise between inlet and outlet of water heater
365	=	Days per year
1,000,000	=	Btu per MMBtu

Electric Savings Algorithms

There are no electric savings from this measure.

Energy Savings

ΔkWh = 0 kWh

Demand Savings

ΔkW = 0 kW

Where:

ΔkWh	= gross customer annual kWh savings for the measure.
ΔkW	= gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Tankless Water Heater	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
Tankless Water Heater	20

Source: Energy Star Residential Water Heaters: Final Criteria Analysis, April 1, 2008, p. 10.

Water Savings

There are no water savings for this measure.

4.3 Combined Space and Domestic Hot Water Usage

4.3.1 Combination Boiler - Space Heating and DHW

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure applies to residential-sized combination boilers purchased at the time of natural replacement. These are integrated boilers that provide hot water for space heating and on-demand domestic hot water and have minimal or no hot

water storage. A qualifying combination boiler (combi boiler) must meet minimum efficiency requirements (AFUE).

Definition of Baseline Condition

The efficiency levels of the gas-fired boiler and stand-alone storage water heater that would have been purchased absent this or another DSM program are shown in the following table.

Equipment Type	**Baseline**[13]
Gas Boiler	84% AFUE

Equipment Type	**Usage Draw Pattern**	**Baseline UEF**[14]
Gas Stand-alone Storage Water Heater	Very Small	0.27
Gas Stand-alone Storage Water Heater	Low	0.52
Gas Stand-alone Storage Water Heater	Medium	0.58
Gas Stand-alone Storage Water Heater	High	0.64

Baseline usage draw pattern is established by the capacity of the water heater, using the table below:

Usage Draw Pattern	**Max GPM**	**Daily Volume in Gallons (*V*)**
Very Small	0 ≤ GPM < 1.7	10
Low	1.7 ≤ GPM < 2.8	38
Medium	2.8 ≤ GPM < 4.0	55
High	4.0 ≤ GPM	84

[13] Existing residential boiler federal standard as of 10/1/2022.
[14] Based on the federal standard for residential gas-fired water heater as of June 2017 and assumed typical 40 gallon storage. https://www.law.cornell.edu/cfr/text/10/430.32

If the water heater capacity is not available, assume medium usage draw pattern.

Definition of Efficient Condition

The installed gas furnace or boiler must have an AFUE greater than that shown in the table below. Efficient model minimum AFUE requirements are detailed below.

Equipment Type	Minimum AFUE
Gas Combi Boiler	94% AFUE 0.94 UEF

Gas Savings Algorithms

MMBtu savings are realized due to the increase in AFUE of the new equipment. MMBtu savings vary by equipment type due to differences in model specific baseline AFUE and high efficiency AFUE percentages. Savings are calculated from the baseline new unit to the installed efficient unit.

$$Annual\ Gas\ Savings\ (MMBtu) = Annual\ Gas\ Savings_{SH} + Annual\ Gas\ Savings_{DHW}$$

$$Annual\ Gas\ Savings_{SH} = \frac{Capacity_{Out}}{1{,}000} \times \left(\frac{1}{AFUE_{Base}} - \frac{1}{AFUE_{Eff}}\right) \times EFLH_{Heat}$$

Where:

Annual Gas Savings$_{SH}$ = Space heating annual gas savings (MMBtu)

Annual Gas Savings$_{DHW}$ = Domestic Hot Water annual gas savings (MMBtu)

Capacity $_{Out}$ = Output capacity of equipment to be installed (kBtu/hr)

1,000 = Conversion from kBtu to MMBtu

$AFUE_{Base}$ = Efficiency of new baseline equipment (Annual Fuel Utilization Efficiency)

$AFUE_{Eff}$ = Efficiency of new equipment

$EFLH_{Heat}$ = Equivalent Full Load Heating Hours Hours (Refer to EFLH table by climate zone in References Section)

The following formula for DHW gas savings is based on the DOE test procedure for water heaters.

$$Annual\ Gas\ Savings_{DHW} = \frac{\left(\frac{1}{UEF_{Base}} - \frac{1}{UEF_{Eff}}\right) \times V \times \rho \times c_p \times 67 \times 365}{1{,}000{,}000}$$

Where:

UEF_{Base}	=	Uniform Energy Factor of baseline water heater. See UEF based on usage draw pattern in Baseline section above. If draw pattern cannot be established assume medium draw pattern.
UEF_{Eff}	=	Uniform Energy Factor of efficient combi boiler. Since the combi boiler has no or little storage, standby losses are assumed to be negligible and the UEF is assumed to be the same as the AFUE.
V	=	Daily volume of hot water usage in gallons. See table in baseline section. If usage draw pattern is unknown, assume medium (55 gallons/day).
ρ	=	Water density at 125°F (8.24 lb/gal)
c_p	=	Specific heat of water (1.00 Btu/lb °F)
67	=	°F temperature rise between inlet and outlet of water heater
365	=	Days per year
1,000,000	=	Btu per MMBtu

Electric Savings Algorithms

Energy Savings

ΔkWh = 0 kWh

Demand Savings

ΔkW = 0 kW

Where:

ΔkWh = Gross customer annual kWh savings for the measure.

ΔkW = Gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Gas Combi Boiler	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
Gas Combi Boiler	20

Source: Same as lifetime estimate used for tankless water heater.

Water Savings

There are no water savings for this measure.

4.4 All End Uses

4.4.1 Custom Measure

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure applies to all residential time of replacement custom measures, not otherwise specified in this TRM.

Definition of Baseline Condition

The baseline represents the typical equipment that is installed without a DSM program. The efficiency level is based on the current Federal standards, or state and local building codes that are applicable.

Definition of Efficient Condition

The efficient measure is any equipment that uses less energy than the baseline equipment.

Gas Savings Algorithms

The generalized equation for a custom measure compares the baseline usage to the efficient usage.

$$Annual\ Gas\ Savings\ (MMBtu) = BaselineUse - EfficientUse$$

Where:

BaselineUse **=** The gas usage of baseline equipment or building.

EfficientUse **=** The gas usage of efficient equipment or building.

Electric Savings Algorithms

Energy Savings

ΔkWh = *BaselinekWh - EfficientkWh*

Demand Savings

ΔkW = *BaselinekW - EfficientkW*

Where:

ΔkWh **=** Gross customer annual kWh savings for the measure.

ΔkW **=** Gross customer summer load kW savings for the measure.

BaselinekWh **=** The electric kWh usage of baseline equipment or building.

EfficientkWh **=** The electric kWh usage of efficient equipment or building.

BaselinekW **=** The electric kW usage of baseline equipment or building.

EfficientkW **=** The electric kW usage of efficient equipment or building.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	**Free Ridership**	**Spillover**
Custom Measure	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Where available, custom measure lifetimes should be based on similar measures defined elsewhere in this TRM.

Water Savings

The water savings are the difference between the baseline and efficient equipment annual water usage in gallons.

5 Residential Early Replacement Market

5.1 Space Heating End Use

5.1.1 Kit Infiltration Reduction

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This involves decreasing the amount of air exchange between the inside of the house or unit and the outdoors using simple air sealing items included in kits mailed to customers.

Definition of Baseline Condition

The baseline is the house in its pre-treatment condition, with opportunities for infiltration reductions.

Definition of Efficient Condition

Any decrease in infiltration will reduce energy consumption compared to the pre-treated house.

Gas Savings Algorithms

$$Annual\ Gas\ Savings\ (MMBtu) = Default\ Savings$$

Where:

Default Savings = Deemed savings from kit air sealing measures. See table of default savings by measure.

Electric Savings Algorithms

Though there may be some electric cooling savings, however, no savings are currently assumed.

Default savings values for Kit Air Sealing Measures

Air Sealing Measure	MMBtu Savings	Source
Switch/Outlet Covers	1.64	Columbia Gas VA (CVA) savings assumption adjusted by HDD in Columbia Gas PA (CPA) territory relative to CVA HDD.
Caulk	0.37	CVA savings assumption adjusted by HDD in CPA territory relative to CVA HDD.
Foam Sealant	0.37	CVA savings assumption adjusted by HDD in CPA territory relative to CVA HDD.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Measure	Free Ridership	Spillover
Infiltration Reduction	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Measure	Measure Lifetime
Kit Infiltration Reduction	15

Source: Current assumption used by Columbia Gas VA.

Water Savings

There are no water savings for this measure.

5.1.2 Infiltration Reduction

Unique Measure Code(s): TBD

Draft date: 2/5/24

Effective date: TBD

End date: TBD

Measure Description

This involves decreasing the amount of air exchange between the inside of the house or unit and the outdoors without buffering from any adjacent unit(s) by sealing the sources of leaks, while maintaining minimum air exchange for air quality.

Definition of Baseline Condition

The baseline is the house in its pre-treatment condition, with opportunities for infiltration reductions.

Definition of Efficient Condition

Any decrease in infiltration will reduce energy consumption compared to the pre-treated house.

Gas Savings Algorithms

$$Annual\ Gas\ Savings\ (MMBtu) = \frac{HDD_t\ \times\ 24 \times \left(CFM50_{pre} - CFM50_{post}\right)}{(21.5\ \times AFUE \times 1{,}000{,}000)}$$

Where:

HDD_t = Heating degree days at temperature t, where t=63°F if no programmable thermostat has been installed and t=62°F if a programmable thermostat has been installed. See the Reference Tables section at the end of this document for projected HDD.

24 = hours/day

$CFM50_{pre}$ = CFM50 of building shell leakage as measured by a blower door test before treatment.

$CFM50_{post}$ = CFM50 of building shell leakage as measured by a blower door test after treatment.

21.5 = factor to convert CFM50 value to Btu/hrF heat loss rate, calculated from hourly infiltration modeling[15]

AFUE = rated AFUE of heating system. If no rating is available then use the method described in the Efficient Space Heating System section for calculating the AFUE. The AFUE of replacement equipment should be used if the heating system replacement precedes the air sealing work.

Electric Savings Algorithms

If the type of air conditioning is known, then use the appropriate algorithm below. If the type or existence of air-conditioning is not known, then assume that 45% have air-conditioning and estimate the cooling savings as 45% of a house with central air conditioning.[16]

Reduced furnace fan or boiler circulator pump usage is also likely to occur and provide electricity savings during both the heating and cooling seasons.

Energy Savings

$\Delta kWh = \Delta kWh_{Aux} + \Delta kWh_{Cool}$

$\Delta kWh_{Aux} = Annual\ Gas\ Savings\ (MMBtu) \times Auxiliary$

ΔkWh_{Cool} = 0 kWh if house has no air conditioning

[15] An hourly infiltration was calculated using a modified version of the LBL (a.k.a. Sherman-Grimsrud) infiltration model with a wind effect modification (EPRI RP 2034-40, Palmiter and Bond 1991) using Philadelphia TMY2 hourly weather data. This analysis result was then adjusted to account for an assumed party wall leakage fraction of 12% and an estimated 10% thermal regain from infiltration/exfiltratiom. The resulting value of 21.5 is consistent with statistical analyses of empirical data using CFM50 values and actual gas use and savings from CWP evaluations.
[16] Percentage of houses with air-conditioning from UGI data.

= ΔkWh_{CAC} if house has central air conditioning

= ΔkWh_{RAC} if house has room air conditioning

= 45% × ΔkWh_{CAC} if no information about air conditioner

$$\Delta kWh_{CAC} = \frac{CDD \times 24 \times DUA \times \left(CFM50_{pre} - CFM50_{post}\right)}{\left(21.5 \times SEER_{CAC} \times 1000\frac{W}{kW}\right)}$$

$$\Delta kWh_{RAC} = \frac{CDD \times 24 \times DUA \times F_{Room\ AC} \times \left(CFM50_{pre} - CFM50_{post}\right)}{\left(21.5 \times \overline{EER}_{RAC} \times 1000\frac{W}{kW}\right)}$$

Demand Savings

ΔkW = 0 kW if house has no air conditioning

= ΔkW_{CAC} if house has central air conditioning

= ΔkW_{RAC} if house has room air conditioning

$$\Delta kW_{CAC} = \frac{\Delta kWh_{CAC}}{EFLH_{cool}} \times CF_{CAC}$$

$$\Delta kW_{RAC} = \frac{\Delta kWh_{RAC}}{EFLH_{cool\ RAC}} \times CF_{RAC}$$

Where:

ΔkWh = gross customer annual kWh savings for the measure.

ΔkW = gross customer summer load kW savings for the measure.

Auxiliary = *Heating system auxiliary usage per MMBTU consumption (5.02 From Vermont Technical Reference Manual)*

CDD = *Cooling Degree Days (Degrees F * Days). See the Reference Tables section at the end of this document for projected CDD.*

DUA = *Discretionary Use Adjustment to account for the fact that people do not always operate their air conditioning system when the outside temperature is greater than 65F.*

$SEER_{CAC}$ = *Seasonal Energy Efficiency Ratio of existing home central air conditioner (Btu/W▪hr) (See table below for default values if actual values are not available)*

$\overline{EER}_{RAC}$ = *Average Energy Efficiency Ratio of existing room air conditioner (Btu/W▪hr) (See table below for default values if actual values are not available)*

CF_{CAC} = Demand Coincidence Factor for central AC systems (See table below)

CF_{RAC} = Demand Coincidence Factor for Room AC systems (See table below)

$EFLH_{cool}$ = Equivalent Full Load Cooling hours for Central AC and ASHP (Refer to EFLH table by climate zone in References Section)

$EFLH_{cool\ RAC}$ = Equivalent Full Load Cooling hours for Room AC (Refer to EFLH table by climate zone in References Section)

$F_{Room\ AC}$ = Adjustment factor to relate insulated area to area served by Room AC units

The default values for each term are shown in the table below.

Default values for algorithm terms, Ceiling/Attic and Wall Insulation

Term	Type	Value	Source
DUA	Fixed	0.75	OH TRM[17]
$SEER_{CAC}$	Variable	Default values: Early Replacement = 10 Replace on Burnout = 13	PUC Technical Reference Manual
		Nameplate	Contractor Data Gathering
$\overline{EER}_{RAC}$	Variable	Default = 9.8	DOE Federal Test Procedure 10 CFR 430, Appendix F (Used in ES Calculator for baseline)
		Nameplate	Contractor Data Gathering
CF_{CAC}	Fixed	0.70	PUC Technical Reference Manual
CF_{RAC}	Fixed	0.58	PUC Technical Reference Manual
$F_{Room,AC}$	Fixed	0.38	Calculated[18]

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

[17] "State of Ohio Energy Efficiency Technical Reference Manual," prepared for the Public Utilities Commission of Ohio by Vermont Energy Investment Corporation. August 6, 2010.

[18] From PECO baseline study, average home size = 2323 ft^2, average number of room AC units per home = 2.1. Average Room AC capacity = 10,000 BtuH per ENERGY STAR Room AC Calculator, which serves 425 ft^2 (average between 400 and 450 ft^2 for 10,000 BtuH unit per ENERGY STAR Room AC sizing chart). $F_{Room,AC}$ = (425 ft^2 * 2.1)/(2323 ft^2) = 0.38

Measure	Free Ridership	Spillover
Infiltration Reduction	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Measure	Measure Lifetime
Infiltration Reduction	20

Source: NYSERDA Home Performance with Energy Star.

Water Savings

There are no water savings for this measure.

5.1.3 Roof and Cavity Insulation

Unique Measure Code(s): TBD

Draft date: 2/5/24

Effective date: TBD

End date: TBD

Measure Description

This involves increasing the insulation levels in either the attic or walls which directly define the boundary between the house or unit and the outdoors.

Definition of Baseline Condition

The baseline is amount of insulation in the house in its pre-treatment condition.

Definition of Efficient Condition

Any increase in insulation will reduce energy consumption compared to the pre-treated house.

Gas Savings Algorithms

$$Annual\ Gas\ Savings\ (MMBtu) = \frac{HDD_t\ \times\ 24\ \times\ AREA\ \times \left({}^{1}/_{R_{pre}} - {}^{1}/_{R_{post}}\right)}{(AFUE \times 1{,}000{,}000)}$$

Where:

HDD_t = Heating degree days at temperature t, where t=63°F if no programmable thermostat has been installed and t=62°F if a programmable thermostat has been installed. See the Reference Tables section at the end of this document for projected HDD.

24 = Hours per day

AREA = Net insulated area in square feet. Estimated at 85% of gross area for cavities.

R_{pre} = R value of roof/cavity pre-treatment. R_{pre} = 5 unless there is existing insulation.

R_{post} = R value of roof/ cavity after insulation is installed.

AFUE = Rated AFUE of heating system. If no rating is available then use the method described in the Efficient Space Heating System section for calculating the AFUE. The AFUE of replacement equipment should be used if the heating system replacement precedes the air sealing work.

Electric Savings Algorithms

If the type of air conditioning is known, then use the appropriate algorithm below. If the type or existence of air-conditioning is not known, then assume that 45%

have air-conditioning and estimate the cooling savings as 45% of a house with central air conditioning.[19]

Reduced furnace fan or boiler circulator pump usage is also likely to occur and provide electricity savings during both the heating and cooling seasons.

Energy Savings

$\Delta kWh = \Delta kWh_{Aux} + \Delta kWh_{Cool}$

$\Delta kWh_{Aux} = Annual\ Gas\ Savings\ (MMBtu) \times Auxiliary$

ΔkWh_{Cool} = 0 kWh if house has no air conditioning
= ΔkWh_{CAC} if house has central air conditioning
= ΔkWh_{RAC} if house has room air conditioning
= 45% × ΔkWh_{CAC} if no information about air conditioner

$$\Delta kWh_{CAC} = \frac{CDD \times 24\frac{hr}{day} \times DUA}{SEER_{CAC} \times 1000\frac{W}{kW}} \times \left[AREA \times \left(\frac{1}{R_{pre}} - \frac{1}{R_{post}}\right)\right]$$

$$\Delta kWh_{RAC} = \frac{CDD \times 24\frac{hr}{day} \times DUA \times F_{Room\ AC}}{\overline{EER}_{RAC} \times 1000\frac{W}{kW}} \times \left[AREA \times \left(\frac{1}{R_{pre}} - \frac{1}{R_{post}}\right)\right]$$

Demand Savings

ΔkW = 0 kW if house has no air conditioning
= ΔkW_{CAC} if house has central air conditioning
= ΔkW_{RAC} if house has room air conditioning
= 45% × ΔkW_{CAC} if no information about air conditioner

[19] Percentage of houses with air-conditioning from UGI data.

$$\Delta kW_{CAC} = \frac{\Delta kWh_{CAC}}{EFLH_{cool}} \times CF_{CAC}$$

$$\Delta kW_{RAC} = \frac{\Delta kWh_{RAC}}{EFLH_{cool\ RAC}} \times CF_{RAC}$$

Where:

ΔkWh = gross customer annual kWh savings for the measure.

ΔkW = gross customer summer load kW savings for the measure.

Auxiliary = *Heating system auxiliary usage per MMBTU consumption (5.02 From Vermont Technical Reference Manual)*

CDD = *Cooling Degree Days (Degrees F * Days) See the Reference Tables section at the end of this document for projected CDD.*

DUA = *Discretionary Use Adjustment to account for the fact that people do not always operate their air conditioning system when the outside temperature is greater than 65F.*

$SEER_{CAC}$ = *Seasonal Energy Efficiency Ratio of existing home central air conditioner (Btu/W▪hr) (See table below for default values if actual values are not available)*

$\overline{EER}_{RAC}$ = *Average Energy Efficiency Ratio of existing room air conditioner (Btu/W▪hr) (See table below for default values if actual values are not available)*

CF_{CAC} = *Demand Coincidence Factor for central AC systems (See table below)*

CF_{RAC} = *Demand Coincidence Factor for Room AC systems (See table below)*

$EFLH_{cool}$ = *Equivalent Full Load Cooling hours for Central AC and ASHP (Refer to EFLH table by climate zone in References Section)*

$EFLH_{cool\ RAC}$ = *Equivalent Full Load Cooling hours for Room AC (Refer to EFLH table by climate zone in References Section)*

$F_{Room\ AC}$ = *Adjustment factor to relate insulated area to area served by Room AC units*

The default values for each term are shown in the table below.

Default values for algorithm terms, Ceiling/Attic and Wall Insulation

Term	Type	Value	Source
DUA	Fixed	0.75	OH TRM[20]
$SEER_{CAC}$	Variable	Default values: Early Replacement = 10 Replace on Burnout = 13	PUC Technical Reference Manual
		Nameplate	Contractor Data Gathering
$\overline{EER}_{RAC}$	Variable	Default = 9.8	DOE Federal Test Procedure 10 CFR 430, Appendix F (Used in ES Calculator for baseline)
		Nameplate	Contractor Data Gathering
CF_{CAC}	Fixed	0.70	PUC Technical Reference Manual
CF_{RAC}	Fixed	0.58	PUC Technical Reference Manual
$F_{Room,AC}$	Fixed	0.38	Calculated[21]

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Measure	Free Ridership	Spillover
Insulation	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Measure	Measure Lifetime
Roof Insulation	40

[20] "State of Ohio Energy Efficiency Technical Reference Manual," prepared for the Public Utilities Commission of Ohio by Vermont Energy Investment Corporation. August 6, 2010.

[21] From PECO baseline study, average home size = 2323 ft^2, average number of room AC units per home = 2.1. Average Room AC capacity = 10,000 BtuH per ENERGY STAR Room AC Calculator, which serves 425 ft^2 (average between 400 and 450 ft^2 for 10,000 BtuH unit per ENERGY STAR Room AC sizing chart). $F_{Room,AC}$ = (425 ft^2 * 2.1)/(2323 ft^2) = 0.38

Cavity Insulation	40

Source: NYSERDA Home Performance with Energy Star.

Water Savings

There are no water savings for this measure.

5.2 Domestic Hot Water End Use

5.2.1 Low Flow Showerhead

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure relates to the installation of a low flow showerhead in a home. This is an early replacement direct install or kit measure.

Definition of Baseline Condition

The baseline is the flow rate of the showerhead being replaced. If this is not available a baseline value of 2.5 GPM will be used.

Definition of Efficient Condition

The flow rate of the efficient showerhead should be greater than the flow rate of the baseline condition. If this value is not available it is assumed to be 1.5 GPM[22].

Water Savings Algorithms

The water savings for low flow showerheads are due to the reduced amount of water being used per shower.

[22] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)

$$\Delta Gallons = \frac{\left(GPM_{base} - GPM_{eff}\right) \times N_{persons} \times T_{person-day} \times N_{showers-day} \times 365 \times ISR}{N_{showerheads-home}}$$

Where:

$\Delta Gallons$	=	Gallons of water saved
GPM_{base}	=	Maximum gallons per minute of baseline showerhead. Default = 2.5 GPM if measured rate is not available[23]
GPM_{eff}	=	Maximum gallons per minute of the efficient showerhead
$N_{persons}$	=	Average number of people per household. Actual or defaults: SF=2.5, MF=1.7, Unknown=2.5 [24]
$T_{person-day}$	=	Average minutes per person per day used for showering. 7.8 min/day [25]
$N_{showers-day}$	=	Average number of showers per person per day. 0.6 showers/person/day [26]
365	=	Days per year
ISR	=	In service rate. Kit Default = 35%. Direct install Default = 100%. [27]
$N_{showerheads-h}$	=	Average number of showers per home. Actual or defaults: SF=1.6, MF=1.1, Unknown=1.5 [28]

Natural Gas Savings Algorithms

Gas energy savings result from reducing the amount of incoming cold water required to be heated due to the efficient showerhead.

$$\Delta MMBtu = \frac{\left[\Delta Gallons \times 8.3 \times c_p \times (T_{out} - T_{in})\right] / 1{,}000{,}000}{RE_{DHW}}$$

[23] The Energy Policy Act of 1992 established the maximum flow rate for showerheads at 2.5 gallons per minute (GPM)
[24] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[25] Ibid.
[26] Ibid.
[27] Ibid.
[28] Ibid.

Where:

$\Delta MMBtu$	=	MMBtu of saved natural gas
8.3	=	Constant to convert gallons to pounds (lbs.)
c_p	=	Average specific heat of water at temperature range (1.00 Btu/lb·°F)
T_{out}	=	Assumed temperature of water coming out of showerhead (degrees Fahrenheit) 101 °F
T_{in}	=	Assumed temperature of water entering house (degrees Fahrenheit) 52 °F
RE_{DHW}	=	Recovery efficiency of the domestic hot water heater = 75%[29]

Electric Savings Algorithms

It is assumed that all low flow showerheads are installed in homes that heat water using natural gas. There are no additional electric savings claimed.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

The measure life of a low flow showerhead is assumed to be 9 years[30].

5.2.2 Low Flow Faucet Aerators

[29] Review of AHRI Directory suggests range of recovery efficiency ratings for new Gas DHW units of 70-87%. The average of existing units is estimated at 75% by the Northeast Energy Efficiency Partnerships' Mid-Atlantic Technical Reference Manual Version 1.1 (October 2010).
[30] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (June 2011)

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure relates to the installation of a low flow faucet aerator in either a kitchen or bathroom.

Definition of Baseline Condition

The baseline is the flow rate of the existing faucet. If this is not available, it is generally assumed that a faucet will already have a standard faucet aerator using 2.2 GPM.

Definition of Efficient Condition

The efficient condition is a faucet aerator that has a flow rate lower than the baseline condition. If this value is not available than the flow rate is assumed to be 1.5 GPM[31].

Water Savings Algorithms

The water savings for low flow faucet aerators are due to the reduced amount of water being used per minute that flows down the drain (instead of being collected in the sink).

$$\Delta Gallons = \frac{\left(GPM_{base} - GPM_{eff}\right) \times N_{persons} \times T_{person-day} \times DF \times 365 \times ISR}{N_{faucets-home}}$$

Where:

$\Delta Gallons$	=	Gallons of water saved
GPM_{base}	=	Gallons per minute of baseline aerator = 2.2 GMP[32]
GPM_{eff}	=	Gallons per minute of the efficient aerator

[31] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[32] Ibid

$N_{persons}$	=	Average number of people per household. Actual or Defaults: SF=2.5, MF=1.7, Unknown=2.5[33]
$T_{person-day}$	=	Average minutes per person per day of faucet hot water usage. Kitchen=4.5, Bathroom=1.6, Unknown=6.1[34]
365	=	Days per year
DF	=	Drain rate, the percentage of water flowing down the drain. Kitchen=75%, Bathroom=90%, Unknown=79.5%[35]
ISR	=	In service rate. Kit delivery default = 28%, Direct install default = 100%[36]
$N_{faucets-home}$	=	Average Number of Faucets per home. Actual or for defaults see table below.

Average Number of Faucets per Home[37]

Faucet Type	Single Family	Multifamily	Unknown
Kitchen	1.1	1.0	1.0
Bathroom	2.2	1.2	2.0
Unknown	3.3	2.2	3.0

Natural Gas Savings Algorithms

Gas energy savings result from avoiding having to heat the saved water due to the efficient aerator.

$$\Delta MMBtu = \frac{\left[\Delta Gallons \times 8.3 \times c_p \times (T_{out} - T_{in})\right] / 1{,}000{,}000}{RE_{DHW}}$$

Where:

$\Delta MMBtu$	=	MMBtu of saved natural gas
8.3	=	Constant to convert gallons to pounds (lbs.)
c_p	=	Average specific heat of water at temperature range (1.00 Btu/lb·°F)

[33] Ibid
[34] Ibid
[35] Ibid
[36] Ibid
[37] Ibid

T_{out}	=	Average mixed water temperature flowing from the faucet (degrees Fahrenheit) Kitchen=93 °F, Bathroom=86 °F, Unknown=87.8 °F [38]
T_{in}	=	Assumed temperature of water entering house (degrees Fahrenheit) 52 °F [39]
RE_{DHW}	=	Recovery efficiency of the domestic hot water heater = 75%[40]

Electric Savings Algorithms

It is assumed that all faucet aerators as part of the gas utility's program are installed in homes that heat water using natural gas. There are no additional electric savings claimed.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

The measure life of a faucet aerator is assumed to be 10 years[41].

[38] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[39] Ibid
[40] See assumption for low flow shower head.
[41] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)

6 Reference Tables

6.1 Residential

6.1.1 Heating and Cooling EFLH

Heating and Cooling Equivalent Full Load Heating Hours

Reference Location	Zone	Heating EFLH for non-HP (Fossil Fuel Furnace or Boiler)
Allentown	C	906
Binghamton, NY	A	1,152
Bradford	G	1,347
Erie	I	1,054
Harrisburg	E	997
Philadelphia	D	761
Pittsburgh	H	942
Scranton	B	1,000
Williamsport	F	935
Weighted Avg CPA		1013

Source: Act 129 August 2019 TRM, Appendix A

Notes: ZIP codes associated with each PA climate zone may be found in the Act 129 August 2019 TRM, Appendix A, tab “Zip code lookup table.”

6.1.2 HDD & CDD

Heating Degree Days and Cooling Degree Days

Territory	HDD63	HDD62	CDD
Allentown	6,683	6,413	773
Binghamton, NY	5,350	5,110	405
Bradford	4,703	4,481	204
Erie	3,951	3,747	579
Harrisburg	4,512	4,294	1,121
Philadelphia	5,217	4,980	1,184
Pittsburgh	6,686	6,418	726
Scranton	5,054	4,830	608
Williamsport	5,477	5,241	759
Weighted Avg CPA	5,229	4,998	705

Sources: DegreeDays.net 2017-2019 for HDD. Act 129 August 2019 TRM, Appendix A for CDD.

Columbia Gas of Pennsylvania

Updated Three-Year Energy Efficiency Plan – ~~Settlement Scenario~~

January 1, 2023 – December 31, 2025

March XX, 2024 ~~*September 16, 2022*~~

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1 Introduction and Background

1.1 Plan Update

The updated plan outlined below is being proposed to meet two primary objectives. First, necessary updates were made to projections and costs based on the performance trends experienced in 2023. Secondly, new measures are being proposed to be added to the Residential Prescriptive (RP) program to address new technology and achieve alignment with federal efficiency initiatives that will be launching during the term of this filing. These two objectives and the benefits to the proposed updates are outlined in greater detail below.

Updated Costs and Projections

Participation trends in 2023 showed much greater than anticipated demand for the Online Audit Kit (OAK) program and lower than anticipated demand for the RP program. The updated tables throughout the plan show actual participation numbers from 2023 with preliminary cost and savings figures for each program, including Portfolio Wide (PW) administrative costs. The final cost and savings figures are still being finalized and will be filed in the required Annual Report, shortly after the date of this filing. In addition, participation, and spending projections for 2024 and 2025 were updated to match the trends shown in 2023. The result of this update is greater participation in the OAK program and slightly lower participation in the RP program.

Added RP Rebate Measures

To address newly available high efficiency natural gas heating technology, residential natural gas heat pumps are being added to the RP program. The efficiency of this measure can exceed 140% and provides the highest efficiency option available on the market for customers heating their home with natural gas. This measure is being proposed with two different baselines. A furnace baseline for forced air natural gas heat pumps and a boiler baseline for air to water natural gas heat pumps. In particular, the air to water natural gas heat pump provides a

much-needed higher efficiency alternative to customers that are looking to achieve the lowest natural gas usage possible while utilizing the existing infrastructure from their natural gas boiler.

In addition to natural gas heat pumps, a rebate is being added for customers who install insulation and air sealing in their home. This measure provides customers with long lasting energy savings by upgrading the performance of their building shell and aligns with the Federal Inflation Reduction Act (IRA) that is likely to be launched in Pennsylvania sometime toward the end of 2024 or beginning of 2025.

~~1.1~~1.2 Plan Overview

This plan provides a detailed description of the design and implementation of the energy efficiency and conservation portfolio ("EE&C Portfolio" or "Portfolio") that Columbia Gas of Pennsylvania, Inc. ("Columbia Gas" or "the Company") is proposing to offer in its Three-Year Energy Efficiency ("EE Plan" or "Plan"). The Plan builds on other voluntary gas energy efficiency plans offered by natural gas distribution companies serving Pennsylvania, and specifically targets residential customers. This document provides an updated scenario that aligns with settlement conditions to maintain a budget of $4 million over the 3-year period. In this scenario, the Residential Prescriptive program's initial year participation was reduced and projected ramp up was taken down to minimal levels for 2024 and 2025, with associated reductions in variable administration and marketing costs. Similarly, the first year and ramp up for the Online Audit Kit Program was adjusted downward significantly for 2024 and 2025. Portfolio wide costs were maintained at current levels to maintain full oversight of the portfolio.

The Plan has a three-year duration, beginning January 1, 2023 and ending December 31, 2025. Over the three years of the Plan, Columbia Gas plans to spend $4.0 million on the administration and delivery of two residential energy efficiency programs. The programs are projected to save 1.2~~3~~ million Dth of natural gas over the lifetime of the measures installed. From a total resource perspective, the portfolio present value of benefits is $14.4~~10.9~~ million, with $5.1 million in present value of costs, leading to a present value of net benefits of $9.4~~5.7~~ million

and a TRC BCR of 2.8512. Furthermore, the energy efficiency programs are expected to save 3,467041 MWh of electricity, 47984 million gallons of water, create between 3738 and 7576 jobs, and avoid the emission of CO_2 equivalent to over 2,869900 cars being removed from the road over the lifetime of installed measures.

1.21.3 Plan Development

The Plan was developed to help Columbia Gas' residential customers to address barriers to using natural gas more efficiently. It has two programs:

- Residential Prescriptive (RP) Program
- Online Audit Kit (OAK) Program

The RP Program is based on rebate programs run in Pennsylvania by other natural gas distribution companies. The OAK Program is based on a successful program run by Columbia Gas of Virginia for over the past decade.

Various market characteristics were gathered for Columbia Gas' territory, including avoided costs for natural gas and electricity, demographic, building stock, and equipment market characteristics. Next, measures were characterized and screened for cost effectiveness using the TRC test. Incentive levels were established for these measures and projects, generally set to be in-line with the other programs in Pennsylvania. The cost-effective measures and projects were then used to calculate savings and maximum participation levels. Programs were staged to account for the ramp-up required for new programs. Finally, non-incentive budgets were developed to address fixed and variable costs associated with each program and the portfolio. For the settlement scenario, budgets were constrained to a $4 million overall spend.

1.31.4 Portfolio Costs

The following table provides an overview of the spending by year and program for the total EE Plan. The maximum projected budget in a year is $1.95 million in FY

2025, approximately 0.3428% of Columbia Gas' FY 2020 revenues.[1] Although Act 129's requirements are not mandatory for voluntary natural gas distribution company energy efficiency programs, this level is well under the 2% cap that Act 129 imposes on electric efficiency programs in Pennsylvania.[2] Since only residential customers are eligible for the programs, it is anticipated that all costs will be recovered from the residential rate class, excluding Customer Assistance Program ("CAP") customers.

Table 1. Projected Spending for EE Plan by Program

Projected Costs (Nominal)	2023	2024	2025	2023 - 2025
Residential Prescriptive Program	$311,100650,000	$626789,000	$1,055,700978,000	$1,992,8002,417,000
Online Audit Kit Program	$222,900216,630	$551,300242,720	$636,000311,650	$1,410,200771,000
Portfolio Wide Costs	$125300,000	$234254,000	$238258,000	$597812,000
Total	**$659,0001,166,630**	**$1,411,300285,720**	**$1,929,700547,650**	**$4,000,000**

The portfolio-wide cost lines from the previous table are costs that apply to all programs in the EE portfolio. They are costs incurred at the portfolio level for program development, design, tracking, reporting, and administrative overhead. Development costs for the portfolio occur in the first year as programs are designed and reporting infrastructure is put in place. These costs become a smaller percentage of the portfolio as the rest of the programs ramp up. In the final year, the portfolio wide costs represent 1317% of the portfolio total cost, and, over the three-year period, they represent 1620% of the portfolio's costs. The following table provides a portfolio-level look at costs by category.

[1] $3.8 million is 0.7% of total 2020 revenues of $555 million from Columbia's Annual Report of Columbia Gas of Pennsylvania, Inc. Year Ended December 21, 2020 at p. 26.
[2] *See* 66 Pa.C.S. § 2806.1(g) (limiting the total cost of an EDC's EE&C Plan to 2% of the EDC's total annual revenue as of December 31, 2006).

Table 2. Projected Efficiency Portfolio Budgets by Category

Category	2023	2024	2025	2023 - 2025
Customer Incentives	$320,000~~487,630~~	$714,300~~703,720~~	$1,031,700~~832,650~~	$2,066~~024~~,000
Administration	$298~~504~~,000	$581~~453~~,000	$647~~481~~,000	$1,526~~438~~,000
Marketing	$38~~132~~,000	$72~~77~~,000	$107~~86~~,000	$217~~295~~,000
Inspections	$3~~23~~,000	$24~~32~~,000	$34~~38~~,000	$61~~93~~,000
Evaluation	$0~~20,000~~	$20,000	$110,000	$130~~150~~,000
Total	**$659,000~~1,166,630~~**	**$1,411,300~~285,720~~**	**$1,929,700~~547,650~~**	**$4,000,000**

~~1.4~~1.5 Portfolio Benefits

~~1.4.1~~1.5.1 Natural Gas Savings

The following tables provide projected natural gas savings by program and sector for the EE Plan.

Table 3. Projected First Year Gas Savings by Program (Dth)

Program	2023	2024	2025	2023 - 2025
Residential Prescriptive Program	6,447~~14,518~~	15,719~~20,339~~	21,989~~23,952~~	44,154~~58,809~~
Online Audit Kit Program	7,446~~2,666~~	14,024~~5,367~~	15,943~~6,709~~	37,413~~14,743~~
Total	**13,893~~17,184~~**	**29,742~~25,707~~**	**37,932~~30,661~~**	**81,567~~73,552~~**

Table 4. Projected Lifetime Gas Savings by Program (Dth)

Program	2023	2024	2025	2023 - 2025
Residential Prescriptive Program	119,875~~264,136~~	270,261~~369,495~~	408,386~~432,463~~	798,523~~1,066,094~~
Online Audit Kit Program	90,326~~35,903~~	156,820~~72,154~~	184,309~~90,192~~	431,455~~198,248~~
Total	**210,201~~300,039~~**	**427,082~~441,648~~**	**592,695~~522,655~~**	**1,229,978~~264,342~~**

~~1.4.2~~1.5.2 Other Resource Savings

The following table shows electric savings for measures installed under the energy efficiency programs in the EE&C Portfolio. The electric savings are secondary savings from measures that primarily save natural gas, such as air-conditioning savings from thermostats. This section contains ancillary water savings from gas efficiency measures that also save water, such as low-flow faucet aerators and showerheads.

Table 5. Projected Electric and Water Savings

	2023	2024	2025	2023 - 2025
First Year				
Energy (MWh)	2565	95	145116	265276
Demand (kW)	4.511.7	16.9	43.120.8	64.449.3
Water (Million Gallons)	7.91.5	19.73.1	20.23.9	47.98.4
Lifetime				
Energy (MWh)	276720	1,040	2,1501,281	3,467041
Water (Million Gallons)	78.815.1	197.430.8	202.338.5	478.584.4

1.4.31.5.3 Emission Reductions

This section contains projections for CO_2 emission reductions due to the energy efficiency programs. The total lifetime savings of 76 thousand tons of CO_2 is equivalent to removing over 2,897900 cars off the road. The following table breaks out the emission reductions due to gas savings and electric savings. While the emissions reductions are projected below, the main TRC test for the portfolio does not include any monetized value for these emissions reductions.

Table 6. Projected Lifetime CO_2 Emission Reductions by Energy Source (Short Tons)

Savings Source	2023	2024	2025	2023 - 2025
Natural Gas	12,29717,552	24,98425,836	34,67330,575	71,95473,964
Electricity	252658	950	1,964170	3,1672,778
Total	12,54918,210	25,93526,787	36,63731,745	75,12076,742

1.4.41.5.4 Job Creation

Investing in cost-effective energy efficiency creates jobs in two ways, one direct and the other indirect, as discussed in a 2012 white paper from the ACEEE.[3] Direct job creation results from hiring related to implementing the programs. Indirect job creation results from the substitution of capital spent on natural gas with capital spent in the local economy. Additional jobs are created by the indirect or income effect from cost-effective energy efficiency investment. Further, the net economic benefits from efficiency investment reduce household and business gas bills and raise household disposable incomes and business profitability.

[3] "Energy Efficiency Job Creation: Real World Experiences" Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.

Customers will tend to spend most of this additional money and save the rest. This additional spending creates a "multiplier" effect through the cycle of re-spending of the initial cost savings, which stimulates aggregate demand for goods and services. Satisfying increased demand for goods and services requires more labor. While some of the jobs created leak into the broader U.S. and global economy, a good portion (possibly higher than 80%) of jobs created due to energy efficiency stay within the Commonwealth. The approach of looking at net job creation through both direct means and with economic multiplier effects is endorsed in the 2012 white paper from ACEEE.[4]

The number of jobs created from investments in energy efficiency directly relates to the total resource value of the energy that these measures save. Studies of employment impacts of Demand Side Management ("DSM") use energy savings as a surrogate for total resource value. A meta-study of U.S. data found that estimates for the number of jobs created had a wide range, but that most studies estimate that between 30 and 60 net jobs are created by saving one TBtu.[5] In New York, New Jersey, and Pennsylvania, the ACEEE projected that 164,320 jobs, or 59 for every TBtu saved, could be attributed to EE in 1997 through 2010.[6]

As shown in the following table, Columbia Gas estimates that its gas energy efficiency programs portfolio will generate between 38 and 76 net additional jobs over the lifetime of the efficiency measures installed over the next five-years. This range is based on assuming that each TBtu of gas savings creates between 30 and 60 full-time equivalent jobs in Pennsylvania.

[4] Energy Efficiency Job Creation: Real World Experiences" Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.
[5] Laitner, Skip, and Vanessa McKinney. June 2008. *Positive Returns: State Energy Efficiency Analyses Can Inform U.S. Energy Policy Assessments*. Washington, D.C.: American Council for an Energy Efficiency Economy.
[6] Nadel, Steven, Skip Laitner, Marshall Goldberg, Neal Elliott, John DeCicco, Howard Geller, and Robert Mowris. 1997. *Energy Efficiency and Economic Development in New York, New Jersey, and Pennsylvania. Washington, D.C.*: American Council for an Energy Efficiency Economy.

Table 7. Estimated Job Creation due to Energy Efficiency Programs

	JOB CREATION IMPACTS OF GAS EFFICIENCY PORTFOLIO		
	30 Jobs/TBtu	45 Jobs/TBtu	60 Jobs/TBtu
TOTAL PORTFOLIO			
2023	79	1114	1518
2024	13	1920	2526
2025	1716	2624	3531
TOTAL	**3738**	**5657**	**7576**

1.51.6 Cost-Effectiveness Analysis

The following table provides Total Resource Cost (TRC) test cost-effectiveness projections for the EE Plan.

Table 8. TRC Cost-effectiveness Summary of Portfolio (2022$)

Program	Total Resource PV Benefits	Total Resource PV Costs	Total Resource PV Net Benefits	Total Resource B/C Ratio
Residential Prescriptive Program	$6,388,9708,383,549	$3,270,996690,323	$3,117,9754,693,226	1.952.27
Online Audit Kit Program	$8,060,1882,472,719	$1,262,372695,683	$6,797,8161,777,035	6.383.55
Portfolio Wide Costs	$0	$536,886738,970	($536,886738,970)	-
EE Programs	**$14,449,15910,856,268**	**$5,070,254124,977**	**$9,378,9055,731,291**	**2.8512**

While the portfolio is cost effective using the primary TRC Test, if the values for demand-response induced pricing effects ("DRIPE")[7] and internalized market prices for carbon dioxide ("CO_2") are included, the portfolio would show substantially more benefits.

1.5.11.6.1 Cost-Effectiveness Analysis Methodology

The cost-effectiveness results reported in the Plan followed standard industry practices for utilizing the TRC Test for cost effectiveness. The TRC Test methodology used is similar to that used by other natural gas distribution companies serving Pennsylvania that offer energy efficiency programs, and by the Act 129 Utilities. To calculate benefits, projected natural gas, electricity, and water savings are multiplied by avoided costs, and this stream of future values is

[7] DRIPE accounts for the suppression effects on wholesale prices from reduced usage due to DSM.

discounted to the present. The cost side of the test consists of the present value of all incremental costs incurred by participants, including net operation and maintenance costs, and the non-incentive costs incurred by the portfolio administrator. If the benefits outweigh the costs (the benefit-cost ratio is above one), then the total cost of energy services for an average customer within the territory will fall and the portfolio is considered cost effective

The analysis used a real discount rate (RDR) of 3%. The RDR was calculated using an assumption of a nominal discount rate ("NDR") of 5% and inflation rate of 2.0%, which comes from the Act 129 Phase IV TRC Test Order.[8]

~~1.5.2~~1.6.2 Avoided Costs

The avoided cost of natural gas for Columbia Gas of Pennsylvania was developed in a similar manner to other Pennsylvania natural gas distribution companies offering energy efficiency programs and includes the costs of baseload and storage capacity, along with an estimate of avoidable local distribution costs. The avoided costs for baseload capacity were computed as the cost of Columbia Gas Transmission (TCO) FTS, Henry Hub commodity was priced using NYMEX futures from March 7, 2022 through 2027. The futures prices and the 2022 Annual Energy Outlook ("AEO") forecasts are very close to one another in 2027 and 2028, and differ by less than 10% on an annual basis through the end of the futures in 2034. The Annual Energy Outlook projections were used from 2028 onward. The avoided costs for heating load were computed from the Columbia Gas Transmission SST rate, plus refill from the Columbia FSS rate, adjusted for load factor over the heating season. Commodity costs include the commodity charge and gas retention from the TCO tariffs. The avoided costs also include an allowance for avoidable load-related distribution investments, borrowed from UGI's estimates in its 2018 EE&C filing, at Docket No. R-2018-3006814.

The Plan also uses avoided costs for electric energy and peak demand based on weighted average annual values from the electric utilities in Columbia

[8] Act 129 Phase IV 2021 Total Resource Cost (TRC) Test (Case No. M-2019-3006868). Final Order dated December 19, 2019. P. 20

Gas' territory, including Duquesne Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn. Values for the various electric utilities came from the respective Act 129 Phase IV filings for each utility.

Avoided costs for water came from the Act 129 Phase IV TRC Test Order.

~~1.6~~1.7 Implementation

~~1.6.1~~1.7.1 Program Staging

The Company anticipates that it will require six to nine months post Plan approval to finalize implementation details, hire vendors, and begin the marketing and outreach for ramping up the programs. All programs are projected to begin operations by July 1, 2023. This will give the programs a short year of activity in 2023, with significantly more activity projected in 2024 with the anticipation of full participation levels in 2025.

~~1.6.2~~1.7.2 Administration

The Portfolio will be managed by Columbia Gas, who will engage the services of various contractors to fulfill all the roles required to implement the Plan. The table below describes the main roles in the management of the Plan.

Table 9. Overview of Administration Roles

Role	Description
Plan Administrator	Primarily responsible for program and portfolio planning, management and reporting. Supervises and manages all other roles.
Implementation and Design Consultants	Provides assistance in the design and implementation on multiple aspects of the portfolio, including, but not limited to, program design, reporting, marketing, and training.
Implementation Contractor	Directly responsible for main aspects of program delivery, including but not limited to, customer engagement and retention, technical assistance, measure installation, rebate processing, program tracking, inspection, and reporting.
Evaluator	Performs independent program and portfolio evaluations that are used to verify savings and guide future plans.

~~1.6.3~~1.7.3 Marketing

Columbia Gas will investigate the use of a branded micro-website for the programs, for which multiple streams of advertising will lead back to, such as print, online ads, social media, bill inserts, trade ally outreach and residential canvassing efforts. These efforts are anticipated to be particularly important for driving participation in the Online Audit Kit program, which in turn may feed into the Residential Prescriptive Program.

Columbia Gas will also look to partner with local businesses and trade organizations (builders, contractors, electricians, plumbers, HVAC service providers, equipment suppliers, etc.) to familiarize them with program opportunities, energy efficiency practices and implementation requirements and to utilize them, where appropriate, as one of the program's service delivery channels.

- Targeting equipment manufacturers, distributors, installation contractors and retailers/vendors to make sure they offer high-efficiency equipment and can make customers aware of available incentives.
- Partnering with community-based organizations to develop outreach and program delivery strategies.
- Working with Act 129 electric administrators to combine marketing and delivery options and address all aspects of efficiency at the same time.

Additional details for each program are in the individual program plans, and Columbia Gas will develop a more detailed marketing strategy for each of the programs and for the entire portfolio as part of the program setup.

~~1.6.4~~1.7.4 Reporting

Columbia Gas will submit an annual report on the EE Plan each April, three months after the close of the program year. This report will provide information on activity for the previous year and progress towards three-year goals, including, but not limited to:

- First year and lifetime savings;
- Participation;
- Spending;

- Cost effectiveness;
- Highlights of portfolio and program activity; and
- Updates to program delivery and design.

In-order to tie savings and costs together as effectively as possible, results will be reported based on commitments made. Any measures that have been verified as installed within a program year along with any costs committed to these measures, including administration costs, will be counted for that year.

~~1.6.5~~1.7.5 Program Flexibility

To make sure that the EE&C Portfolio is able to address changing market conditions and improve service delivery as quickly as possible, Columbia Gas requires flexibility in the allocation of budgets and implementation of program improvements. This plan document provides the principles and three-year goals that Columbia Gas is seeking, but certain adjustments, such as providing incentives for new measures or moving budgets between years and programs, may be required to meet these goals. Columbia Gas will include any such adjustments in its annual report but does not anticipate seeking initial approval for such updates, considering that all costs are anticipated to be collected from the same rate class. Columbia Gas will file an updated EE Plan in anticipation of material changes that may have a serious effect on goals, such as:

- The addition or removal of a program;
- A need for total funding levels above those approved for the plan term; and
- Significant changes to cost-effectiveness projections, such as an update to avoided costs or a large reduction in portfolio spending projections.

~~1.7~~1.8 Evaluation, Measurement, and Verification

~~1.7.1~~1.8.1 Technical Reference Manual

To maintain consistency with existing gas efficiency programs in Pennsylvania, Columbia Gas will utilize a Technical Reference Manual (“TRM”) based on the most recent version of the UGI Gas, Inc. TRM and Columbia Gas VA’s experience with its online audit program. The Columbia Gas TRM will only contain those

measures relevant to the programs proposed in this plan, and will include updates to some measure assumptions to calibrate them to Columbia Gas' service territory (such as equivalent full load heating hours and heating degree days). In the future, any results from program evaluations that affect deemed savings calculations will also be added to the TRM. The proposed TRM is included as Attachment A to this plan.

~~1.7.2~~1.8.2 Tracking System

Columbia Gas will require that its coordinators collect all relevant customer, application, measure, and contractor information and that this data is provided in a timely fashion. Columbia Gas will regularly review this data, and will aggregate cost, savings, and participation data to a centralized database controlled by Columbia Gas that will be the source for program management and reporting.

~~1.7.3~~1.8.3 Inspections

Inspections may be performed on a sub-set of applications before any incentive is paid. Inspectors will determine whether the measure is operational and matches the application, and they will solicit customer feedback on the programs. Inspection rates for prescriptive programs will be designed to gather a statistically significant sample of program activity. See individual program plans for additional details.

~~1.7.4~~1.8.4 Evaluations

Columbia Gas will monitor the ongoing progress of the EE Plan to provide the highest possible service to customers, while maintaining controls to maximize the potential for savings and costs to be properly verified and counted. Columbia Gas will closely track program data, perform inspections of completed projects, and perform periodic evaluations for all the programs.

Columbia Gas will, at a minimum, evaluate each of its programs once adequate participation levels have been reached and a full 12 months of post-participation billing data has been collected. As part of the initial program development, Columbia Gas will work with the selected evaluator to establish the methodology and goals of the evaluation. Initial objectives include:

- Verifying energy savings and associated costs;
- Assessing market attitudes towards the program, including contractors, customers, and efficient equipment suppliers; and
- Measuring the effectiveness of current program design, marketing, and service delivery.

The evaluation section of the individual program descriptions includes additional details on evaluation schedules and goals unique to that program.

2 Program Plans

2.1 Residential Prescriptive

Objective	The Residential Prescriptive (RP) program is designed to overcome market barriers to energy efficient space and water heating equipment and building shell upgrades in the residential sector through rebates and customer awareness. The objective of the program is to avoid lost opportunities by encouraging consumers to install the most efficient gas heating technologies available when replacing older, less efficient equipment and make long lasting improvements to their building shell through insulation and air sealing. The program also aims to strengthen Columbia Gas' relationship with HVAC contractors, suppliers, and other trade allies.
Eligible Rate Class	RDS/RSS
Cost Effectiveness	***Three-Year Cost-Effectiveness Results (2022$)***

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC Test	$6,388,9708,383,549	$3,270,996690,323	$3,117,9754,693,226	1.952.27
Gas Admin Test	$6,206,2328,246,078	$1,776,0402,179,527	$4,430,1926,066,551	3.4978

Savings Projections	***Three-Year Savings Projections***

First Year Savings	2023	2024	2025	2023 - 2025

	Natural Gas (Dth)	6,44714,518	15,71920,339	21,98923,952	**44,15458,809**
	Electric Energy (MWh)	25.165.5	94.6	145116.4	**265.1276.5**
	Peak Demand (kW)	4.511.7	16.9	43.120.8	**64.449.3**
	Water (Million Gallons)	0.0	0.0	0.0	**0.0**
	Lifetime Savings	**2023**	**2024**	**2025**	**2023 - 2025**
	Natural Gas (Dth)	119,875264,136	270,261369,495	408,386432,463	**798,5231,066,094**
	Electric Energy (MWh)	276.1720.3	1,040.5	2,150.21,280.6	**3,466.8041.4**
	Water (Million Gallons)	0.0	0.0	0.0	**0.0**

Budget Projections

Three-Year Budgets (Nominal)

Costs by Category	**2023**	**2024**	**2025**	**2023 - 2025**
Customer Incentives	$213,10046 2,000	$480652,000	$779,700768, 000	**$1,472,800882,000**
Administration	$7591,000	$7073,000	$10778,000	**$252242,000**
Marketing	$2074,000	$5232,000	$7534,000	**$147140,000**
Inspections	$323,000	$2432,000	$3438,000	**$6193,000**
Evaluation	$0	$0	$60,000	**$60,000**
Total	**$311,10065 0,000**	**$626789,000**	**$1,055,70097 8,000**	**$1,992,8002,417 ,000**

Participation Projections

Three-Year Participation Projections

Projected Units	**2023**	**2024**	**2025**	**2023 - 2025**
Furnace - ENERGY STAR	237 520	500 700	600 800	**1,337 2,020**
Boiler - 94+ AFUE	19 20	30	40	**89 90**

	Combi Boiler - 94+ AFUE	33 ~~80~~	60 ~~120~~	100 ~~140~~	**193 ~~340~~**
	Wifi Thermostat - ENERGY STAR	345 ~~900~~	1,300	1,600	**3,245 ~~800~~**
	Tankless Water Heater - ENERGY STAR	63 ~~120~~	120 ~~170~~	150 ~~200~~	**333 ~~490~~**
	Gas Heat Pump (Furnace Baseline)	-	-	2	**2**
	Gas Heat Pump (Boiler Baseline)	-	-	2	**2**
	Insulation and Air Sealing	-	-	164	**164**
	Total	**697 ~~1,640~~**	**2,010 ~~320~~**	**2,658 ~~780~~**	**5,199 ~~6,740~~**
Program Rollout	*Jan 2023 – Jun 2023*	Finalize program process and implementation details, select vendors, and develop initial marketing push			
	Jul 2023	Launch Program			
	2023 - 2024	Continue engagement activities with customers and trade allies.			
	2025	Reach full anticipated participation levels.			
Program Design	The RP Program offers rebates for qualifying insulation and air sealing project, residential-sized space and water heating equipment and controls. For most measures, customers will have a contractor install the measure and receive a rebate to offset some of the incremental cost of the higher efficiency equipment. Smaller measures, such as Wi-Fi enabled thermostats, will only require a valid proof of purchase before a rebate is issued. Customers will be encouraged to process rebates through an online portal, but may also submit a paper application through the mail. Columbia Gas may also provide the option to purchase qualified smart thermostats via an online marketplace.				

	If program funds begin to run low, incentive levels may be lowered, or equipment removed from the program if additional budget adjustments cannot be made. Columbia Gas will aim to provide as little interruption to customers as possible due to such adjustments. Columbia Gas will continue to examine other equipment for potential inclusion in the program, as well as the relative market adoption of equipment already receiving incentives.
Target Market and End Uses	The RP targets residential consumers who use natural gas to heat their homes and/or generate hot water. In general, the program aims to incentivize only the highest levels of efficient equipment on the market. The minimum level of efficiency for measures offered through the RP program will be ENERGY STAR®, when available, and in some cases may exceed ENERGY STAR®. On the space heating side, the program provides incentives for ENERGY STAR® labeled smart thermostats, furnaces, high efficiency boilers, ~~and~~ combination boilers, and natural gas powered heat pumps.~~.~~ ENERGY STAR® smart thermostats offer the potential for deeper savings than traditional programmable thermostats due to the wide range of features and feedback they offer. ENERGY STAR® requirements for furnaces drive customers toward the highest efficiency tier of condensing units (95+ AFUE) and require efficient fans that save electricity. The program would also require boilers to go towards the highest efficiency tier with an AFUE of at least 94. Offering~~Finally, offering~~ incentives for combination space and water heating boilers addresses two types of end-use with one piece of equipment. These “combi boilers” also address issues with orphaned water heaters having existing atmospheric venting systems that are no longer adequate, when switching to condensing heating

	equipment. Finally, offering incentives for the newly emerging technology of natural gas-powered heat pumps provides customers the ability to heat their homes with the highest efficiency available in natural gas space heating. The programThe program also addresses water heating savings by offering incentives for ENERGY STAR® tankless water heaters. The program also addresses long-term savings by offering incentives for customers to upgrade the performance of their building shell through insulation and air sealing.

Financial Incentives

Incentives were designed to be in line with other offerings in the region and/or cover approximately two-thirds of the incremental cost of the measure. The table below lists the proposed incentive schedule.

Proposed Residential Prescriptive Program Rebates (Nominal)

Equipment	Minimum Efficiency	Proposed Incentive	Maximum Incentive
Smart Thermostat	ENERGY STAR®	$100	$100
Furnace	ENERGY STAR®	$400	$500
Boiler	94+ AFUE	$1,000	$1,500
Combi Boiler	94+ AFUE	$1,200	$1,800
Tankless Water Heater	ENERGY STAR®	$400	$500
Gas Heat Pump (Furnace Baseline)	Gas Heat Pump Forced Air	$2,000	$5,000
Gas Heat Pump (Boiler Baseline)	Gas Heat Pump Air to Water	$2,000	$5,000
Insulation and Air Sealing	N/A	25% Cost ($2,500 Cap)	$2,500

All equipment besides the Wi-Fi thermostat must be powered by natural gas. Insulation and Air Sealing customers must have natural gas as their heat source.

Marketing Approach

The RP program may be marketed through inclusion on Columbia's website and through social media, as well as through bill inserts and other media messaging. The main way that many customers will hear about the RP Program is through HVAC contractors, weatherization contractors, and plumbers, and

	the program will be a key part of trade ally outreach efforts. Incentives will help these contractors sell jobs, and efforts such as cobranding and potentially assigning incentives to contractors will provide trade allies with even more tools to move customers to higher efficiency levels.
Evaluation, Measurement, and Verification	Quality Assurance All applications will require proof of purchase and a valid Columbia Gas account number. Rebates received as an instant rebate via a qualified participating contractor or equipment distributor will be accompanied by an invoice showing the point of sale discount passed on to the customer. The rebate processor will verify that the equipment is eligible for the rebate based on the model's Air-Conditioning Heating and Refrigeration Institute (AHRI) number before issuing any rebate. The program's rebate processor will maintain a real-time database of rebate activity, which will be periodically reviewed by Columbia Gas and stored separately for long-term purposes. There will be inspections of approximately five percent (5%) of non-thermostat equipment rebates and approximately one percent (1%) of Wi-Fi thermostat rebates to obtain a statistically significant sample of activity. The inspection will consist of verifying that the rebated equipment is installed and operational and conclude with a short informational interview with the participant. Virtual inspections will be explored to reduce program costs and increase inspection rates. Evaluations A third-party vendor will evaluate the program's process and impacts after sufficient participation has occurred in the third year of the Plan.

Program Administration	Rebate Processing and Inspection The rebate processor will accept customer applications, track and verify application information, notify the customer of any issues, maintain a call center, and report results to Columbia Gas. The rebate processor may also be responsible for other programs to streamline portfolio management. The rebate processor will also be responsible for inspections. Marketing and Outreach Columbia Gas and their vendors will handle marketing and outreach for the RP program. Evaluator A third-party evaluator will be retained to perform evaluations.

2.2 Online Audit Kit

Objective

The Online Audit Kit (OAK) Program is designed to provide residential customers with information on how to improve the efficiency of their homes along with free, targeted energy savings kits. The program also provides a way for customers to engage with Columbia Gas and learn about the RP Program.

Eligible Rate Class

RSD/RSS

Cost Effectiveness

Three-Year Cost-Effectiveness Results (2022$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC Test	$8,060,1882,472,719	$1,262,372695,683	$6,797,8161,777,035	6.383.55
Gas Admin Test	$2,820,6211,548,703	$1,262,372695,683	$1,558,249853,020	2.23

Savings Projections

Three-Year Savings Projections

First Year Savings	2023	2024	2025	2023 - 2025
Natural Gas (Dth)	7,4462,666	14,0245,367	15,9436,709	**37,41314,743**
Electric Energy (MWh)	0.0	0.0	0.0	**0.0**
Peak Demand (kW)	0.0	0.0	0.0	**0.0**
Water (Million Gallons)	7.91.5	19.73.1	20.23.9	**47.98.4**
Lifetime Savings	**2023**	**2024**	**2025**	**2023 - 2025**
Natural Gas (Dth)	90,32635,903	156,82072,154	184,30990,192	**431,455198,248**
Electric Energy (MWh)	0.0	0.0	0.0	**0.0**
Water (Million Gallons)	78.815.1	197.430.8	202.338.5	**478.584.4**

Budget Projections

Three-Year Budgets (Nominal)

Costs by Category	2023	2024	2025	2023 - 2025
Customer Incentives	$106,900~~25,630~~	$234,300~~51,720~~	$252,000~~64,650~~	**$593,200~~142,000~~**
Administration	$98~~113~~,000	$277~~126~~,000	$302~~145~~,000	**$677~~384~~,000**
Marketing	$18~~58~~,000	$20~~45~~,000	$32~~52~~,000	**$70~~155~~,000**
Inspections	$0	$0	$0	**$0**
Evaluation	$0~~20,000~~	$20,000	$50,000	**$70~~90~~,000**
Total	**$222,900~~216,630~~**	**$551,300~~242,720~~**	**$636,000~~311,650~~**	**$1,410,200~~771,000~~**

Participation Projections

Three-Year Participation Projections

Projected Kits	2023	2024	2025	2023 - 2025
Water Heating Kit	2,455~~470~~	6,150~~960~~	6,300~~1,200~~	**14,905~~2,630~~**
Space Heating Kit	1,339~~780~~	1,400~~560~~	2,100~~1,950~~	**4,839~~290~~**
Total	**3,794~~1,250~~**	**7,550~~2,520~~**	**8,400~~3,150~~**	**19,744~~6,920~~**

Program Rollout

Jan 2023 – Jun 2023	Finalize program process and implementation details, select vendors, and develop initial marketing push
Jul 2023	Launch Program
2023 - 2024	Continue engagement activities with customers and trade allies.
2025	Reach full anticipated participation levels.

Program Design

The OAK Program provides a way for customers to undergo an online audit of their home, which will result in a customized set of recommendations. The customer will then be eligible to receive up to two

	targeted energy saving kits, shipped to their home at no cost. The first kit is for customers who use natural gas for water heating, and the second kit is for customers who utilize natural gas to heat their homes. Participating customers will also be referred to the RP program incentives if appropriate. To reach customers who do not have easy access to the internet, a phone version of the audit will be made available.
Target Market and End Uses	There will be two kits available for customers. The water heating kit will include measures such as high-efficiency showerheads and low-flow faucet aerators. The space heating kit will include low-cost measures such as outlet and light switch gaskets, caulk, and foam sealant along with instructions on effective installation.
Financial Incentives	Kits will be provided at no cost to the customer.
Marketing Approach	The OAK program will be marketed through bill inserts, social media, and on Columbia Gas' website. Other outreach efforts may include email, radio, and print advertisements. The program will also act as a referral service for customers who may want to participate in the RP program.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> Columbia Gas will perform a survey of participants every year to determine installation rates for energy saving kits and assess customers satisfaction with program recommendations. <u>Evaluations</u>

	The program will undergo a process and impact evaluation in the third year once sufficient time has passed for the program to achieve meaningful participation.
Program Administration	Online Audit and Kit Provider Columbia Gas will hire a vendor to provide an online audit solution and package and send energy saving kits to customers. Marketing and Outreach Columbia Gas and their vendors will handle marketing and outreach for the program. Evaluator A third-party evaluator will be retained to perform annual participant surveys and regular program evaluations.

3 Appendices

3.1 Avoided Cost Tables

Gas Avoided Costs (2022$/Dth)

Year	Base	Space Heating	Domestic Hot Water
2023	$4.67	$10.49	$6.12
2024	$4.48	$10.42	$5.97
2025	$4.46	$10.47	$5.96
2026	$4.47	$10.57	$6.00
2027	$4.49	$10.67	$6.04
2028	$4.66	$10.90	$6.22
2029	$4.84	$11.14	$6.41
2030	$4.92	$11.30	$6.51
2031	$5.04	$11.49	$6.66
2032	$5.10	$11.62	$6.73
2033	$5.20	$11.79	$6.85
2034	$5.21	$11.87	$6.87
2035	$5.22	$11.96	$6.91
2036	$5.25	$12.06	$6.95
2037	$5.29	$12.17	$7.01
2038	$5.32	$12.28	$7.06
2039	$5.34	$12.38	$7.10
2040	$5.40	$12.52	$7.18
2041	$5.43	$12.63	$7.23
2042	$5.43	$12.70	$7.24
2043	$5.45	$12.81	$7.29
2044	$5.40	$12.85	$7.26
2045	$5.39	$12.93	$7.27
2046	$5.40	$13.03	$7.30
2047	$5.41	$13.13	$7.34
2048	$5.46	$13.27	$7.41
2049	$5.46	$13.37	$7.43
2050	$5.47	$13.48	$7.47

Developed by Resource Insight, Inc.

Other Resource Avoided Costs (2022$)

Year	All-Year Energy ($/kWh)	Generation Capacity ($/kW-yr)	T&D ($/kW-yr)	Water ($/gal)
2023	$0.0324	$54.63	$53.93	$0.013
2024	$0.0324	$54.63	$53.93	$0.013
2025	$0.0323	$54.63	$53.93	$0.013
2026	$0.0335	$54.64	$53.93	$0.013
2027	$0.0348	$54.64	$53.93	$0.013
2028	$0.0362	$54.64	$53.93	$0.013
2029	$0.0374	$54.63	$53.93	$0.013
2030	$0.0380	$54.63	$53.93	$0.013
2031	$0.0390	$54.63	$53.93	$0.013
2032	$0.0404	$54.63	$53.93	$0.013
2033	$0.0413	$54.63	$53.93	$0.013
2034	$0.0420	$54.63	$53.93	$0.013
2035	$0.0415	$54.64	$53.93	$0.013
2036	$0.0411	$54.63	$53.93	$0.013
2037	$0.0414	$54.63	$53.93	$0.013
2038	$0.0415	$54.63	$53.93	$0.013
2039	$0.0414	$54.63	$53.93	$0.013
2040	$0.0416	$54.63	$53.93	$0.013
2041	$0.0418	$54.63	$53.93	$0.013
2042	$0.0418	$54.63	$53.93	$0.013
2043	$0.0418	$54.63	$53.93	$0.013
2044	$0.0418	$54.63	$53.93	$0.013
2045	$0.0418	$54.63	$53.93	$0.013
2046	$0.0418	$54.63	$53.93	$0.013
2047	$0.0418	$54.63	$53.93	$0.013
2048	$0.0418	$54.63	$53.93	$0.013
2049	$0.0418	$54.63	$53.93	$0.013
2050	$0.0418	$54.63	$53.93	$0.013

3.2 Detailed Measure Assumptions

	Costs		Savings				
Measure Name	**Incentive**	**Incr. Cost**	**Lifetime (Yrs)**	**Dth**	**kWh**	**kW**	**Water (Gal)**
Residential Prescriptive Program							
Furnace - ENERGY STAR	$400.00	$758.40	20	13.99	0	0	0
Boiler - 94+ AFUE	$1,000.00	$1,785.00	25	12.83	0	0	0
Combi Boiler - 94+ AFUE	$1,200.00	$2,526.18	25	22.72	0	0	0
Wifi Thermostat - ENERGY STAR	$100.00	$150.00	11	4.52	73	0.01	0
Tankless Water Heater - ENERGY STAR	$400.00	$592.85	20	9.18	0	0	0
Gas Heat Pump (Furnace)	$2,000.00	$17,195.75	15	40.46	0	0	0
Gas Heat Pump (Boiler)	$2,000.00	$14,007.50	15	36.09	0	0	0
Insulation & Air Sealing	$925.00	$3,700.00	30	12.50	176.74	0.1361	0
Online Audit Kit Program							
Web Faucet Aerator - Kitchen	$2.0070	$2.0070	10	0.51	0	0	941
Web Faucet Aerator - Bathroom	$1.000.70	$1.000.70	10	0.11	0	0	201
Web High Efficiency Showerhead	$5.004.96	$5.004.96	10	0.51	0	0	934
Web Switch/Outlet Cover	$2.5040	$2.5040	15	1.64	0	0	-
Web Caulk	$3.0012	$3.0012	15	0.37	0	0	-
Web Foam Sealant	$6.0021	$6.0021	15	0.37	0	0	-
Water Heating Kit	$20.008.98	$20.008.98	1	-	0	0	-
Space Heating Kit	$6.507.27	$6.507.27	1	-	0	0	-

3.3 Detailed Program and Portfolio Cost-effectiveness

Energy Efficiency Programs' Cost Effectiveness over Three-Year Portfolio (2022$)

	Total Resource			Gas Energy System		
Program	Present Value Benefit	Present Value Cost	PV of Net Benefits	Present Value Benefit	Present Value Cost	PV of Net Benefits
Portfolio Total	$14,449,15910,856,268	$5,070,254124,977	$9,378,9055,731,291	$9,026,852794,781	$3,575,297614,180	$5,451,5556,180,601
Non-Measure Costs		$1,730,783792,202			$1,730,783792,202	
Total Measure Costs	$14,449,15910,856,268	$3,339,471332,775	$11,109,6887,523,493	$9,026,852794,781	$1,844,514821,979	$7,182,338972,803
Program						
Residential Prescriptive Program						
Program Total	$6,388,9708,383,549	$3,270,996690,323	$3,117,9754,693,226	$6,206,2328,246,078	$1,776,0402,179,527	$4,430,1926,066,551
Non-Measure Costs		$464,179484,717			$464,179484,717	
Total Measure Costs	$6,388,9708,383,549	$2,806,8173,205,607	$3,582,1535,177,942	$6,206,2328,246,078	$1,311,861694,810	$4,894,3716,551,268
Online Audit Kit Program						
Program Total	$8,060,1882,472,719	$1,262,372695,683	$6,797,8161,777,035	$2,820,6211,548,703	$1,262,372695,683	$1,558,249853,020
Non-Measure Costs		$729,718568,515			$729,718568,515	
Total Measure Costs	$8,060,1882,472,719	$532,654127,168	$7,527,5352,345,551	$2,820,6211,548,703	$532,654127,168	$2,287,9671,421,535
Portfolio Wide Costs						
Program Total	-	$536,886738,970	$(536,886738,970)	-	$536,886738,970	$(536,886738,970)
Non-Measure Costs		$536,886738,970			$536,886738,970	
Total Measure Costs	-	-	-	-	-	-

3.4 Technical Reference Manual (TRM)

Document to follow below

Technical Reference Manual

Measure Savings Algorithms

Columbia Gas of Pennsylvania

February 19~~5~~, 2024

Prepared by:



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Prepared by: Green Energy Economics Group, Inc.

1 Cross-Sector TRM Issues

1.1 Establishing Baselines

The savings methods and assumptions can differ substantially based on the program delivery mechanism for each measure type. Within each of the measure protocols in the TRM, there is a definition for the measure's baseline efficiency, a critical input into the savings calculations. Most measures will fall into one of two categories, each with a baseline that is most commonly used:

- One for market-driven choices – often called "lost opportunity" and either replacing equipment that has failed (replace on burnout) or new installations (new construction)
- One for discretionary installations – either early replacement or retrofit

For all new construction (NC) and replace on burnout (ROB) scenarios, the baseline is typically a jurisdictional code or a national standard; however, there may be cases where a market baseline is appropriate. In these scenarios, the Commission has a preference for codes and standards as it is too expensive and time consuming to conduct annual market baseline and characterization research. Additionally, the TRM provides estimates for gross energy savings only, whereas net savings "…include the effects of free-ridership, spillover, and induced market effects."

For discretionary installation scenarios, the baseline is typically the existing equipment efficiency, but in the case of early replacement (EREP), at some point the savings calculations must incorporate changes to the baseline for new installations (e.g., code or market changes) to account for eventual natural replacement of the equipment. This approach encourages residential and business consumers to replace working inefficient equipment and appliances with new high-efficiency products rather than taking no action to upgrade or only replacing them with new standard-efficiency products.

All baselines are designed to reflect current market practices that are updated periodically to reflect upgrades in federal equipment standards, building code, or information from evaluation results. Specifically for commercial and industrial measures, Pennsylvania has adopted the 2015 International Energy Conservation Code (IECC) per 34 Pa. Code Section 403.21, effective October 1, 2018. Per Section 401.2 of IECC 2015, commercial buildings must comply with either "[t]he requirements of ANSI/ASHRAE/IESNA Standard 90.1[-2013]" or comply with the requirements outlined in IECC 2015 Chapter 4. In accordance with IECC 2015, commercial protocols relying on code standards as the baseline condition may refer to either IECC 2015 or ASHRAE 90.1-2013 per the program design.

The baseline estimates used in the TRM are based on applicable federal standards, or are documented in baseline studies or other market information. This TRM reflects the most up-to-date codes, practices, and market transformation effects. The measures herein include, where appropriate, schedules for the implementation of Federal standards to coincide with the beginning of a program year. These implementation schedules apply to measures where the Federal standard is considered the baseline, as described herein or otherwise required by law. In cases where the ENERGY STAR criterion is considered the eligibility requirement and the existing ENERGY STAR Product Specification Version expires in a given year, the new ENERGY STAR Product Specification Version will become the eligibility requirement at the start of the next consecutive program year.

The combined effect of measure retention and persistence is the ability of installed measures to maintain the initial level of energy savings or generation over the measure life. If the measure is subject to a reduction in savings or generation over time, the reduction in retention or persistence is accounted for using factors in the calculation of resource savings.

2 Residential Time of Replacement Market

2.1 Space Heating End Use

2.1.1 Efficient Space Heating System

Unique Measure Code(s): TBD
Draft date: 23/196/2442
Effective date: TBD
End date: TBD

Measure Description
This measure applies to residential-sized gas furnaces, ~~and~~ boilers, and gas heat pumps purchased at the time of natural replacement. A qualifying furnace or boiler must meet minimum efficiency requirements (AFUE).

Definition of Baseline Condition
The efficiency levels of the gas-fired furnaces or boilers that would have been purchased absent this or another DSM program are shown in the following table. The baseline for a gas heat pump is the type of equipment currently in place and being replaced.

Equipment Type	Baseline AFUE
Gas Furnace	80%
Gas Boiler	84%

Definition of Efficient Condition
The installed gas furnace or boiler must have an AFUE greater than that shown in the table below. Efficient model minimum AFUE requirements are detailed below.

Equipment Type	Minimum AFUE
Gas Furnace	95%
~~Gas Furnace with ECM Fan~~	~~95%~~
Gas Boiler	94%
Gas Heat Pump	>100%

Gas Savings Algorithms
MMBtu savings are realized due to the increase in AFUE of the new equipment. MMBtu savings vary by equipment type due to differences in model specific baseline AFUE and high efficiency AFUE percentages. Savings are calculated from the baseline new unit to the installed efficient unit.

$$Annual\ Gas\ Savings\ (MMBtu) = \frac{Capacity_{Out}}{1{,}000} \times \left(\frac{1}{AFUE_{Base}} - \frac{1}{AFUE_{Eff}}\right) \times EFLH_{Heat}$$

Where:

$Capacity_{Out}$ = Output capacity of equipment to be installed (kBtu/hr)
1,000 = Conversion from kBtu to MMBtu
$AFUE_{Base}$ = Efficiency of new baseline equipment (Annual Fuel Utilization Efficiency)
$AFUE_{Eff}$ = Efficiency of new equipment
$EFLH_{Heat}$ = Equivalent Full Load Heating Hours (Refer to EFLH table by climate zone in References Section)

Electric Savings Algorithms

Energy Savings

$\Delta kWh = 0$ kWh

Demand Savings

$\Delta kW = 0$ kW

Where:

ΔkWh = Gross customer annual kWh savings for the measure.
ΔkW = Gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Gas Furnace	0%	0%
Gas Furnace with ECM Fan	0%	0%
Gas Boiler	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
Gas Furnaces	20
Gas Boilers	25
Gas Heat Pump	15

Sources: Lifetime estimates used by Efficiency Vermont, PGW and UGI for furnaces and boilers. Gas heat pump lifetime from Illinois TRM, Version 11.0, Volume 2, p 575.

Water Savings

There are no water savings for this measure.

2.1.2 WiFi Thermostat – ENERGY STAR®

Unique Measure Code(s): TBD
Draft date: 23/196/2442
Effective date: TBD
End date: TBD

Measure Description
This is an ENERGY STAR® WiFi thermostat controlling a residential-sized gas furnace or boiler.

Definition of Baseline Condition
The baseline is a manual thermostat where each temperature setting change requires human intervention or a conventional programmable.

Definition of Efficient Condition
The efficient thermostat is one that is WiFi enabled, ENERGY STAR® certified and can be programmed to automatically increase or lower the temperature setting at different times of the day and week.

Gas Savings Algorithms

$$Annual\ Gas\ Savings\ (MMBtu) = SH_{pre} \times ESF$$

Where:

SH_{pre}	=	Space Heat MMBtu gas usage with manual thermostat = 70.6 [1]
ESF	=	Percentage savings from WiFi thermostat compared to non-WiFi connected thermostat. See table below by installation method.

Heating Energy Savings Factors (ESF)

[1] Space-heat usage assumption from examination of Columbia Gas PA residential usage by month.

Program Type	Baseline	Air Source Heat Pump	Furnace/Boiler Heating (Electric or Fossil)
Upstream buy-down (Customer Self-Installation)	Unknown Mix Default	6.4%[a]	6.4%[a]
Customer Self-Installation with Education	Unknown Mix Default	7.9%[b]	7.9%[b]
Professional Installation	Manual	11.5%[c]	11.5%[c]
	Conventional programmable	7.9%[d]	7.9%[d]

[a] *Average of heating estimates from two studies.*

[b] *Heating savings are based on average of savings from unknown mix default with customer self-installation and average of professional installation savings from manual and programmable thermostats. In this case, 7.9%=((11.5%×0.42 + 7.9%×0.58) + 6.4%) / 2*

[c] *Average of four heating savings estimates from four studies.*

[d] *The ESF value for a is applied here as an estimate until information becomes available showing different savings incented through a direct install program.*

Source for table values: Act 129 Phase IV TRM.

Electric Savings Algorithms

If the type of air conditioning is known, then use the appropriate algorithm below. If the type or existence of air-conditioning is not known, then assume that 45% have central air-conditioning and estimate the cooling savings as 45% of a house with central air conditioning.[2]

Reduced furnace fan or boiler circulator pump usage is also likely to occur and provide electricity savings during both the heating and cooling seasons, but these auxiliary savings are not accounted for in the following algorithms.

Energy Savings

$\Delta kWh = \Delta kWh_{Aux} + \Delta kWh_{Cool}$

ΔkWh_{Aux} = Furnace Fan kWh savings

ΔkWh_{Cool} = 0 kWh if house has no air conditioning
= ΔkWh_{CAC} if house has central air conditioning
= 0 if house has room air conditioning
= 45% × ΔkWh_{CAC} if no information about air conditioner

Deemed Savings ΔkWh

Program Type	Baseline	Fossil Fuel Furnace (Fan Only) ΔkWh_{Aux}	CAC Cooling ΔkWh_{CAC}
Upstream buy-down (Customer Self-Installation)	Unknown Mix Default	48	77

[2] Percentage of houses with central air-conditioning from 2009 RECS data.

Customer Self-Installation with Education	Unknown Mix Default	60	120
Professional Installation	Manual	87	182
	Conventional programmable	60	150

Source: Act 129 Phase IV TRM.

Demand Savings

ΔkW ~~=~~ = 0 kW if house has no air conditioning
= ΔkW_{CAC} if house has central air conditioning
= 0 if house has room air conditioning
= 45% × ΔkW_{CAC} if no information about air conditioner
= *0.0130 kW default*

~~0 kW~~

Deemed Savings ΔkW

Program Type	Baseline	ASHP Cooling	CAC Cooling ΔkW_{CAC}
Upstream buy-down (Customer Self-Installation)	Unknown Mix Default	0.0269	0.0289
Customer Self-Installation with Education	Unknown Mix Default	0.0418	0.0450
Professional Installation	Manual	0.0633	0.0680
	Conventional programmable	0.0521	0.0560

Source: Act 129 Phase IV TRM.

Where:

ΔkWh = gross customer annual kWh savings for the measure.
ΔkW = gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
WiFi Thermostat	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
WiFi Thermostat	11

Source: August 2019 Act 129 TRM, Volume 2, p.47.

Water Savings
There are no water savings for this measure.

2.2 Water Heating End Use

2.2.1 Tankless Water Heater

Unique Measure Code(s): TBD
Draft date: 3/6/22
Effective date: TBD
End date: TBD

Measure Description
This measure is an on-demand gas water heater.

Definition of Baseline Condition
The efficiency levels of the gas-fired stand-alone storage water heater that would have been purchased absent this or another DSM program are shown in the following table.

Equipment Type	Usage Draw Pattern	Baseline UEF[3]
Gas Stand-alone Storage Water Heater	Very Small	0.27
Gas Stand-alone Storage Water Heater	Low	0.52
Gas Stand-alone Storage Water Heater	Medium	0.58
Gas Stand-alone Storage Water Heater	High	0.64

Baseline usage draw pattern is established by the capacity of the installed tankless water heater, using the table below:

Usage Draw Pattern	Max GPM	Daily Volume in Gallons (*V*)
Very Small	$0 \leq GPM < 1.7$	10
Low	$1.7 \leq GPM < 2.8$	38
Medium	$2.8 \leq GPM < 4.0$	55
High	$4.0 \leq GPM$	84

If the tankless water heater capacity is not available, assume medium usage draw pattern.

Definition of Efficient Condition
The installed tankless water heater must have an UEF greater than that shown in the table below. Efficient model minimum UEF requirements are detailed below.

Equipment Type	Minimum UEF
Gas Tankless Water Heater	0.87

Gas Savings Algorithms
The following formula for gas savings is based on the DOE test procedure for water heaters[4].

[3] Based on the federal standard for residential gas-fired water heater as of June 2017 and assumed typical 40 gallon storage. https://www.law.cornell.edu/cfr/text/10/430.32
[4] 10 CFR Appendix E to Subpart B of Part 430, Uniform Test Method for Measuring the Energy Consumption of Water Heaters

$$Annual\ Gas\ Savings\ (MMBtu) = \frac{\left(\frac{1}{UEF_{Base}} - \frac{1}{UEF_{Eff}}\right) \times V \times \rho \times c_p \times 67 \times 365}{1{,}000{,}000}$$

Where:

UEF_{Base}	=	Uniform Energy Factor of baseline water heater based on usage draw pattern
UEF_{Eff}	=	Uniform Energy Factor of efficient water heater
V	=	Daily volume of hot water usage in gallons. See table in baseline section. If usage draw pattern is unknown, assume medium (55 gallons/day).
ρ	=	Water density at 125°F (8.24 lb/gal)
c_p	=	Specific heat of water (1.00 Btu/lb °F)
67	=	°F temperature rise between inlet and outlet of water heater
365	=	Days per year
1,000,000	=	Btu per MMBtu

Electric Savings Algorithms

There are no electric savings from this measure.

Energy Savings

ΔkWh = 0 kWh

Demand Savings

ΔkW = 0 kW

Where:

ΔkWh	= gross customer annual kWh savings for the measure.
ΔkW	= gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Tankless Water Heater	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
Tankless Water Heater	20

Source: Energy Star Residential Water Heaters: Final Criteria Analysis, April 1, 2008, p. 10.

Water Savings
There are no water savings for this measure.

2.3 Combined Space and Domestic Hot Water Usage

2.3.1 Combination Boiler - Space Heating and DHW

Unique Measure Code(s): TBD
Draft date: 3/6/22
Effective date: TBD
End date: TBD

Measure Description
This measure applies to residential-sized combination boilers purchased at the time of natural replacement. These are integrated boilers that provide hot water for space heating and on-demand domestic hot water and have minimal or no hot water storage. A qualifying combination boiler (combi boiler) must meet minimum efficiency requirements (AFUE).

Definition of Baseline Condition
The efficiency levels of the gas-fired boiler and stand-alone storage water heater that would have been purchased absent this or another DSM program are shown in the following table.

Equipment Type	Baseline[5]
Gas Boiler	84% AFUE

Equipment Type	Usage Draw Pattern	Baseline UEF[6]
Gas Stand-alone Storage Water Heater	Very Small	0.27
Gas Stand-alone Storage Water Heater	Low	0.52
Gas Stand-alone Storage Water Heater	Medium	0.58
Gas Stand-alone Storage Water Heater	High	0.64

Baseline usage draw pattern is established by the capacity of the water heater, using the table below:

Usage Draw Pattern	Max GPM	Daily Volume in Gallons (*V*)
Very Small	$0 \leq GPM < 1.7$	10
Low	$1.7 \leq GPM < 2.8$	38
Medium	$2.8 \leq GPM < 4.0$	55

[5] Existing residential boiler federal standard as of 10/1/2022.
[6] Based on the federal standard for residential gas-fired water heater as of June 2017 and assumed typical 40 gallon storage. https://www.law.cornell.edu/cfr/text/10/430.32

High	4.0 ≤ GPM	84

If the water heater capacity is not available, assume medium usage draw pattern.

Definition of Efficient Condition

The installed gas furnace or boiler must have an AFUE greater than that shown in the table below. Efficient model minimum AFUE requirements are detailed below.

Equipment Type	Minimum AFUE
Gas Combi Boiler	94% AFUE 0.94 UEF

Gas Savings Algorithms

MMBtu savings are realized due to the increase in AFUE of the new equipment. MMBtu savings vary by equipment type due to differences in model specific baseline AFUE and high efficiency AFUE percentages. Savings are calculated from the baseline new unit to the installed efficient unit.

$$Annual\ Gas\ Savings\ (MMBtu) = Annual\ Gas\ Savings_{SH} + Annual\ Gas\ Savings_{DHW}$$

$$Annual\ Gas\ Savings_{SH} = \frac{Capacity_{Out}}{1{,}000} \times \left(\frac{1}{AFUE_{Base}} - \frac{1}{AFUE_{Eff}}\right) \times EFLH_{Heat}$$

Where:

Annual Gas Savings$_{SH}$ = Space heating annual gas savings (MMBtu)
Annual Gas Savings$_{DHW}$ = Domestic Hot Water annual gas savings (MMBtu)
Capacity$_{Out}$ = Output capacity of equipment to be installed (kBtu/hr)
1,000 = Conversion from kBtu to MMBtu
AFUE$_{Base}$ = Efficiency of new baseline equipment (Annual Fuel Utilization Efficiency)
AFUE$_{Eff}$ = Efficiency of new equipment
EFLH$_{Heat}$ = Equivalent Full Load Heating Hours Hours (Refer to EFLH table by climate zone in References Section)

The following formula for DHW gas savings is based on the DOE test procedure for water heaters.

$$Annual\ Gas\ Savings_{DHW} = \frac{\left(\frac{1}{UEF_{Base}} - \frac{1}{UEF_{Eff}}\right) \times V \times \rho \times c_p \times 67 \times 365}{1{,}000{,}000}$$

Where:

UEF_{Base} = Uniform Energy Factor of baseline water heater. See UEF based on usage draw pattern in Baseline section above. If draw pattern cannot be established assume medium draw pattern.
UEF_{Eff} = Uniform Energy Factor of efficient combi boiler. Since the combi boiler has no or little storage, standby losses are assumed to be negligible and the UEF is assumed to be the same as the AFUE.
V = Daily volume of hot water usage in gallons. See table in baseline section. If usage draw pattern is unknown, assume medium (55 gallons/day).

ρ	=	Water density at 125°F (8.24 lb/gal)
c_p	=	Specific heat of water (1.00 Btu/lb °F)
67	=	°F temperature rise between inlet and outlet of water heater
365	=	Days per year
1,000,000	=	Btu per MMBtu

Electric Savings Algorithms

Energy Savings

ΔkWh = 0 kWh

Demand Savings

ΔkW = 0 kW

Where:

ΔkWh	=	Gross customer annual kWh savings for the measure.
ΔkW	=	Gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Gas Combi Boiler	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
Gas Combi Boiler	20

Source: Same as lifetime estimate used for tankless water heater.

Water Savings

There are no water savings for this measure.

2.4 All End Uses

2.4.1 Custom Measure

Unique Measure Code(s): TBD
Draft date: 3/6/22
Effective date: TBD
End date: TBD

Measure Description
This measure applies to all residential time of replacement custom measures, not otherwise specified in this TRM.

Definition of Baseline Condition
The baseline represents the typical equipment that is installed without a DSM program. The efficiency level is based on the current Federal standards, or state and local building codes that are applicable.

Definition of Efficient Condition
The efficient measure is any equipment that uses less energy than the baseline equipment.

Gas Savings Algorithms
The generalized equation for a custom measure compares the baseline usage to the efficient usage.

$$Annual\ Gas\ Savings\ (MMBtu) = BaselineUse - EfficientUse$$

Where:

BaselineUse	=	The gas usage of baseline equipment or building.
EfficientUse	=	The gas usage of efficient equipment or building.

Electric Savings Algorithms

Energy Savings
ΔkWh = *BaselinekWh - EfficientkWh*

Demand Savings
ΔkW = *BaselinekW - EfficientkW*

Where:

ΔkWh	=	Gross customer annual kWh savings for the measure.
ΔkW	=	Gross customer summer load kW savings for the measure.
BaselinekWh	=	The electric kWh usage of baseline equipment or building.
EfficientkWh	=	The electric kWh usage of efficient equipment or building.
BaselinekW	=	The electric kW usage of baseline equipment or building.
EfficientkW	=	The electric kW usage of efficient equipment or building.

Freeridership/Spillover
Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Custom Measure	0%	0%

Persistence
The persistence factor is assumed to be one.

Measure Lifetimes
Where available, custom measure lifetimes should be based on similar measures defined elsewhere in this TRM.

Water Savings
The water savings are the difference between the baseline and efficient equipment annual water usage in gallons.

3 Residential Early Replacement Market

3.1 Space Heating End Use

3.1.1 Kit Infiltration Reduction

Unique Measure Code(s): TBD
Draft date: 3/6/22
Effective date: TBD
End date: TBD

Measure Description
This involves decreasing the amount of air exchange between the inside of the house or unit and the outdoors using simple air sealing items included in kits mailed to customers.

Definition of Baseline Condition
The baseline is the house in its pre-treatment condition, with opportunities for infiltration reductions.

Definition of Efficient Condition
Any decrease in infiltration will reduce energy consumption compared to the pre-treated house.

Gas Savings Algorithms

$$Annual\ Gas\ Savings\ (MMBtu) = Default\ Savings$$

Where:
Default Savings = Deemed savings from kit air sealing measures. See table of default savings by measure.

Electric Savings Algorithms

Though there may be some electric cooling savings, however, no savings are currently assumed.

Default savings values for Kit Air Sealing Measures

Air Sealing Measure	MMBtu Savings	Source
Switch/Outlet Covers	1.64	Columbia Gas VA (CVA) savings assumption adjusted by HDD in Columbia Gas PA (CPA) territory relative to CVA HDD.
Caulk	0.37	CVA savings assumption adjusted by HDD in CPA territory relative to CVA HDD.
Foam Sealant	0.37	CVA savings assumption adjusted by HDD in CPA territory relative to CVA HDD.

Freeridership/Spillover
Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Measure	Free Ridership	Spillover
Infiltration Reduction	0%	0%

Persistence
The persistence factor is assumed to be one.

Measure Lifetimes

Measure	Measure Lifetime
Kit Infiltration Reduction	15

Source: Current assumption used by Columbia Gas VA.

Water Savings
There are no water savings for this measure.

3.1.2 Infiltration Reduction

Unique Measure Code(s): TBD
Draft date: 2/5/24
Effective date: TBD
End date: TBD

Measure Description
This involves decreasing the amount of air exchange between the inside of the house or unit and the outdoors without buffering from any adjacent unit(s) by sealing the sources of leaks, while maintaining minimum air exchange for air quality.

Definition of Baseline Condition
The baseline is the house in its pre-treatment condition, with opportunities for infiltration reductions.

Definition of Efficient Condition
Any decrease in infiltration will reduce energy consumption compared to the pre-treated house.

Gas Savings Algorithms

$$Annual\ Gas\ Savings\ (MMBtu) = \frac{HDD_t\ \times\ 24 \times \left(CFM50_{pre} - CFM50_{post}\right)}{(21.5\ \times AFUE \times 1{,}000{,}000)}$$

Where:

HDD_t =	Heating degree days at temperature t, where t=63°F if no programmable thermostat has been installed and t=62°F if a programmable thermostat has been installed. See the Reference Tables section at the end of this document for projected HDD.
24 =	hours/day
$CFM50_{pre}$ =	CFM50 of building shell leakage as measured by a blower door test before treatment.
$CFM50_{post}$ =	CFM50 of building shell leakage as measured by a blower door test after treatment.
21.5 =	factor to convert CFM50 value to Btu/hrF heat loss rate, calculated from hourly infiltration modeling[7]
AFUE =	rated AFUE of heating system. If no rating is available then use the method described in the Efficient Space Heating System section for calculating the AFUE. The AFUE of replacement equipment should be used if the heating system replacement precedes the air sealing work.

Electric Savings Algorithms

If the type of air conditioning is known, then use the appropriate algorithm below. If the type or existence of air-conditioning is not known, then assume that 45% have air-conditioning and estimate the cooling savings as 45% of a house with central air conditioning.[8]

[7] An hourly infiltration was calculated using a modified version of the LBL (a.k.a. Sherman-Grimsrud) infiltration model with a wind effect modification (EPRI RP 2034-40, Palmiter and Bond 1991) using Philadelphia TMY2 hourly weather data. This analysis result was then adjusted to account for an assumed party wall leakage fraction of 12% and an estimated 10% thermal regain from infiltration/exfiltratiom. The resulting value of 21.5 is consistent with statistical analyses of empirical data using CFM50 values and actual gas use and savings from CWP evaluations.
[8] Percentage of houses with air-conditioning from UGI data.

Reduced furnace fan or boiler circulator pump usage is also likely to occur and provide electricity savings during both the heating and cooling seasons.

Energy Savings

$\Delta kWh = \Delta kWh_{Aux} + \Delta kWh_{Cool}$

$\Delta kWh_{Aux} = Annual\ Gas\ Savings\ (MMBtu) \times Auxiliary$

ΔkWh_{Cool} = 0 kWh if house has no air conditioning
= ΔkWh_{CAC} if house has central air conditioning
= ΔkWh_{RAC} if house has room air conditioning
= 45% × ΔkWh_{CAC} if no information about air conditioner

$$\Delta kWh_{CAC} = \frac{CDD \times 24 \times DUA \times (CFM50_{pre} - CFM50_{post})}{\left(21.5 \times SEER_{CAC} \times 1000 \frac{W}{kW}\right)}$$

$$\Delta kWh_{RAC} = \frac{CDD \times 24 \times DUA \times F_{Room\ AC} \times (CFM50_{pre} - CFM50_{post})}{\left(21.5 \times \overline{EER}_{RAC} \times 1000 \frac{W}{kW}\right)}$$

Demand Savings

ΔkW = 0 kW if house has no air conditioning
= ΔkW_{CAC} if house has central air conditioning
= ΔkW_{RAC} if house has room air conditioning

$$\Delta kW_{CAC} = \frac{\Delta kWh_{CAC}}{EFLH_{cool}} \times CF_{CAC}$$

$$\Delta kW_{RAC} = \frac{\Delta kWh_{RAC}}{EFLH_{cool\ RAC}} \times CF_{RAC}$$

Where:

ΔkWh = gross customer annual kWh savings for the measure.
ΔkW = gross customer summer load kW savings for the measure.

Auxiliary = *Heating system auxiliary usage per MMBTU consumption (5.02 From Vermont Technical Reference Manual)*

CDD = *Cooling Degree Days (Degrees F * Days). See the Reference Tables section at the end of this document for projected CDD.*

DUA = *Discretionary Use Adjustment to account for the fact that people do not always operate their air conditioning system when the outside temperature is greater than 65F.*

$SEER_{CAC}$ = *Seasonal Energy Efficiency Ratio of existing home central air conditioner (Btu/W•hr) (See table below for default values if actual values are not available)*

$\overline{EER}_{RAC}$ = *Average Energy Efficiency Ratio of existing room air conditioner (Btu/W•hr) (See table below for default values if actual values are not available)*

CF_{CAC} = *Demand Coincidence Factor for central AC systems (See table below)*

CF_{RAC} = Demand Coincidence Factor for Room AC systems (See table below)

$EFLH_{cool}$ = Equivalent Full Load Cooling hours for Central AC and ASHP (Refer to EFLH table by climate zone in References Section)

$EFLH_{cool\ RAC}$ = Equivalent Full Load Cooling hours for Room AC (Refer to EFLH table by climate zone in References Section)

$F_{Room\ AC}$ = Adjustment factor to relate insulated area to area served by Room AC units

The default values for each term are shown in the table below.

Default values for algorithm terms, Ceiling/Attic and Wall Insulation

Term	Type	Value	Source
DUA	Fixed	0.75	OH TRM[9]
$SEER_{CAC}$	Variable	Default values: Early Replacement = 10 Replace on Burnout = 13	PUC Technical Reference Manual
		Nameplate	Contractor Data Gathering
$\overline{EER}_{RAC}$	Variable	Default = 9.8	DOE Federal Test Procedure 10 CFR 430, Appendix F (Used in ES Calculator for baseline)
		Nameplate	Contractor Data Gathering
CF_{CAC}	Fixed	0.70	PUC Technical Reference Manual
CF_{RAC}	Fixed	0.58	PUC Technical Reference Manual
$F_{Room,AC}$	Fixed	0.38	Calculated[10]

Freeridership/Spillover
Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Measure	Free Ridership	Spillover
Infiltration Reduction	0%	0%

Persistence
The persistence factor is assumed to be one.

Measure Lifetimes

[9] "State of Ohio Energy Efficiency Technical Reference Manual," prepared for the Public Utilities Commission of Ohio by Vermont Energy Investment Corporation. August 6, 2010.
[10] From PECO baseline study, average home size = 2323 ft^2, average number of room AC units per home = 2.1. Average Room AC capacity = 10,000 BtuH per ENERGY STAR Room AC Calculator, which serves 425 ft^2 (average between 400 and 450 ft^2 for 10,000 BtuH unit per ENERGY STAR Room AC sizing chart). $F_{Room,AC}$ = (425 ft^2 * 2.1)/(2323 ft^2) = 0.38

Measure	Measure Lifetime
Infiltration Reduction	20

Source: NYSERDA Home Performance with Energy Star.

Water Savings

There are no water savings for this measure.

3.1.3 Roof and Cavity Insulation

Unique Measure Code(s): TBD
Draft date: 2/5/24
Effective date: TBD
End date: TBD

Measure Description
This involves increasing the insulation levels in either the attic or walls which directly define the boundary between the house or unit and the outdoors.

Definition of Baseline Condition
The baseline is amount of insulation in the house in its pre-treatment condition.

Definition of Efficient Condition
Any increase in insulation will reduce energy consumption compared to the pre-treated house.

Gas Savings Algorithms

$$Annual\ Gas\ Savings\ (MMBtu) = \frac{HDD_t \times 24 \times AREA \times \left({}^{1}/_{R_{pre}} - {}^{1}/_{R_{post}}\right)}{(AFUE \times 1{,}000{,}000)}$$

Where:

HDD_t	=	Heating degree days at temperature t, where t=63°F if no programmable thermostat has been installed and t=62°F if a programmable thermostat has been installed. See the Reference Tables section at the end of this document for projected HDD.
24	=	Hours per day
AREA	=	Net insulated area in square feet. Estimated at 85% of gross area for cavities.
R_{pre}	=	R value of roof/cavity pre-treatment. R_{pre} = 5 unless there is existing insulation.
R_{post}	=	R value of roof/ cavity after insulation is installed.
AFUE	=	Rated AFUE of heating system. If no rating is available then use the method described in the Efficient Space Heating System section for calculating the AFUE. The AFUE of replacement equipment should be used if the heating system replacement precedes the air sealing work.

Electric Savings Algorithms
If the type of air conditioning is known, then use the appropriate algorithm below. If the type or existence of air-conditioning is not known, then assume that 45% have air-conditioning and estimate the cooling savings as 45% of a house with central air conditioning.[11]

Reduced furnace fan or boiler circulator pump usage is also likely to occur and provide electricity savings during both the heating and cooling seasons.

[11] Percentage of houses with air-conditioning from UGI data.

Energy Savings

$\Delta kWh = \Delta kWh_{Aux} + \Delta kWh_{Cool}$

$\Delta kWh_{Aux} = Annual\ Gas\ Savings\ (MMBtu) \times Auxiliary$

ΔkWh_{Cool} = 0 kWh if house has no air conditioning
= ΔkWh_{CAC} if house has central air conditioning
= ΔkWh_{RAC} if house has room air conditioning
= 45% × ΔkWh_{CAC} if no information about air conditioner

$$\Delta kWh_{CAC} = \frac{CDD \times 24\frac{hr}{day} \times DUA}{SEER_{CAC} \times 1000\frac{W}{kW}} \times \left[AREA \times \left(\frac{1}{R_{pre}} - \frac{1}{R_{post}}\right)\right]$$

$$\Delta kWh_{RAC} = \frac{CDD \times 24\frac{hr}{day} \times DUA \times F_{Room\ AC}}{\overline{EER}_{RAC} \times 1000\frac{W}{kW}} \times \left[AREA \times \left(\frac{1}{R_{pre}} - \frac{1}{R_{post}}\right)\right]$$

Demand Savings

ΔkW = 0 kW if house has no air conditioning
= ΔkW_{CAC} if house has central air conditioning
= ΔkW_{RAC} if house has room air conditioning
= 45% × ΔkW_{CAC} if no information about air conditioner

$$\Delta kW_{CAC} = \frac{\Delta kWh_{CAC}}{EFLH_{cool}} \times CF_{CAC}$$

$$\Delta kW_{RAC} = \frac{\Delta kWh_{RAC}}{EFLH_{cool\ RAC}} \times CF_{RAC}$$

Where:

ΔkWh = gross customer annual kWh savings for the measure.
ΔkW = gross customer summer load kW savings for the measure.

Auxiliary = *Heating system auxiliary usage per MMBTU consumption (5.02 From Vermont Technical Reference Manual)*

CDD = *Cooling Degree Days (Degrees F * Days) See the Reference Tables section at the end of this document for projected CDD.*

DUA = *Discretionary Use Adjustment to account for the fact that people do not always operate their air conditioning system when the outside temperature is greater than 65F.*

$SEER_{CAC}$ = *Seasonal Energy Efficiency Ratio of existing home central air conditioner (Btu/W▪hr) (See table below for default values if actual values are not available)*

$\overline{EER}_{RAC}$ = *Average Energy Efficiency Ratio of existing room air conditioner (Btu/W▪hr) (See table below for default values if actual values are not available)*

CF_{CAC} = *Demand Coincidence Factor for central AC systems (See table below)*

CF_{RAC} = Demand Coincidence Factor for Room AC systems (See table below)

$EFLH_{cool}$ = Equivalent Full Load Cooling hours for Central AC and ASHP (Refer to EFLH table by climate zone in References Section)

$EFLH_{cool\ RAC}$ = Equivalent Full Load Cooling hours for Room AC (Refer to EFLH table by climate zone in References Section)

$F_{Room\ AC}$ = Adjustment factor to relate insulated area to area served by Room AC units

The default values for each term are shown in the table below.

Default values for algorithm terms, Ceiling/Attic and Wall Insulation

Term	Type	Value	Source
DUA	Fixed	0.75	OH TRM[12]
$SEER_{CAC}$	Variable	Default values: Early Replacement = 10 Replace on Burnout = 13	PUC Technical Reference Manual
		Nameplate	Contractor Data Gathering
$\overline{EER}_{RAC}$	Variable	Default = 9.8	DOE Federal Test Procedure 10 CFR 430, Appendix F (Used in ES Calculator for baseline)
		Nameplate	Contractor Data Gathering
CF_{CAC}	Fixed	0.70	PUC Technical Reference Manual
CF_{RAC}	Fixed	0.58	PUC Technical Reference Manual
$F_{Room,AC}$	Fixed	0.38	Calculated[13]

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Measure	Free Ridership	Spillover
Insulation	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

[12] "State of Ohio Energy Efficiency Technical Reference Manual," prepared for the Public Utilities Commission of Ohio by Vermont Energy Investment Corporation. August 6, 2010.

[13] From PECO baseline study, average home size = 2323 ft^2, average number of room AC units per home = 2.1. Average Room AC capacity = 10,000 BtuH per ENERGY STAR Room AC Calculator, which serves 425 ft^2 (average between 400 and 450 ft^2 for 10,000 BtuH unit per ENERGY STAR Room AC sizing chart). $F_{Room,AC}$ = (425 ft^2 * 2.1)/(2323 ft^2) = 0.38

Measure	Measure Lifetime
Roof Insulation	40
Cavity Insulation	40

Source: NYSERDA Home Performance with Energy Star.

Water Savings

There are no water savings for this measure.

3.2 Domestic Hot Water End Use

3.2.1 Low Flow Showerhead

Unique Measure Code(s): TBD
Draft date: 3/6/22
Effective date: TBD
End date: TBD

Measure Description
This measure relates to the installation of a low flow showerhead in a home. This is an early replacement direct install or kit measure.

Definition of Baseline Condition
The baseline is the flow rate of the showerhead being replaced. If this is not available a baseline value of 2.5 GPM will be used.

Definition of Efficient Condition
The flow rate of the efficient showerhead should be greater than the flow rate of the baseline condition. If this value is not available it is assumed to be 1.5 GPM[14].

Water Savings Algorithms
The water savings for low flow showerheads are due to the reduced amount of water being used per shower.

$$\Delta Gallons = \frac{\left(GPM_{base} - GPM_{eff}\right) \times N_{persons} \times T_{person-day} \times N_{showers-da} \times 365 \times ISR}{N_{showerheads-hom}}$$

Where:

$\Delta Gallons$	=	Gallons of water saved
GPM_{base}	=	Maximum gallons per minute of baseline showerhead. Default = 2.5 GPM if measured rate is not available[15]
GPM_{eff}	=	Maximum gallons per minute of the efficient showerhead
$N_{persons}$	=	Average number of people per household. Actual or defaults: SF=2.5, MF=1.7, Unknown=2.5 [16]
$T_{person-day}$	=	Average minutes per person per day used for showering. 7.8 min/day [17]
$N_{showers-day}$	=	Average number of showers per person per day. 0.6 showers/person/day [18]
365	=	Days per year
ISR	=	In service rate. Kit Default = 35%. Direct install Default = 100%. [19]
$N_{showerheads-home}$	=	Average number of showers per home. Actual or defaults: SF=1.6, MF=1.1, Unknown=1.5 [20]

[14] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[15] The Energy Policy Act of 1992 established the maximum flow rate for showerheads at 2.5 gallons per minute (GPM)
[16] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[17] Ibid.
[18] Ibid.
[19] Ibid.
[20] Ibid.

Natural Gas Savings Algorithms
Gas energy savings result from reducing the amount of incoming cold water required to be heated due to the efficient showerhead.

$$\Delta MMBtu = \frac{[\Delta Gallons \times 8.3 \times c_p \times (T_{out} - T_{in})] / 1{,}000{,}000}{RE_{DHW}}$$

Where:

$\Delta MMBtu$	=	MMBtu of saved natural gas
8.3	=	Constant to convert gallons to pounds (lbs.)
c_p	=	Average specific heat of water at temperature range (1.00 Btu/lb·°F)
T_{out}	=	Assumed temperature of water coming out of showerhead (degrees Fahrenheit) 101 °F
T_{in}	=	Assumed temperature of water entering house (degrees Fahrenheit) 52 °F
RE_{DHW}	=	Recovery efficiency of the domestic hot water heater = 75%[21]

Electric Savings Algorithms
It is assumed that all low flow showerheads are installed in homes that heat water using natural gas. There are no additional electric savings claimed.

Freeridership/Spillover
Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Persistence
The persistence factor is assumed to be one.

Measure Lifetimes
The measure life of a low flow showerhead is assumed to be 9 years[22].

3.2.2 Low Flow Faucet Aerators

Unique Measure Code(s): TBD
Draft date: 3/6/22
Effective date: TBD
End date: TBD

Measure Description
This measure relates to the installation of a low flow faucet aerator in either a kitchen or bathroom.

Definition of Baseline Condition
The baseline is the flow rate of the existing faucet. If this is not available, it is generally assumed that a faucet will already have a standard faucet aerator using 2.2 GPM.

Definition of Efficient Condition

[21] Review of AHRI Directory suggests range of recovery efficiency ratings for new Gas DHW units of 70-87%. The average of existing units is estimated at 75% by the Northeast Energy Efficiency Partnerships' Mid-Atlantic Technical Reference Manual Version 1.1 (October 2010).
[22] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (June 2011)

The efficient condition is a faucet aerator that has a flow rate lower than the baseline condition. If this value is not available than the flow rate is assumed to be 1.5 GPM[23].

Water Savings Algorithms
The water savings for low flow faucet aerators are due to the reduced amount of water being used per minute that flows down the drain (instead of being collected in the sink).

$$\Delta Gallons = \frac{(GPM_{base} - GPM_{eff}) \times N_{persons} \times T_{person-day} \times DF \times 365 \times ISR}{N_{faucets-home}}$$

Where:

$\Delta Gallons$	=	Gallons of water saved
GPM_{base}	=	Gallons per minute of baseline aerator = 2.2 GMP[24]
GPM_{eff}	=	Gallons per minute of the efficient aerator
$N_{persons}$	=	Average number of people per household. Actual or Defaults: SF=2.5, MF=1.7, Unknown=2.5[25]
$T_{person-day}$	=	Average minutes per person per day of faucet hot water usage. Kitchen=4.5, Bathroom=1.6, Unknown=6.1[26]
365	=	Days per year
DF	=	Drain rate, the percentage of water flowing down the drain. Kitchen=75%, Bathroom=90%, Unknown=79.5%[27]
ISR	=	In service rate. Kit delivery default = 28%, Direct install default = 100%[28]
$N_{faucets-home}$	=	Average Number of Faucets per home. Actual or for defaults see table below.

Average Number of Faucets per Home[29]

Faucet Type	Single Family	Multifamily	Unknown
Kitchen	1.1	1.0	1.0
Bathroom	2.2	1.2	2.0
Unknown	3.3	2.2	3.0

Natural Gas Savings Algorithms
Gas energy savings result from avoiding having to heat the saved water due to the efficient aerator.

$$\Delta MMBtu = \frac{[\Delta Gallons \times 8.3 \times c_p \times (T_{out} - T_{in})] / 1{,}000{,}000}{RE_{DHW}}$$

Where:

$\Delta MMBtu$	=	MMBtu of saved natural gas
8.3	=	Constant to convert gallons to pounds (lbs.)
c_p	=	Average specific heat of water at temperature range (1.00 Btu/lb·°F)

[23] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[24] Ibid
[25] Ibid
[26] Ibid
[27] Ibid
[28] Ibid
[29] Ibid

T_{out}	=	Average mixed water temperature flowing from the faucet (degrees Fahrenheit) Kitchen=93 °F, Bathroom=86 °F, Unknown=87.8 °F [30]
T_{in}	=	Assumed temperature of water entering house (degrees Fahrenheit) 52 °F [31]
RE_{DHW}	=	Recovery efficiency of the domestic hot water heater = 75%[32]

Electric Savings Algorithms
It is assumed that all faucet aerators as part of the gas utility's program are installed in homes that heat water using natural gas. There are no additional electric savings claimed.

Freeridership/Spillover
Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Persistence
The persistence factor is assumed to be one.

Measure Lifetimes
The measure life of a faucet aerator is assumed to be 10 years[33].

[30] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[31] Ibid
[32] See assumption for low flow shower head.
[33] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)

4 Reference Tables

4.1 Residential

4.1.1 Heating and Cooling EFLH

Heating and Cooling Equivalent Full Load Heating Hours

Reference Location	Zone	Heating EFLH for non-HP (Fossil Fuel Furnace or Boiler)
Allentown	C	906
Binghamton, NY	A	1,152
Bradford	G	1,347
Erie	I	1,054
Harrisburg	E	997
Philadelphia	D	761
Pittsburgh	H	942
Scranton	B	1,000
Williamsport	F	935
Weighted Avg CPA		1013

Source: Act 129 August 2019 TRM, Appendix A
Notes: ZIP codes associated with each PA climate zone may be found in the Act 129 August 2019 TRM, Appendix A, tab "Zip code lookup table."

4.1.2 HDD & CDD

Heating Degree Days and Cooling Degree Days

Territory	HDD63	HDD62	CDD
Allentown	6,683	6,413	773
Binghamton, NY	5,350	5,110	405
Bradford	4,703	4,481	204
Erie	3,951	3,747	579
Harrisburg	4,512	4,294	1,121
Philadelphia	5,217	4,980	1,184
Pittsburgh	6,686	6,418	726
Scranton	5,054	4,830	608
Williamsport	5,477	5,241	759
Weighted Avg CPA	5,229	4,998	705

Sources: DegreeDays.net 2017-2019 for HDD. Act 129 August 2019 TRM, Appendix A for CDD.

COLUMBIA STATEMENT NO. 14

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
BRIAN MCCAUL ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

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I. Introduction

Q. Please state your name and business address.

A. Brian McCaul, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc., ("Columbia" or "the Company") as the Vice President of Gas Operations.

Q. What are your responsibilities as Vice President of Gas Operations?

A. My responsibilities include overseeing:

- Delivery of safe and reliable natural gas distribution service to our customers;
- Leak detection, leak investigation, leak response and leak repair activities;
- Customer metering activities;
- Plant operations;
- All required leakage surveys and system inspections, testing and inspection of cathodic protection systems for steel facilities, and performing underground facilities locating for third-party excavators;
- The day-to-day operations of Columbia's physical natural gas piping system; and

- Field customer service to Columbia customers including odor complaints, meter turn-ons and turn offs, and all other customer interfacing field interactions.

Q. Please briefly describe your educational and professional experience.

A. I have an Associate's Degree in Nuclear Technology from the University of Phoenix and a Bachelor's degree in Business from the University of Phoenix. I have over 30 years of experience in power generation, primarily in a regulated environment. I have held both technical and leadership roles in multiple technologies, including gas, nuclear, oil, coal, solar (PV and thermal), wind and battery storage. I was a nuclear reactor operator in the US Navy from 1993-1999. I spent five years at Constellation Energy as a Nuclear Control Technician and received an INPO Journeyman's certification. Prior to joining Columbia, I held numerous roles at NextEra Energy from 2004-2023, including Production Technician-I&C, Plant Manager, Plant General Manager and Regional General Manager in both Wind and Solar /Battery storage.

Q. Have you testified before this or any other Commission?

A. Yes, I testified on behalf of Columbia Gas of Maryland in Case No. 9709 before the Maryland Public Service Commission.

Q. What is the purpose of your direct testimony?

A. I will testify regarding Columbia's Distribution Integrity Management Program ("DIMP") and provide an overview of Columbia's distribution system. I will also

discuss Columbia's historic operating performance, the initiatives taken to improve its overall safety and compliance efforts and the metrics that are used to track performance and progress, and the planned system enhancements to Columbia's operations. In addition, I will also briefly introduce NiSource's plans to replace outdated, legacy information technology ("IT") systems through the design, development, and implementation of a new Work and Asset Management ("WAM") program for the scheduling, dispatch, and execution of work and the management of underlying assets.

II. Overview of Columbia's Pipeline Distribution System

Q. Please describe Columbia's distribution system.

A. Currently, Columbia serves approximately 445,000 residential, industrial and commercial customers. The Company owns and operates a natural gas distribution system in 26 counties serving 450 communities spread across Pennsylvania. As of January 1, 2024, Columbia provides that service through approximately 7,793 miles of distribution and transmission mains and approximately 442,939 services that it owns, operates, and maintains.[1] These facilities (again, as of January 1, 2024) are composed of approximately 812 miles of bare steel, 22 miles of cathodically protected bare steel, 35 miles of wrought iron mains (in total, 869 miles of "first generation

[1] I note that in compliance with Section 1510 of the Pennsylvania Public Utility Code, in Western Pennsylvania the Company does not own the service lines all the way to the building, but terminates its ownership at the curb valve, typically found at or near the property line. If there is no curb valve on the service line, Columbia's ownership terminates at the property line itself. The customer then installs and maintains the remainder of the service line to the building.

steel and wrought iron priority pipe" main), and 33,379 bare steel services.[2] The balance of the system is comprised of cathodically protected coated steel (some of which is pre-1971 coasted steel), or plastic (some of which is pre-1982 plastic, priority pipe) mains and services, and 22 miles classified as other.[3] Please note that, as of the end of December 2022, all known cast iron has been eliminated from Columbia's Distribution System.

Columbia's distribution infrastructure constitutes the final step in the delivery of natural gas to customers from the producing regions of the Southern United States, Western Canada, and in-state Pennsylvania-produced Marcellus and shallow well supplies. Columbia distributes natural gas by taking it from delivery points (or "city gates") along interstate pipelines, then transporting it through relatively small-diameter distribution mains and services that network underground through cities, towns, and neighborhoods to meet the demands of end-use customers. After taking delivery of natural gas at the city gate, Columbia then steps down the transmission pressure to local distribution pressure, further filters the gas to remove moisture and particulates that may damage Columbia's system, and then in some cases increases the amount of odorant known as mercaptan (the "rotten egg smell") to the natural

[2] The terms "bare steel," "unprotected coated steel," "unprotected steel," and "wrought iron" as explained further below, are used interchangeably and all refer to steel pipe without cathodic protection that is susceptible to corrosion.

[3] It should be noted that in 2011 Columbia deployed a Geographical Information System ("GIS") Mapping System to provide both mapping and data retrieval capabilities on its system and facilities. The 22 miles of "other" main appear to be anomalies in the data conversion and through a scrubbing process have been reduced from over 43 miles in 2012.

gas before it is put into the distribution system. The gas then goes into the distribution system where the pressure is often further reduced to delivery pressure in a series of district regulator stations, before being delivered to each customer. Once the gas is delivered on the customer's side (or the property line in Western Pennsylvania), it is owned by the customer and becomes the responsibility of the customer. In sum, Columbia's distribution system moves relatively small volumes of natural gas at lower pressures over shorter distances to a far greater number of individual users than its interstate pipeline counterparts.

Q. Please describe the years, types, and operating characteristics of the various pipe materials that have historically been installed in Columbia's system.

A. The system is comprised of many different types of pipe. From the 1850s to the early 1900s, Columbia's predecessor companies installed cast iron pipe throughout the early distribution systems. Cast iron, wrought iron and wood were among the first materials available, and cast iron had the advantage in that it was relatively strong and was easy to install. However, it was vulnerable to breakage from ground movement. When the pipe was buried to typical depths of between two and five feet, if the soil beneath the pipe or to its side was disturbed and pressure exerted on the pipe, it could crack. Further, each pipe section was not easily joined, so joints were prone to leaks. Finally, it was determined that it was unsuitable for long-distance transportation of gas because it was unable to withstand high pressures.

Q. How did the industry react to the problems present with the use of cast iron?

A. By the early 1900s, the industry had adopted steel and wrought iron piping for mains. These were deemed to be stronger than cast iron and able to withstand greater pressure. During this time, bare steel and wrought iron began replacing cast iron pipe as the material of choice when building a natural gas distribution system. During the pre- and post-World War II construction boom, gas utilities like Columbia, along with developers and customers, installed a significant amount of bare steel mains and services. Bare steel is steel pipe that has no exterior coating and has no cathodic protection installed on the pipe. The use of bare steel and wrought iron was common until the 1950s and 1960s when the industry began to realize that, despite its initial strength, bare steel was subject to corrosion and, in order to increase long-term safety and reliability, coating and cathodic protection should be applied to all new piping systems to slow the inevitable deterioration process. Both exterior coatings and cathodic protection were designed to inhibit corrosion. Columbia installed its last bare steel pipe in the 1960s. By 1970, the federal government prohibited the installation of bare steel and wrought iron for natural gas distribution system infrastructure.

Q. What did the industry do to combat the problem of bare steel corrosion?

A. The fact is that all metals corrode as a result of the natural process of chemical interactions with their physical environment, most commonly caused by moist soil

(which creates an electrolyte) around the pipe. In these circumstances, direct electric current flows from the metal surface into the electrolyte and, as the metal ions leave the surface of the pipe, corrosion takes place. This current flows in the electrolyte to the site where oxygen or water is being reduced. This site is referred to as the cathode or cathodic site. To combat corrosion, natural gas distribution companies ("NGDCs") began using coated steel. Unprotected coated steel ("UPCS" or "coated steel") refers to steel pipe with an exterior coating (intended to electrically isolate the steel from the surrounding electrolytes in the soil).

Q. Did the use of UPCS solve the problem?

A. No, despite the best efforts of industry, and even though it was for a time an accepted industry standard, UPCS corroded as well. But for the period from the 1940s through the 1960s, as the industry assessed its options, it was one of just a few alternative piping materials available to meet the public demand for service. By 1970, Columbia had laid its last non-cathodically protected coated steel segment. Coated steel pipe continues to be used, but it is cathodically protected with an electric current. Further, since that time Columbia has retrofitted all its unprotected coated steel facilities with cathodic protection systems.

Q. **What is the outlook for UPCS pipe?**

A. Since Columbia installed the last miles of UPCS in 1970, that pipe is reaching the end of its useful life just by the passage of time and the inevitable resulting corrosion. In addition, however, even though that pipe was coated to protect against corrosion,

some of that pipe is now being found to have been ineffectively coated. Ineffectively coated steel pipe refers to coated steel pipe that may have inadequate, field-applied coatings. Columbia continues to perform all routine monitoring and inspecting activities to ensure that this type of coated steel pipe will continue to operate safely, however, Columbia has a long-term concern that field-applied coatings used primarily on steel pipe prior to 1955 - and intermittently between 1955 to 1970 - have or will become ineffective over time. As this occurs, these coated steel lines demonstrate the leakage characteristics of our bare steel pipe. In the interest of safety and reliability, Columbia has been replacing many sections of coated steel main installed prior to 1971 as it is encountered in association with a bare steel replacement project. Columbia first inspects the pipeline coating for damage (e.g., scrapes, gouges), deterioration, or disbonding (e.g., cracking, blistering, chipping, flaking, or loose) and completes a field analysis to assess the cathodic protection current requirements of the pipe. To the extent that these analyses identify segments of protected steel pipe that are ineffectively coated, Columbia replaces that pipe as part of its replacement program.

Q. What materials replaced bare steel and coated steel?

A. Coated steel pipe continues to be used, but it is cathodically protected with an electric current. The pipe breakthrough for the natural gas industry came in the mid-1960s with the introduction of plastic (polyethylene) pipe for gas distribution applications.

Q. What is "cathodic protection?"

A. Cathodic protection is a procedure by which underground metal pipe is protected against corrosion and deterioration (i.e., rusting and pitting) by applying an electrical current to the pipe. Cathodic protection reduces corrosion by making that surface the cathode and another metal the anode of an electrochemical cell. A primary function of a coating on a cathodically protected pipe is to reduce the surface area of exposed metal on the pipeline, thereby reducing the current necessary to cathodically protect the metal. At present, the principal methods for mitigating corrosion on underground steel pipelines are external coatings and cathodic protection.

Q. Has Columbia further improved the functionality of its piping since the introduction of cathodically protected steel?

A. Yes, it has. Cathodically protected steel has all the advantages of steel in terms of strength and, because of its impressed electrical current, is highly corrosion resistant. However, it is more costly to purchase and install, and requires more ongoing maintenance than the next generation pipe – plastic.

Q. What are the benefits of plastic pipe?

A. Plastic pipe has proven to be very good for distribution-level pressures. It has strength and flexibility, and, as a result, is generally immune to the stress of ground movement. Plastic is also less costly to purchase and easier to join and install than steel pipe. In addition, plastic does not corrode and, therefore, does not require cathodic protection.

Q. Does plastic pipe have any drawbacks?

A. The two significant drawbacks to plastic include:

- Relative vulnerability to excavation damage as compared to steel. As a result, excavators who do not dig by hand (despite being required to do so by One-Call laws) in the vicinity of plastic facilities are more likely to damage them. Steel piping has greater tensile strength and thus is somewhat more likely to be able to resist external impact.
- "First Generation" plastic pipe also known as "Pre-1982 Plastic", typically installed between mid to late 1960s and 1981 in most distribution systems are more brittle than today's material (due to the different composition of the base plastic material) and has demonstrated itself to be prone to stress propagation cracking under some circumstances. In a special investigation report completed by the National Transportation Safety Board on April 23, 1998, it concluded that between the 1960s through the early 1980s, the procedure used in the United States by manufacturers to rate the strength of this plastic pipe may have overrated the strength and resistance to brittle-like cracking. The investigation performed further clarified that such first-generation plastic pipe was susceptible to premature brittle-like failures when subjected to stress intensification and as a result represented a potential safety hazard. Given the safety concerns that arise when this pipe is subjected to stress intensification, the most efficient course of action has been for Columbia to replace Pre-1982 pipe when it is encountered in

association with a pipeline replacement project. This eliminates the need to induce stress on the first-generation plastic pipe during the standard squeeze-off operation performed to control or stop gas flow when preparing to reuse and reconnect existing first-generation plastic pipe to newly installed plastic pipe, and it eliminates the risk of the pipe cracking due to earth movement or other forces. As this Pre-1982 pipe continues to age, the risk of it developing Type 1 leaks continues to grow and will need to be replaced even when it is not associated with a bare steel or cast-iron replacement program. Thus, in certain limited cases, Columbia's first-generation plastic pipe has generated Type-1 leaks due to longitudinal cracking along the pipe.

Q. What is Columbia doing to address these concerns?

A. Regarding excavation damage, Columbia continues to focus on improving facility damage rates. In 2007, damages per thousand locates were at 5.39. By 2023, the damages per thousand locate tickets was 2.11. Locate ticket volumes were up 10% when compared to 2020, which indicates that excavators are increasing their One-Call efforts. Nevertheless, total number of damages increased from 278 in 2020 to 318 in 2023. Excavator negligence remains the highest cause of damages to our facilities, at 53% of total damages in 2023.

In response to excavator damages, Columbia adopted a "Damage Prevention Risk Model" to guide its outreach to the riskiest excavators. Columbia is continuing

the practice of using "marker balls" when installing its new plastic facilities. These marker balls are placed in the ground above the pipe after it has been installed and enable Columbia to locate it later using electronic technology.

Columbia continues to deploy global positioning system ("GPS") mapping and locating technology that provide sub-decimeter accuracy in identifying the location of new or replacement facilities. This technology will enable the Company to accurately locate its new facilities in the field.

In order to address the issues discussed above with Pre-1971 coated steel pipe and Pre-1982 plastic pipe, Columbia has replaced sections that are uncovered in the course of executing the Company's infrastructure replacement program. Through continued efforts to identify and reduce risk, Columbia evaluates risks from all pipe materials, including first generation plastic pipe and Pre-71 coated steel, along with bare steel, cast iron (all known cast iron was eliminated across the system in 2022) and wrought iron. Those sections identified as higher risk within the system are prioritized for replacement and are included as priority pipe in the Company's current Long Term Infrastructure Improvement Plan.

Q. How does Columbia classify leaks it detects on its system?

A. Columbia classifies each gas leak according to its severity: Type-1, Type-2, or Type-3. A Type-1 leak is hazardous and requires immediate remediation and repair. A Type-2 gas leak is non-hazardous at the time of detection, but requires a scheduled repair based on the potential for becoming a hazard. A Type-3 gas leak is defined as

"non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous."

These gas leak classifications are defined in the Gas Piping Technology Committee ("GPTC") American National Standards Institute ("ANSI") Z380.1 "Guide for Gas Transmission and Distribution Piping Systems." The Guide is commonly utilized by gas operators and State pipeline regulators, including the Commonwealth of Pennsylvania, as an interpretation of "DOT 192 2003 CFR Title 49, Part 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards."

III. Federal Pipeline Safety Rules and Advisories

Q. Please describe the Federal Pipeline Safety Rules and Advisories that are affecting and will continue to affect Columbia's Pipeline Safety Strategy and Operational Execution.

A. Some of the more significant and impactful Final Rules or Advisories issued in the last several years or that are being considered for the future, are as follows:

- Integrity Management Program for Gas Distribution Pipelines (74 FR 63906) - This final rule amended the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management ("IM") programs. The IM programs required by this rule are similar to those required for gas transmission pipelines but tailored to reflect the differences in and among distribution facilities. Distribution integrity

management is playing a significant role in Columbia's gas operations, allowing us to focus resources to reduce risks, thereby improving safety for our customers, the public, and our employees.

- Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (84 FR 52180; RIN 1) – Pursuant to National Transportation Safety Board ("NTSB") recommendations and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, PHMSA has promulgated regulations governing the safety of gas transmission pipelines. The purpose of this final rule is to increase the level of safety associated with the transportation of gas. This rule requires operators of certain onshore steel gas transmission pipeline segments to reconfirm the maximum allowable operating pressure ("MAOP") of those segments and gather any necessary material property records they might need to do so, where the records needed to substantiate the MAOP are not traceable, verifiable, and complete. PHMSA is also requiring operators to perform integrity assessments on transmission pipelines outside of high consequence areas ("HCAs") with an MAOP greater than or equal to 30% of the specified minimum yield strength (SMYS) and are located in Class 3 locations, Class 4 locations, and in the newly defined moderate consequence areas ("MCAs"). An operator must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete

initial assessment for all applicable pipeline segments no later than July 3, 2034. These assessments will provide important information to operators about the conditions of their pipelines, including the existence of internal and external corrosion and other anomalies, and will provide an elevated level of safety for the populations in MCAs while continuing to allow operators to prioritize the safety of HCAs.

- Pipeline Safety: Requirement of Valve Installation and Minimum Rupture Detection Standards (87 FR 20940). PHMSA has promulgated regulations to the Federal Pipeline Safety Regulations applicable to most newly constructed and entirely replaced onshore gas transmission pipelines with diameters of 6 inches or greater. In the revised regulations, PHMSA requires operators of these lines to install rupture-mitigation valves (i.e., remote-control or automatic shut-off valves) or alternative equivalent technologies and establishes minimum performance standards for those valves' operation to prevent or mitigate the public safety and environmental consequences of pipeline ruptures. This final rule establishes requirements for rupture-mitigation valve spacing, maintenance and inspection, and risk analysis. The final rule also requires operators of gas pipelines to contact 9–1–1 emergency call centers immediately upon notification of a potential rupture and conduct post-rupture investigations and reviews.

- Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (87 FR 52224; RIN 2). PHMSA has promulgated regulations to the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. The amendments in this final rule clarify certain integrity management provisions, codify a management of change process, update and bolster gas transmission pipeline corrosion control requirements, require operators to inspect pipelines following extreme weather events, strengthen integrity management assessment requirements, adjust the repair criteria for high-consequence areas, create new repair criteria for non-high consequence areas, and revise or create specific definitions related to the above amendments.

Q. Will PHMSA's focus on Transmission Lines have any significant impact on Columbia operations?

A. Yes, "Transmission Line" is defined in CFR 49, Part 192 as "a pipeline or connected series of pipelines, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream of a distribution center; (2) has an MAOP of 20 percent or more of SMYS [System Minimum Yield Strength]; (3) transports gas within a storage field; or (4) is voluntarily designated by the operator as a

transmission line.." Columbia has 40.7 miles of transmission class pipelines (7.13 miles within HCAs) per the 2022 PHMSA Annual Report for Natural Gas Transmission and Gathering Systems for Columbia that meet this definition. Further, following the San Bruno, California explosion which occurred on a Pacific Gas and Electric Transmission Line in 2010, PHMSA has focused attention on the quality and comprehensiveness of system records for these lines, particularly around the pressure testing data, pipe material and design information, and wall thickness of existing transmission line systems. Because there was no federal mandate requesting such reports, Columbia, like many other NGDCs and transmission companies, is lacking certain data, particularly on segments installed prior to current code standards and the issuance of Federal Pipeline Safety Regulations instituted on August 1, 1971. PHMSA focused heavily on regulations for Transmission Operations between 2019 and 2022, as highlighted earlier in this testimony. Additional regulations coming out of the PIPES Act of 2020 are expected to impact transmission operations, in the coming years.

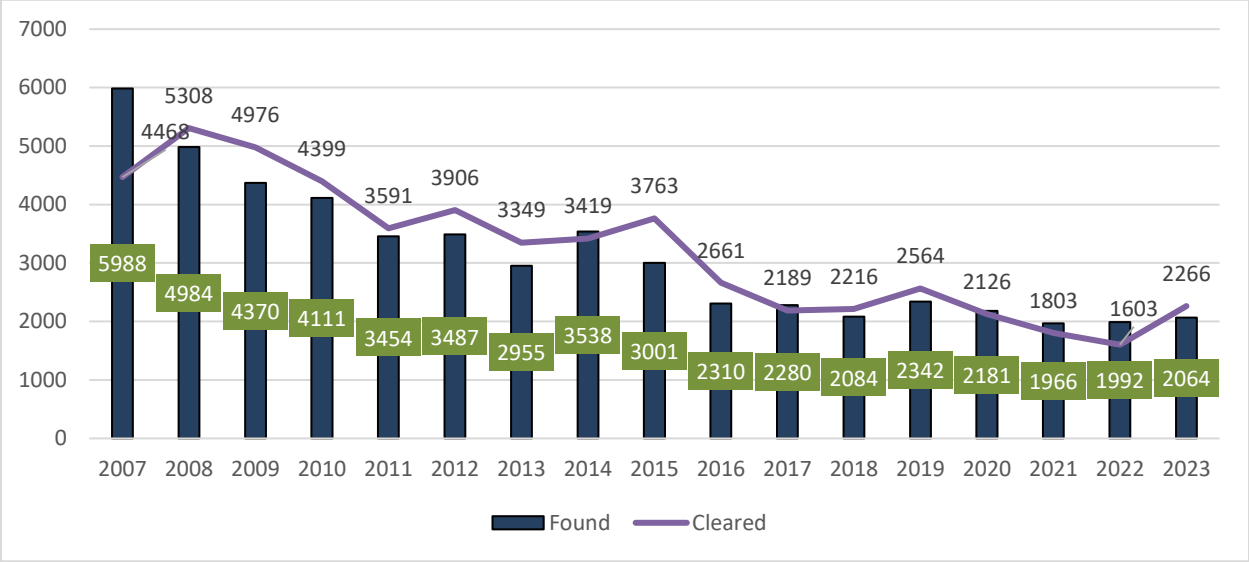
Q. Are there any additional details demonstrating the improvement of Columbia's system operations?

A. Some of the results from DIMP-driven practice enhancements or procedural changes, which improve Columbia's system, include:

Leakage Reduction: Since the inception of our accelerated infrastructure replacement program, Grade 2 leaks have been significantly reduced, thereby

increasing the safety of our customers. Figure 1 below shows a comparison of Grade 2 leaks found during the year, as compared to Grade 2 leaks repaired during the year. In the last fifteen years alone, Columbia's pipeline replacement efforts were responsible for cutting the number of leaks found from 4,984 in 2008 to only 2064 in 2023. That is more than a 58% reduction in leaks. That reduction in leaks improves safety, reduces methane emissions, and even improves service to customers since there are fewer service interruptions due to water offs and leakage repairs. Going forward, the reduction of Grade 2 leaks will continue to be a focus.

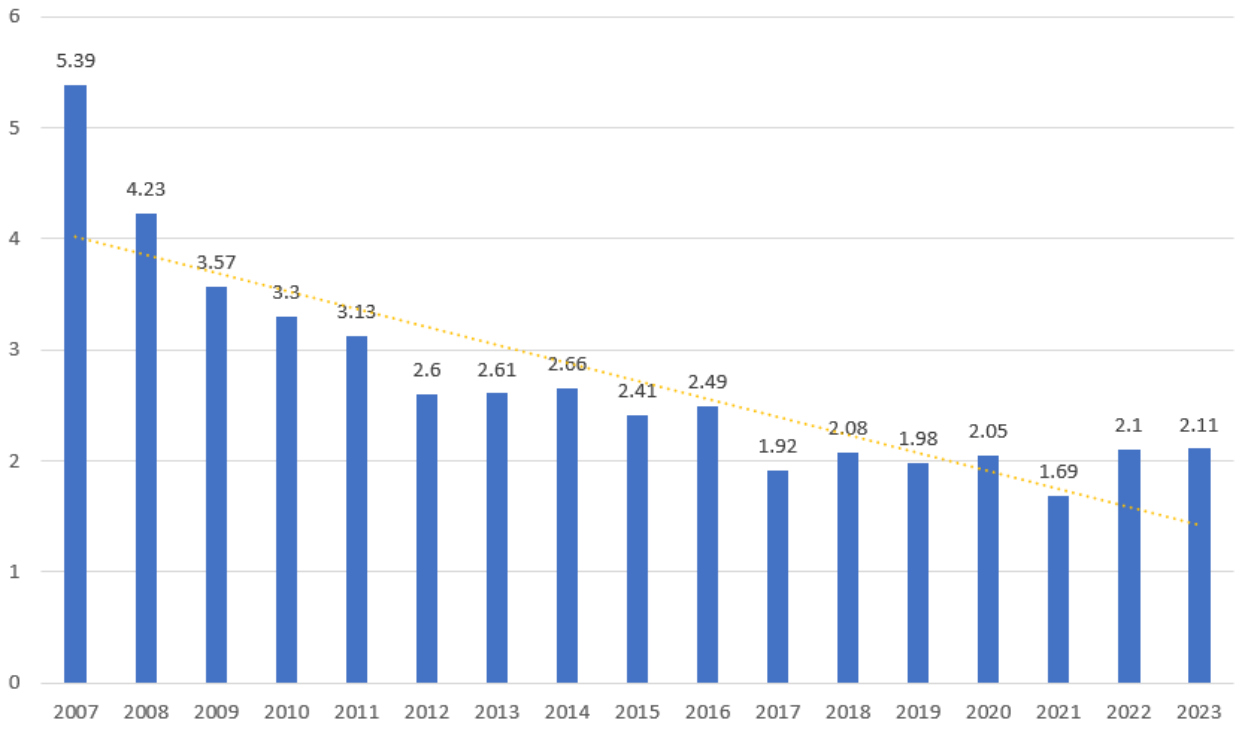
Figure 1
Columbia Gas of Pennsylvania, Inc.
Grade 2 Leaks



Damage Prevention: The Company continues to focus on damage prevention. Since 2007, the Company reduced damages per 1,000 locates, as noted in Figure 2 below. In particular, the Company has focused on improving third party damages per

1,000 locates, as excavation damage is the leading cause of federally reportable pipeline incidents. These efforts have contributed to the 60% reduction in the damage rate on the Columbia system between 2007 and 2023, from a damage per thousand (locate requests) rate of 5.39 in 2007 to a damage per thousand rate of 2.11 through December 31, 2023, as shown in Figure 2 below.

Figure 2
Columbia Gas of Pennsylvania
Damages per Thousand



- *Training Center*. Columbia constructed a new training center that opened in mid-2016 which provides the facilities needed to conduct classroom training, enhanced hands-on training and operator qualification training. The facility is currently being used for multiple training purposes, including new

employee training, employees transitioning into higher skilled positions, annual refresher training for the existing workforce and emergency response training. A great deal of thought, research and best practices were considered when developing the new training approach and designing the training facility. Trainers traveled to industry leading training facilities and natural gas organizations across the country. The Company studied best practices of organizations outside the natural gas distribution industry, who are trained to respond to crisis and emergency situations. Columbia formed focus groups to gain insight and obtain feedback from front-line employees about their perceptions of and experiences with training, as well as the accessibility of standards while performing on-the-job tasks. The developed curriculum incorporates end-to-end training of Columbia's field technology, such as mobile data terminal units and work management systems, to technical training for operator qualifications. This end-to-end training educates employees on every aspect of the job and its importance, from physical work performed to its accurate documentation.

IV. Columbia's Operating Performance

Q. In addition to Columbia's intense focus on pipeline safety, what are some of the practice enhancements or procedural changes regarding operating performance that are specific to customer delivery performance?

A. Over the course of the last eight years, Columbia initiated and/or continues to expand on a number of customer service delivery improvements. These improvements include 45-minute or less emergency response times and providing customers the option of a two-hour appointment window, which have resulted in a safer and better experience for our customers. For example:

- Columbia implemented 45-minute or less Emergency Response Rate targets. Emergency response rates are integral to public safety. The sooner the first Columbia responder arrives at a possible emergency, the quicker the situation can be stabilized, made safe, and ultimately remediated. Since 2006, Columbia has implemented a very structured approach to improving its emergency response times, including the addition of field operations positions, additional off hours shifts, the use of GPS technology to enable dispatching the closest/quickest responder to emergencies, and instructing all employees to focus on responding to reported emergencies as safely and as quickly as possible. In addition, Columbia continues to make enhancements in an effort to keep emergency response rates down. Starting in 2011, Columbia implemented an automated crew call out and resource management system to call the service technician located closest to an issue that requires a response after hours. Columbia also negotiated additional language to our labor contracts which requires a service technician to be on Emergency Responder Rotation so that we have an initial responder available

24 hours a day, 365 days a year. Additionally, the Company negotiated residency requirements to better support emergency response efforts. The results of these focused efforts have resulted in improved performance in emergency response times. A comparison of the data showing the 45-minute or less response rates from 2015 to 2023 as follows:

	2015	**2016***	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
Day	96.79%	99.17%	99.16%	98.70%	98.99%	99.51%	99.5%	99.6%	99.5%
Evening	90.95%	95.24%	94.87%	95.61%	97.28%	97.09%	96.1%	96.3%	97.1%
Holiday	91.59%	92.11%	85.25%	86.32%	88.79%	95.35%	92.4%	91.2%	97.7%
Overnight	85.87%	94.86%	95.19%	92.43%	90.42%	95.62%	95.6%	96.4%	97.5%
Weekend	82.76%	91.83%	92.66%	91.72%	93.66%	95.31%	95.1%	93.2%	94.7%
Total	**92.68 %**	**96.88 %**	**96.82 %**	**96.40 %**	**97.28 %**	**98.12 %**	**97.8%**	**97.7%**	**98.2%**
**Note: Columbia implemented 45-minute response targets in 2016*									

- Columbia achieved an increase in the number of Columbia's on-time customer appointments, as measured by the overall annual percentage of on-time appointments met[4]. As more and more customers need to take time off from work to provide access to their homes for routine meter turn-on, turn-off, and other service-related activities, it is incumbent upon the Company to be as efficient as possible with the customers' time. Therefore, in 2007, Columbia began to focus specific attention on improving its percentage of on-

[4] The percent of customer-generated appointments that are met within the appointment window or according to state regulation, where applicable.

time appointments. It did so by tasking the Integration Center (Columbia's Centralized Scheduling and Dispatch Center) with improving field employees' daily schedules to align more closely with the needs of customer appointments, and to shift non-emergency work, when possible, to meet appointments that, for a variety of reasons, might otherwise be missed. As a result of these efforts, Columbia has been able to improve its on-time appointment rates from 97.83% in 2014, to a rate of 99.82% in 2023.

Q. Please describe the Company's reduction in Occupational Safety and Health Administration ("OSHA") recordable injuries.

A. Columbia continues to enhance its culture of safety for customers, communities, and employees. Employee safety has significantly improved as Columbia has experienced a significant reduction in OSHA Recordable Injuries. For comparison, at the end of 2006, Columbia had 48 OSHA recordable injuries. This past year in 2023, our frequency was 15 OSHA recordable injuries which is a reduction in frequency of 69%. Columbia has previously received industry awards from both the American Gas Association and the Energy Association of Pennsylvania in recognition of its safety performance. Our goal is for every employee to go home safe and healthy every day. Columbia's safety efforts include:

Each week, a safety communication is distributed to all Columbia leadership. The safety message includes a summary of our safety performance including lagging and

leading indicators. Data driven and seasonal safety discussion materials are included for each Leader to discuss with their team of workers.

Columbia delivers safety training to all employees. This employee safety training encompasses role-specific training ranging from employee safe driver training, work zone intrusion awareness to office ergonomics.

Columbia utilizes employee-led local and state-wide safety teams, which include front line workers, leaders, contractors, and managers. These teams provide feedback to the organization to drive continuous improvement and communicate recommendations on, and implement, safety improvement opportunities throughout the organization. Minutes from these meetings are shared with other teams and posted virtually for access by others.

Columbia performs a robust post-incident review and root cause analysis involving the team of the affected business unit of every worker injury and preventable vehicle collision that involves a Columbia employee. Work zone intrusions and near miss post incident review discussions are also conducted.

Columbia has implemented the Energy Wheel or an energy-based hazard recognition program where we focus on sources of energy that when released can cause serious injury or fatality (SIF) events. This program better facilitates the prevention of fatalities and serious injuries that are life threatening or life changing for the employee. As the Columbia Energy Wheel safety program evolves, this year we will be progressing towards the high energy concepts of "STKY – Stuff that Kills You" and

"HECA" High Energy Control assessments where we identify hazards and implement direct controls focused specifically on the hazard so that if energy is released, no one is hurt or injured. HECA is a method of measuring safety based on the proportion of high-energy hazards with a corresponding direct control. HECA focuses on SIF prevention and the measurement of safety as the presence of safeguards.

Supplementing our Energy-Based Hazard Recognition program, Columbia has also created and implemented a Serious Injury or Fatality (SIF)/Severe PVC Incident Program. A SIF event classification is based upon the amount and source of high energy present and the severity of the event. Should a SIF events occur, they are shared throughout Columbia Gas, for learning opportunities.

A core component of the Columbia safety program is the job site safety observation initiative in which leaders and other support teams perform job site safety observations in the field to coach employees on safe working behaviors, field work activities, and to provide both positive and constructive feedback to employees in the field. Each Leader in the organization is required to spend time in the field conducting job site observations on our work sites and projects. This program also includes our executives who are required to visit and to spend time with our employees in the field. Our job site observation data is measured, monitored, and communicated weekly and monthly as leading safety indicator across the organization.

Columbia employees evaluate risk and identify the work hazards at each job site prior to starting work and complete a pre-job safety briefing which is reviewed and discussed with each employee on the job site or project. Our pre-job briefing process also reinforces that all workers on our sites and projects have stop work responsibility. This year, we will be adding hazards related to the Energy Wheel. Columbia is currently meeting with local collective bargaining units to discuss vehicle telematics and the use of the Blackline safety device. The purpose of vehicle telematics is to improve the safety of Columbia employees, while providing a tool for improving driving behaviors and fleet optimization. Telematics will focus on improving safety through providing the driver the ability to correct their driving behaviors, coaching, and protecting drivers from false claims with video exoneration. The Blackline safety device is an intrinsically safe wearable unit that provides the employee with a handful of safety features aimed at enhancing their level of worker safety when used in the field. It functions as personal gas detection monitor (H2S, Oxygen, Carbon Monoxide, LEL), worker fall and 'no movement" detection, two-way voice, and text messaging, push to talk communication with other Blackline units, silent and audible SOS alerts, and employee location.

Q. Regarding Columbia's operating performance, does the Company meet or exceed state and federal requirements for leak surveying?

A. Yes, in 2007, Columbia began an accelerated leakage survey program to inspect all bare steel mains annually, instead of the three-year interval which is required in the

leakage survey requirements of CFR 49, Part 192. While annual surveys have been performed for bare steel since 2007, Columbia has significantly reduced its inventory of bare steel and seen a significant reduction in found leaks and plans to return to the three-year leak survey interval for bare steel due to the decreased inventory and reduced risks. Columbia intends to utilize the current resources to assist in the implementation of Picarro leak detection to help drive risk down across our system.

Q. Please provide a brief overview of the WAM component of NiSource's planned 5-year IT Transformation?

A. The term "WAM" refers to the development and system-wide deployment of new integrated work and asset management IT systems to replace existing programs that are at or near the end of their useful lives, not fully integrated and at risk of failure. As explained by Company witness Skinner, NiSource's existing information technology systems that the WAM program will replace are at the end of their useful lives, and, in some cases, are no longer supported. And, that in order to continue to provide reasonable and adequate service to customers, NiSource must replace its aging infrastructure and invest in new software systems. NiSource has focused on maintaining and repairing its core systems over the last 20 years, as opposed to making significant investments in new technology. As a result, the current systems that are at or nearing the end of their useful lives are at risk of failure. In addition to requiring significant upgrades, the current systems are costly to support and present risks in operating the business, including cyber vulnerability risks.

Company witness Skinner provides additional testimony regarding NiSource's IT Transformation plan and WAM in Statement No. 16.

Q. How will the WAM program benefit Columbia's operations?

A. The WAM program consists of three major components: (1) the "Work Management Initiative," which will substantially improve Columbia Gas' work and asset planning and management processes; (2) the "Mobile Workforce Initiative," which will support integrated planning of work in the field, scheduling, and work route planning; and (3) the "Mobile Mapping Initiative," which will provide mapping technology and functionality and allow front-line employees to view and capture more robust details about Columbia Gas' infrastructure when and where the work happens.

Q. Do you have any additional comments regarding the WAM program? How will these measures benefit Columbia's operations?

A. Yes. The WAM program will replace NiSource's outdated systems with systems that are the new industry standard and that can readily be integrated and supported over the estimated 15-year life of the assets. As a result of implementing the WAM program, NiSource anticipates improved operational efficiencies by reducing the amount of time spent in the field per work request, travel time and organization of travel time, and scheduling and dispatching time. Implementation of the WAM program will allow NiSource to begin using proven, fully integrated systems that are designed to be flexible and allow for growth for many years.

Q. Do have any comments regarding NiSource's efforts to drive continuous improvement?

A. Yes, it does. As noted by Company witness Kempic in Statement No. 1, in 2023, NiSource bolstered its continuous improvement and cost savings efforts, by establishing a dedicated team, consisting of field employees, that was tasked with looking at our largest cost drivers as an organization and working with subject matter experts and leadership to find opportunities to increase efficiencies, lean out processes, and reduce cost.

Through these efforts, Columbia was able to ensure proper charging on leak repair and leak survey work (Picarro); reduce inefficiencies related to locates by reducing locate ticket volume through appropriate reduction of 811 buffers around our facilities and using a risk driven approach to un-locatable facilities. In addition, the Company implemented a job scouting process to reduce rework on jobs day to day and pushed capacity of our workforce by focusing on productivity metrics daily.

Q. Does this complete your Prepared Direct Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 15

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
NICHOLAS BLY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

I. Introduction

Q. Please state your name and business address.

A. Nicholas Bly, 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC") as the NCSC Accounting Manager, effective January 1, 2024. I was previously a manager within the Financial Planning & Analysis ("FP&A") department focused on Corporate O&M and Indirects, of which NCSC is the largest component.

Q. What are your responsibilities?

A. In my prior role as a manager in the FP&A department, my principal responsibilities included budgeting and forecasting operations and maintenance ("O&M") expenses for the corporate functions and overhead costs across all NiSource, Inc. companies ("NiSource"), including NCSC and Columbia Gas of Pennsylvania ("Columbia"). In carrying out those duties, I was responsible for a number of activities, including developing financial plans with budget owners, monthly reporting and variance analysis, updating current year forecast through the present estimate process, and other ad hoc financial support for the corporate functions.

In my current role, I am responsible for maintaining the processes and controls to identify and record transactions related to NCSC and the corresponding

allocations to the NiSource operating companies, including Columbia.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Business Administration with a concentration in Accounting and minor in Philosophy and Religious Studies from Winthrop University in Rock Hill, South Carolina in May 2006. My career began in the audit practice of Deloitte in Columbus, Ohio, where I first was exposed to the utility industry as my main client from 2008-2010 was an electric utility. In 2010, I began working for NCSC as a Senior Financial Analyst in a Consolidation Accounting role. In the following years, I also served as a Lead Analyst in Corporate Development, Lead Analyst in Corporate Budgeting, Manager in Corporate FP&A, and Manager in Treasury before leaving NCSC in 2016. From 2017 – 2020, I served in a multifunctional finance and operations role for JadeTrack, Inc. In October 2020, I re-joined NCSC in FP&A. In January 2024, I transferred into my current role. Lastly, I'm a Certified Public Accountant and Certified Treasury Professional.

Q. Have you ever testified before a regulatory Commission?

A. Yes. I previously testified before the Indiana Commission on behalf of NIPSCO in Cause Numbers 45621, 45772, and 45967. I've also testified before the Pennsylvania Commission on behalf of Columbia Gas of Pennsylvania in Docket No. R-2022-3031211.

II. Statement of Purpose

Q. Please describe the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to provide background on the budgeting process for corporate functions, overhead expenses, and how that relates to the financial plan for Columbia. My testimony supports Columbia's projected Operations and Maintenance ("O&M") expenses for the Fully Projected Future Test Year ("FPFTY") for NiSource Corporate Services for Columbia Gas of Pennsylvania. Company Witness Nicole Paloney will be supporting the budgeting process for the Gas Utility Departments for Columbia Gas of Pennsylvania at Columbia Statement No. 9. The following chart illustrates the costs elements in Exhibit 104, Schedule 1 pages 5 and 6 supported by myself and Witness Paloney. Lastly, I will be providing background and budget information on a key IT project known as the Work and Asset Management ("WAM") program that's currently under development.

Cost Element Category	Company Witness
Labor	Bly/Paloney
Incentive Compensation	Bly
Pension	Bly
Pension Deferral Amortization	Bly
OPEB	Bly
Other Employee Benefits	Bly
Outside Services	Bly/Paloney
Building Leases	Bly/Paloney
Other Rent and Leases	Bly/Paloney
Corporate Insurance	Bly
Injuries and Damages	Bly
Employee Expenses	Bly/Paloney
Company Memberships	Paloney
Utilities and Fuel Used in Company Operations	Bly/Paloney
Advertising	Bly/Paloney
Fleet & Other Clearing	Bly/Paloney
Materials & Supplies	Bly/Paloney
Other O&M	Bly/Paloney
PUC, OCA, OSBA Fees	Paloney
NCSC	Bly

Q. Please define Corporate O&M and Overheads.

A. Corporate O&M includes functions such as Information Technology, Finance, Accounting, Legal, Tax, Supply Chain, Treasury, Risk Management, Call Center Operations, Human Resources, Safety Services, and Utility Operation Support. Overheads include short and long-term incentive compensation, retirement benefits (e.g. 401K, pension), insurance benefits (e.g. disability), health benefits (e.g. vision, medical), and the use of shared assets.

Q. Can you describe the annual budget development process for Corporate O&M and Overheads?

A. The NiSource O&M expense budgeting methodology is a combination of a "top down" and "grass roots" approach, which facilitates decision points to ensure the highest and best use of available dollars. "Top down" is necessary to ensure NiSource maintains its financial commitments (e.g. credit rating) to ensure capital availability necessary to maintain the infrastructure to deliver safe, reliable energy. "Grass roots" is necessary to capture the detailed department level requirements of the business and provide each functional leader with an operating budget. Ultimately, the overall NiSource O&M targets are established and presented by the Chief Financial Officer and SVP of Financial Planning & Analysis to the Executive Leadership Team for approval. Department budgets are refined and updated as necessary after targets are set.

Q. Please elaborate.

A. Using the O&M targets set by the Executive Leadership Team as a guidepost, it is the responsibility of the Financial Planning team along with functional leaders to work together to ensure functional O&M budgets are developed in accordance with overall financial goals and objectives.

Budgeted expenses are grounded in a trailing 12-month historical spend with merit increases and inflation adjusted for each year thereafter, delineated by cost categories such as labor, materials, and outside services. Overhead costs are calculated based on labor (e.g. incentive compensation) or provided to us via actuarial firms (e.g. pension and benefits).

Q. What are the principal assumptions used in the development of the labor cost element for specific department budgets?

A. The starting point for labor costs is the current organizational chart, which is then reviewed with each functional leader to properly reflect their organization for the upcoming year, including any terminations, additions, or transfers. The labor planning module calculates annual salary increases for merit. Additionally, the planning system reduces labor expense by a capitalization rate consistent with historical results by department, as many departments within the company work on projects that qualify for balance sheet treatment and are not immediately expensed through O&M. The labor expense values by department are compared to the prior

year for reasonableness before the plan is finalized.

Q. What are the principal assumptions used in the development of the non-labor cost elements for specific department budgets?

A. Non-labor non-overhead expenses (aka Direct Expenses) are rooted in historical trends to reflect normal ongoing levels of expense and are then adjusted up or down for known activities or events reasonably expected to occur or not recur.

Q. Does Corporate O&M and Overheads include allocations from NCSC, and if so, how are the allocation of costs to Columbia determined?

A. Yes, NCSC is a subset of the budget for Corporate O&M and Overheads. Allocations from NCSC to the operating companies are based on historical distributions and adjusted as necessary to best represent expense planned to future periods.

Q. Is the budget development process consistent with the prior rate case?

A. Yes, the process is consistent.

Q. Is the budget reviewed throughout the year?

A. Yes. On a monthly basis an analysis that compares budget to actual results is completed and reviewed. This analysis provides key drivers for variances for both monthly and year-to-date results. In addition to monthly variance analysis, present

estimate updates are conducted with function leaders that provide forecast updates for the current year and any impact to future years. Documentation of the drivers of the variance are maintained and evaluated in future planning cycles to ensure proper consideration of new and developing forecast items.

Q. How does NiSource's public commitment to flat O&M impact cost of service in this case?

A. The intent is to ensure customer affordability via a focused effort on becoming more efficient and effective with every O&M dollar spent. Please note, flat O&M relates to NiSource in total and will not translate directly at lower levels; NiSource companies, departments, or cost categories may be up or down individually. That said, as shown in Attachment NB-1, O&M is lower by over $10 million as-filed in this case for the FPFTY (calendar year 2025) versus the prior case FPFTY (calendar year 2023).

Q. What is the WAM program?

A. Over the next five years, NiSource plans to replace outdated legacy IT systems with integrated, secure, and reliable systems that will improve employee performance and benefit our customers. The first step in this five-year transformation is implementation of the WAM program that will facilitate the planning, scheduling, dispatch, and execution of the work on and management of utility assets. The WAM program is underway and will be fully completed in 2025. Please refer to Company

witness Skinner's testimony (Columbia Statement No. 16) for more information on the WAM program.

Q. How are actual WAM capital and O&M expenses being allocated to Columbia and NiSource's other operating units?

A. When possible, costs are directly charged to Columbia and NiSource's other operating units. Capital and O&M expenses that support multiple NiSource operating units and therefore are not directly charged costs, will be allocated to the operating companies benefited by the development and implementation of the WAM program. The bases of allocation to the benefitting companies are either (1) the combination of total gross fixed assets and total O&M expense, or (2) the number of retail customers, through the applicable billing pool defined in the affiliate service agreement between Columbia and NCSC.[1]

Q. How are budgeted WAM capital and O&M expenses allocated to Columbia and NiSource's other operating units?

A. WAM is an IT Project planned for NCSC and is allocated consistent with the methods described in earlier Q&A's pertaining to the O&M Budget. Capital is allocated consistent with the prior Q&A discussing actual allocations in that WAM has several sub-projects and each is assigned a billing pool that best represents the benefiting

[1] Service Agreement between NCSC and Columbia dated January 1, 2015 ("Service Agreement").

operating units.

Q. Based on the allocation methodologies applied by NiSource, what portion of the cost of the WAM program in the FTY and FPFTY relates to Columbia?

A. Total estimated WAM program costs are $258.8 million in the FTY and FPFTY, of which approximately 12.2% of the costs relate to Columbia; this equates to $26.6 million of capital cost and $5.0 million of one-time O&M expenses.[2]

Q. Is the allocation methodology used by NiSource to allocate the costs of the WAM program to each of NiSource's operating units reasonable?

A. Yes. The basis of allocation to the benefitting companies are consistent with the methodologies described herein for budgeting or consistent with the methodologies prescribed in the Service Agreement for actuals.

Q. What capital costs will NiSource incur as part of the WAM program?

A. NiSource will incur two principal types of capital costs associated with the WAM program: (1) costs associated with design and implementation of the WAM program hardware and internal-use software; and (2) costs associated with implementing the cloud computing systems eligible for capitalization pursuant to FERC Guidance

[2] *See* Exhibit 108, Schedule 1, page 1 and Exhibit 104, Schedule 1, page 2, lines 1 and 7.

(Attachment NB-2). NiSource expects to incur $142.4 million of the first category of costs, of which $17.4 million relate to Columbia. NiSource anticipates capitalizing $78.9 million associated with the second category of costs, of which $9.2 million relate to Columbia.

Q. Does this complete your direct testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA **Attachment NB-1**
Docket No. R-2024-3046519 **Page 1 of 1**
NCSC prior case to current case comparison

Line No.	Ref	Description		*Amount*
1	Exhibit 104, Schedule 1, Page 2, Line 22 (1)	Normalized FPFTY Twelve Months Ended December 31, 2023	$	176,340,225
2	Kelley Miller Rebuttal Testimony Table KKM 1-R (1)	O&M Correction	$	2,607,000
3		Total filed in 2022 rate case	$	178,947,225
4				
5	Exhibit 104, Schedule 1, Page 2, Line 21 (2)	Normalized FPFTY Twelve Months Ended December 31, 2025	$	168,723,021
6		Over/(Under) prior case	$	(10,224,204)
7				
8				
9				
10				
11	*Footnotes:*			
12	*(1) Reference to prior rate case Docket No. R-2022-3031211*			
13	*(2) Reference to current case Docket No. R-2024-3046519*			

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. AI20-1-000
December 20, 2019

TO ALL JURISDICTIONAL PUBLIC UTILITIES AND LICENSEES, NATURAL GAS COMPANIES, AND CENTRALIZED SERVICE COMPANIES

Subject: Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract

The Financial Accounting Standards Board (FASB) has issued Accounting Standards Update (ASU) No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement,* to reduce potential diversity in practice in accounting for the costs of implementing cloud computing arrangements that are service contracts. ASU No. 2018-15 aligns the accounting for costs incurred to implement a cloud computing arrangement that is a service contract with the guidance on capitalizing costs associated with developing or obtaining internal-use software. Specifically, ASU No. 2018-15 clarifies that an entity obtaining a service contract in a cloud computing arrangement should follow the existing guidance in Accounting Standards Codification (ASC) 350-40 to determine which implementation costs can be capitalized and which costs must be expensed, and further provides that the capitalized implementation costs shall be amortized over the term of the associated arrangement. In addition, ASU No. 2018-15 requires the capitalized implementation costs to be reported on the balance sheet in the same line item as any prepayment of the service fees for the associated cloud computing arrangements. The related amortization expense is required to be reported in the same expense line item on the income statement as the expense for the service fees of the associated cloud computing arrangement. For most jurisdictional entities, ASU No. 2018-15 is effective January 1, 2020 for accounting and financial reporting under generally accepted accounting principles (GAAP).

Commission staff received many inquiries from industry participants regarding clarification on how to apply ASU No. 2018-15 within the framework and regulatory intent of the Commission's existing accounting requirements. As discussed herein, for regulatory accounting and reporting to the Commission, jurisdictional entities will be permitted to capitalize certain implementation costs and to amortize those costs over the term of the associated cloud computing arrangement. However, in capitalizing these

costs, jurisdictional entities must adhere to the regulations related to plant construction costs set forth under Part 101, Part 201, and Part 367 of the Commission's regulations.[1] Jurisdictional entities must also follow the guidance provided herein with regards to the accounts they should use to record the capitalized costs and the related amortization expense. Service fees and other non-capital costs for the cloud computing arrangement are generally recorded as an expense.

The accounting guidance included herein is intended to result in consistent accounting for the same types of costs incurred for cloud computing arrangements and internal-use software projects for accounting and financial reporting to the Commission. The Commission's accounting requirements are not intended to automatically reflect changes in FASB's Accounting Standards Codification, and FASB updates should not be construed as required for regulatory accounting and reporting to the Commission. However, upon analysis, the Commission may issue accounting guidance to clarify how provisions of an ASU can be reflected within the Commission's existing accounting and financial reporting requirements. Accordingly, this accounting guidance is intended to provide clarity and certainty on how jurisdictional entities should apply the Commission's accounting and reporting requirements related to cloud computing arrangements in response to ASU No. 2018-15.

1. **Question:** How should jurisdictional entities capitalize implementation costs related to cloud computing arrangements?

Response: Implementation costs related to cloud computing arrangements are similar to the costs incurred to develop internal-use software and should be accounted for on the same basis. Jurisdictional entities have historically determined capitalizable internal-use software costs in a manner consistent with the requirements of ASC 350-40, which is an acceptable approach for accounting and financial reporting to the Commission. Accordingly, it is also appropriate for jurisdictional entities to determine capitalized implementation costs related to cloud computing consistent with ASC 350-40. Examples of implementation costs that may be capitalized include upfront costs to integrate with on-premise software, coding, configuration, and customization.

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[1] *See* 18 C.F.R. Part 101, Electric Plant Instructions No. 3 (Components of Construction) and No. 4 (Overhead Construction Costs). *See also* 18 C.F.R. Part 201, Gas Plant Instructions No. 3 (Components of Construction) and No. 4 (Overhead Construction Costs). *See also* 18 C.F.R. Part 367, Service Company Property Instructions No. 367.51 (Components of Construction) and No. 367.52 (Overhead Construction Costs).

2. **Question:** What accounts should jurisdictional entities use to record capitalized implementation costs related to cloud computing arrangements for Commission accounting and reporting purposes?

Response: Jurisdictional entities should record capitalized implementation costs associated with cloud computing arrangements as a utility plant asset, consistent with the Commission's accounting requirements for internal-use software. Accordingly, jurisdictional entities should record capitalized implementation costs in Account 303 (Miscellaneous Intangible Plant), provided such costs are not specifically provided for in other utility plant accounts. For example, public utilities are required to record software used to support regional transmission and market operations in Account 383 (Computer Software). Accordingly, a public utility's capitalized cost related to cloud computing arrangements for regional transmission and market operations should be recorded in Account 383.

3. **Question:** What accounts should jurisdictional entities use to record the amortization or depreciation of capitalized implementation costs related to cloud computing arrangements for Commission accounting and reporting purposes?

Response: Jurisdictional entities should amortize or depreciate capitalized cloud computing costs consistent with the requirements of the utility plant accounts in which they are recorded. Specifically, the amortization of capitalized cloud computing costs recorded as intangible utility plant should be recorded in Account 404 (Amortization of Limited-Term Electric Plant)[2] for public utilities and centralized service companies, and Account 404.3 (Amortization of Other Limited-Term Gas Plant) for natural gas companies.[3] The amortization of capitalized cloud computing costs not classified as intangible utility plant should be recorded in Account 403 (Depreciation Expense).

If a jurisdictional entity believes that its facts and circumstances warrant the use of alternative accounts other than those prescribed herein to record the capitalized costs and related amortization, the jurisdictional entity should request clarification or approval from the Chief Accountant to use the alternative accounting treatment.

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[2] *See* 18 C.F.R. Parts 101 and 367 (2019).

[3] *See* 18 C.F.R. Part 201 (2019).

Docket No. AI20-1-000

The Commission delegated authority to act on this matter to the Director of the Office of Enforcement or his designee under 18 C.F.R. § 375.311 (2019). The Director has designated this authority to the Chief Accountant. This letter constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2019).

Sincerely,

Steven D. Hunt

Steven D. Hunt
Chief Accountant and Director
Division of Audits and Accounting
Office of Enforcement

COLUMBIA STATEMENT NO. 15-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
NICHOLAS BLY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

I. Introduction

Q. Please state your name and business address.

A. Nicholas Bly, 290 West Nationwide Boulevard, Columbus, Ohio 43215.

Q. Have you previously filed testimony in this matter?

A. Yes.

II. Purpose and Summary of Testimony

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to portions of the direct testimony filed by Witness Greg R. Meyer on behalf of the Office of Consumer Advocate ("OCA") specifically, the recommendation to disallow recovery of Directors and Officers Liability insurance ("D&O"). I will also be responding to portions of the direct testimony filed by Witness Christian Yingling on behalf of the Bureau of Investigation & Enforcement ("I&E"); specifically, the second disallowance based on a 20% payroll expense factor. Lastly, I am sponsoring an update to NiSource Corporate Services Company ("NCSC") expenses related to the closure of the Smithfield Care Center.

III. Insurance Adjustment

Q. Please summarize Witness Meyer's proposed adjustment to insurance.

A. Witness Meyer asserts D&O benefits shareholders not ratepayers, as it insures "actions of management that go against the principles of safe and reliable service." (OCA Statement No. 2, p. 20 – 21).

Q. Do you agree with Witness Meyer's assessment of the purpose of D&O insurance and to which party it benefits? If not, why not?

A. I do not. The fact of the matter is that the general purpose of insurance policies is to reduce the risk of exposing the Company and its customers to higher costs due to unforeseen circumstances. Insurance in all forms is a normal cost of doing business. If D&O coverage did not exist, it would either be difficult to find willing participants to be directors and officers, or directors' and officers' compensation would be increased so they could procure their own independent coverage, which would be passed through to ratepayers in payroll costs.

Lastly, D&O insurance covers a broader number of scenarios than Witness Meyer implies despite his own definition which correctly cites that ". . . legal actions can include shareholder class action, failure to manage, act or disclose, stock value decreases, and regulatory claims." (OCA Statement No. 2, p. 20). A critical flaw in his analysis is that he assumes the only purpose of D&O insurance is to pay claims against Directors and Officers. A key provision of D&O coverage includes legal and investigative fees to help defend management in lawsuits filed for any number of reasons. For example, a shareholder may take issue with the Company's insistence on providing safe and reliable service to the customers at the detriment of shareholders. In such an example ratepayers can benefit from the Company providing its management D&O coverage as it helps protect management in the event of an unpopular shareholder, but pro-customer decision.

IV. Benefits Adjustment

Q. Please summarize Witness Yingling's proposed adjustment to Benefits.

A. Witness Yingling notes the Company has historically underspent benefits expense as compared to budget and recommends applying a 20% rate to his payroll expense allowance. In reaching his 20% recommendation, Witness Yingling states that over the last three years, "the Company's actual benefits expense is consistently at approximately 19.34% of the payroll expense." (I&E Statement No. 1, p. 21). Accordingly, this 20% recommendation is approximately Witness Yingling's calculated three-year historical average of 19.34%.

It's important to clarify Witness Yingling's proposed adjustment of $1,077,432 is comprised of two adjustments. The first is the use of a 20% payroll factor as opposed to the Company planning method. The second is the use of a lower payroll expense upon which he applied his 20% payroll factor. Please see the table below for a modified version of Witness Yingling's table from page 22 of his testimony.

1. FPFTY Benefits Expense Claim	$	8,527,000
2. Profit-Sharing Adjustment $413,427	$	413,427
3. Adjusted Benefits Expense (1 – 2) $8,113,573	$	8,113,573
4. I&E Adjustment at 20% of Payroll Expense Allowance of $38,227,431	$	7,645,486
5. I&E Recommended Reduction (3 - 4) from the 20% Payroll Factor	$	468,087
6. I&E Recommended Reduction from lower Payroll Expense	$	609,345
7. Total I&E Recommended Reduction (5 + 6)	$	1,077,432

Q. Do you agree with either component of the benefits expense adjustment proposed by Witness Yingling?

A. I do not. The company opposes any adjustments to Other Employee Benefits Expense resulting from proposed adjustments to payroll expense that are not accepted. Please refer to the rebuttal testimony of Columbia Witness Leal (Columbia Statement No. 21-R) for further testimony related to payroll expense.

Additionally, the use of a payroll factor, whether it be 20% or some other value, is an oversimplification and incorrect way to budget employee benefits. Employee benefits requires the use of an actuary capable of considering all relevant factors such as but not limited to high-cost claimants, company-specific and nationwide claims trends, and inflation specific to health benefits. Lastly, I do understand the recent historical variances cast doubt on the current forecast, however Employee Benefits have been complicated in recent years by all things associated with the COVID pandemic, such as unpredictable patient behavior and high initial inflation that has eased. A review of the first six months of 2024 is presented below to illustrate improved alignment with the current budget.

	PLAN			ACTUAL			VARIANCE		
	Six Months Ended June 30, 2024			Six Months Ended June 30, 2024			Six Months Ended June 30, 2024		
	Gross	Capital	Net	Gross	Capital	Net	Gross	Capital	Net
Other Benefits	$ -	$ -	$ -	$ 93,857	$ -	$ 93,857	$ 93,857	$ -	$ 93,857
Employee Medical Health Insurance	$ 4,171,876	$ 1,967,668	$ 2,204,208	$ 4,287,890	$ 2,590,250	$ 1,697,641	$ 116,015	$ 622,582	$ (506,567)
401K	$ 2,298,583	$ 1,034,891	$ 1,263,692	$ 2,038,067	$ 1,016,966	$ 1,021,100	$ (260,516)	$ (17,925)	$ (242,592)
Dental	$ 232,792	$ 104,810	$ 127,982	$ 224,367	$ -	$ 224,367	$ (8,425)	$ (104,810)	$ 96,385
Group Life Active	$ 122,500	$ 55,153	$ 67,347	$ 160,981	$ -	$ 160,981	$ 38,481	$ (55,153)	$ 93,634
Long Term Disability	$ 192,500	$ 86,669	$ 105,831	$ 229,785	$ -	$ 229,785	$ 37,285	$ (86,669)	$ 123,954
Profit Sharing	$ 365,000	$ 164,334	$ 200,666	$ 266,516	$ -	$ 266,516	$ (98,484)	$ (164,334)	$ 65,850
Vision	$ 51,500	$ 23,187	$ 28,313	$ 30,433	$ -	$ 30,433	$ (21,067)	$ (23,187)	$ 2,120
Total	**$ 7,434,751**	**$ 3,436,712**	**$ 3,998,038**	**$ 7,331,895**	**$ 3,607,216**	**$ 3,724,679**	**$ (102,855)**	**$ 170,504**	**$ (273,359)**

V. Update to NCSC Expenses

Q. What is your update to NCSC Expenses for the FPFTY?

A. NCSC closed the Smithfield Care Center in May 2024 and there are no plans for a replacement facility. Care Center employees remain in their current role but have been enabled to work remotely. NCSC Expenses of $71,249,563 in the FPFTY (Exhibit 104, Schedule 1, Page 2, Line 20) are being reduced by $490,926 to $70,758,637 and is reflected in Company witness Komenda's Exhibit BJK-1R.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 16

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
GREGORY SKINNER ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 15, 2024

I. Introduction

Q. Please state your name and business address.

A. Gregory Skinner, 290 West Nationwide Boulevard, Columbus, OH 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC") as Vice President IT Utilities Systems.

Q. What are your responsibilities as Vice President of IT Utilities Systems?

A. As Vice President of IT Utilities Systems, I am responsible for developing information technology ("IT") strategy and corresponding integrated IT roadmap investments to support NiSource Inc.'s ("NiSource") multi-year business and IT transformation effort. As it relates to this proceeding, I am responsible for the design, development, and implementation of the Work and Asset Management ("WAM") transformation program.

Q. Please briefly describe your professional experience.

A. I began my career in 1997 at Accenture, where I worked for approximately seven years as a Consultant and as Manager of Global Architecture & Core Technologies. In 2004, I took a position with Horizon Services Group, LLC, where I served initially as IT Manager and later as Senior IT Manager of Customer Logistics Solutions for approximately four years. I joined NCSC in 2008, where I have worked in various capacities over the last fifteen years. From June 2008 to September 2012, I worked as the Manager of IT Service Delivery, from October 2012 to May 2015 I worked as

the Director of IT (Finance) Transformation, from June 2015 to December 2017 I worked as the Vice President of IT Project Delivery, and from January 2018 to June 2022 I worked as the Vice President of IT Infrastructure. I have served in my current role as Vice President of IT Utilities Systems since May 2022.

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to support Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or "Company") expenditures for improvements to its information technology ("IT") systems through the design, development, and implementation of a new WAM program for the scheduling, dispatch, and execution of work and the management of underlying assets. Specifically, I describe NiSource's planned five-year IT transformation plan and schedule, which includes the WAM program. I provide overview for the WAM program and explain why it is reasonable and necessary. Company witness Bly provides support for the allocation to Columbia, and the bases thereof, in his testimony (Columbia Statement No. 15).

Q. Are you sponsoring any attachments to your direct testimony?

A. Yes. I am sponsoring Exhibit GS-1, attached to my direct testimony, which is a presentation titled "*Transformation Roadmap Overview*" that provides an overview of NiSource's IT transformation program and the expected implementation schedule. This attachment was prepared by me or under my direction and supervision.

Q. What is your involvement with the implementation of the WAM

program?

A. As part of my role as Vice President of IT Utilities Systems, I am responsible for the operation and maintenance of NiSource's IT programs as they exist today and the planned five-year transformation to future state architecture that will result in standardized, integrated, secure, and reliable systems. I will be responsible for overseeing and delivering the IT transformation with quality and adhering to the budget. As part of that, I was responsible for planning the request for proposals ("RFP") processes undertaken for the WAM program.

II. THE IT TRANSFORMATION AND NEED TO REPLACE OR UPGRADE NiSOURCE'S IT SYSTEMS

Q. Please describe NiSource's plan to transform its IT systems over the next five years.

A. Over the next five years, NiSource plans to replace outdated legacy IT systems with integrated, secure, and reliable systems that will improve employee performance and benefit our customers. The first step in this planned five-year transformation is implementation of the WAM program that will facilitate the planning, scheduling, dispatch, and execution of the work on, and management of, utility assets. The WAM program is underway and will be fully completed in 2025. The second step of the IT transformation will be the completion of a Customer Transformation, which is expected to be underway in 2025. Once completed, the One Customer Information system will provide a better experience for customers

and facilitate provision of service to customers. The final step of the planned five-year IT transformation will be the implementation of a new financial system, beginning in 2027. Exhibit GS-1 provides a comprehensive overview of the planned five-year IT transformation plan.

Q. Why it is necessary for NiSource to undertake the planned five-year IT transformation, including implementation of the WAM program?

A. NiSource's focus on maintaining and repairing its core natural gas and electric delivery systems over the last 20 years or so has resulted in limited investments in new information systems technology. Consequently, NiSource's current state of IT architecture is a complex array of legacy systems often with redundant applications. Our review of the current state architecture revealed a critical need for IT investment, including deployment of new work and asset management systems. The WAM program, for instance, will allow NiSource to retire approximately 19 applications, which are complex and operationally inefficient.

Q. Are the systems being retired as part of the IT transformation at the end of their useful lives?

A. Yes. In fact, many of these systems are no longer supported or soon will no longer be supported by their respective software providers. As part of its overall risk management strategy, NiSource has been tagging these systems for the last several years as either at risk for failure or as being unable to upgrade and, therefore, in need of replacement. The current systems also create cyber vulnerability risks. Every year,

support for these software packages and the underlying infrastructure continues to wane and the risks associated with them continue to grow. NiSource has determined that investments must be made now to move to state-of-the-art software platforms to support operations and benefit customers.

Q. How do the current IT systems create cyber vulnerability risks?

A. NiSource's current legacy IT systems create cybersecurity vulnerabilities that require significant effort to overcome. It is increasingly difficult to patch and protect systems residing on outdated infrastructure. NiSource devotes significant resources to ensure its IT systems are secure. Among other things, NiSource has a very robust patching and threat monitoring program through its cybersecurity organization. However, NiSource must put additional protections in place to secure the systems until they can be placed on more modern platforms.

Q. Do the legacy IT systems that will be replaced as part of the IT transformation create other risks?

A. Yes. The current IT systems present significant risks in operating the business, including operational risks, reputational risks, regulatory risks, system risks, and customer support risks. As I mentioned, a number of the current IT systems are at or are nearing the end of their useful lives and are at risk of failure. Because of their age, it would take an extraordinary effort to recover the systems in the event of an outage or cybersecurity event. NiSource could be faced with a multiday effort to restore the systems, which would be disruptive. The disparate IT systems also require

significant manual work practices that are prone to human error. The existing legacy systems also lack technical support and cannot be upgraded, which limits NiSource's ability to take advantage of new features and capabilities that could create efficiencies that benefit our customers.

Q. Would it make sense to spend money upgrading the existing IT infrastructure?

A. No. The age of the systems is such that they would require significant upgrades and any investment would likely result in a temporary, rather than permanent, solution. It would be imprudent to spend money to attempt to work within the existing outdated systems because upgrades would not resolve the core issues and risks associated with these systems, including cybersecurity risks. The current systems are also costly to support, and it is difficult to introduce new capabilities and improvements to those systems, which could not be resolved by a mere upgrade.

Q. Do problems with the current IT systems hinder the ability to complete work?

A. Yes. The current IT systems are significantly underperforming as compared to newer technology, which results in additional operating impediments. For instance, due to limitations of the system, NiSource has created many workarounds that cause inefficiencies. The legacy IT systems also create difficulties in recruiting and retaining a modern workforce and propagate circumstances where certain groups are familiar

with specific platforms and others are not, which inhibits the ability to integrate IT operations and promote efficiency.

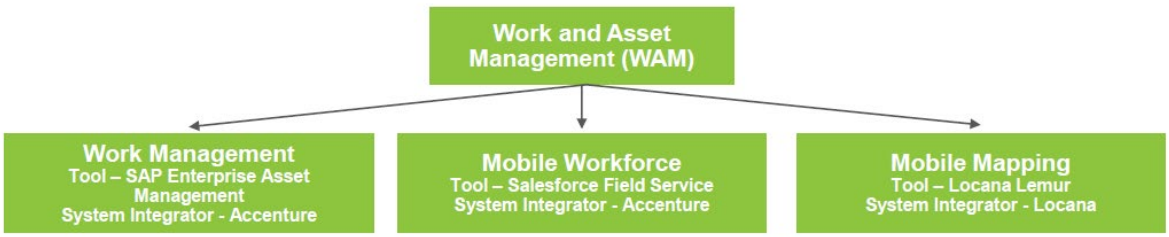
Q. In your opinion, are the current IT systems adequate to support NiSource's growing customer and business requirements?

A. No. The current IT systems need to be replaced to adequately support NiSource's existing operations.

III. THE WAM PROGRAM COMPONENT OF THE IT TRANSFORMATION

Q. Please describe the first step of NiSource's IT transformation, the WAM program.

A. The WAM program involves the development and system-wide deployment of new, integrated work and asset management IT systems to replace existing programs that are at or nearing the end of their useful lives, not fully integrated, and at risk of failure. The WAM program is a substantial NiSource-wide project, and subsidiary operating companies and their customers will benefit significantly from it. The three components of the WAM program are shown below:



Q. Please describe the three components shown in the chart above that comprise the WAM program.

A. The three core new systems comprising the WAM program are: (1) the "Work Management Initiative," which is technology to perform work and asset planning, initiation, execution tracking, closeout and reporting to standardize and enhance business processes, support strong asset maintenance, safety, compliance and risk management; (2) the "Mobile Workforce Initiative," which is technology that supports integrated planning of work in the field, scheduling, and work route planning and efficiency to provide an updated scheduling and dispatch solution and help bring NiSource into the digital age of utility services by giving front-line employees an easy-to-use mobile application to view assigned work, indicate work status and track completed tasks ; and (3) the "Mobile Mapping Initiative," which is a Geographic Information System ("GIS") mapping technology that will include functionality on mobile devices for improved asset data capture and as-builts in the field, which will allow front-line employees to view and capture more robust details about infrastructure when and where the work happens.

Q. How will the three components of the WAM program work together?

A. As an example, an existing asset with a defined maintenance schedule would exist within the Work Management Initiative system. As the maintenance date for this asset approaches, this information is presented to the scheduling team to prepare for the work that will be needed to perform maintenance (materials, permits, etc.).

When the work is ready to be executed it can then be scheduled and dispatched through the Mobile Workforce Initiative software. A technically-qualified field worker will receive a dispatched work order with all associated information on the asset including prior work performed and location details. The field worker will be able to locate the asset through the Mobile Mapping Initiative software to begin the work. Upon completion of the work, the field worker will capture the work performed in the Mobile Workforce Initiative application and make any real-time edits to the map in the Mobile Mapping application, all of which are sent back to the Work Management Initiative software to close out the work. This will all be fully integrated and seamless as opposed to requiring views of, and entries in, multiple applications as is required under the current state systems.

Q. Please summarize the benefits of the WAM component of the IT transformation.

A. At a high-level, benefits of the WAM program include:

- Standardization of end-to-end work and asset management processes supported by a new integrated solution including industry-standard software;
- Utilization of compatible unit estimating to standardize designs, materials, and tools;
- Incorporation of Operator Qualifications in work scheduling and assignment to promote efficiency in completing work in the field;

- Time savings through automation to support the scheduling, assigning, routing of work, and as-built records closeout – which will reduce wrench time, travel time and idle time;
- Modern data capture solution enabled by dynamic smart forms;
- Improved data quality through the ability to view and update asset data and data records on maps; and
- Improved reporting and data availability across common platforms.

Q. What is the core enterprise software backbone that will be used for the Work Management Initiative component of the WAM program?

A. The core enterprise software for the Work Management Initiative will be the SAP Enterprise Asset Management ("SAP") system. SAP will replace the existing outdated custom work management system used to maintain and perform work on assets, and several related systems (document and data warehouse repositories that encompass asset and operational data for reporting). Those systems have been in service for approximately fifteen to twenty years in some cases and are no longer officially supported by vendors.

Q. Will the SAP software improve functionality?

A. Yes. Once implemented, the new SAP software will simplify data entry and create a single source for asset management data, which will improve accessibility for NiSource employees. The Work Management Initiative software will serve as the single source of truth for assets, health, and maintenance information, as well as for

warehouse and materials management. Currently, this data is housed in multiple locations, which results in redundant and manual processes.

Q. What are some of the other benefits of using SAP software?

A. The SAP software (Work Management Initiative) will be integrated with the SalesForce software (Mobile Workforce Initiative) and Lemur Software (Mobile Mapping Initiative) as part of the WAM program and will be used as the backbone of the planned five-year IT transformation. In making this necessary investment, NiSource has chosen to implement a platform that allows software to be implemented on a proven, fully integrated basis. SAP is a top-tier, proven software that is used by many large utilities in their daily operations.

Q. How were the software platforms and service providers selected?

A. Key service providers and software platforms were selected through competitive RFP processes. The WAM program team, advisory council members, and other NiSource employees (including myself) participated in this process. We attended software demonstrations and considered both software applications and potential bolt on software functionality. WAM program team members also participated in site visits to companies currently using enterprise software, conducted telephone reference checks, and conducted on-site demonstrations. NiSource chose SAP, Salesforce, and Locana (Lemur) based on a number of factors, including the estimated total cost of ownership.

Q. In addition to the competitive RFP process, what other steps were taken to ensure the WAM program was undertaken at a reasonable cost?

A. Starting in 2019 and continuing through 2021, multiple evaluations took place with key partners to evaluate the technology landscape, opportunities for transformation and the sequencing of transformation to begin to formulate the total cost of ownership for a multi-year transformation. This review was again conducted in 2022 to confirm the approach, sequencing, and funding requirement for transformation. In the 2022 review, the WAM program was prioritized to start as the first major program in the transformation and the costs to implement were vetted through a competitive RFP process.

Q. How will customers benefit from the WAM program?

A. As with NiSource's other legacy IT business systems, the systems used for work and asset management are at the end of their useful lives and are not fully integrated. As a result, NiSource's current architecture is a complex array of legacy systems implemented as separate projects over time, wired together through complex integrations with varying degrees of efficacy, which leads to a wide array of issues. The WAM program will address these issues, provide new and improved features, and ultimately facilitate the provision of better service to customers. A more specific customer benefit of the WAM program worth noting is that the Mobile Mapping Initiative will offer a significant reduction in cycle time from when work is performed in the field to when maps are updated. Under NiSource's prior IT systems, these

updates took 30 days. By significantly cutting down on the time required to make these mapping updates, the Mobile Mapping Initiative will reduce the opportunity for a dig-in or damage to assets that could result in a customer outage.

IV. STATUS OF WAM IMPLEMENTATION

Q. What is the status of the implementation of the WAM program?

A. The WAM program has been fully planned and organized, with a full IT strategy in place. Deployment of the software backbone for the Mobile Mapping Initiative began in 2023. Implementation of the Work Management Initiative and Mobile Workforce Initiative began in 2023, with the goal of full WAM program implementation before the end of 2025.

Q. Please describe NiSource's progress to date implementing the planned five-year IT transformation.

A. A timeline showing the progress in completing the five-year IT transformation to date and the upcoming steps is included in Exhibit GS-1. Initially, stakeholders from across the NiSource companies were engaged to create and refine the five-year IT Strategy. Once completed, a frontline roadshow was conducted to gain detailed feedback to be used throughout execution of the planned five-year IT strategy. NiSource worked with key executive stakeholders across NiSource to define vision and user-centric strategy, workshopped with key stakeholders across NiSource to develop strategy to fine tune strategy, budgeting and staffing.

Q. Are Columbia employees participating in the design and implementation of the new systems?

A. Yes. Employees of all NiSource companies have had, and will continue to have, extensive involvement in the recommended improvements. As a practical matter, it is imperative that all NiSource employees be involved in the implementation of the program to ensure business and IT needs are properly served by the program at all stages of implementation.

V. REASONABLENESS OF THE COST OF THE WAM PROGRAM

Q. What is the projected cost of the WAM program to NiSource, and ultimately to Columbia?

A. The projected cost of the WAM program to NiSource in combined capital cost, capitalized software costs, and operations and maintenance costs is $258.8 million in the Future Test Year ("FTY") and the Fully Projected Future Test Year ("FPFTY"). Importantly, NiSource is managing the cost of the WAM program in its entirety, as opposed to by category. Company witness Bly supports the amount that is projected to be allocated to Columbia in Statement No 15. Implementation of the WAM program was deemed to be the most cost-effective solution to meet the business needs of NiSource, its subsidiaries, and customers and the cost of the WAM program were derived through competitive processes.

Q. Are you sponsoring the amount of WAM program cost that is projected to be allocated to Columbia?

A. No. Company witness Bly supports the $31.6 million that is projected to be allocated to Columbia and describes the allocation methodology applied. I support the total projected cost of the WAM program in the FTY and FPFTY and discuss why implementation of the WAM program was deemed to be the most cost-effective solution to benefit customers and meet the business needs of NiSource and its subsidiaries.

Q. Do you believe the cost of the WAM program is less expensive than costs that might be incurred if NiSource were to attempt to upgrade and maintain the existing legacy systems?

A. In my opinion, yes, assuming such an upgrade were even possible – which it is not. As discussed above, NiSource's software systems have already reached or are soon to be reaching the end of their useful life. Simply put, NiSource must invest in new software systems to replace aging software products to continue to provide reliable and efficient service to customers. Trying to patch or upgrade the legacy systems would be imprudent. The WAM program will result in a fully integrated IT system, supported by proven software platforms, and designed to be flexible and allow for growth for many years, including serving as a foundational platform for IT enhancements for customer service and accounting.

VI. CONCLUSION

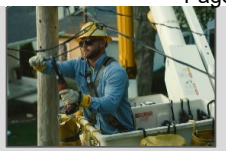
Q. In your opinion, is the implementation of the WAM program reasonable and necessary?

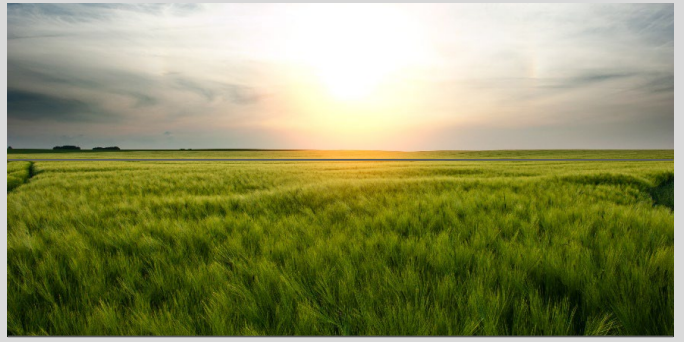
A. Yes, and the costs set forth by Company witness Bly are reasonably necessary to complete the work on the WAM program. In my opinion, the decision to replace NiSource's existing information technology systems is not only prudent but also absolutely necessary. NiSource's current information technology systems are at or near the end of their useful lives and must be replaced. NiSource has taken a holistic look at the software needs of the entire company and built a solution that will meet the customer service, safety, and network reliability needs of all customers, including the customers of Columbia, now and in the future. The WAM program component of the IT transformation involves the implementation of robust, integrated software platforms and represents a unique capital project both in scope and complexity. As indicated above, the costs of the WAM program are reasonable, and the WAM program team will carefully manage the costs of the WAM program to provide its customers and other stakeholders with the greatest value at a reasonable cost.

Q. Does this complete your Prepared Direct Testimony?

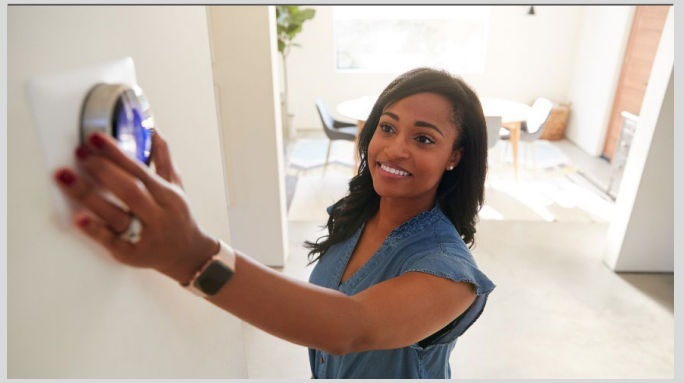
A. Yes, it does.







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



Transformation Roadmap Overview

Melody Birmingham
EVP & Chief Innovation Officer





WHY CHANGE? | CRITICAL NEED FOR STRATEGIC IT INVESTMENT

Current State – at risk and unstable

NiSource's approach to maintaining and repairing its core systems over the last approximately 20 years resulted in limited investment in new technology.

End of Life IT Systems
Non-Standard Processes; IT systems at risk of failure

↑ Costs ↑ Risk ↑ Complexity
↑ Cyber Vulnerability ↓ Business Value ↓ Skill Depth

- Complex and costly to support and introduce new capabilities/investments
- Disparate and manual work practices prone to human error and "waste"
- Significant risk in operating the business (Operational, Reputational, Regulatory, System, Customer, Cyber)
- Data unable to be leveraged to optimize decision making
- Significantly underperforming IT industry benchmarks (high cost with poor performance)
- Unable to recruit and retain modern workforce
- Propagates multiple, non-productive, sub-cultures

Future State – modern and reliable



By shifting our investment into core system replacements over the next 5+ years, NiSource's future state architecture will be greatly simplified leading to standard processes and secure and reliable systems

Modernized IT Systems
Standardized processes; Stable, reliable and secure IT systems

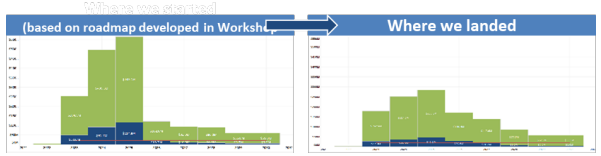
↓ Costs ↓ Risk ↓ Complexity
↓ Cyber Vulnerability ↑ Business Value ↑ Skill Depth

- New platforms allow efficient workflow reducing waste
- Significantly reduced risk in operating the business (Operational, Reputational, Regulatory, System, Customer, Cyber)
- Increased visibility into data to drive risk-informed decisions
- Positions NiSource for future strategic investments and to achieve aspirational goals
- Meeting or exceeding IT industry benchmarks (lower cost with high performance)
- Competitively recruit modern workforce
- ONE NiSource culture

ROADMAP PRIORITIZATION AND SEQUENCING

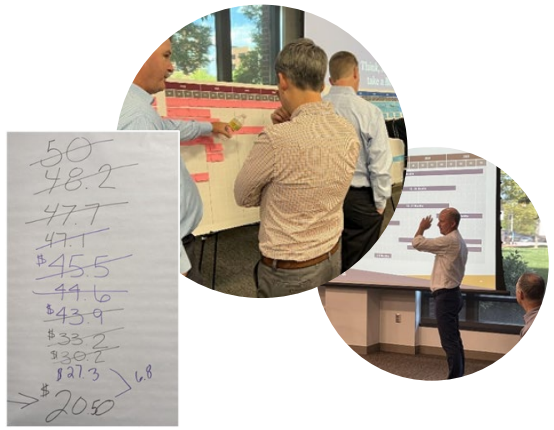
Utilizing evolving industry trends, NiSource's aspirational commitments, known system dependencies, risks, and financial constraints, the cross-functional working team prioritized and sequenced strategic initiatives.











STAKEHOLDER ENGAGEMENT AND COMMUNICATION

Stakeholders from across NiSource were engaged to create and refine the 5-Year IT Strategy. Once completed, a frontline employee roadshow was conducted to gain detailed feedback to be used throughout execution of the 5-Year Strategy.

1

User-Centric Strategy

Output: Vision for the IT 5-Year Strategy

Workshop with key executive stakeholders across NiSource to define vision and user-centric strategy

2

Vision and Strategy

Output: Consolidated roadmap that ties back to the vision

Workshop with key executive stakeholders across NiSource to develop strategy to achieve vision

3

Budget and Strategy

Output: Updated strategy based on budget and resource constraints

Workshop with Finance and Accounting to finetune strategy against budgeting and staffing

4

Execution Plan

Output: Alignment and plan for execution

Workshop with key executive stakeholders across NiSource to plan for execution using our Vision and Mission (change impact incorporated).

5

Frontline Socialization

Output: Feedback for execution

Workshop with Finance and Accounting to finetune strategy against budgeting and staffing

6

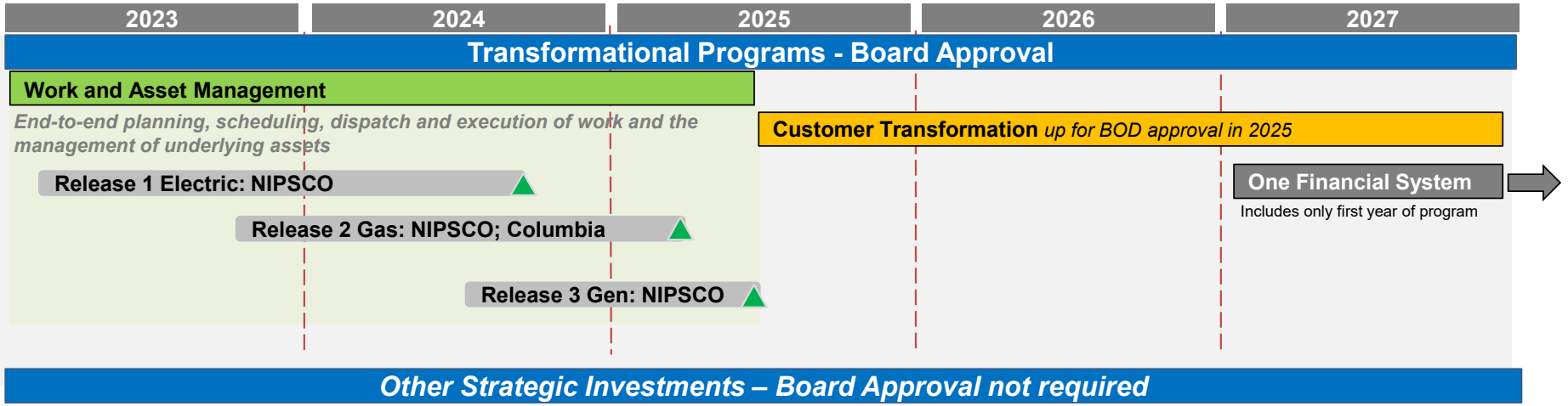
Broad Socialization

Output: Awareness

Broad communications to leaders and employees across NiSource will begin in January. The goal is to create awareness across NiSource of the 5-Year IT Strategy, capabilities to be delivered and when they will be delivered.

IT 5-YEAR STRATEGY

By shifting our investment into core system replacements over the next 5+ years, NiSource's future state architecture will be greatly simplified leading to standard processes and secure and reliable systems for our employees and our customers.



Utilities

Field Mobility ('23-'25)
One GIS ('23-'24)
Planning and Analytics Tool ('25)

Corporate/Customer

***IVR Refinement ('24-'25)**
HR (multiple initiatives) ('23-'25)

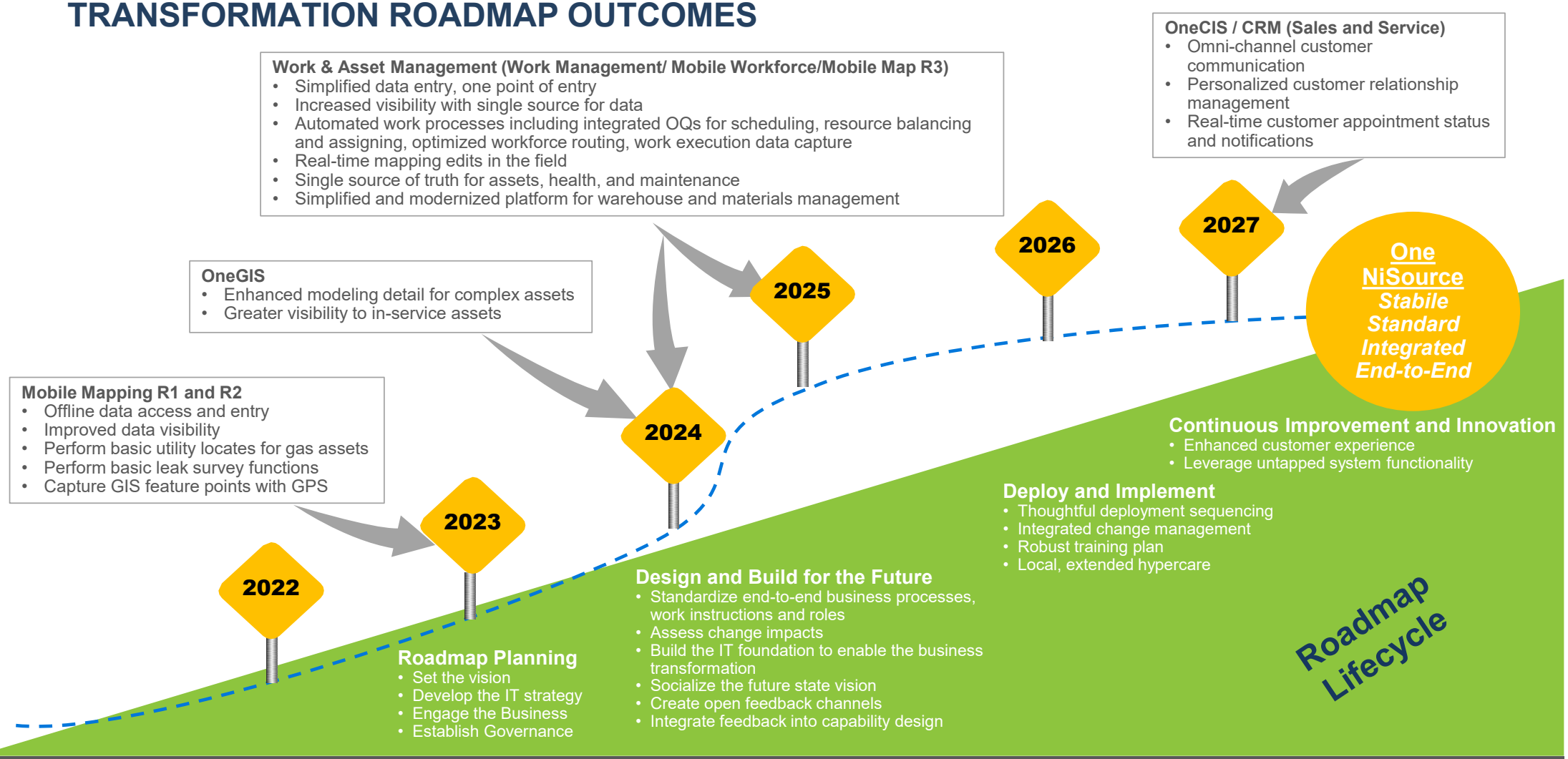
Cyber/Technology

Gas and Electric AMI Tech Enablement ('23-'25+)
Move to Cloud (multiple initiatives) ('23-'25+)
Cyber Security (multiple initiatives) ('23-'25+)

Legend: Impacted Areas Utilities | Customer | Finance/Corporate | Release

*IVR Refinement timeframe are estimates, current project is pending approval

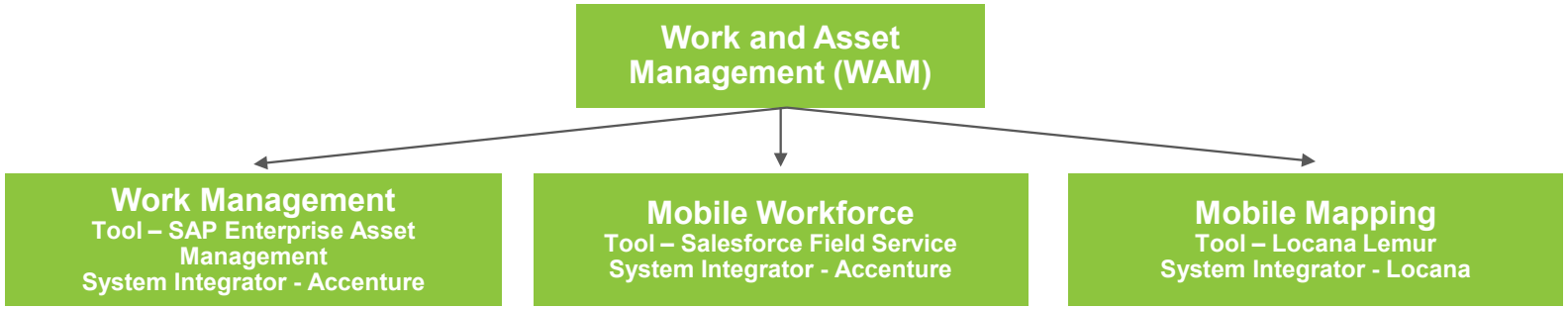
TRANSFORMATION ROADMAP OUTCOMES



READY FOR LAUNCH | WORK AND ASSET MANAGEMENT PROGRAM

Work and Asset Management is prioritized for investment based on the level of risk to support existing systems and the opportunity to impact a large employee population in driving efficiencies and eliminating waste across the work management, engineering, and field operation functions.

One Program with Three Integrated Projects



Overview

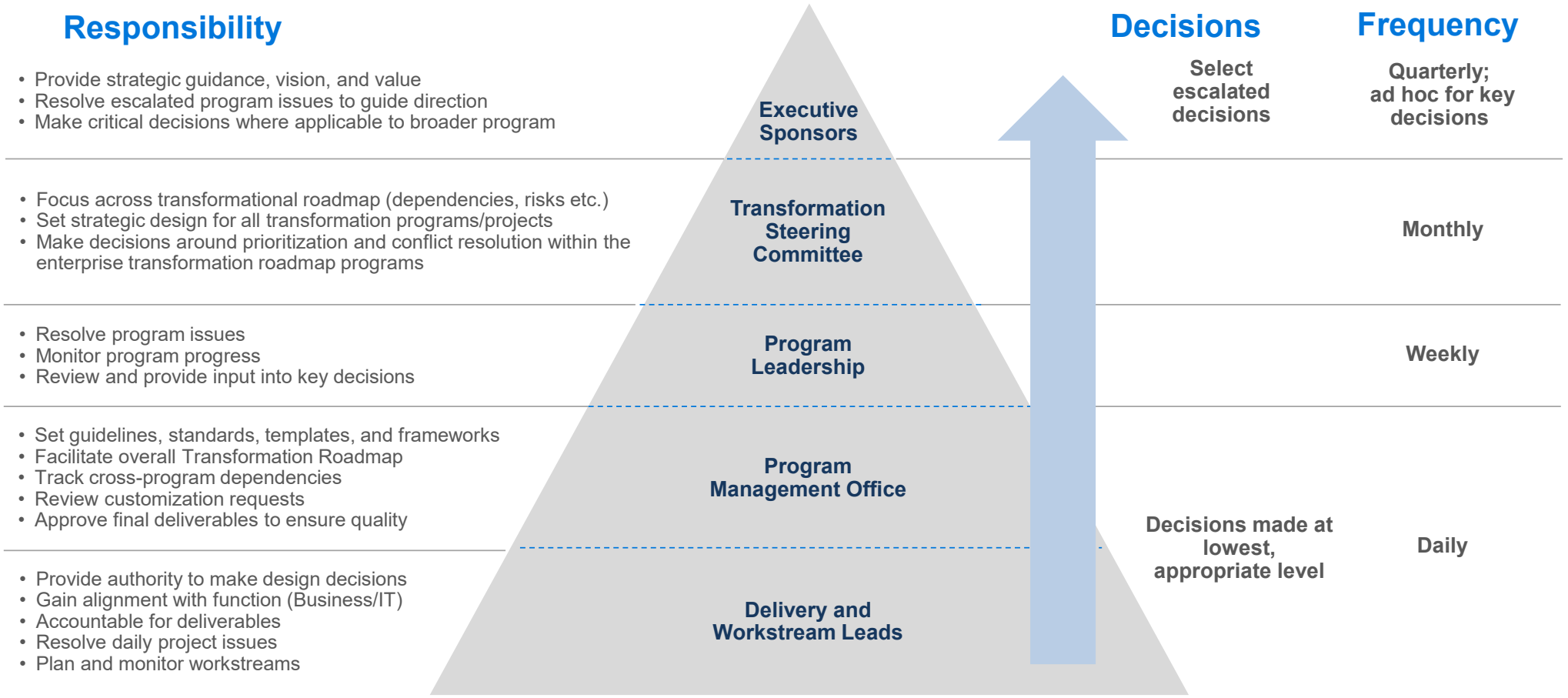
Implementation of industry leading processes supported by best-in-class technology to manage work and assets through work planning and initiation, field scheduling and dispatch, and work execution and closeout

- *Work Management* – Work and asset planning, initiation, execution tracking, closeout and reporting
- *Mobile Workforce* - Integrated field resource planning, work scheduling, and route optimization to support efficient work execution
- *Mobile Mapping* - Geographic Information System (GIS) mapping functionality on mobile devices for improved asset data capture and as-builts in the field

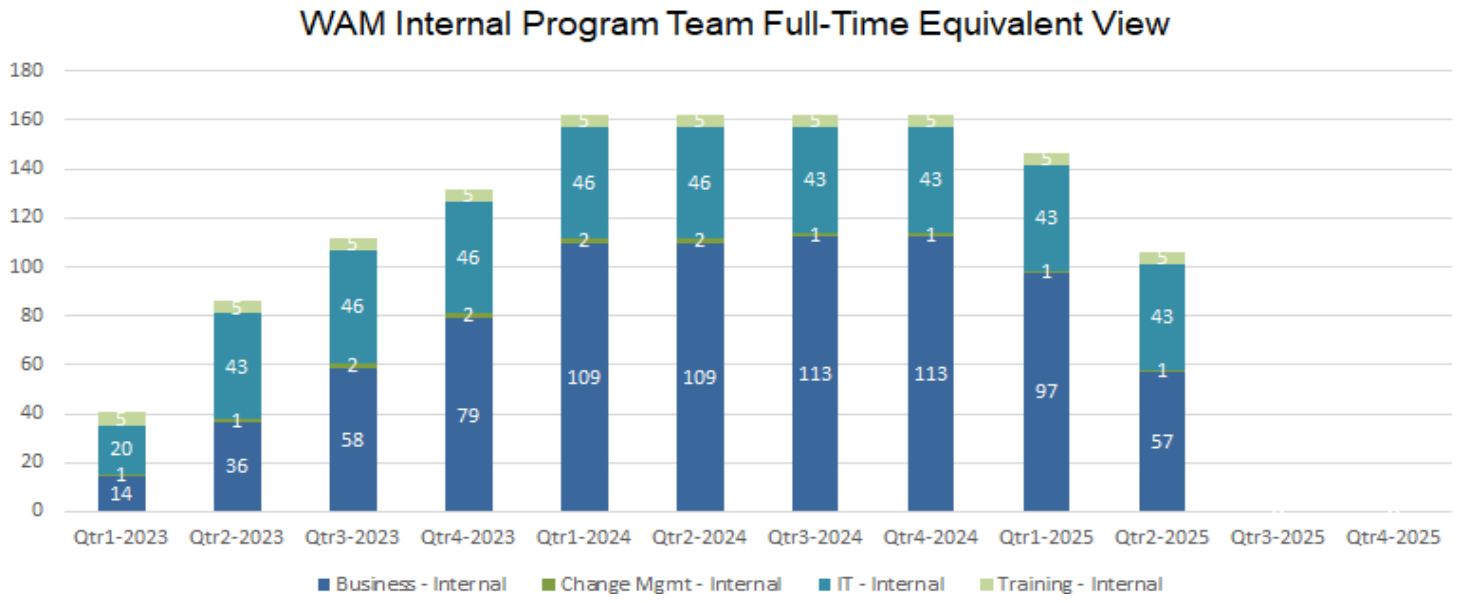
Benefits

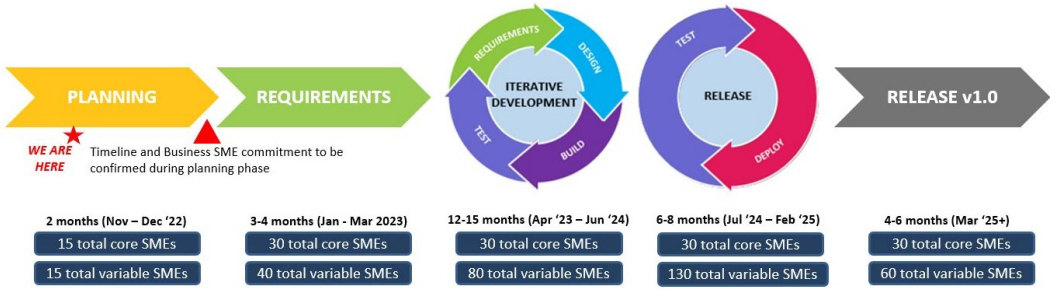
1. Standardization of end-to-end Work and Asset Management processes supported by a new integrated solution including Work Management (SAP Enterprise Asset Management), Mobile Workforce (Salesforce Field Service), and Mobile Mapping (Lemur)
2. Utilization of compatible unit estimating to standardize designs, materials, and tools required
3. Incorporation of Operator Qualifications in work scheduling and assignment
4. Time savings through automation to support the scheduling, assigning, routing of work, and as-built records closeout
5. Modern data capture solution enabled by dynamic smart forms as a part of Mobile Workforce
6. Improved data quality through the ability to view and update asset data and data records on maps
7. Improved reporting and data availability across common platforms

TRANSFORMATION ROADMAP GOVERNANCE



INTERNAL RESOURCE PLAN VIEW





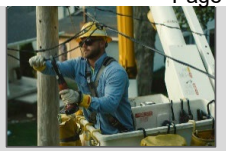
Resource Planning

- Team structures, project plans, and final resource plans are in progress for a February project launch
- External Resource Plans (not displayed) include an additional ~200-250 onshore and offshore IT System Integrators, IT Service Providers, Change Management, Communications, and Training resources to support the program

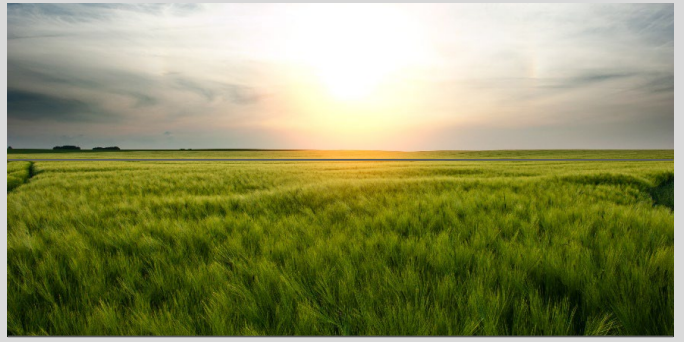
PROGRAM RISK MITIGATION

Key Areas for Risk		Mitigation Strategies
Change Management	Underestimating the magnitude of cultural change	• Align the organization's leaders early around a clear outcome • Engage frequently with employees to share progress and collect feedback • Maintain the leadership capability and discipline to facilitate changes in the organization
Resources & Skillsets	Dedicating the right internal and external talent to the program	• Assign dedicated resources to the program with clear delivery roles and responsibilities • Develop a comprehensive resource plan and approach for capacity management • Source and upskill resources that bring leadership with a transformation mindset
Process Standardization	Driving process standardization across multiple regulated entities	• Apply industry best practices, partner experience and solution capability designs • Establish clear direction that differences than can be standardized will be standardized • Formalize process to review and approve any deviations from standard processes
Governance & Integration	Ensuring program objectives are met and risks are managed	• Established governance functions to facilitate decision making, risk management and key program delivery objectives – resource management, scope, budget, and timeline • Provide alignment on key interdependencies with other programs and business priorities



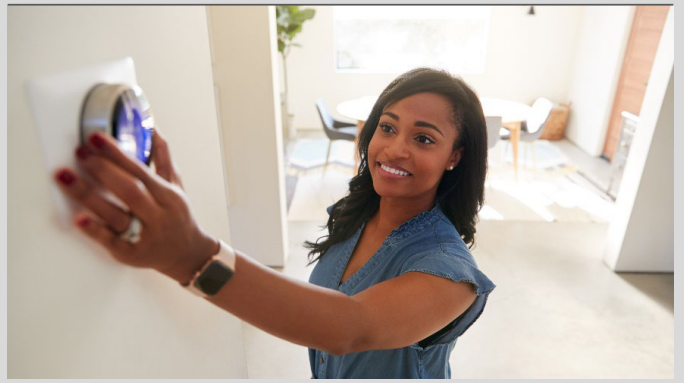


NiSource®



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

Appendix







Program Leadership Structure

NiSource Decision Makers	Supporting Partners
NiSource	*Partners*

Executive Sponsors
NiSource

Transformation Steering Committee (ELT Delegates)
NiSource, *Partners*

Program Leadership - IT	Program Leadership - Business	Program Leadership - Business Integration & Org Readiness
NiSource, *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*

EPMO	IT PMO
NiSource, *Partners*	**NiSource,** *Partners*

Delivery Leads	Data Lead	Change Management Lead	Communications Lead	Training Lead	HR Lead
NiSource, *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*

Workstream Leads Workstream	Workstream Leads Workstream	Workstream Leads Workstream	Workstream Leads Workstream	Workstream Leads Workstream	Workstream Leads Workstream	Workstream Leads Workstream
NiSource, *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*	**NiSource,** *Partners*

91% of the utilities companies in the Forbes Global 2000 are SAP customers

Americas





Europe, Middle East, Africa





Asia-Pacific





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Examples of large utilities serving 5+ million contracts

COLUMBIA STATEMENT NO. 17-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
GEORGE DICE
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

I. Introduction

Q. Please state your name and business address.

A. George Dice, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC") as Vice President, Customer Care Centers.

Q. Have you previously filed testimony in this matter?

A. No.

Q. Have you testified before this or any other Commission?

A. Yes, I have testified on behalf of Columbia Gas of Ohio in Case No. 21-637-GA-AIR before the Public Utilities Commission of Ohio.

Q. Please briefly summarize your professional experience.

A. I began my employment with NCSC is 2008. From the beginning of my career with NCSC, I have led and supported NiSource's Customer Care Center organization. Prior to my promotion in September of 2019 to Vice President, Customer Care Centers, I served as Operations Support Director for NiSource from 2008 to 2019. From 1998 to 2008, I was Manager of Care Center Operations for outsourced customer experience technology and service companies.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony served in this proceeding submitted by Nicolas DeMarco of the Office of Consumer Advocate ("OCA"), and James Crist of Lumen Group, LLC on behalf of Penn State University ("PSU").

Q. What issues will you address related to Mr. DeMarco's testimony?

A. I will address Mr. DeMarco's assessment of Columbia's Call Center performance, and his recommendations for more oversight of third party vendors. I will also address his recommendation to remove customer social security numbers ("SSN") from account records following the completion of an initial credit check.

Q. What issues will you address related to Mr. Crist's testimony?

A. I will address Mr. Crist's assessment of the account issues experienced by PSU, his recommendations on providing communication to existing customers regarding requests received to start, stop, or transfer gas services, as well as his recommendation to add two-factor authentication to prevent similar account issues from occurring in the future.

Q. Do you agree with Mr. DeMarco's assertion on page 5 of his direct testimony that it is too early to determine whether the solutions that Columbia implemented to improve its call center performance will be successful and if not, why?

A. I disagree with Mr. DeMarco's statement. Data regarding the solutions created and implemented in 2023, as described by Columbia witness Mark Kempic (Columbia

Statement No. 1), demonstrates an improvement in the percentage of calls answered within 30 seconds and improved call abandonment rates.

Q. What are the percentages of calls answered within 30 seconds and call abandonment rates from January through May 2024?

A. Please see the table below for the requested data.

% of calls answered in 30 seconds	January	February	March	April	May
OVERALL	84.05%	83.21%	82.38%	80.60%	85.47%

Call Abandonment Rate	January	February	March	April	May
OVERALL	2.38%	1.90%	2.15%	2.79%	2.08%

These data points demonstrate that the measures Columbia implemented in 2023 are succeeding. Whereas the Company's rate of calls answered within 30 seconds was 72.93% in 2023 and 74% in 2022 and 2021, the rate during 2024 exceeds 80%. And, whereas Columbia's call abandonment rates in 2023, 2022, and 2021 were 6.93%, 7.46%, and 7%, respectively, the aggregate rate during 2024 is only 2.26%.

Q. What is the projection for the percentage of calls answered within 30 seconds and call abandonment rates for year-end 2024?

A. The 2024 year-end performance for percentage of calls answered within 30 seconds is currently projected to be 82% and the call abandonment rate is projected to be 3.5% for the same time period.

Q. Does Columbia have a response to Mr. DeMarco's recommendation that Columbia should have direct line of sight into the performance of third-party payment agents (OCA St. 7, p. 8)?

A. As mentioned in Columbia's response to OCA-7-009 (attached hereto as Exhibit GD-R-1), to which Mr. DeMarco refers, the third-party payment vendor handles Columbia's automated customer payment calls via Interactive Voice Response ("IVR"). Columbia will evaluate the efficacy and costs associated with additional quality assurance monitoring and oversight of third-party payment vendors performance for this purpose in future contract amendments.

Q. Does Columbia currently use third-party vendors to augment its Customer Call Center ("CCC") staff?

A. No. As Mr. DeMarco noted, Columbia's response to OCA 15-001 (attached hereto as Exhibit GD-R-2) indicated that Columbia temporarily used two third-party contractors to augment its staff. (OCA St. 7, p. 7). Columbia is no longer retaining the services of those third-party contractors.

Q. Will Columbia use a third-party vendor again in the future to augment CCC staff and, if so, will the Company include a detailed and comprehensive plan to oversee the vendor's performance?

A. If Columbia uses a third-party vendor for call center staff augmentation or for other call center related services in the future, a detailed and comprehensive plan would

be included within the contract terms to manage and oversee the vendor's performance and compliance with applicable laws and regulations.

Q. Do you agree with Mr. DeMarco's recommendations that Columbia cease its practice of retaining SSNs in its system after a credit check is conducted and if not, why?

A. No. Columbia must comply with the Red Flag Rule, which is a Federal Trade Commission regulation that requires the Company to create a process to identify and prevent identity theft. In our established process, we must obtain a valid SSN to identify and prevent identity theft. We retain the SSN in our customer information system; however, Columbia redacts the customer's full SSN from its customer information database so that users who do not have the security access level required to complete specific transactions cannot access a customer's full SSN. Additionally, the SSN number is used to assist in identifying customers with bad debt, which allows for the appropriate transfer of debt or collections and helps the Company manage arrears and overall uncollectable debt.

Q. On pages 8 to 10 of his direct testimony, Mr. DeMarco discusses Columbia's UCARE Report Statistics and refers to the Company's report root cause analysis performed to find the cause of customer complaints since 2021. Can you describe the Company's actions taken in response to its UCARE report root cause analysis?

A. Customer Care Center leaders, the Manager of Regulatory Compliance, and the Manager of Universal Services conduct monthly meetings to review any concerns, including errors with denials of credit. In addition to ensuring all coaching opportunities are addressed, the following actions have been taken as a result of those meetings:

Call Aid updates: The Denial form was updated to document the appropriate account in the Company's customer information system automatically. The Senior Guide was updated to provide a check list for reference to ensure denials have all the appropriate information. Reminders were issued to CSRs to obtain and document the financial information and include the appropriate ID requirement when a verify ID indicator is provided by the customer information system.

Training updates: A Disputes and Denials Refresher quiz was created. A minimum score of 80% is required to pass. Any agent below that percentage is coached and then retakes the course. Real Time Analysts monitor pending denials closely with Team Leaders to ensure denials are reviewed and sent within 3 business days.

Q. Do you agree with Mr. Crist's description of the account management issues that were experienced at Penn State?

A. I disagree with Mr. Crist's description that identity theft occurred through Columbia's systems or processes. In the PSU account situation, a third party transferred a PSU account into their name, an external action that did not originate from Columbia's systems or processes. In addition, PSU did not contact Columbia

after receiving the final bill notice which was delivered shortly after service was transferred in December 2023, or when a monthly bill was not received for three consecutive months prior to termination in April 2024. At the time of termination in April, Columbia left a copy of the termination notice at the property itself.

Q. Do you agree with Mr. Crist's recommendation of sending an email to an existing account holder, when Columbia has an email address for a customer, whenever a start, stop, or transfer of gas service at the service address is requested, at least forty-eight (48) hours prior to the change taking effect (PSU St. No. 1, p. 22)?

A. I would first note that it has been a long-standing practice of Columbia and the utility industry in general to "force disconnect" an existing customer when a new applicant seeks to connect gas service in their name and the new applicant provides all of the required information to enable the company to run a credit check on them and establish service in their name. In this case, the applicant provided valid information which passed a third party credit check as described in more detail below. Having said that, Columbia will consider initiating an email to the existing customer, if an email address is available, upon request to start, or transfer the gas services of an active gas account into another name. Columbia will also evaluate the feasibility of initiating a change to the final bill by making the "final bill" notification more prominent on the bill or whether it is feasible to create a letter notification that would be emailed or mailed to the existing customer when a transfer of service

occurs. However, the Company does not believe it is appropriate to require the existing customer to affirmatively sign off on the transfer of service to the new applicant since an existing customer could simply ignore the request and delay transfer of service.

Q. Do you agree with Mr. Crist's recommendations to add two-factor authentication to prevent similar account transfers from occurring in the future?

A. No. Having two-factor authentication and limitations on making changes online would not have prevented the transfer of the PSU account from occurring. In response to PSU 4-001 (Attached as Exhibit GD-R-3), Columbia describes the mandatory requirements to establish service in a new name. These mandatory requirements include: First/Last Name, SSN, and date of birth. Once the required information is provided by the applicant, the company performs the Identify and Credit Check via real time through an Equifax interface, which requires a minimum of two data points to match, including SSN. If at least two data points match and the SSN is valid, the gas service account would be established for the applicant as the new customer at that location and service would be transferred from the existing customer. In PSU's situation, the "applicant" provided all of the mandatory information, and that information passed the Equifax Identification and Credit Check validation, so the account was established in the new customer's name and new mailing address.

It is important to note that the gas service account is established in the new customer's name prior to the creation of a website log in and password, which is where two factor authentication would even come into play, so two factor authentication would not have prevented the account from being force disconnected out of PSU's name.

The Identity and Credit Check process is the same for applicants who call the call center to transfer service to their name, so two factor authentication would not have prevented this from occurring in that situation either. Because no access to the current account-holder's information or account is required to transfer service to a new customer, a two-factor identification process is not necessary because it would not have prevented service from being transferred to the applicant's name and billing address.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

OFFICE OF CONSUMER ADVOCATE INTERROGATORIES
Set 7

Question No. OCA 7-009:

If the Columbia Gas of Pennsylvania relies on third-party contractors for interactions with Columbia Gas of Pennsylvania customers, such as but not limited to customer service or collections, please provide any reports, documents, or other internal materials that reflect the results of the quality assurance process conducted by the third-party relating to adherence to Pennsylvania specific customer service, consumer protection, and service quality policies and regulations created since January 1, 2022.

Response:

Paymentus, the third-party contractor handling Columbia Gas automated customer payment, calls via IVR, does conduct quality assurance, and checks on their Call Center agents; however, the results of those checks are not shared with Columbia Gas of Pennsylvania.

In relation to third-party collection contractors in Pennsylvania, there have been no new changes in processes since January 1, 2022. From April 2022 to August 2022 (partial collection season), monthly reports (see sample report attached as OCA 7 – 009 Attachment A (Contractor performance)) were reviewed by the Columbia Gas of Pennsylvania Collections Leader to include spot checks of accounts and regular check-ins by phone with the contractor manager to assure that all regulatory and contractual expectations were followed.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

OFFICE OF CONSUMER ADVOCATE INTERROGATORIES
Set 15

Question No. OCA 15-001:

If Columbia Gas of Pennsylvania (Columbia) relies on third-party contractors for interactions with Columbia customers, such as but not limited to customer service or collections, please provide any reports, documents, or other internal materials that reflect the results of the quality assurance process conducted by Columbia relating to the third-party contractors' adherence to Pennsylvania specific customer service, consumer protection, and service quality policies and regulations created since January 1, 2022.

This is a continuing data request during the pendency of this proceeding.

> (Per prior agreement, the OCA agrees to limit the above questions to where interactions with customers is intended to be a routine part of the job and not where it is incidental. The OCA is looking for third party contractors for the call center and any field personnel who do the collections at premises/disconnections where personal contract is required to be attempted.)

Response:

> Due to the temporary nature of the Agile One and LJ Ross staff augmentation resources during the first quarter of 2024, the inbound calls that were answered by their agents were monitored and coached by the interim Columbia team leader ensuring Columbia's call scripting and requirements were followed – just as though they were Columbia employees. Please see attachment CONFIDENTIAL

OCA 15-001 Attachment B for the coaching log. In addition, the agents were part of a daily Microsoft Teams chat with a Columbia team leader during their work hours where questions could be asked and answered in real time to ensure the agents were supported during customer calls.

Paymentus interactions with Columbia customers do not include any information outside of customer account number, payment amount, and payment method. Paymentus is level 1 PCI compliant, and Columbia requires confirmation of continued compliance from Paymentus annually. See OCA 15-001 Attachment A.

Please reference OCA 7-008 subpart a, regarding collections at premises/disconnection.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 4

Question No. PSU 4-001:

Please describe the process applicants use to initiate gas service at a property address. Provide all written procedures and manuals.

Response:

Upon request from an applicant, the Customer Care Center representative will follow our Call Aid process to initiate gas service at a property address, see OCA – 7 – 022 Attachment C CONFIDENTIAL. Applicants can also establish service using our website.

Experience on web:

Our web self-service tool to offer customers the ability to Start, Stop or Move their billing service is fully automated. The customer-facing start/stop/move application is hosted as by a third party, Smart Energy Water (SEW), and this application connects with multiple NiSource IT systems and processes including our billing system (DIS Mainframe) and Equifax, to complete an identify check. The start/stop/move process flow is set up in a multi-screen format to make it user-friendly.

On the website (www.columbiagaspa.com/start), this is the customer experience:

1) Step 1 – User locates the property where they are starting service in their name via an address search for services within our service territory. The user also enters their mailing address and what service they are selecting (gas).
2) Step 2 – User enters personal account information, including:
    a. First/Last Name (Mandatory)
    b. Social Security Number (Mandatory)
    c. Date of Birth (Mandatory)
    d. Phone Number
    e. Email Address
    f. Emergency Contact Name (Optional)

g. Emergency Contact Phone Number (Optional)
h. Authorized User (Optional)
i. Moving From Address (Optional)
j. Do you rent or own your home? (Rent/Own)
k. Will the gas service be used for residential purpose only? (Yes/No)
l. Will you be occupying the property and placing service in your name? (Yes/No)

Once this information is entered, the customer agrees to undergo an identity/credit check via a real-time Equifax interface. The Equifax identity/credit check requires a minimum of two data points to match, including the SSN. Since SSN is currently mandatory. If the customer matches the Name or Prior Mailing Address in addition to the SSN, then Equifax will execute the match and return the pass/fail ID check.
If Equifax rejects the check, the user cannot continue to Step 3.

3) Step 3 – If a security deposit is required, user agrees to a deposit amount.
Note: A security deposit screen will display only if a security deposit is required.
If a customer's identity was NOT established, this will translate to a company-specific error message, "We're Sorry. We're unable to complete your online request at this time. Please contact us at 1-888-460-4332 and we will be happy to assist you further."

4) Step 4 – User selects Start Service Date
   a. After selecting a start date, a Review screen is presented (start service address, start service date, deposit details if applicable, mailing address, account holder information, terms & conditions), and the user selects next/confirm button to proceed to the next step.
5) Step 5 – User reviews information and submits order.

Experience on Columbia Gas Mobile App:
Our Mobile App self-service tool to start/stop/move billing service is fully automated. The customer-facing start/stop/move application is hosted by a third party, Smart Energy Water (SEW), and this application connects with multiple NiSource IT systems and processes, including our billing system (DIS Mainframe), and Equifax to complete an identify check. The start/stop/move process flow is in a multi-screen format, making it user-friendly and mirrors the same experience as the website. To either start, stop or move, the user can select "Start, Stop, and Move" from the Homepage shortcut tile menu, or log in to the mobile app with an account and select "Service" in the bottom navigation. The address of the user will display on the top left of the app. The user will need to select Start, Stop or Move to proceed to the next step.

User selects START:

1) Step 1 – User locates the property where they are starting service in their name via an address search for services within our service territory. The user also enters their mailing address and what service they are selecting (gas).
2) Step 2 – User selects the intended address and answers the following questions before selecting Next. The user is required to complete the form on Step 2 in order to proceed to the next screen. The user enters personal account information, including:
    a. First/Last Name (Mandatory)
    b. Social Security Number (Mandatory)
    c. Date of Birth (Mandatory)
    d. Phone Number
    e. Email Address
    f. Emergency Contact Name (Optional)
    g. Emergency Contact Phone Number (Optional)
    h. Authorized User (Optional)
    i. Moving From Address (Optional)
    j. Do you rent or own your home? (Rent/Own)
    k. Will the gas service be used for residential purpose only? (Yes/No)
    l. Will you be occupying the property and placing service in your name? (Yes/No)

    Once this information is entered, the customer agrees to undergo an identity/credit check via a real-time Equifax interface. The Equifax identity/credit check requires a minimum of two data points to match, including the SSN. Since SSN is currently mandatory, if the customer matches the Name or Prior Mailing Address in addition to the SSN, then Equifax will execute the match and return the pass/fail ID check. If Equifax rejects the check, the user cannot continue to Step 3.
3) Step 3 – If a security deposit is required, the user agrees to a deposit amount. Note: A security deposit screen will display only if a security deposit is required. If a customer's identity was NOT established, this will translate to a company-specific error message, "We're Sorry. We're unable to complete your online request at this time. Please contact us at 1-888-460-4332 and we will be happy to assist you further."

4) Step 4 – User selects Start Service Date.
After selecting a start date, a Review screen is presented (start service address, start service date, deposit details if applicable, mailing address, account holder information, terms & conditions), and the user selects next/confirm button to proceed to the next step.

5) Step 5 – If customer needs to make an up-front payment, a Deposit Payment screen is presented.
    a. User can select amount to pay, choose or add payment method. (If they choose “add a payment method”, the user will go through the add a payment process.) Then the user can make a payment.
    b. If successful and the user chooses to proceed, a confirmation screen will display.

Experience on IVR: The IVR does not offer the function to start gas service. In the IVR, customers that call in and select the option to start gas service are routed out of the IVR to reach a customer service representative.

COLUMBIA STATEMENT NO. 18-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
DEBORAH DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

Introduction

Q. Please state your name and business address.

A. My name is Deborah Davis. My business address is 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as the Manager of Universal Services.

Q. Have you previously filed testimony in this matter?

A. No.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony served in this proceeding related to Universal Service Programs provided by Mr. Roger Colton on behalf of the Office of Consumer Advocate ("OCA"), and Ms. Jennifer Warabak on behalf of the Pennsylvania Weatherization Providers Task Force ("PWPTF").

Q. What issues will you address related to Mr. Colton's testimony?

A. I will address Mr. Colton's recommendations to add a new definition for "Confirmed Low-Income customer" to the Company's tariff, to add language under "Special Provisions" of the Company's tariff and to make personal contact with Confirmed Low-Income customers prior to disconnection for nonpayment. I will also address the additional notifications Mr. Colton is recommending that the Company make to Confirmed Low-Income customers. I will address additional tariff changes Mr. Colton is recommending and issues Mr. Colton raises regarding security deposits.

Finally, I will address Mr. Colton's recommendation to use speech analytics to identify potential Customer Assistance Program ("CAP") enrollees.

Q. Please explain your understanding of Mr. Colton's testimony as it relates to defining "Confirmed Low-Income customer."

A. On pages 38 through 39 of his direct testimony, Mr. Colton suggests that existing regulations imply that a utility should not require total household income to establish a customer as "Confirmed Low-Income." Instead, Mr. Colton claims that a verbal acknowledgement that a customer receives SNAP, TANF, free school lunches, or SSI is sufficient to categorize a household as "Confirmed Low- Income".

Q. Do you agree with Mr. Colton's interpretation of the definition of "Confirmed Low-Income customer"?

A. No. I disagree for several reasons. First, Mr. Colton relies exclusively on the definition of "Confirmed Low-Income Residential Account" in the Commission's USECP reporting requirements regulations (52 Pa. Code § 62.2) in making his recommendation. Yet, the language in other Commission regulations explicitly identifies "household income" as the way to determine a customer's low-income status. For example, 52 Pa. Code § 56.41(4) provides, "A customer is confirmed to be eligible for a customer assistance program by the public utility when the customer provides income documents or other information that he or she is eligible for state benefits based upon household income eligibility requirements that are consistent with those of the public utility's customer assistance programs." In addition, "household income" is defined as "The combined gross income of all adults in a residential household who benefit from the public utility service." 52

Pa. Code § 56.2. The Company complies with existing regulations by attempting to obtain the total household income, rather than relying on a single income source as suggested by Mr. Colton.

Second, Mr. Colton states on page 52 of his direct testimony "The remedy for unpaid bills by low-income customers is not to place those customers on a deferred payment arrangement, but rather to enroll those customers in CAP (with its arrearage forgiveness provisions)." If the goal is for a low-income customer to enter and receive CAP benefits, total household income is required. Without total household income, the percent of income option would not be an available option and the Company would not be complying with its USECP. Reporting total household income is equally as straightforward as reporting type of income source. Another concern is that the other programs mentioned may not have the same income guidelines as CAP or may not require proof of income. Furthermore, it should not be assumed that a (1) person household receiving SSI is at or below 150% of the federal poverty level. The individual could also be receiving a pension that is considered reportable income and factored in when determining total household income. Total household income is the only way to ensure a household is within the guidelines of the program.

Q. How does the Company currently define "confirmed low-income"?

A. When a customer contacts the Company for a payment arrangement, a delay of disconnection or other relevant reasons, the Company obtains financial information that includes household composition and total monthly income. All customers who identify as at or below 150% of the federal poverty level ("FPL") are

considered confirmed low-income. In addition, a customer who has not contacted the Company to offer household financial information but receives LIHEAP is also considered confirmed low-income since their income was validated by the Pennsylvania Department of Human Services.

Q. What is the Company's position on changing the definition of confirmed low-income?

A. Through its USECP proceeding at Docket No. M–2023–3039487, the Company was recently directed to work with its Universal Service Advisory Council ("USAC") to identify opportunities to improve low–income customer count accuracy. Order at paragraph 6(g) (April 4, 2024). Changing the definition in the manner suggested by Mr. Colton would reduce the accuracy of the Company's current practices and infringe on the process already begun with Columbia's USAC. The Company will continue to work with its USAC as directed by the Commission. The Company should follow the Commission's directive in its USECP order and refrain from making any changes without input from all USAC members.

Q. Do you agree with Mr. Colton's recommendation, on pages 39 through 40 of his direct testimony, that language should be added to each of Columbia's residential tariffs that "A confirmed low-income residential account, including applicants, will be afforded each protection accorded by tariff or regulation, which tariff or regulation applies to any customer or applicant with household income at or below 150% of the Federal Poverty Level"?

A. No. This language suggests the customer would not have a choice on whether to join CAP, a payment plan or a budget. The Company does not agree that forcing, or even choosing a customer's option for them, is appropriate. The Company strives to ensure customers are aware of their options, understand the benefits of each option, and are provided an easy way to choose and enroll in the desired option. The Company does not support choosing an option for a customer or forcing a customer into any option at all.

Additionally, this proposed language is misleading in that Mr. Colton states it would only apply to customers or applicants with household income at or below 150% of the FPL. Yet, Mr. Colton's definition of "Confirmed Low-Income customer" may include customers with higher incomes by allowing customers to verify income without providing total household income.

Q. What issue raised by Mr. Colton will you address next?

A. I will address Mr. Colton's recommendations regarding non-payment disconnections of low-income customers.

Q. Please address Mr. Colton's assertions on page 42 of his direct testimony that Columbia's Universal Service programs are not entirely successful in helping low-income customers maintain gas service.

A. The Company recognizes the value of its Universal Service programs to help low-income customers maintain gas service and reduce arrears. Significant effort is taken to educate customers on available programs. Household financial information is updated when a customer contacts the Company for a payment arrangement. All customers found eligible for programs are provided program

details and methods to apply for benefits. Mr. Colton's assumption that all customers will join CAP if they are made aware of the program is not accurate. There are reasons customers at or below 150% of the FPL choose to not join CAP.

Q. Can you elaborate on the reasons a confirmed low-income customer may not join CAP?

A. Yes. The Company explains all options to a customer when they call for assistance. Even when a referral is made to CAP, they are still offered a payment plan, as required. This stops all collection activity, at a minimum, until after the first payment is due. It is the Company's experience that once a customer learns they are safe from disconnection for nonpayment, the immediate crisis is resolved, and the motivation to take further action for a long-term solution diminishes. Mr. Colton provides statistics on pages 49 and 50 of his direct testimony of the Company's "Successful versus Unsuccessful payment arrangements." I suspect he is defining success as payment arrangements where the balances are paid in full upon completion. However, it is the Company's experience that many customers view entering a payment arrangement and preventing disconnection as successful. Their reason for contacting the Company was to stop the disconnection of service, which was achieved. The fact that they may not be able to afford the payment when it is due is not the primary issue or the goal of that contact. There are some customers who do seek a long-term solution and fully intend to complete the CAP application process. However, after reviewing their supporting income documentation, they recognize they do not meet the income qualifications for the program, and as a result, they do not follow through.

When a CAP customer calls to make a payment arrangement after disconnection, the Company is required to offer the options of a plan on the outstanding balance or to catch up on the missed CAP payments. Most of these customers opt for the lower upfront payment of 1/24th of the outstanding balance even though it is explained that CAP is the best long-term option and assistance for the missed CAP payments can be obtained through LIHEAP, CRISIS, and/or Hardship funds. The primary goal for the customer during that call is to restore service, so the customer may choose the less costly and timely resolution. Customers can re-enroll in CAP once their missed CAP payments are paid. However, once a customer restores service utilizing the 1/24th plan option, they lose access to programs specifically intended to intervene in crisis situations.

Other reasons customers do not choose CAP include not wanting to pay higher bills in the summer months, the sense that "others deserve it more than I do," or the expectation that the situation is temporary, and they will be able to afford their full bill soon, so they do not want to sign up for a program they will not need in the future.

Q. In Mr. Colton's direct testimony on page 46, he recommends a personal contact prior to disconnection to offer the CAP program. Do you agree with this recommendation?

A. No. I think this is an unnecessary delay. A limited number of confirmed low-income customers would be facing disconnection without having heard of the CAP program. They would have had to ignore all notices up to that point and chosen not to call the Company. As stated above, every low-income customer is referred to CAP

when they contact the Company. The Company currently delays collections for two months if the customer agrees to apply for CAP, and they have not done so within the most recent twelve months. This delay provides ample time for the customer to complete the CAP application and submit all supporting documentation. The Company follows all required notices during its collection process, and this additional step would only serve to add another delay.

Q. What issue raised by Mr. Colton would you like to address next?

A. Mr. Colton has recommended several opportunities for the promotion of the CAP program. I will address each one individually.

Q. On page 47 of his direct testimony, Mr. Colton recommends that low-income customers who are negotiating a deferred payment agreement ("DPA") with the Company, as well as customers from whom the Company receives information placing them in an income tier of 0% to 150% FPL, should be provided a stand-alone written Plain English notice informing those customers of their right, in the alternative, to enroll in the Company's CAP. Has the Company attempted any additional contacts to this specific group of customers in the past?

A. Yes. In the fall of 2023, the Company attempted additional contacts to all customers on level 1 payment agreements (at or below 150% of the FPL) and shared the results with its USAC. One piece of this outreach included mailing 348 letters to customers that were on level 1 payment agreements and eligible for an expedited enrollment into CAP. When reviewing records three weeks later, only seven customers had followed up to Columbia's outreach.

Q. Does the Company intend to do any additional outreach to customers at or below 150% of the FPL?

A. Yes, the Company intends to participate in the Pennsylvania Department of Human Services data sharing agreement. As a result, the Company will be conducting additional outreach to educate customers on CAP and the streamlined process for enrollment when they receive a LIHEAP grant.

Q. Is the Company willing to work with its USAC to develop a new stand-alone Plain English notice to customers at or below 150% of the FPL when negotiating a payment arrangement?

A. The Company is willing to consider this new outreach initiative on a pilot basis with its USAC if the costs of postage will be recovered through its Universal Service Rider. Extending the outreach initiative beyond a pilot would need to be weighed against the cost to non-CAP ratepayers once the results are confirmed. It is important to note the Company is required to offer a payment plan to customers who have not recently made contact and negotiated payment arrangements. The Company cannot delay entering customers into a payment plan even though it would help motivate customers to enroll in CAP. Customers will still need to be placed on an agreement with this stand-alone piece sent separately at the same time.

Q. Please address Mr. Colton's recommendation on page 53 of his direct testimony that customers who have had service disconnected for nonpayment, and who remain disconnected at the time of the Company's Cold Weather Survey ("CWS") undertaken for the PUC, should be

provided a written, stand-alone, plain English notice of their right to enroll in the Company's CAP.

A. Currently, the Company does provide written information about programs and the availability with dates and eligibility guidelines to these customers. However, there is no stand-alone piece on CAP. The Company is willing to consider this new outreach initiative on a pilot basis with its USAC if any additional postage costs incurred will be recovered through its Universal Service Rider. Extending the outreach initiative beyond a pilot would need to be weighed against the cost to non-CAP ratepayers once the results are confirmed.

Q. Mr. Colton recommends on page 56 of his direct testimony that confirmed low-income customers achieving a minimum arrears of $300 should receive a stand-alone written Plain English notice of their right to enter into CAP along with an explanation of CAP's arrearage forgiveness benefits. Does the Company agree with this recommendation?

A. The Company is willing to consider this new outreach initiative on a pilot basis with its USAC if postage costs will be recovered through its Universal Service Rider. Extending the outreach initiative beyond a pilot would need to be weighed against the cost to non-CAP ratepayers once the results are confirmed.

Q. Mr. Colton recommends on pages 59 and 60 of his direct testimony that confirmed low-income customers receive the stand-alone written plain English notice when a security deposit is waived.

A. The Company is willing to consider this new outreach initiative on a pilot basis with its USAC if postage costs will be recovered through its Universal Service Rider. Extending the outreach initiative beyond a pilot would need to be weighed against the cost to non-CAP ratepayers once the results are confirmed.

Q. Mr. Colton discusses the use of speech analytics software in his direct testimony on pages 61 through 65. Does the Company agree with Mr. Colton's recommendation that Columbia be directed to extend any future use of speech analytics software to assist with the quality monitoring of phone calls involving, or potentially involving, universal service programs and other low-income customers? Further, would the Company ask for input from its USAC on what terms would be tracked?

A. As mentioned, the Company does not currently have speech analytics software nor does it monitor calls using speech analytics. The Company is willing to consider the ability and cost associated with using speech analytics for this purpose in a future proceeding.

Q. What other issue raised by Mr. Colton will you address?

A. Mr. Colton recommends several additional changes to the Company's tariff. I will address each individually.

Q. On page 67 of his direct testimony, Mr. Colton suggests the tariff should be revised to include his new interpretation of confirmed low income as it relates to not charging security deposits. Do you agree?

A. No. For the same reasons identified above in my rebuttal to Mr. Colton's recommendation regarding the definition of "Confirmed Low-Income customer," the

Company does not agree with waiving security deposits to customers that have not provided total household income that identifies them as at or below 150% of the FPL. The Commission's regulations related to security deposits specifically mention "household income" and outline various ways to demonstrate household income. *See* 52 Pa. Code § 56.41(4). In addition, 52 Pa. Code § 56.2 defines household income as "the combined gross income of all adults in a residential household who benefit from the public utility service." Therefore, the Company already complies with existing regulations by attempting to obtain the total household income, rather than relying on a single income source as suggested by Mr. Colton.

Q. Please address Mr. Colton's recommendation in his direct testimony on page 67 that the tariff should be revised to reflect the USECP Order directing that Columbia may apply an existing security deposit to the account balance only with the customer's informed consent.

A. The Company filed a Petition for Reconsideration of the April 4, 2024, USECP Order, regarding the manner of refunding security deposits. The Petition was granted; however, the Commission has not entered a decision on the merits of this issue. The Company does not agree that any changes should be made until that Petition is decided.

Q. Is the Company proposing any changes to the tariff language regarding security deposits?

A. Yes. Current Company policies, as outlined in this proceeding as well as in Columbia's USECP, do not match the Company's current tariff language, which states

"A Customer or Applicant who is confirmed to be eligible for the Customer Assistance Program shall not be asked to provide a cash deposit."

Q. How does the Company propose to amend the language?

A. The Company proposes to amend the language as follows: "A Customer or Applicant that self declares or provides income documentation that household income is at or below 150 % of poverty or less shall not be asked to provide a cash deposit." This tariff revision is reflected in Columbia Witness Danhires' rebuttal testimony.

Q. Does the Company currently refund security deposits to customers that are confirmed low-income?

A. Yes. The Company agreed in its 2021 rate case Docket No. R-2021-3024296 to refund security deposits of customers who are identified as confirmed low-income on a semi-annual basis. The Company began refunding security deposits to confirmed low-income customers in January 2022. Furthermore, beginning in June 2023, the Company has proactively reviewed and refunded the security deposits of confirmed low-income customers on a monthly basis. It is important to note that the Company does not charge a security deposit to customers that have established themselves as confirmed low income. However, customers' incomes do change. Once the Company is made aware a customer who was not low income has become confirmed low-income, the Company's customer service representative is instructed to refund any remaining deposit. The monthly review is a safety net to ensure no manual errors occurred.

Q. Is the Company willing to report the number of customers with waived or refunded security deposits to its USAC at each meeting?

A. Yes.

Q. Does the Company agree with Mr. Colton's recommendation on page 70 of his direct testimony to modify its tariff to include his interpretation of the definition of "Confirmed Low- Income customer"?

A. No, for reasons previously mentioned, the Company does not support changing the definition of "Confirmed Low-Income customer."

Q. Do you agree that Columbia's tariff language regarding credit scoring methodology should be amended to include the following language: "that fall within the range of general industry practice, provided that the methodology does not directly, or have the effect of, discriminating based on a protected class as set forth in the federal Equal Credit Opportunity Act," as recommended by Mr. Colton on page 71 of his direct testimony?

A. No. The Company's tariff language currently states, "The Company uses a generally accepted credit scoring methodology, in the range of general industry practice, based on an Applicant or Customer's utility payment history. The Company will access one of three major credit reporting agencies that use a commercially recognized credit scoring methodology. The payment history of the applicant or customer that is available to the credit reporting agency determines the credit score."

This language is comparable to the language found in 52 Pa. Code § 56.32 that states "which employs standards for using the methodology that fall within the

range of general industry practice. The credit scoring methodology utilized for this purpose must specifically assess the risk of public utility bill payment."

Since the tariff is in line with PUC regulations, the Company does not agree the tariff needs to be modified.

Q. Are there any other issues raised by Mr. Colton that you would like to address?

A. No. If I have failed to address each and every topic, however, it should not be construed as agreement with Mr. Colton's statements or recommendations.

Q. What issues will you address regarding Ms. Warabak's testimony?

A. I will address her recommendation to increase the Company's annual LIURP and Hardship Fund funding. I will also address her recommendation on the distribution of Hardship funds by geography.

Q. Do you believe there is a need for additional LIURP funds?

A. No, the Company is still carrying over funds from the prior year. The Company continues to struggle with finding cooperative participants and spending its full annual budget.

In addition, the Company's contractors that also work with the state weatherization assistance program are struggling to complete Columbia jobs because they have too much work from the state and lack resources and staff.

Q. Are there any other reasons the LIURP budget should not be increased?

A. Yes. Columbia ratepayers paid $40,281,480 for Universal Service Programs in 2022. With the exception of Philadelphia Gas Works' ratepayers, they paid more than any

other gas ratepayers in Pennsylvania. The next highest utility program cost just over $25,000,000 according to the Public Utility Commission's 2022 Universal Service Programs and Collections Performance report. Raising the funding level of LIURP will only exacerbate these differences and may not have any impact if the Company cannot find the resources to spend the funds.

Q. Does the Company support increasing its Hardship Fund budget?

A. No. There is no need to increase the Hardship Fund. The Company currently has over $1 million in available Hardship funds and expects to carry over funds into the next program year. In addition, the Company will add a minimum of $675,000 to the fund in October 2024 as a result of its annual contribution and customer match as well as the balance up to $375,000 of federal pipeline penalty credits and refunds that were approved for this use at Docket No. P-2018-3000160.

Q. Does the Company support Ms. Warabak's recommendation on page 5 of her direct testimony to allocate funds to specific geographical areas?

A. No. The Company recognizes the value of such allocations when funds are scarce and there is a possibility, due to administrative inconsistencies, that some areas may not be able to access funds as quickly as others. If funds were scarce, there would be a value to geographical allocations. However, the Company currently has ample funds, and no customers have been turned away in several years due to lack of funds. Therefore, the risk associated with allocating funds based on geography is that money will be unspent in some areas while a need exists in others. For these reasons, the Company does not support the geographical allocation of funds.

Q. Does this complete your prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 19-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
KIMBERLY CARTELLA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

I. Introduction

Q. Please state your name and business address.

A. My name is Kimberly K. Cartella, and my business address is 3101 North Ridge Road East, Lorain, Ohio 44055.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC") as the Vice President Total Rewards. I develop and implement strategies for compensation and benefits plans provided to the employees of NiSource Inc. ("NiSource") and its subsidiaries, including Columbia Gas of Pennsylvania ("Columbia" or the "Company").

Q. What is your educational background?

A. I received a Bachelor of Science degree in Financial Planning from Purdue University in 1992. I am a certified Professional in Human Resources and a Certified Compensation Professional.

Q. What is your employment history?

A. I have worked for NiSource in a human resources capacity since 1999. I have held the position of Vice President Total Rewards since 2022. Prior to that, I was Director of Compensation, Manager of Compensation, Senior Compensation Analyst, Senior Human Resource Consultant, and Executive/College Recruiter.

Q. Have you previously filed testimony in this matter?

A. No.

Q. Have you previously submitted testimony in matters before the Pennsylvania Public Utility Commission ("Commission")?

A. Yes. I previously submitted rebuttal testimony in Columbia's base rate proceedings at Docket No. R-2015-2468056, Docket No. R-2016-2529660, Docket No. R-2018-2647577, Docket No. R-2020-3018835, and Docket No. R-2021-3024296 and Docket No. R-2022-3031211.

II. Purpose and Summary of Testimony

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony served in this proceeding by the Bureau of Investigation and Enforcement ("I&E") witness Christian Yingling and the Pennsylvania Office of Consumer Advocate ("OCA") witness Greg R. Meyer regarding employee incentive compensation, profit sharing awards, and stock awards.

III. Incentive Compensation Adjustment

Q. Please describe NiSource's total rewards philosophy.

A. NiSource's total rewards philosophy is to compensate employees and provide benefits that are competitive in comparison to the utility industry, as well as general industry (non-utility) employers, to attract, retain and motivate employees who are qualified to perform the functions needed by the Company. This philosophy enables the Company to meet its obligations to provide safe, reliable, and affordable service to its customers. This philosophy is consistent across all NiSource companies.

Q. Please briefly describe Mr. Yingling's position regarding incentive compensation.

A. Mr. Yingling states that the Company's incentive compensation claim is $2,562,000. He further explains that historically, the Company's three-year average incentive payout ratio is 6.89% of the payroll expense as calculated. He then explains the Company's $2,562,000 incentive compensation claim is based upon "a 6.70% payout factor of the FPFTY payroll expense claim of $38,227,431." He then recommends that the incentive compensation payout factor of 6.70%, instead of his calculated three-year average incentive payout ratio of 6.89%, should be applied to his recommended payroll (labor) expense allowance of $35,180,705. Mr. Yingling's proposed calculation results in an incentive compensation claim of $2,357,107. Therefore, he proposes a disallowance of $204,893 (the Company's amount of $2,562,000 minus his calculated amount of $2,357,107) (I&E Statement No. 1, p. 16-18).

Q. Do you agree with Mr. Yingling's recommended disallowance?

A. No. Although Mr. Yingling agrees with the Company's proposed incentive compensation payout factor of 6.70%, his proposed disallowance stems from his reduction of the FPFTY payroll expense claim from $38,227,431 to $35,180,705. Company witness Leal (Columbia Statement No. 21-R) provides rebuttal with respect to Mr. Yingling's payroll expense adjustment.

Separately, I would like to note that Mr. Yingling's assertion that his "recommended allowance for incentive compensation ... is reasonable and supported by the Company's historic average actual payout factor" reverts to the

use of historical ratemaking principles rather than the use of a FPFTY which is the basis for this case and the past eight base rate cases that the Company has filed. (I&E Statement No. 1, p. 17). The Company's annual budget projects FPFTY Incentive Program expense calculated on the anticipated base salary of employees during the period and the assumption of achieving the target performance levels described in the Incentive Plan which is the anticipated level of achievement. As such, Mr. Yingling's adjustment to incentive compensation should be rejected.

Q. Please briefly describe Mr. Yingling position on NCSC stock reward expense (i.e., long-term incentives or "LTI").

A. Mr. Yingling proposes 100% disallowance of the NCSC LTI expense of $3,504,198. He claims LTI rewards are "linked to financial goals and targets such as earnings per share, rate of return on equity, or appreciation of the parent company's stock" and that they are limited to certain top-level executives (I&E Statement No. 1, p. 32).

Q. Do you agree with Mr. Yingling's recommendation?

A. No, the Company rejects Mr. Yingling's recommendation to disallow 100% of NCSC LTI rewards. These rewards are not based upon return on equity or appreciation of the parent company's stock. The Company recognizes that the LTI rewards should not be based upon financial metrics alone but should also include the achievement of goals that are beneficial to customers. LTI rewards are based on achievement of essential operational metrics that include safety, employee engagement, environmental greenhouse gas emission reductions, operational excellence and net operating earnings per share which is driven by the Company

meeting its budget. See Exhibit KC-1R for details of the LTI reward metrics for 2018-2023. LTI rewards are part of the Company's design of its total rewards program that is designed to compensate employees and provide benefits that are competitive in comparison to the utility industry, as well as general industry (non-utility) employers, to attract, retain, and motivate employees who are qualified to perform the functions needed by the Company and to provide safe, reliable, and cost-effective service to its customers. These rewards are not limited to certain top-level executives as Mr. Yingling states. These rewards are provided to leaders in positions at the Director level and above and will be reduced if essential safety, customer, and financial goals are not achieved.

Q. From a policy perspective, why is it important that LTI rewards be recovered in base rates?

A. If the Commission disallows recovery of LTI rewards, it sends the message that variable incentive compensation is not valued as a viable tool to encourage company efficiencies and promote customer service and safety goals. Further, denial of recovery of LTI rewards means that fixed base pay without incentives would become the preferable means to attract, motivate, and retain talented employees while retaining a reasonable opportunity for full recovery of that compensation. Incentive compensation is an element of competitive total compensation in the labor market both within the utility industry and within the broader employer base.

Q. Do customers also benefit from the Company attracting, motivating, and retaining quality leadership talent?

A. Yes. Retaining key leaders and attracting new talented individuals is critical to maintaining high quality of service, efficiency, and safety; therefore, offering LTI rewards is an appropriate cost of providing reliable service to Columbia's customers. If the Company did not provide LTI rewards, it would be at high risk of losing talent to competitors. The potential departure of Company leadership would create a loss of valuable skills and would have a significant financial impact in the form of turnover costs, including recruiting, relocation, and training costs. In addition, leadership sets the tone and direction for the Company. Failure to retain and attract experienced, skilled leaders can adversely affect Columbia's ability to continue to provide safe and reliable service for its customers.

Q. Please describe Mr. Yingling's position regarding profit sharing awards.

A. Mr. Yingling proposes that the entire amount of the profit-sharing expense of $413,427 for the Company and $230,925 for NCSC be removed. He further states that employees' eligibility and performance criteria are laid out in the NiSource Inc. - Omnibus Incentive Plan and that "this type of benefit is unrelated to the provision of safe and reliable service, and therefore, ratepayers should not be responsible for paying a benefit available only to certain high-level executive-type positions." (I&E Statement No. 1, p. 31).

Q. Do you agree with Mr. Yingling's recommendation?

A. No. As part of the total rewards package to attract, retain and motivate employees who are qualified to perform the functions needed by the Company, profit sharing is an element of the Company's Retirement Savings Plan (401(k)), not the Omnibus

Incentive Plan as Mr. Yingling states, and supports employees' saving for retirement. See GAS-RR-024 for the NiSource Retirement Savings Plan document – Attachment R. All employees, not just certain high-level executives, as Mr. Yingling states, are eligible for the Retirement Savings Plan, an important vehicle to help employees fund their retirement. Company contributions for Profit Sharing are deposited into employees' retirement accounts, which supplements employees' individual contributions to their retirement accounts. Absent these contributions, the Company would have to make other adjustments to its total compensation package, such as increases to base pay, to remain competitive in the market for quality employees. As an element of a balanced competitive benefits program, the entire profit-sharing expense of $413,427 for the Company and $230,925 for NCSC should be allowed.

Q. Please briefly describe Mr. Meyer's position regarding incentive compensation.

A. Mr. Meyer states that the Company offers two overarching types of incentive compensation: Cash Based Awards Programs or Short-Term Incentive Plans ("STIP") and a 2020 Omnibus Incentive Plan. He also states that the Company is seeking recovery of $2,562,000 of incentive compensation expense. Mr. Meyer recommends removing the portion of the incentive compensation that is related to achieving financial goals which results in a reduction of $1,793,400. He states that "[t]hese amounts of compensation are tied heavily to factors that benefit shareholders and the Company has failed to demonstrate that there is a direct

benefit to Columbia Gas' ratepayers for this portion of the incentive compensation plans." (OCA Statement No. 2, p. 12).

Q. Does Mr. Meyer acknowledge that the Company's incentive compensation plan includes consideration of operational goals?

A. Yes, Mr. Meyer proposes to allow 30% of the incentive compensation claimed by the Company, effectively conceding there are operational goals in the incentive compensation plan. These goals also are identified in GAS-RR-027, Attachments A and B.

Q. Do you agree with Mr. Meyer's proposed adjustments?

A. No, the Company rejects these proposed adjustments for reasons explained below.

Q. Why does NiSource provide cash-based incentive compensation?

A. STIP rewards are based on achievement of essential operational metrics that include safety, operational excellence and net operating earnings per share which is driven by the Company meeting its budget. Like the LTI rewards discussed above, STIP rewards are part of the Company's design of its total rewards program that is designed to compensate employees and provide benefits that are competitive in comparison to the utility industry, as well as general industry (non-utility) employers, to attract, retain and motivate employees who are qualified to perform the functions needed by the Company and to provide safe, reliable, and cost-effective service to its customers.

Q. Do you have any further comments with respect to Mr. Yingling's and Mr. Meyer's testimony on incentive compensation and stock rewards?

A. Yes. I am advised by counsel that the Commission has allowed recovery of incentive compensation as a part of payroll where the compensation plan includes provisions that are designed to provide benefits to customers, as the Company's plan does. I am further advised that the Commission has allowed full recovery of incentive compensation amounts even where financial performance is a trigger to payment of the rewards. Moreover, I am aware of the PPL Electric Utilities decision that permitted incentive compensation consistent with prior Commission decisions when such compensation programs are focused on improving operations effectiveness. *Pa. PUC v. PPL Electric Utilities Corp., R-2102-2290597,* (Order entered Dec. 28, 2012).

Q. Should the full level of FTY and FPFTY incentive compensation be allowed?

A. Yes, the full level of FTY and the FPFTY incentive compensation should be permitted as explained above.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

2018-2020 LTI Goals

Performance Shares/ Weighting		2018-2020 Goals		
1. Cumulative NOEPS	81.25%	Stretch -	200%	$4.28
		Target -	100%	$4.08
		Trigger -	50%	$3.00
1a. Cumulative NOEPS Modifier: Relative Total Shareholder Return		First Quartile		25%
		Second Quartile		0
		Third Quartile		0
		Fourth Quartile		-25%
2. Customer Value Index	18.75% (1/5 each)	Safety		
		Customer		
		Financial		
		Culture		
		Environmental		

2019-2021 LTI Goals

Performance Shares/ Weighting		2019-2021 Goals		
1. Cumulative NOEPS	81.25%	Stretch -	200%	$4.35
		Target -	100%	$4.14
		Trigger -	50%	$3.93
1a. Cumulative NOEPS Modifier: Relative Total Shareholder Return		First Quartile		25%
		Second Quartile		0
		Third Quartile		0
		Fourth Quartile		-25%
2. Customer Value Index	18.75% (1/5 each)	Safety		
		Customer		
		Financial		
		Culture		
		Environmental		

2020-2022 LTI Goals

Performance Shares/ Weighting		2020-2022 Goals	
1. Cumulative NOEPS	81%	Stretch - 200% Target - 100% Trigger - 50%	$4.47 $4.25 $4.03
1a. Cumulative NOEPS Modifier: Relative Total Shareholder Return		First Quartile	25%
		Second Quartile	0
		Third Quartile	0
		Fourth Quartile	-25%
2. Customer Value Index	19% (1/4 each)	Safety	
		Customer	
		Culture	
		Environmental	

2021-2023 LTI Goals

Performance Shares/Weighting		2021-2023 Goals		
Financial				
Cumulative NOEPS	50%	Stretch -	200%	$4.50
		Target -	100%	$4.28
		Trigger -	50%	$4.06
rTSR (percentile)	50%	Stretch -	200%	80
		Target -	100%	50
		Trigger -	25%	30
Safety				
Safety: Scorecard	+/-20% Magnifier	+20% -	20%	120
		Goal -	0%	100
		-20% -	-20%	80
Workforce & Sustainability				
Environmental: Greenhouse Gas Emission Reduction	+/-10% Magnifier	Reduce CO2 emissions by 11.9 million tonnes		
		+10% -	10%	182,373
		Goal -	0%	147,569
		-10% -	-10%	< Goal
DEI: Diversity of Workforce	+/-10% Magnifier	+10% -	10%	12
		Goal -	0%	10
		-10% -	-10%	8

2021-2023 Special Performance Goals

Performance Shares	Weight	2021-2023 Goals		
Relative Total Shareholder Return	100%	Stretch -	200%	90
		Target -	100%	55
		Trigger -	50%	50
Safety: Scorecard	+/-20% Magnifier	Stretch -	20%	120
		Target -	0%	100
		Trigger -	-20%	80

Note: Vesting dates=67% of award on 2/28/23 and 33% on 2/28/24

2022-2024 LTI Goals

Performance Shares/Weighting		2022-2024 Goals		
Financial				
Cumulative NOEPS	50%	Stretch -	200%	$4.99
		Target -	100%	$4.75
		Trigger -	50%	$4.51
rTSR (percentile)	50%	Stretch -	200%	80
		Target -	100%	50
		Trigger -	25%	30
Safety				
Safety: Scorecard	+/-20% Magnifier	+20% -	20%	120
		Goal -	0%	100
		-20% -	-20%	80
Workforce & Sustainability				
Environmental: Greenhouse Gas Emission Reduction	+/-10% Magnifier	Reduce CO2 emissions by 11.9 million tonnes		
		+10% -	10%	42.6%
		Goal -	0%	14.4%
		-10% -	-10%	< Goal
DEI: Diversity of Workforce	+/-10% Magnifier	+10% -	10%	12
		Goal -	0%	11
		-10% -	-10%	10

2023-2025 LTI Goals

Performance Measures/ Weighting		2023-2025 Goals		
Financial				
Cumulative NOEPS	50%	Stretch -	200%	$5.16
		Target -	100%	$5.01
		Trigger -	50%	$4.86
rTSR (percentile)	25%	Stretch -	200%	80
		Target -	100%	50
		Trigger -	25%	30
Operational Excellence & Safety				
Annual Operational Excellence Index Scorecard: 3 Year Average	10%	Stretch -	200%	1.06
		Target -	100%	1.00
		Trigger -	50%	0.92
Workforce & Sustainability				
Employee Engagement Index Score	5%	Stretch -	200%	81%
		Target -	100%	79%
		Trigger -	50%	77%
Economic Inclusion: Supplier Diversity	5%	Stretch -	200%	30%
		Target -	100%	25%
		Trigger -	50%	22%
Environmental GHG	5%	Reduce CO2 emissions by 11.9 million tonnes		
		Stretch -	200%	34%
		Target -	100%	15.3%
		Trigger -	50%	<15.3%

2024-2026 LTI Goals

Performance Measures/ Weighting		2024-2026 Goals		
Financial				
Cumulative NOEPS	55%	Stretch -	200%	$5.64
		Target -	100%	$5.53
		Trigger -	50%	$5.42
rTSR (percentile)	25%	Stretch -	200%	80
		Target -	100%	50
		Trigger -	25%	30
Operational Excellence & Safety				
Annual Operational Excellence Index Scorecard: 3 Year Average	10%	Stretch -	200%	1.03
		Target -	100%	1.00
		Trigger -	50%	0.94
People and Culture; Sustainability				
Employee Engagement Index Score	5%	Stretch -	200%	84%
		Target -	100%	82%
		Trigger -	50%	80%
Environmental	5%	Add 2,020 MW (ICAP) of renewable generation and energy storage		
		Stretch -	200%	50.0%
		Target -	100%	46.0%
		Trigger -	50%	34.0%

2018-2020 LTI Goals

Performance Shares/ Weighting		2018-2020 Goals		
1. Cumulative NOEPS	81.25%	Stretch -	200%	$4.28
		Target -	100%	$4.08
		Trigger -	50%	$3.00
1a. Cumulative NOEPS Modifier: Relative Total Shareholder Return		First Quartile		25%
		Second Quartile		0
		Third Quartile		0
		Fourth Quartile		-25%
2. Customer Value Index	18.75% (1/5 each)	Safety		
		Customer		
		Financial		
		Culture		
		Environmental		

2019-2021 LTI Goals

Performance Shares/ Weighting		2019-2021 Goals		
1. Cumulative NOEPS	81.25%	Stretch -	200%	$4.35
		Target -	100%	$4.14
		Trigger -	50%	$3.93
1a. Cumulative NOEPS Modifier: Relative Total Shareholder Return		First Quartile		25%
		Second Quartile		0
		Third Quartile		0
		Fourth Quartile		-25%
2. Customer Value Index	18.75% (1/5 each)	Safety		
		Customer		
		Financial		
		Culture		
		Environmental		

2020-2022 LTI Goals

Performance Shares/ Weighting		2020-2022 Goals	
1. Cumulative NOEPS	81%	Stretch - 200% Target - 100% Trigger - 50%	$4.47 $4.25 $4.03
1a. Cumulative NOEPS Modifier: Relative Total Shareholder Return		First Quartile	25%
		Second Quartile	0
		Third Quartile	0
		Fourth Quartile	-25%
2. Customer Value Index	19% (1/4 each)	Safety	
		Customer	
		Culture	
		Environmental	

2021-2023 LTI Goals

Performance Shares/Weighting		2021-2023 Goals		
Financial				
Cumulative NOEPS	50%	Stretch -	200%	$4.50
		Target -	100%	$4.28
		Trigger -	50%	$4.06
rTSR (percentile)	50%	Stretch -	200%	80
		Target -	100%	50
		Trigger -	25%	30
Safety				
Safety: Scorecard	+/-20% Magnifier	+20% -	20%	120
		Goal -	0%	100
		-20% -	-20%	80
Workforce & Sustainability				
Environmental: Greenhouse Gas Emission Reduction	+/-10% Magnifier	Reduce CO2 emissions by 11.9 million tonnes		
		+10% -	10%	182,373
		Goal -	0%	147,569
		-10% -	-10%	< Goal
DEI: Diversity of Workforce	+/-10% Magnifier	+10% -	10%	12
		Goal -	0%	10
		-10% -	-10%	8

2021-2023 Special Performance Goals

Performance Shares	Weight	2021-2023 Goals		
Relative Total Shareholder Return	100%	Stretch -	200%	90
		Target -	100%	55
		Trigger -	50%	50
Safety: Scorecard	+/-20% Magnifier	Stretch -	20%	120
		Target -	0%	100
		Trigger -	-20%	80

Note: Vesting dates=67% of award on 2/28/23 and 33% on 2/28/24

2022-2024 LTI Goals

Performance Shares/Weighting		2022-2024 Goals		
Financial				
Cumulative NOEPS	50%	Stretch -	200%	$4.99
		Target -	100%	$4.75
		Trigger -	50%	$4.51
rTSR (percentile)	50%	Stretch -	200%	80
		Target -	100%	50
		Trigger -	25%	30
Safety				
Safety: Scorecard	+/-20% Magnifier	+20% -	20%	120
		Goal -	0%	100
		-20% -	-20%	80
Workforce & Sustainability				
Environmental: Greenhouse Gas Emission Reduction	+/-10% Magnifier	Reduce CO2 emissions by 11.9 million tonnes		
		+10% -	10%	42.6%
		Goal -	0%	14.4%
		-10% -	-10%	< Goal
DEI: Diversity of Workforce	+/-10% Magnifier	+10% -	10%	12
		Goal -	0%	11
		-10% -	-10%	10

2023-2025 LTI Goals

Performance Measures/ Weighting		2023-2025 Goals		
Financial				
Cumulative NOEPS	50%	Stretch -	200%	$5.16
		Target -	100%	$5.01
		Trigger -	50%	$4.86
rTSR (percentile)	25%	Stretch -	200%	80
		Target -	100%	50
		Trigger -	25%	30
Operational Excellence & Safety				
Annual Operational Excellence Index Scorecard: 3 Year Average	10%	Stretch -	200%	1.06
		Target -	100%	1.00
		Trigger -	50%	0.92
Workforce & Sustainability				
Employee Engagement Index Score	5%	Stretch -	200%	81%
		Target -	100%	79%
		Trigger -	50%	77%
Economic Inclusion: Supplier Diversity	5%	Stretch -	200%	30%
		Target -	100%	25%
		Trigger -	50%	22%
Environmental GHG	5%	Reduce CO2 emissions by 11.9 million tonnes		
		Stretch -	200%	34%
		Target -	100%	15.3%
		Trigger -	50%	<15.3%

2024-2026 LTI Goals

Performance Measures/ Weighting		2024-2026 Goals		
Financial				
Cumulative NOEPS	55%	Stretch -	200%	$5.64
		Target -	100%	$5.53
		Trigger -	50%	$5.42
rTSR (percentile)	25%	Stretch -	200%	80
		Target -	100%	50
		Trigger -	25%	30
Operational Excellence & Safety				
Annual Operational Excellence Index Scorecard: 3 Year Average	10%	Stretch -	200%	1.03
		Target -	100%	1.00
		Trigger -	50%	0.94
People and Culture; Sustainability				
Employee Engagement Index Score	5%	Stretch -	200%	84%
		Target -	100%	82%
		Trigger -	50%	80%
Environmental	5%	Add 2,020 MW (ICAP) of renewable generation and energy storage		
		Stretch -	200%	50.0%
		Target -	100%	46.0%
		Trigger -	50%	34.0%

COLUMBIA STATEMENT NO. 20-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
DAVID BOKASH
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

July 11, 2024

I. Introduction

Q. Please state your name and business address.

A. David Bokash, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") and have been in the role of Manager of Large Customer Relations since 2008.

Q. Please briefly describe your duties as Columbia's Manager of Large Customer Relations.

A. As Manager of Large Customer Relations (LCR), I lead an account management team that is responsible for managing production, procurement and facility relationships with Columbia's large commercial and industrial natural gas customers and leverages those relationships to provide excellent customer experience and satisfaction. I facilitate Columbia's new business projects and economic development activities for prospective large commercial and industrial customers that includes project management to connect customers to Columbia's gas distribution system. In addition, I oversee the negotiations of customer flex rate agreements involving the bypass of Columbia's facilities to an alternative fuel source. The flex rate negotiation process involves gathering of all the facts surrounding the customer's bypass information such as, but not limited to, the type

of alternative fuel source, bypass route, project constructability, bypass cost, alternative fuel costs, project payback, cost of capital, etc. and using this information to determine if it warrants Columbia offering a flex rate.

Q. Have you previously filed testimony in this matter?

A. No.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony served in this proceeding by Mark D. Ewen on behalf of the Office of the Small Business Advocate ("OSBA").

Q. OSBA Witnesses Ewen recommend on page 9 his direct testimony that the Company conduct competitive alternative analysis for each flex customer every two years. Do you agree such a mandate should be adopted?

A. No. There should not be a mandate or requirement as to the type of analysis or information Columbia develops to support granting a flex rate. There is no filing requirement as to what information is necessary to meet the Company's burden of proof on this issue.

Flex agreements are based on the unique circumstances of the customer, with the economic analysis for the bypass performed based on market conditions at the time the contract is entered into. The facts and circumstances regarding economic analysis may change over time, however, absent specific contractual agreements to update the contract, the rate will remain the same throughout the duration of the

contract as facts and circumstances dictate at the time the agreement was entered into. For example, if I obtained a fixed 30-year mortgage at the time when the market supported a 3% interest rate, the lender would not be permitted to raise that rate in the future, even if circumstances warranted a different rate. Any analysis performed would not impact Columbia's ability to change the terms of the contract, and therefore, such analysis is not necessary. Columbia currently undertakes an analysis of competitive alternatives at the time it negotiates new flex agreements. Columbia has not entered into a flex agreement exceeding ten years since 2017 with more recent agreements being in the range of five years. Columbia believes interim analyses serve no purpose and should not be required.

Q. Is a competitive alternative analysis for each flex customer with an every two year frequency a practical guideline?

No. To conduct a competitive alternative analysis every two years where Columbia's rate recovery could be impacted, the Company would need the customer to also go through the process of updating its bypass options and costs. Performing these analyses are time consuming as they can take months to complete that involve internal staffing and more than likely third-party consulting and associated costs. It is not likely that customers would be willing to perform such a review every two years, particularly since they are under no contractual obligation to do so. In addition, customers tend to accept bypass payback periods longer than two years due to the upside of low ongoing operating costs after the initial bypass project is

paid back. This leads customers to look at a bypass project with payback terms greater than two years and to seek flex agreements matching their payback term. If Columbia were subject to the risk of non-recovery of the shortfall based upon a two-year competitive analysis, Columbia would need to add language to its flex rate contracts to transfer that risk to the flex rate customer. Customers would not agree to longer term agreements with the utility knowing there would be a flex rate true-up every two years based on a new competitive alternative analysis. This would lead to more customers selecting to bypass as it would allow for them to have control over their costs over time verses being subject to possible rate fluctuations due to frequent competitive alternative analysis review. Since Columbia conducts a competitive analysis at the time it negotiates a new agreement including the review of the customer's analysis, it believes that this is the appropriate time for such analysis.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 21-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	)	

REBUTTAL TESTIMONY OF
JASON LEAL
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

NON PROPRIETARY VERSION

July 11, 2024

Introduction

Q. Please state your name and business address.

A. My name is Jason Leal. My business address is 801 East 86th Avenue, Merrillville, Indiana 46410.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Lead Financial Planning Analyst at NCSC in the Financial Planning & Analysis ("FP&A") department.

Q. Please describe your educational background.

A. In 2008, I graduated from Purdue University with a Bachelor of Science degree in Business Administration, majoring in Accounting. I also obtained a Master of Business Administration degree from the University of Southern Indiana in 2021.

Q. Please describe your employment background.

A. I have over 15 years of experience in a variety of FP&A and regulatory support roles, with a primary focus on NiSource Inc. subsidiaries, such as Columbia Gas of Pennsylvania, Inc. I was employed by Northern Indiana Public Service Company LLC ("NIPSCO") in January 2009 as a Financial Analyst in the Rates and Regulatory department. My responsibilities included providing regulatory support for NIPSCO's Electric Fuel Cost Adjustment ("FAC") and NIPSCO's Gas Fuel Cost Adjustment ("GCA") filings. In July 2010, I was promoted to the position of Senior Regulatory Analyst. In July 2013, I accepted a position as a Senior Financial

Analyst in the FP&A department. My responsibilities included the budgeting and variance analysis of various components of NIPSCO's Income Statement. In November 2017, I was promoted to the position of Lead Financial Analyst. In October 2018, I accepted a position as Lead Regulatory Analyst in the Regulatory Strategy and Support department. My responsibilities included providing regulatory support for NIPSCO's Environmental Cost Recovery Mechanism ("ECRM"), Environmental Expense Recovery Mechanism ("EERM"), and Federally Mandated Cost Adjustment ("FMCA") tracker filings. I also supported the preparation and coordination of Columbia Gas of Maryland, Inc. regulatory filings. I assumed my current position as Lead Financial Analyst in the FP&A department for NCSC in March 2021. In my current role, my principal responsibilities include budgeting and variance analysis of direct operations and maintenance ("O&M") expenses for both Columbia Gas of Maryland, Inc. and Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company").

Q. Have you previously testified before any other regulatory agency?

A. Yes. I have presented direct testimony for NIPSCO before the Indiana Utility Regulatory Commission ("IURC") in Cause No. 44340-FMCA-13 supporting NIPSCO's proposed ratemaking treatment for FMCA factors and to effectuate the timely recovery of federally mandated costs incurred in connection with NIPSCO's federally mandated compliance projects.

Q. Have you previously filed testimony in this matter?

A. No.

Q. Will you be adopting the direct testimony of Nicole M. Paloney (Columbia Statement No. 9)?

A. Yes. While Ms. Paloney is out on medical leave, I will be adopting her direct testimony.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to respond to portions of the direct testimonies of witnesses Christian Yingling and Esyan A. Sakaya filed on behalf of the Bureau of Investigation and Enforcement ("I&E").

Q. How will your rebuttal testimony be organized?

A. My rebuttal testimony relates to I&E's requested O&M adjustments and recommendations. I will specifically address the following issues:

- Payroll Expense
- Incentive Compensation
- Other Employee Benefits Expense
- Employee Expense
- Advertising Expense
- Hydrogen Blending

I will address the testimony of each of the witnesses listed above as they relate to those topics.

Q. What adjustments of I & E Witness Yingling will you be responding to?

A. I will be responding to several issues from Witness Yingling. I will be responding to his proposed vacancy adjustment as it drives his adjustments for payroll expense,

incentive compensation, and other employee benefits expense. I will also be responding to his proposal to reduce employee expenses and advertising expenses.

Payroll Expense

Q. Please summarize the vacancy adjustments proposed by Witness Yingling.

A. Witness Yingling is proposing a reduction to Payroll Expense in the amount of $3,046,726 related to vacant/unfilled positions that arise due to unpredictable normal vacancies, such as retirements, resignations, transfers, and layoffs that occur throughout the year. To calculate the adjustment, Mr. Yingling first calculates an **[BEGIN CONFIDENTIAL]**

[END CONFIDENTIAL]. Witness Yingling further states it is unreasonable to assume that the Company will fill and maintain 100% full staffing of 728 budgeted positions throughout the FPFTY and there will always be a certain level of normal vacancies due to retirements, resignations, transfers, and layoffs on a day-to-day operating basis.

Q. Do you agree with this adjustment?

A. No. Witness Yingling's calculation of the vacancy adjustment is inaccurate due to the erroneous assumption that the Company's payroll expense claim is based on a complete authorized complement of employees. In past cases, the Company has made its payroll expense claim based upon its full authorized complement of employees, which included vacant positions in the employee complement. However, beginning in its 2022 rate case and continuing in this case, the Company changed its approach. The Company ceased using authorized positions to develop its projected headcount and is instead using actual employees, exclusive of vacancies in projecting 728 active full-time employees for 2024 and 2025, as Columbia witness Nicole Paloney stated in her direct testimony on page 8 of Columbia Statement No. 9. As provided in the Company's response to I&E-RE-11-D Question A to which Mr. Yingling referred, the FTY and FPFTY assumes the same level of actual headcount as the end of year HTY as no incremental positions were included in the budget. This therefore emphasizes that headcount in the current case is not inclusive of vacancies, whereas in past cases prior to 2022, the headcount in the case included vacancies. Mr. Yingling is improperly double-counting vacancies, which were already removed from the Company's headcount in this case. Consequently, the Company rejects the vacancy adjustment and all other adjustments to O&M resulting from the impact of this adjustment.

Incentive Compensation

Q. Will you be addressing the adjustment made to Incentive Compensation?

A. Yes. The Company opposes any adjustment to incentive compensation resulting from proposed adjustments to payroll expense that are not accepted. Please refer to the rebuttal testimony of Columbia Witness Cartella (Columbia Statement No. 19-R) for further testimony related to incentive compensation.

Other Employee Benefits Expense

Q. Will you be addressing the adjustments made to Other Employee Benefits Expense?

A. Yes. The Company opposes any adjustment to Other Employee Benefits Expense resulting from proposed adjustments to payroll expense that are not accepted. Please refer to the rebuttal testimony of Columbia Witness Bly (Columbia Statement No. 15-R) for further testimony related to Other Employee Benefits Expense.

Employee Expense

Q. Please summarize the reduction to Employee Expenses recommended by witness Yingling.

A. Based on the fluctuations in Employee Expenses during the historic years of 2021 ($1,057,284), 2022 ($1,974,603), and 2023 ($1,094,169), Witness Yingling suggests that a three-year historic average be applied. The implementation of this methodology leads to a reduction of $187,648 in employee expenses.

Q. Do you agree with witness Yingling's recommendation to use a three-year historic average for employee expenses due to the fluctuating nature of this expense?

A. No. Prior to the 2020 COVID pandemic, the Company's employee expenses were $1,543,490 in 2019 as shown in Table JL R-1 below. The COVID-19 pandemic

implemented travel restrictions, resulting in employee expenses as low as $1,057,284, from 2020 to the HTY, with the exception of 2022. The increased amounts in the FTY and FPFTY restore the level of spending to pre-pandemic levels, while also accounting for the increased costs of hotels and transportation. The FPFTY amount of $1,563,445 is a mere 1.3% increase in comparison to the 2019 amount of $1,543,490. This expenditure level enables the company to conduct in-person departmental meetings, trainings, and collaborations on-site, which had been either limited or denied since the beginning of the pandemic.

Table JL R-1

Fiscal Year	Expense
2019	$1,543,490
2020	$1,233,894
2021	$1,057,284
2022	$1,974,603
HTY	$1,094,169
FTY	$1,614,000
FPFTY	$1,563,000

Q. Please explain why 2022 Per Books Employee Expense of $1,974,603 is higher than other years.

A. The higher expense in 2022 is driven by $781,840 (I&E Exhibit No. 1, Schedule 6, Page 4, Line 10) in discretionary bonuses that were distributed to employees across the company. Clothing Allowance spend of $534,049 (I&E Exhibit No. 1, Schedule 6, Page 4, Line 9) also contributed to a higher employee expense amount in 2022 in result of Union Negotiation Agreements.

Q. Please summarize Columbia's claim for Employee Expenses.

A. Columbia rejects I&E's proposed adjustment to Employee Expenses for the FPFTY based upon using an average of historical information during the peak of the COVID pandemic. Columbia's claim remains at $1,563,000 to restore the level of spending to pre-pandemic levels.

Advertising Expense

Q. Do you agree with witness Yingling's recommendation to reduce advertisement expense by $247,646 to smooth out highs and lows over the last three fiscal years of actuals?

A. No. The three years of historic data (2021, 2022, 2023) within Mr. Yingling's table on page 29, line 1 of his Direct Testimony are not comparable to FTY and FPFTY data because of changes in the way certain costs are being budgeted and booked by cost element. His table reflects data that is not comparable due to accounting changes for recording actual costs incurred. Further, budgeted FTY and FPFTY data includes amounts that align with other categories in the historic years, in addition to advertisement expenses, specifically for Public Awareness, whereas the actuals in Mr. Yingling's table do not. Also, the data in the table are inconsistent in presenting the adjustment for non-recoverable expenses, which the Company removes for ratemaking purposes.

Q. Have you put together an updated table with appropriate comparative information?

A. Yes. The data in Table JL R-2 below presents comparative information. With this alignment, the FTY and FPFTY Expenses on lines 8 through 10 are in line with actual spending from 2021 to 2023.

Table JL R-2

Line No.	Description	2021	2022	2023	FTY	FPFTY
1	Advertising - General	$ 228,211	$ 240,165	$ 178,256	$ 97,235	$ 110,332
2	Advertising - PHMSA RP 1162 Public Awareness	145,322	112,493	52,084	200,000	200,000
3	Advertising - Count on Columbia	197,590	280,000	298,028	300,000	300,000
4	**Total Per books (or Per Budget) Advertising[1]**	**571,123**	**632,658**	**528,368**	**597,235**	**610,332**
5	PHMSA RP1162 Public Awareness in NCSC[2]	55,836	-	-	-	-
6	PHMSA RP1162 Public Awareness in Other Categories[2]	101,107	177,507	145,083	-	-
7	Count on Columbia - in Outside Services[3]	-	20,000	-	-	-
8	**Total Comparitive Information**	**728,066**	**830,165**	**673,451**	**597,235**	**610,332**
9	Adjustment to Remove Non-Recoverable	(171,829)	(130,108)	(131,155)		
10	**Net Advertising (With Public Awareness)**	**$ 556,237**	**$ 700,057**	**$ 542,296**	**$ 597,235**	**$ 610,332**

[1] Per books totals tie back to Exhibit No. 4, Schedule No. 1, page 2; and Exhibit No. 104, Schedule No. 1, Page 2.

[2] All cost categories for Public Awareness are needed to provide comparitive information to budget amounts. Includes costs related to Education Programs, Print Materials - Mailings & Bill Inserts, Education and Safety Promotional Items, and PA One Call Collaboration Sponsorships.

[3] All cost categories for Count on Columbia are needed to provide comparitive information to Budget Amounts.

Q. Please explain PHMSA RP1162 Public Awareness expenses in Table JL R-2 on Line No 5.

A. The costs on line 5 represent NCSC allocated costs to Columbia of PA related to PHMSA RP1162 Public Awareness for 2019 Actual Expense but would have been included in the Budgeted amounts for the FTY and the FPFTY on Line 2. Columbia budgets for PHMSA RP1162 Public Awareness in one category.

Q. Please explain PHMSA RP1162 Public Awareness expenses in Table JL R-2 on Line No 6.

A. The costs on line 6 represent the PHMSA RP1162 Public Awareness costs that are accounted for in other cost categories for Actual Expense but are included in the Budgeted amounts for the FTY and the FPFTY on Line 2. Columbia budgets for PHMSA RP1162 Public Awareness in one category and it includes costs related to Education Programs, Print Materials - Mailings & Bill Inserts, Education and Safey promotional items, and PA One Call Collaboration Sponsorships.

Q. Please summarize Columbia's claim for Advertising.

A. Columbia rejects I&E's proposed adjustment to Advertising Expense for the FPFTY based upon an average of inconsistent historical information. Columbia's claim remains at $610,332, noting that this amount includes recoverable Advertising Expense, as well as all recoverable expenses for Public Awareness.

Hydrogen Blending

Q. Do you agree with witness Sakaya's recommendation to deny Columbia from recovering $54,000 in O&M expense related to the purchase of hydrogen for its Hydrogen Blending Skid at the Columbia Gas training center in Monaca, Pennsylvania?

A. No.

Q. Why does Mr. Sakaya recommend denying the recovery of hydrogen costs for Columbia's Hydrogen Blending Skid?

A. Mr. Sakaya posits that ratepayers should not have to pay for the Company's purchase of hydrogen since it is not currently being blended into Columbia's operating system serving customers.

Q. What is the Company's purpose for purchasing hydrogen?

A. The Company purchases hydrogen to blend it with natural gas in a controlled environment and in a real home setting for the purpose of better understanding hydrogen and demonstrate that blending hydrogen with natural gas can contribute to a reduction in carbon emissions.

Q. Can the purchase of hydrogen for Columbia's Hydrogen Blending Skid be considered a Research and Development ("R&D") Cost, and if so, why?

A. Yes. The purchase of hydrogen for Columbia's Hydrogen Blending Skid provides the Company's employees with the opportunity to become educated and familiar with hydrogen blends. This also enables the Company to conduct long-term and extensive trials to better understand hydrogen safety before it is introduced into Columbia's distribution system. The Company's trials can assist in determining the optimal percentage of hydrogen that will most benefit its customers. With the increasing interest in low-carbon solutions, it is anticipated that the demand for hydrogen will increase. The information obtained through Columbia's project will be utilized not only to educate Columbia's employees but also its customers on the safety and benefits of a hydrogen blended system.

Q. Are there any Commission decisions that support the recovery of Research and Development Costs?

A. Yes. I am advised by counsel that the Commission supported the recovery of R&D costs in the following two cases. In 1990, even though 36% of Natural Fuel Gas Distribution Company's (NFGD) original claim was denied, the Commission adopted the OCA proposal that NFGD's Research Demonstration & Development ("RD&D") costs be established for ratemaking purposes (*Pa. P.U.C. v National Fuel Gas Distribution Corp., 73 Pa. P.U.C 552 (1990)* Docket No. R-901670). In 1994, the Commission again adopted the OCA proposal that NFGD's RD&D costs be recovered in a base rate case filed by NFGD. This decision was made even though a percentage

of NFGD's original claim was denied (*PA PUC v NFGD Corp*. Docket No. R-00942991 (Opinion & Order Dec 6, 1994).

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes, it does.

I&E Statement No. 1
Witness: Christian Yingling
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2024-3046519

Direct Testimony

of

Christian Yingling

Bureau of Investigation & Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christian Yingling, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATION AND EMPLOYMENT BACKGROUND?

A. An outline of my education and employment background is attached as Appendix A.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. I&E's analysis in the proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to review the base rate filing of Columbia Gas of Pennsylvania, Inc. (Columbia or Company) and make recommended adjustments to the Company's proposed operating and maintenance (O&M) expenses for the fully projected future test year (FPFTY) ending December 31, 2025. I also present the overall I&E recommended revenue requirement based on my adjustments and the adjustments of the other I&E witnesses.

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 1 contains schedules that support my direct testimony.

Q. WHAT TEST YEARS IS COLUMBIA USING IN THIS PROCEEDING?

A. Columbia is using the twelve months ended November 30, 2023, as the historic test year (HTY), the twelve months ending November 30, 2024, as the future test year (FTY), and the thirteen months ending December 31, 2025, as the FPFTY in this proceeding (Columbia Volume 10, Statement No. 4, p. 3).

Q. WHAT IS COLUMBIA'S REQUESTED REVENUE INCREASE?

A. Columbia is requesting an annual total revenue increase of $124,138,477 based upon the FPFTY pro forma revenue requirement, which reflects a total rate base claim of $3,489,087,567 and overall rate of return computed at 8.71% for its gas

distribution operations (Columbia Volume 10, Statement No. 4, p. 4 and Columbia Volume 6, Exhibit No. 102, Schedule 3, p. 3).

SUMMARY OF ADJUSTMENTS

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS.

A. The following table summarizes my recommended adjustments:

	Company Claim	I&E Recommended Allowance	I&E Adjustment
O&M Expenses:			
Rate Case Expense	$1,008,000	$558,079	($449,921)
Payroll Expense	$38,227,431	$35,180,705	($3,046,726)
Incentive Compensation	$2,562,000	$2,357,107	($204,893)
Other Employee Benefits	$8,527,000	$6,475,569	($2,051,431)
Injuries and Damages	$398,074	$239,681	($158,393)
Employee Expense	$1,563,000	$1,375,352	($187,648)
Advertising Expense	$610,332	$565,128	($45,204)
NCSC Allocated Compensation – Profit Sharing & Stock Rewards	$3,735,123	$0	($3,735,123)
Total O&M Adjustments			**($9,879,339)**

OVERALL I&E POSITION

Q. WHAT IS I&E'S TOTAL RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for the Company is $852,535,123. This recommended revenue requirement represents an increase of $66,428,044 to the Company's claimed present rate revenues of $786,107,079. This total

recommended allowance incorporates my adjustments made in this testimony to O&M expenses, and those recommended adjustments made in the testimony of I&E witnesses DC Patel (I&E Statement No. 2) and Esyan Sakaya (I&E Statement No. 3). A calculation of the I&E recommended revenue requirement is shown below:

Columbia Gas of PA, Inc.		TABLE I			
R-2024-3046519		INCOME SUMMARY			
	12/31/25	INVESTIGATION & ENFORCEMENT			
	Proforma	[			]
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	786,107,079	0	786,107,079	66,428,044	852,535,123
Deductions:					
O&M Expenses	393,489,441	-9,933,339	383,556,102	956,836	384,512,938
Depreciation	141,404,702	0	141,404,702		141,404,702
Taxes, Other	4,630,755	0	4,630,755	0	4,630,755
Income Taxes:					
Current State	411,513	680,434	1,091,947	4,484,778	5,576,725
Current Federal	3,479,437	1,943,110	5,422,547	12,807,150	18,229,697
Deferred Taxes	28,943,957	0	28,943,957		28,943,957
ITC	-121,211	0	-121,211		-121,211
Total Deductions	572,238,594	-7,309,795	564,928,799	18,248,764	583,177,563
Income Available	213,868,485	7,309,795	221,178,280	48,179,280	269,357,560
Rate Base	3,489,087,567	0	3,489,087,567	0	3,489,087,567
Rate of Return	6.13%		6.34%		7.72%

RATE CASE EXPENSE

Q. BRIEFLY DESCRIBE THE NATURE AND TYPES OF EXPENDITURES TYPICALLY ALLOWED AS A PART OF A REGULATED UTILITY'S OVERALL RATE CASE EXPENSE.

A. The nature and types of individual expenditures that comprise a utility's allowable

claim for rate case expense are those directly incurred to compile, present, and defend a utility's request for a base rate increase before the Commission. The actual expenditures and estimated costs typically found in an allowable rate case expense claim include legal fees for outside counsel, fees to outside consultants, and the cost of printing, document assembly, and postage.

Q. HOW HAS THE COMMISSION TRADITIONALLY TREATED RATE CASE EXPENSE FOR RATEMAKING PURPOSES?

A. The Commission has historically stated that it considers prudently incurred rate case expense as an ongoing expense, occurring at irregular intervals, related to the rendering of utility service. The Commission has also cited the importance of considering the involved utility's history regarding the frequency of rate case filings as an essential element to determine the normalized level of rate case expense for ratemaking purposes.

Q. HOW IS THE FREQUENCY OF RATE CASE FILINGS DETERMINED?

A. The frequency is determined by calculating the average number of months between the utility's recent base rate case filings.

Q. WHAT IS THE COMPANY'S CLAIM FOR RATE CASE EXPENSE?

A. The Company's FPFTY claim for rate case expense is $1,008,000 (Columbia Volume 6, Exhibit No. 104, Schedule 1, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has normalized the entire estimated rate case expense of $1,008,000 over a 12-month period based on prior base rate case filing experience and the expectation of annual future base rate case filings (Columbia Volume 10, Statement No. 4, pp. 21, and 38).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No. I disagree with the Company's claimed total rate case expense of $1,008,000, and I disagree with applying a 12-month normalization period, because it is not supported by the Company's historic actual rate case expenses and the historic rate case filing frequency.

Q. WHAT IS YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. I recommend that the Company's total rate case expense first be adjusted based on the 2020 fully litigated rate case actual expense (the most recently litigated Columbia rate case) as calculated below and then normalized over a period of 16 months resulting in a FPFTY allowance of $558,079 ((adjusted expense of $744,106 ÷ 16 months) x 12 months), or a reduction of $449,921 ($1,008,000 - $558,079) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. First, in response to I&E-RE-04-D, Attachment A along with Volume 6, Exhibit

104, Schedule No. 2, p. 14, the Company provided a breakdown of actual rate case expense incurred and claimed in the last three base rate cases as shown in the table below (I&E Exhibit No. 1, Schedule 1, p. 2):

	R-2020-3018835	**R-2021-3024296**	**R-2022-3031211**	**R-2024-3046519 Claimed**
Gannett Fleming	$38,185	$37,106	$44,249	$60,000
Moul and Associates	$96,188	$66,375	$62,954	$76,000
Post and Schell	$572,287	$409,295	$421,781	$750,000
Concentric Energy Advisors	$40,000	-	$29,453	-
James Cawley	$18,600	-	-	-
Green Efficiency Group	-	-	$108,680	$60,000
Legal Notices	$15,051	$12,722	$43,180	$32,000
Travel Expense	$1,085	-	-	$5,000
Miscellaneous: Supplies, Courier, etc.	$1,126	-	-	$25,000
Total Actual Expense	**$782,522**	**$525,497**	**$710,297**	**-**
Total Expense Claimed	$1,060,000	$1,060,000	$1,254,200	$1,008,000
% of Actual Expense Incurred	**73.82%**	**49.58%**	**56.63%**	**-**
Case Resolution	Fully Litigated	Settled	Settled	-

The above table shows that historically the Company's rate case expense claims are overstated irrespective of the method of case resolution. I recommend adjusting the FPFTY claimed expense of $1,008,000 to $744,106 ($1,008,000 x 0.7382) based on the 2020 fully litigated rate case actual expense experience factor of 73.82% (shown above) to reduce the unreasonable impact to O&M expense resulting from the Company's routine overstatement of costs.

Second, the Company's proposed normalization period fails to properly rely upon the historic data and is speculative in nature. In contrast to the Company's claimed 12-month normalization period, I recommend a 16-month normalization period, which is reasonable and is validated by the Company's recent filing history as shown in the table below (I&E Exhibit No. 1, Schedule 1, p. 2):

Docket No.	Filing Date	Filing Interval – Months	Average of Three Intervals – Months
R-2024-3046519	03/15/2024	24 months	16 months
R-2022-3031211	03/18/2022	12 months	
R-2021-3024296	03/30/2021	11 months	
R-2020-3018835	04/24/2020		

The average historic filing frequency rounds to 16 months ((11 + 12 + 24) = 47 ÷ 3), which supports my recommended normalization period. The Company's rate case expense normalization of 12 months is speculative and is not supported by the historic filing frequency, and the Company is merely relying on its expectation of future base rate case filings. Regardless of whether the Company expects to file yearly base rate cases, it is more appropriate to utilize the historic filing frequency until the data reflects 12-month historic intervals.

Q. SUMMARIZE YOUR RECOMMENDED ADJUSTMENT.

A. The following table summarizes the calculation of my recommended allowance and adjustments:

1. FPFTY rate case expense claim	$1,008,000
2. Allowance at 73.82%	$744,106
3. Expense adjustment	($263,894)
4. Adjusted rate case expense	$744,106
5. Normalization adjustment	($186,026)
6. Normalized allowance	$558,079
7. Total Adjustment (3 + 5)	($449,921)

Q. HAVE OTHER UTILITIES BEEN GRANTED A NORMALIZATION PERIOD BASED ON SPECULATION OF FUTURE FILINGS, AND IF SO, WHAT WAS THE RESULT?

A. Yes. In 2012, the Commission granted PPL Electric Utilities Corporation (PPL) permission to normalize its rate case expense over a 24-month period based on the expected timing of future base rate case filings (*PA. PUC v. PPL Electric Utilities Corporation*, Docket No. R-2012-2290597, pp. 47-48 (Order Entered December 28, 2012). That particular base rate case was filed on March 30, 2012; however, PPL did not file its next rate case until March 31, 2015, which was 36 months after the 2012 rate case filing, resulting in a 12-month mistake. It should be noted that I&E's recommended normalization period in the 2012 PPL proceeding was a 32-month interval based on PPL's historic filing frequency (I&E Statement No. 2, pp. 13-14 at Docket No. R-2012-2290597). I&E's recommendation in that instance produced a much more accurate result than the Company's stated future intention to file a rate case.

Q. ARE THERE ANY COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION FOR A RATE CASE FILING INTERVAL BASED ON HISTORIC FILING FREQUENCY?

A. Yes. The following six cases are the most recent instances where the Commission used the company's historic average filing frequency.

First, in a base rate case filed by Emporium Water Company, the Commission adopted the I&E recommended historic filing frequency finding in favor of I&E's recommended five-year normalization period based on a historic average filing frequency that was rounded down from 64 months (*PA PUC v. Emporium Water Company*, Docket No. R-2014-2402324, p. 50 (Order Entered January 28, 2015).

Second, in a base rate case filed by the City of DuBois, the Commission agreed with I&E's recommendation to use a historic filing frequency finding in favor of I&E's recommended 64-month normalization period, which matched the actual historic filing frequency (*PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, pp. 65-66 (Order Entered March 28, 2017); *PA PUC v. City of DuBois - Bureau of Water*, Docket No. R-2016-2554150, p. 13 (Order Entered May 18, 2017).

Third, in a base rate case filed by Columbia Gas of Pennsylvania, Inc., the Commission held that the normalization period should align with the historic data rather than the company's intent to file its next rate case (*PA PUC v. Columbia*

Gas, Docket No. R-2020-3018835, Opinion and Order, pp. 78-79 (Order Entered February 19, 2021).

Fourth, in a base rate case filed by PECO Energy Company – Gas Division (PECO), the Commission granted I&E's recommended five-year normalization period rather than PECO's claim based on a three-year period because the Commission determined a normalization period based on actual historic filing frequency is more reliable than future speculation (*PA PUC v. PECO Energy Company- Gas Division*, Docket No. R-2020-3018929, Opinion and Order, pp. 117-119 (Order Entered June 22, 2021).

Fifth, in a base rate case filed by Philadelphia Gas Works (PGW), the Commission agreed with I&E's recommended 53-month normalization period rather than PGW's claim based on a three-year period because the Commission determined a normalization period based on actual historic filing frequency and not based on PGW's future intention to file a rate case (*PA PUC v. Philadelphia Gas Works*, Docket No. R-2023-3037933, Opinion and Order, pp. 65-66 (Order Entered November 9, 2023).

Finally, in the most recent base rate case filed by Columbia Water Company, the Commission held that the normalization period should align with the historic filing frequency rather than that company's intent to file its next rate case and the intent to file a base rate case does not justify deviating from the Commission's practice of relying on historical filing frequency (*PA PUC v.*

Columbia Water Company, Docket No. R-2023-3040258, Opinion and Order, p. 34 (Order Entered January 18, 2024).

Q. GIVEN THESE COMMISSION ORDERS AND THE COMPANY'S FILING HISTORY, IS THE CLAIMED 12-MONTH RECOVERY PERIOD REASONABLE?

A. No. The Company has not demonstrated that it will file its next base rate case within twelve months of this rate case. My recommended 16-month normalization period is in the public interest as it moderates the Company's historic filing intervals between rate case filings while also being long enough to protect customers from overpaying for rate case expense.

PAYROLL EXPENSE

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR PAYROLL EXPENSE?

A. The Company's payroll expense claim includes regular payroll, overtime payroll, premium payroll, and net affiliate labor transferred as shown in the breakdown provided in Columbia's filing response to SDR-GAS-RR-026.

Q. WHAT IS THE COMPANY'S CLAIM FOR PAYROLL EXPENSE?

A. The Company is claiming payroll expense of $38,227,431 in the FPFTY (Columbia Volume 6, Exhibit No. 104, Schedule 1, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's claim for the budgeted payroll expense is based on the budgeted FPFTY full-time employee count of 728 (Columbia Statement No. 9, p. 8), and **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** (I&E Exhibit No. 1, Schedule 2, p. 3 CONFIDENTIAL).

Q. DO YOU AGREE WITH THE COMPANY'S PAYROLL EXPENSE CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND?

A. I recommend an allowance of $35,180,705 for payroll expense, or a reduction of $3,046,726 ($38,227,431 - $35,180,705) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A I recommend adjusting the payroll expense claim for a payroll expense adjustment of $3,046,726 for vacant/unfilled positions due to unpredictable normal vacancies, which occur due to retirements, resignations, transfers, etc. throughout the year.

Q. PLEASE EXPLAIN YOUR RECOMMENDED VACANCY ADJUSTMENT.

A. My recommended vacancy adjustment is based on an average of annual normal vacancies experienced in the fiscal years ended November 30, 2021, November 30, 2022, and November 30, 2023. For determining an average annual vacancy rate, first I reviewed the Company's history of actual monthly vacant positions for those three years based on the actual vacant positions as provided in the Company's response to I&E-RE-11-D, Attachment B (I&E Exhibit No. 1, Schedule 3, p. 3). Next, I determined an annual vacancy rate to reflect the most up-to-date information, by averaging the monthly vacancy rates, and then averaged three vacancy rates as summarized in the table below **{BEGIN PROPRIETARY}**:

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	
[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

[1] I&E Exhibit No. 1, Schedule 3, p. 3 shows **{BEGIN PROPRIETARY** [redacted] **{END PROPRIETARY}**.

[redacted] **{END PROPRIETARY}**.

Q. EXPLAIN YOUR RATIONALE FOR THE VACANCY ADJUSTMENT.

A. The Company budgeted its payroll expense based on the FPFTY total employee count of 728, which Columbia expects to maintain throughout the year. However, considering the **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** it is unreasonable to assume that the Company will fill and maintain 100% full staffing of 728 budgeted positions throughout the FPFTY. The Company will continue to experience **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**.

It is important to note that there will always be a certain level of normal vacancies due to retirements, resignations, transfers, layoffs, etc., on a day-to-day operating basis, which are unpredictable and there will always be search and placement time involved in filling normal vacancies.

INCENTIVE COMPENSATION

Q. WHAT IS INCENTIVE COMPENSATION?

A. Incentive compensation consists of payments made to eligible employees that are

in addition to the employees' base salaries and wages. An incentive compensation payout is generally based on the achievement of key performance indicators or triggers (customer service, safety, and financial goals) established by the Company or affiliated/parent company.

Q. WHAT IS THE COMPANY'S CLAIM?

A. The Company's incentive compensation claim is $2,562,000 (Columbia Volume 6, Exhibit No. 104, Schedule 1, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The estimate for incentive compensation is based on the specific salary and incentive potential for each position in accordance with various cash-based award/incentive programs/plans and on the assumption that the total 728 employee positions will be filled and maintained throughout the FPFTY (I&E Exhibit No. 1, Schedule 3, p. 2). The payment of cash-based incentive compensation is based on achievement of performance targets/triggers during the performance period, such as financial (net operating earnings per share (NOEPS), customer care parameters, and safety measures as detailed in the parent Company's incentive plan, "NiSource Inc. - 2020 Omnibus Incentive Plan" (Columbia filing SDR-GAS-027, Attachment A).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend an allowance of $2,357,107 for incentive compensation, or a reduction of $204,893 ($2,562,000 - $2,357,107) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the Company's proposed incentive compensation payout factor of 6.70% of my recommended payroll (labor) expense allowance of $35,180,705. Historically, the Company's average incentive payout ratio is 6.89% of the payroll expense as calculated in the table below (Columbia Volume 2, Exhibit No. 4, Schedule 1, p. 2) (although the 10.08% in 2021 may be an outlier that raises the average):

Fiscal Year Ended	Total O&M Payroll Expense	Incentive Compensation Paid	Payout Factor on Payroll Expense
November 30, 2021	$36,081,489	$3,636,110	10.08%
November 30, 2022	$37,167,108	$1,815,132	4.88%
November 30, 2023	$38,427,989	$2,196,730	5.72%
		Average Payout	6.89%

Nevertheless, the Company has claimed $2,562,000 as a target level payout of incentive compensation, which calculates to a 6.70% payout factor of the

FPFTY payroll expense claim of $38,227,431. Therefore, my recommended allowance for incentive compensation of $2,357,107 (I&E recommended payroll expense of $35,180,705 x payout ratio of 0.067) is reasonable and supported by the Company's historic average actual payout factor as shown in the table above.

OTHER EMPLOYEE BENEFITS EXPENSE

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

A. The other employee benefits claim includes insurance premium costs for health, dental and vision (medical), 401K plan contributions, group life and long-term disability insurance, profit sharing, and other benefits (I&E Exhibit No. 1, Schedule 4, p. 3).

Q. WHAT IS THE COMPANY'S CLAIM FOR OTHER EMPLOYEE BENEFITS EXPENSE?

A. The Company is claiming other employee benefits expense of $8,527,000 (rounded) (Columbia Volume 6, Exhibit No. 104, Schedule 1, p. 2). Based on Columbia's response to I&E-RE-16-D, Attachment A, this expense claim is broken down as shown in the table below (I&E Exhibit No. 1, Schedule 4, p. 5):

Other Benefits	-
Employee Medical Health Insurance	$4,779,435
401K	$2,663,086
Dental	$266,089
Group Life Active	$134,694
Long Term Disability	$211,661
Profit Sharing	$413,427
Vision	$58,825
Total	$8,527,217

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company's FPFTY claim for other employee benefits expense is based on benefits expense planned by a third-party actuarial firm (I&E Exhibit No. 1, Schedule 4, p. 4). The budgeted expense claim is also based on a budgeted employee count of 728 to be maintained throughout the FPFTY.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR OTHER EMPLOYEE BENEFITS EXPENSE?

A. No.

Q. WHAT IS YOUR RECOMMENDATION FOR OTHER EMPLOYEE BENEFITS EXPENSE?

A. I recommend an allowance of $6,475,569 for other employee benefits expense, or

a reduction of $2,051,431 ($8,527,000 - $6,475,569) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I am recommending a reduction to the other employee benefits claim of $8,527,000 in three parts: (1) removal of the profit-sharing cost of $413,427 from benefits expense (I&E Exhibit No. 1, Schedule 4, p. 5); (2) an adjustment to the remaining benefits expense claim of $8,113,573 ($8,527,000 - $413,427) based on a benefits to payroll expense factor of 20% equating to a reduction of $1,077,432 as explained below; and (3) an adjustment for **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}**.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED ADJUSTMENT TO REMOVE THE PROFIT-SHARING EXPENSE CLAIM OF $413,427?

A. Profit-sharing is determined based on employees' eligibility and performance criteria laid out in the NiSource Inc. - Omnibus Incentive Plan and is typically tied to earnings targets and interests of the Company's stockholders. This type of benefit is unrelated to the provision of safe and reliable service. Therefore, ratepayers should not be responsible for paying a benefit available only to certain high-level executive-type positions that is based on a Company's earnings targets rather than goals that benefit ratepayers. Additionally, it is speculative to budget a profit-sharing amount, as the achievement of the Company's earnings and

financial goals or targets depends on several factors. Therefore, I recommend disallowance of the entire profit-sharing expense claim.

Q. EXPLAIN THE BASIS FOR YOUR SECOND ADJUSTMENT TO BENEFITS EXPENSE BASED ON A BENEFITS EXPENSE TO PAYROLL EXPENSE RATIO.

A. First, historically the Company has incurred, or underspent benefits expense as compared to the planned or budgeted expense level as shown in the table below (I&E Exhibit No. 1, Schedule 4, p. 2):

	2021	**2022**	**2023**
Budgeted expense	$8,081,000	$7,364,000	$8,551,000
Actual expense	$6,975,000	$6,603,000	$8,036,000
Variance	($1,106,000)	($761,000)	($515,000)
Underspent %	13.69%	10.33%	6.02%

Second, the Company's actual benefits expense is consistently at approximately 19.34% of payroll expense in the last three years as shown in the table below (I&E Exhibit No. 1, Schedule 4, p. 3):

	Payroll Expense[2]	**Benefits Expense**	**% of Benefits Expense**
2021	$36,081,489	$6,974,756	19.33%
2022	$37,167,108	$6,603,495	17.77%
HTY 2023	$38,427,989	$8,036,006	20.91%
		Three-Year Average	**19.34%**

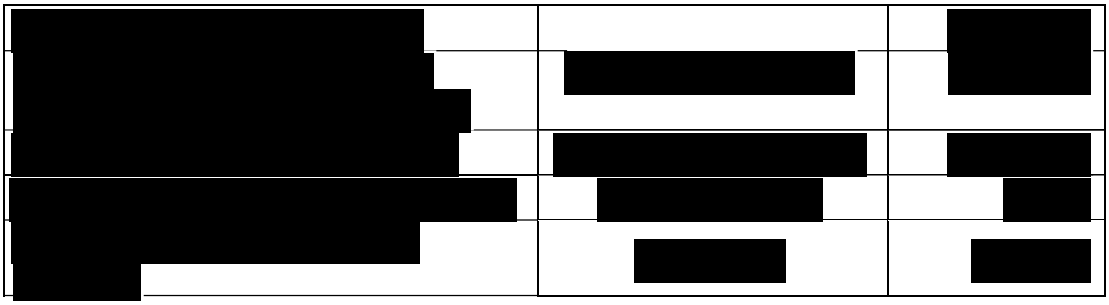
[2] Columbia Volume 2, Exhibit No. 4, Schedule 1, p. 2.

However, the Company has claimed benefits expense at 22.31% and 22.10% of payroll expense in the FTY and FPFTY respectively. Therefore, considering the historic variance in the actual benefits expense as compared to the budgeted amounts as shown in the table above, I recommend adjusting the FPFTY benefits expense claim to 20% of the I&E recommended payroll expense allowance as shown in the table below:

1. FPFTY Benefits Expense Claim	$8,527,000
2. Profit-Sharing Adjustment	$413,427
3. Adjusted Benefits Expense (1 – 2)	$8,113,573
4. I&E Adjustment at 20% of Payroll Expense Allowance of $35,180,705	$7,036,141
5. I&E Recommended Reduction (3 - 4)	$1,077,432

Q. EXPLAIN YOUR THIRD ADJUSTMENT RELATED TO YOUR RECOMMENDED VACANCY ADJUSTMENT AS IT APPLIES TO OTHER EMPLOYEE BENEFITS.

A. My recommendation is based on an **{BEGIN PROPRIETARY}** [redacted]



{END PROPRIETARY}

Q. SUMMARIZE YOUR RECOMMENDATION FOR OTHER EMPLOYEE BENEFITS.

A. Based on the above discussion concerning my recommended benefits expense adjustment and the adjustment for employee vacancies, the total other employee benefits adjustment and allowance are summarized in the table below:

1. FPFTY Other Employee Benefits Claim	$8,527,000
2. Adjustment for Removal of Profit-Sharing Expense	($413,427)
3. Adjustment for Benefits Expense	($1,077,432)
4. Adjustment for Employee Vacancies	($560,572)
5. Total Adjustment to Benefits Expense (2 + 3 + 4)	**($2,051,431)**
6. FPFTY Benefits Expense Allowance (1 – 5)	$6,475,569

<u>INJURIES AND DAMAGES</u>

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR INJURIES AND DAMAGES EXPENSE?

A. The Company's claim for injuries and damages expense includes general liability,

auto liability, and auto physical damage (I&E Exhibit No. 1, Schedule 5, p. 1).

Q. WHAT IS THE COMPANY'S CLAIM FOR INJURIES AND DAMAGES EXPENSE?

A. The Company's claim for injuries and damages expense is $398,074 (Columbia Volume 6, Exhibit No. 104, Schedule 1, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. First, the Company applied a 2023 Gross Domestic Product Implicit Price Deflator (GDPIPD) to the actual expenses of each fiscal year ended November 30, 2019, through November 30, 2023, and calculated the five-year average of $382,017 using the inflated actual expenses for determining the normalized HTY 2023 injuries and damages expense (Columbia Volume 2, Exhibit No. 4, Schedule 2, p. 11, line 8). Then, the Company applied a 2024 average inflation index of 1.99% to the HTY amount of $382,017 to determine the incremental FTY claim and further, applied a 2025 average inflation index of 2.17% to the FTY claim of $389,619 to determine the FPFTY claim of $398,074 (Columbia Volume 6, Exhibit No. 104, Schedule 2, p. 7).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND FOR INJURIES AND DAMAGES EXPENSE?

A. I recommend an allowance of $239,681 for injuries and damages expense, or a reduction of $158,393 ($398,074 - $239,681) to the Company's claim.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. I disagree with the Company's method of calculating its average of five-year inflated actual expenses and the further increases by applying a 2024 and 2025 average inflation index to the inflated average amount of $382,017 to determine the FPFTY claim of $398,074.

In the response to I&E-RE-23-D(B), the Company states that a five-year average, unadjusted for inflation, will not provide an appropriate level of cash payments for 2022-23 costs. I accept that the cash payments incurred five years ago to repair damaged property will cost more today due to inflation (I&E Exhibit No. 1, Schedule 5, p. 2). However, to determine an appropriate allowance for the FPFTY injuries and damages expense, I calculated an average of last three fiscal years' (2021 through 2023) actual payments without an inflation adjustment, which results in my recommended allowance of $239,681 [($307,629 + $83,398 + $328,017) ÷ 3] (Columbia Volume 2, Exhibit No. 4, Schedule 1, p. 2) to even out historic highs and lows of actual payments.

EMPLOYEE EXPENSES

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR EMPLOYEE EXPENSES?

A. The Company's claim for employee expenses includes employee expenses – other, discretionary bonus, business expenses, employee dues and memberships, and meals/entertainment (I&E Exhibit No. 1, Schedule 6, p. 2).

Q. WHAT IS THE COMPANY'S CLAIM FOR EMPLOYEE EXPENSES?

A. The Company's claim for employee expenses is $1,563,000 (Columbia Volume 6, Exhibit No. 104, Schedule 1, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has indicated that the 2023 expense was lower due to the lingering effects of the pandemic on travel (I&E Exhibit No. 1, Schedule 6, p. 1). Thus, FTY and FFPTY amounts reflect budgeted increases.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND FOR EMPLOYEE EXPENSES?

A. I recommend an allowance of $1,375,352 for employee expenses, or a reduction of $187,648 ($1,563,000 - $1,375,352) to the Company's claim.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. I recommend a three-year historic average for this expense due to the fluctuating nature of this expense. The Company has indicated that the 2023 expense was lower due to the lingering effects of the pandemic on travel (I&E Exhibit No. 1, Schedule 6, p. 1). However, 2021 and 2022 would also have been impacted by the pandemic, but expenses in those years were higher. In the absence of support for the higher claim amount, I recommend a three-year average of known experience resulting in an allowance of $1,375,352 [($1,057,284 + $1,974,603 + $1,094,169) ÷ 3 years] (I&E Exhibit No. 1, Schedule 6, p. 4).

ADVERTISING EXPENSE

Q. WHAT IS INCLUDED IN THE COMPANY'S CLAIM FOR ADVERTISING EXPENSE?

A. The Company's claim for advertising expense includes advertisements in newspapers, television, radio, digital social media, and magazines and miscellaneous. These advertisements are for public health and safety, conservation, educational billing, rates, supply, etc., institutional programs, and other advertising programs. (I&E Exhibit No. 1, Schedule 7, p. 2).

Q. WHAT IS THE COMPANY'S CLAIM FOR ADVERTISING EXPENSE?

A. The Company's claim for advertising is $610,332 (Columbia Volume 6, Exhibit 104, Schedule 1, p. 2).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. The Company has incurred a total advertising expense of $528,368 in the HTY 2023. After a ratemaking adjustment for non-recoverable advertisement expense of $131,155, the HTY normalized expense was $491,604 (Columbia Volume 2, Exhibit No. 4, Schedule 2, p. 15).

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM?

A. No.

Q. WHAT DO YOU RECOMMEND FOR ADVERTISING EXPENSE?

A. I recommend an allowance of $565,128 for advertising expense, or a reduction of $45,204 ($610,332 - $565,128) to the Company's claim.

Q. WHAT IS THE BASIS OF YOUR RECOMMENDATION?

A. I recommend advertising expense based on the three-year average of the actual expense from 2021 to 2023 [($571,123 + $632,658 + $491,604) ÷ 3 = $565,128] to smooth out highs and lows experienced in this expense as shown in the table below:

Fiscal year	Expense
2021	$571,123
2022	$632,658
2023	$491,604
FTY	$597,235
FPFTY	$610,332

Additionally, the increases in advertisement expense claims are not supported by reliable estimates based on the HTY 2023 recoverable advertising expense. Columbia did not provide any support with a breakdown of expenses claimed in the FTY and FPFTY in response to I&E-RE-30-D (I&E Exhibit No. 1, Schedule 7, p. 3 - 4).

NCSC ALLOCATED COMPENSATION – PROFIT SHARING AND STOCK REWARDS EXPENSE

Q. WHAT IS INCLUDED IN NCSC ALLOCATED COMPENSATION EXPENSE?

A. NiSource NCSC was established to provide centralized services to the individual operating companies within NiSource and to coordinate the allocation and billing of charges to the NiSource operating companies for services provided by both NCSC directly and by third-party vendors. The rendering of services on a centralized basis enables the affiliates to realize benefits from economies of scale by leveraging the use and specialized expertise of personnel and equipment across

the whole enterprise. Thus, NCSC offers Columbia, as well as the other NiSource distribution companies, access to the depth and breadth of professional experience that may not otherwise be available, or that may be available from consultants at much higher costs. (Columbia Volume 10, Statement No. 4, pp. 15-16).

Q. WHAT PORTION OF NCSC ALLOCATED COMPENSATION ARE YOU ADDRESSING HEREIN?

A. I am addressing allocated profit sharing and stock rewards.

Q. WHAT IS THE COMPANY'S CLAIM FOR NCSC ALLOCATED PROFIT-SHARING, AND STOCK REWARDS EXPENSES?

A. The Company is claiming total profit sharing and stock rewards of $3,735,123 broken down as follows: profit-sharing of $230,925, and stock rewards expense of $3,504,198, which is included in the total NCSC expense claim (I&E Exhibit No. 1, Schedule 8, p. 1).

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIM?

A. As discussed above, these expenses are a part of the NCSC employees' service charge, based on a budgeted allocation in the FTY and FPFTY claims based on the HTY 2023 normalized expense level and ratemaking adjustments.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM FOR NCSC - PROFIT SHARING AND STOCK REWARDS EXPENSES?

A. No.

Q. WHAT DO YOU RECOMMEND FOR NCSC - PROFIT SHARING AND STOCK REWARD EXPENSES?

A. I recommend a complete disallowance of the $3,735,123 claim for NCSC allocated profit sharing and stock rewards expense.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. **Profit-Sharing:**

Per the Company's response to I&E-RE-17-D, the FPFTY NCSC expense claim includes profit-sharing expense of $230,925 (I&E Exhibit No. 1, Schedule 8, p. 1). As discussed in the other employee benefits section above, I reiterate that profit sharing is determined based on an employees' eligibility and performance criteria laid out in the NiSource Inc. - Omnibus Incentive Plan and is typically tied to earning targets and interests of the Company's stockholders. This type of benefit is unrelated to the provision of safe and reliable service, and therefore, ratepayers should not be responsible for paying a benefit available only to certain high-level executive-type positions based on earning targets rather than goals that benefit ratepayers. Additionally, it is speculative to budget a profit-sharing amount as the achievement of the Company's earnings and financial goals, or targets, depends on

several factors. Therefore, I recommend disallowance of the entire profit-sharing expense claim from the FPFTY NCSC expense claim.

Stock Rewards:

Per Company's response to I&E-RE-17-D, the FPFTY NCSC expense claim includes stock rewards expense of $3,504,198 (I&E Exhibit No. 1, Schedule 8, p. 1). Stock rewards are a type of incentive compensation linked to financial goals and targets such as earnings per share, rate of return on equity, or appreciation of the parent company's common stock. These goals are specifically shareholder-oriented goals and not ratepayer goals. Thus, stock rewards should not be funded by ratepayers. Allowing this claim in rates would result in higher rates and revenues at the expense of ratepayers, which would directly benefit the parent company's financial goals. Additionally, it must be noted that stock rewards are limited to certain top-level executives, and therefore, it is not immediately obvious how stock rewards expense is related to providing safe and reliable service to ratepayers. Therefore, I recommend disallowance of the entire stock rewards expense claim from the FPFTY NCSC expense claim.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Professional and Educational Experience

Christian Yingling

Professional Experience

October 2023 to Present
Fixed Utility Financial Analyst
Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
Bureau of Investigation & Enforcement

February 2019 to August 2022
US Army Infantry Officer

Education and Training

SGPS Elizabethtown College, Elizabethtown, Pennsylvania
Master of Science in Finance, 2024

York College of Pennsylvania, York, Pennsylvania
Bachelor of Science in Business Administration, 2018

Testimony Submitted

I have testified and/or submitted testimony in the following proceedings:

- Docket No. R-2023-3040153 – CAN DO Inc. – Water Division (O&M)

I&E Exhibit No. 1
Witness: Christian Yingling
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2024-3046519

Exhibit to Accompany

the

Direct Testimony

of

Christian Yingling

Bureau of Investigation & Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. Staff RE-004-D:

Reference Columbia Volume 6, Exhibit 104, Schedule 2, p. 14 concerning the normalization of rate case expense of $1,008,000:

A. Provide the claimed rate case expense and the actual total dollar amount expended for the settled rate cases at: (1) Docket No. R-2020-3018835; (2) Docket No. R-2021-3024296; and (3) Docket No. R-2022-3031211 along with a detailed breakdown for actual incurred expenses by category (e.g., Gannett Fleming, Moul and Associates, Post and Schell, Green Energy Efficiency Group, Legal Notices, Travel Expense, and Miscellaneous Expenses).

B. Indicate the filing date for each of the above-mentioned rate cases.

Response:

A. Please see I&E RE-004-D Attachment A.

B. Please see I&E RE-004-D Attachment A.

Columbia Gas of Pennsylvania, Inc.
Summary of Rate Case Expense
By Docket #

Line No.	Description	R-2020-3018835	R-2021-3024296	R-2022-3031211
Part A:		**Amount ($)**	**Amount ($)**	**Amount ($)**
1	Gannett Fleming	38,185	37,106	44,249
2	Moul and Associates	96,188	66,375	62,954
3	Post and Schell	572,287	409,295	421,781
4	Concentric Energy Advisors	40,000	-	29,453
5	James Cawley	18,600	-	-
6	Green Efficiency Group	-	-	108,680
7	Legal Notices	15,051	12,722	43,180
8	Travel Expense	1,085	-	-
9	Miscellaneous: Supplies, Courier, Etc.	1,126	-	-
10	**Total**	$ 782,522	$ 525,497	$ 710,297
11	**Amount Requested 1_/**	$ 1,060,000	$ 1,060,000	$ 1,254,200
12	**Amount Approved 2_/**	$ 636,000	$ -	$ -
Part B:				
1	**Filing Date**	4/24/2020	3/30/2021	3/18/2022
2	**Resolution**	Fully Litigated	Settled	Settled

1_/ Requested amounts reflect the budgeted amount for a fully litigated case, however the 2021 and the 2022 cases were settled prior to hearings.
2_/ A 20 month amortization period was approved versus the 12 month requested.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. Staff RE-015-D:

Reference Columbia Volume 2, Exhibit 4, Schedule 1, p. 2 concerning other employee benefits. Provide the following:

A. A detailed breakdown of other employee benefits of $6,974,756, $6,603,495, and $8,036,006 for the fiscal years ended November 30, 2021, November 30, 2022, and November 30, 2023, respectively in the format as provided in response to I&E-RE-17-D in the last rate case at Docket No. R-2022-3031211.

B. A statement showing budgeted versus actual other employee benefits expense incurred for the fiscal years ended November 30, 2021, November 30, 2022, and November 30, 2023, respectively in the format provided in response to I&E-RE-17-D in the last rate case at Docket No. R-2022-3031211.

Response:

A. Please see I&E RE-015-D Attachment A.

B. Please see I&E RE-015-D Attachment B.

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ıer Employee Benefits
-15-D Attachment B

Columbia Gas of Pennsylvania, Inc.
Other Employee Benefits
$000 (Dollars in Thousands)

	PLAN			ACTUAL			VARIANCE		
	Twelve Months Ended November 30, 2023			Twelve Months Ended November 30, 2023			Twelve Months Ended November 30, 2023		
Hyperion Account	Gross	Capital	Net	Gross	Capital	Net	Gross	Capital	Net
Other Benefits	(50)	5	(55)	208		208	258	(5)	263
Employee Medical Health Insurance	9,042	4,054	4,988	9,539	5,751	3,788	497	1,697	(1,200)
401K	4,359	1,910	2,448	4,413	2,197	2,216	55	287	(233)
Dental	404	156	248	477		477	73	(156)	230
Group Life Active	293	115	178	306		306	13	(115)	128
Long Term Disability	393	154	239	448		448	55	(154)	209
Profit Sharing	812	353	459	1,011	480	531	199	127	71
Vision	77	31	46	62		62	(15)	(31)	16
Total	**15,330**	**6,779**	**8,551**	**16,464**	**8,428**	**8,036**	**1,134**	**1,649**	**(515)**

	Twelve Months Ended November 30, 2022			Twelve Months Ended November 30, 2022			Twelve Months Ended November 30, 2022		
Hyperion Account	Gross	Capital	Net	Gross	Capital	Net	Gross	Capital	Net
Other Benefits	(87)	5	(92)	114		114	201	(5)	206
Employee Medical Health Insurance	7,775	3,445	4,330	7,951	4,882	3,068	176	1,437	(1,261)
401K	3,561	1,556	2,004	3,754	1,875	1,878	193	319	(126)
Dental	455	174	281	480		480	25	(174)	199
Group Life Active	284	111	173	296		296	12	(111)	123
Long Term Disability	377	148	229	409		409	32	(148)	180
Profit Sharing	688	296	391	546	247	299	(142)	(49)	(93)
Vision	79	32	47	59		59	(20)	(32)	12
Total	**13,133**	**5,768**	**7,364**	**13,608**	**7,005**	**6,603**	**476**	**1,237**	**(761)**

	Twelve Months Ended November 30, 2021			Twelve Months Ended November 30, 2021			Twelve Months Ended November 30, 2021		
Hyperion Account	Gross	Capital	Net	Gross	Capital	Net	Gross	Capital	Net
Other Benefits	365	159	206	289	-	289	(76)	(159)	83
Employee Medical Health Insurance	8,975	3,925	5,049	7,993	4,731	3,263	(981)	805	(1,787)
401K	3,117	1,367	1,750	3,516	1,680	1,837	400	313	87
Dental	459	200	259	435	-	435	(24)	(200)	176
Group Life Active	271	118	153	294	-	294	23	(118)	141
Long Term Disability	364	159	205	393	-	393	30	(159)	189
Profit Sharing	733	321	412	717	320	397	(16)	(1)	(15)
Vision	84	37	47	67	-	67	(17)	(37)	20
Total	**14,367**	**6,286**	**8,081**	**13,705**	**6,730**	**6,975**	**(662)**	**444**	**(1,106)**

Columbia Gas of Pennsylvania, Inc.
Other Employee Benefits

	12 Months Ending November 30		
Other Employee Benefits	**2021**	**2022**	**2023**
	$	$	$
9001-Benefit-OH Transfers	196	-	-
9006-Employee Medical Health Ins	-	154,716	(18,051)
9007-401K Plan	3,563,935	3,754,638	4,409,608
9008-Dental	434,969	480,033	477,368
9009-Group Life - Active	293,740	296,200	306,114
9010-Long Term Disability	393,315	409,130	448,235
9012-Employee Assistance Program	9,813	8,033	10,571
9013-Employee Benefits	-	(2,243)	-
9014-Post Empl Benefits-FAS112	-	(111,493)	(113,987)
9015-Vision Plan	67,429	58,883	62,138
9017-Profit Sharing	396,897	298,713	530,539
9018-Education Reimbursement	2,707	5,822	7,956
9021-Moving Expense	115,000	40,000	130,000
9022-Medical - Active	7,266,636	8,250,968	9,591,355
9023-HMO	(449,394)	(1,937,127)	(2,171,986)
9026-Flex Spending Health	161,420	173,880	173,100
9031-Pension-Credits	-	-	-
9032-Prescriptions	1,349,758	1,482,073	2,137,578
9033-Pension-SERP	-	-	-
9036-Thrift Restoration - Company	6,090	(1,051)	3,616
9061-Transfer-Employ Med Health Ins	(4,904,284)	(4,882,284)	(5,750,735)
9064-Transfer-Pension-Qualified	-	-	-
9065-Transfer-401K Plan	(1,733,471)	(1,875,396)	(2,197,411)
Total	**6,974,756**	**6,603,495**	**8,036,006**

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. Staff RE-016-D:

Reference Columbia Volume 6, Exhibit 104, Schedule 1, pp. 2-4 concerning other employee benefits. Provide the following:

A. A detailed breakdown of other employee benefits of $8,268,000 and $8,527,000 claimed in the FTY and FPFTY in the same format provided in response to I&E-RE-18-D in last rate case at Docket No. R-2022-3031211.

B. A detailed explanation with supporting calculation for the budgeted increases of $231,994 in the FTY and $259,000 in the FPFTY claims.

C. Supporting calculation and documentation used to determine the FTY and FPFTY other employee benefits dollar amounts needed for each type of expense specified in response to Part A above.

Response:

A. Please refer to I&E RE-016-D Attachment A.

B. Please refer to the response to subpart C.

C. Benefits are planned by a third-party actuarial firm. See I&E RE-016-D Attachment A page 2 for the provided forecast used as the input for the budget.

Columbia Gas of Pennsylvania Inc.

I&E Exhibit No. 1
Schedule 4
Page 5 of 5

	Twelve Months Ended November 30, 2024		
Hyperion Account	**Gross**	**Capital**	**Net**
Other Benefits	30,380	22,291	8,089
Employee Medical Health Insurance	8,854,374	4,446,075	4,408,298
401K	4,649,777	2,105,787	2,543,989
Dental	452,624	181,160	271,464
Group Life Active	253,486	103,073	150,413
Long Term Disability	397,803	113,772	284,031
Profit Sharing	1,007,812	463,471	544,341
Vision	96,232	39,035	57,196
Total	**15,742,487**	**7,474,665**	**8,267,822**

	Twelve Months Ended December 31, 2025					
Hyperion Account	**Gross**	**Capital**	**Net**	**Actuarial Value from page 2**	**Difference from Support**	
Other Benefits	-	-	-			
Employee Medical Health Insurance	9,045,000	4,265,565	4,779,435	9,045,000	0	Active1 + Active HSA + Opt Out Credits
401K	4,844,000	2,180,914	2,663,086	4,844,000	0	
Dental	484,000	217,911	266,089	484,000	-	
Group Life Active	245,000	110,306	134,694	245,000	0	
Long Term Disability	385,000	173,339	211,661	385,000	(0)	
Profit Sharing	752,000	338,573	413,427	752,000	0	
Vision	107,000	48,175	58,825	107,000	0	
Total	**15,862,000**	**7,334,783**	**8,527,217**			

Columbia Gas of Pennsylvania, Inc.

I&E Exhibit No. 1
Schedule 5
Page 1 of 2

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. Staff RE-045:

Reference Columbia's response to I&E-RE-023-D. Provide the following:

A. An explanation for why the property damages in this expense category would not already be covered by business insurance.

B. Examples of types of Injuries and Damages included in this claim.

Response:

A. The Injuries and Damages expense category reflects Columbia Gas of Pennsylvania's deductibles for insurance claims prior to the business insurance being triggered.

B. Injuries and Damages are comprised of the following claim types:

i. General Liability - damage to third party property, and third-party bodily injury.
ii. Auto Liability - third party auto damage, and third-party bodily injury caused by an automobile.
iii. Auto Physical Damage - first party auto damage.

Columbia Gas of Pennsylvania, Inc.

I&E Exhibit No. 1
Schedule 5
Page 2 of 2

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. Staff RE-023-D:

Reference Columbia Volume 2, Exhibit 4, Schedule 2, p. 11 concerning injuries and damages. Provide the following:

A. The source documentation used to obtain the GDP Deflator column 2 and 3 details.

B. Explanation with rationale for applying GDP Deflator to the actual amount paid for injuries and damages each year for 2018/19 through 2022/23 to determine the normalized HTY amount of $367,013 as the basis for the budgeted FTY claim.

Response:

A. Please refer to I&E RE-023-D Attachment A for the requested information. The GDP from Global Insight for January 2024 was utilized.

B. A five-year average, unadjusted for inflation, will not provide an appropriate level of cash payments for 2022-23 costs. The cash payments incurred five years ago to repair damaged property will cost more today due to inflation. While a five-year average appropriately reflects the variable nature of Injuries and Damages, it does not capture the inflationary effects. Thus, the GDP Deflator is used to reflect real dollars for the twelve months ending November 2023, and as such, it is an appropriate basis for determining the budgeted FTY claim.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. Staff RE-036-D:

Reference Columbia Volume 6, Exhibit 104, Schedule 1, p. 2 concerning employee expenses, provide the following:

A. Detailed breakdown for the FTY and FPFTY claims of $1,614,000 and $1,563,000.

B. Detailed explanation for the yearly fluctuation in this expense from $998,597 in the HTY, to $1,614,000 in the FTY, and then $1,563,000 in the FPFTY.

Response:

A. Please see I&E RE-036-D Attachment A for a breakdown of employee expenses by cost categories in the FTY and FPFTY.

B. The Company maintained travel restrictions throughout the HTY, which was a lingering effect from the Covid-19 Pandemic. Since Covid-19 cases have decreased significantly, business travel is expected to increase in 2024 and 2025, with increases to business travel related expenses reflected in the FTY and FPFTY.

Line No.	Cost Category	Normalized HTY Twelve Months Ended November 30, 2023 (1)	Difference (2) = (3) - (1)	Normalized FTY Twelve Months Ended November 30, 2024 (1)	Difference (2) = (3) - (1)	Normalized FPFTY Twelve Months Ended December 31, 2025 (3)
1	Employee Expenses - Other	$ 358,935	$ 303,440	$ 662,374	$ 49,231	$ 711,605
2	Discretionary Bonus	178,757	(163,935)	14,822	(14,822)	-
3	Business Expenses	286,033	549,232	835,265	(52,038)	783,227
4	Employee Dues & Memberships	19,907	(431)	19,476	(2,945)	16,531
5	Meals / Entertainment (50)	250,538	(168,863)	81,675	(29,593)	52,081
6	**Subtotal**	**$ 1,094,169**	**$ 519,442**	**$ 1,613,612**	**$ (50,167)**	**$ 1,563,445**
7	Subtotal Rounded to the Thousands	$ 1,094,169	$ 519,831	$ 1,614,000	$ (51,000)	$ 1,563,000
8	Rate Making Adjustment	$ (95,572)	$ 95,572	$ -	$ -	$ -
9	**Total Employee Expenses**	**$ 998,597**	**$ 615,403**	**$ 1,614,000**	**$ (51,000)**	**$ 1,563,000**

Columbia Gas of Pennsylvania, Inc.

I&E Exhibit No. 1
Schedule 6
Page 3 of 4

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. Staff RE-035-D:

Reference Columbia Volume 2, Exhibit 4, Schedule 1, p. 2 concerning normalized HTY employee expenses of $998,597.

A. Provide a breakdown of expenses by category.

B. Explain why each category listed in response to Part A above is appropriate to include for ratemaking.

C. Provide similar historic breakdowns for the fiscal years 2021 and 2022 of $1,057,284 and $1,974,603.

Response:

A. Please see I&E RE-035-D Attachment A to this response for the breakdown of per books HTY Employee Expenses of $1,094,169 by detailed cost category. The normalized amount of $998,597 consists of the HTY per books amount of $1,094,169 and ratemaking adjustments made on Exhibit 4, Schedule 2, p. 12.

B. The categories of Employee Expenses provided in I&E RE-035-D Attachment A to this response are designed to ensure that the Company is in compliance with IRS and FERC Regulations, as well as rate filings and tax reporting. I&E RE-035-D Attachment B to this response is the current NiSource Business Expense Policy that outlines the various aspects of business expenses that occur within these categories of Employee Expenses, which include business travel, business meals, business meetings and lodging expenses, as well as others. Employee Expenses included in Part A are appropriate for ratemaking as they are normal costs associated with providing safe and reliable service.

C. Please see I&E RE-035-D Attachment A to this response for the breakdown for the 12-months ended November 30, 2021 and November 30, 2022.

Columbia Gas of Pennsylvania, Inc.

Employee Expenses

Line No.	Cost Element	Description	Per Books TME 11-30-2023	Per Books TME 11-30-2022	Per Books TME 11-30-2021
1	3100	Business Expenses	286,033	312,451	192,782
2	3101	Meals 100 Deductible	-	-	-
3	3102	Meals_Entertain 50 Deduc	250,538	263,589	205,637
4	3103	Non-Deductible Business Expense	72,393	65,765	1,203
5	3105	Taxable Business Exp-ERS Only	-	-	-
6	3106	Gifts	6,803	6,663	7,855
7	3502	Employee Dues_Memberships	19,907	10,247	16,311
8	3633	Relocation Reimbursements	-	-	-
9	3650	Clothing Allowance	279,738	534,049	404,910
10	9020	Hire_Spot_Discretionary Bonus	178,757	781,840	228,588
11		Total Per Books	1,094,169	1,974,603	1,057,284
		Per Summary Exhibit 4 Schedule 1	1,094,169	1,974,603	1,057,284
		Check Total	0	0	-

COLUMBIA GAS OF PENNSYLVANIA, INC.
53.53 III. BALANCE SHEET AND OPERATING STATEMENT
A. All UTILITIES

25. Submit details of expenditures for advertising (National and Institutional and Local media). Provide a schedule of advertising expense by major media categories for the test year and the prior two comparable years with respect to:

a. Public health and safety

b. Conservation of energy

c. Explanation of Billing Practices, Rates, etc.

d. Provision of factual and objective data programs in educational institutions

e. Other advertising programs

f. Total advertising expense

Response:

For a schedule of advertising expense by major media categories for the twelve months ended November 30, 2023, 2022, and 2021, see Page 2.

COLUMBIA GAS OF PENNSYLVANIA, INC
ADVERTISING SUMMARY

Line No.		Period Ending 11/30/23 $	Period Ending 11/30/22 $	Period Ending 11/30/21 $
	NEWSPAPER			
1	a. Public Health & Safety	0	0	0
2	b. Conservation	0	0	0
3	c. Educational Billing, Rates, Supply, etc.	0	0	0
4	d. Institutional Programs	0	0	0
5	e. Other Advertising Programs	18,708	557	0
6	Total Newspaper Advertising Expense	18,708	557	0
7				
8	**TELEVISION**			
9	a. Public Health & Safety	31,749	36,869	28,195
10	b. Conservation	0	0	0
11	c. Educational Billing, Rates, Supply, etc.	103,181	133,668	141,490
12	d. Institutional Programs	22,500	0	25,299
13	e. Other Advertising Programs	0	0	0
14	Total Television Advertising Expense	157,430	170,537	194,983
15				
16	**RADIO**			
17	a. Public Health & Safety	29,304	47,150	37,864
18	b. Conservation	0	0	0
19	c. Educational Billing, Rates, Supply, etc.	10,250	11,724	36,885
20	d. Institutional Programs	45,900	82,864	73,489
21	e. Other Advertising Programs	0	0	0
22	Total Radio Advertising Expense	85,454	141,738	148,238
23				
24	**DIGITAL / SOCIAL MEDIA**			
25	a. Public Health & Safety	5,250	4,000	0
26	b. Conservation	0	0	0
27	c. Educational Billing, Rates, Supply, etc.	87,722	99,565	0
28	d. Institutional Programs	0	13,251	0
29	e. Other Advertising Programs	0	0	0
30	Total Radio Advertsing Expense	92,972	116,815	0
31				
32	**MAGAZINES & MISCELLANEOUS**			
33	a. Public Health & Safety	46,978	53,419	87,291
34	b. Conservation	0	0	0
35	c. Educational Billing, Rates, Supply, etc.	81,874	100,009	67,570
36	d. Institutional Programs	62,755	47,243	73,041
37	e. Other Advertising Programs	76,588	0	0
38	Total Mag. & Misc. Advertising Expense	268,195	200,671	227,902
39				
40	Advertising Expense	527,463	632,658	0
41	Misclassified Items	905	990	0
42	Per Books Advertising Expense	528,368	633,648	571,123
43				
44	RP1162 - Public Awareness Advertising Expense moved from Outside Services, Material & Supplies, and Other O&M	95,296	56,112	0
45	Misclassified Items	(905)	(990)	0
46	Total Miscellaneous Adjustments	**94,391**	**55,122**	**0**
47				
48	Adjustments for non recoverable advertising	(131,155)	(130,108)	(171,829)
49				
50	Normalized Expense	491,604	558,662	399,294

Columbia Gas of Pennsylvania, Inc.

I&E Exhibit No. 1
Schedule 7
Page 3 of 4

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. Staff RE-030-D:

Reference Columbia Volume 2, Exhibit 4, Schedule 2, p. 15 concerning advertising expense:

A. Provide copies of all workpapers used to determine the representative level of recoverable HTY advertising of $491,604.

B. Provide all supporting papers and calculations used to determine the Adjustments for Non-Recoverable Advertising of ($131,155).

C. Provide a similar breakdown to that provided in Exhibit 4, Schedule 2, p. 15 for the FPFTY claim of $610,332 shown on Volume 6, Exhibit No. 104, Schedule 1, p. 2.

D. Provide samples of all “other” advertising categories shown in response to Part C above.

Response:

A. See response to OCA 1-003 for CONFIDENTIAL advertising workpapers.

B. See response to OCA 1-003 for CONFIDENTIAL advertising workpapers.

C. A similar breakout of budget FTY and FPFTY is not available as the budget is not compiled by detailed categories.

D. See response in subpart C above.

Columbia Gas of Pennsylvania, Inc.

I&E Exhibit No. 1
Schedule 7
Page 4 of 4

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

OFFICE OF CONSUMER ADVOCATE INTERROGATORIES
Set 1

Question No. OCA 1-003

For each Company witness that filed testimony:

****** OCA agreed to narrow this request to the following: Please provide any final workpapers that witnesses relied upon that have not already been provided either as an exhibit or in responses to standard data requests.

Response:

See files corresponding to responding witnesses in the “Excel Native Form” folder in SharePoint.

Columbia Gas of Pennsylvania, Inc.

I&E Exhibit No. 1
Schedule 8
Page 1 of 1

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RE

Question No. Staff RE-017-D:

Reference Columbia Volume 6, Exhibit No. 104, Schedule 1, pp. 2-4 concerning other employee benefits of $8,268,000 (FTY) and $8,527,000 (FPFTY). State whether all allocated amounts from the parent company and/or affiliated companies are included in response to I&E-RE-16-D, Part A above. If not, identify the following:

A. The account (on Columbia Ex. 104, Sch. 1, p. 2) where such amounts are reflected.

B. The attributable expense amount for profit sharing benefits.

C. The attributable capitalized amount for profit sharing benefits.

D. The attributable expense amount for stock rewards.

E. The attributable capitalized amount for stock rewards.

Response:

A. Amounts pertaining to NCSC employees are allocated from NCSC and are included in line 20, NCSC Expenses.

B. Profit Sharing Expense – FTY $309,273 and FPFTY $230,925.

C. Profit Sharing is not capitalized.

D. Stock Compensation Expense – FTY $3,265,775 and FPFTY $3,504,198.

E. Stock Compensation is not capitalized.

I&E Statement No. 2
Witness: D. C. Patel

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2024-3046519

Direct Testimony

of

D. C. Patel

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

Effective Date of New Rates

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is D. C. Patel and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL EXPERIENCE?

A. My educational and professional experience is set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for representing the public interest in rate and other proceedings before the Commission. I&E's analysis in this proceeding is based on its responsibility to represent the public interest. This responsibility requires balancing the interests of ratepayers, the utility company, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to review the base rate filing of Columbia Gas of Pennsylvania, Inc. (Columbia or Company) and make recommendations regarding the Company's rate of return, including capital structure, cost of long-term debt, cost of short-term debt, the cost of equity, and the overall fair rate of return for the fully projected future test year (FPFTY) ending December 31, 2025. Additionally, I will address Columbia's proposed effective date of new rates, which is prior to the beginning of the FPFTY and its impact on ratepayers.

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. Yes. I&E Exhibit No. 2 contains schedules that support my direct testimony.

BACKGROUND

Q. WHAT IS THE GENERAL DEFINITION OF RATE OF RETURN IN THE CONTEXT OF A RATE CASE?

A. Rate of return is one of the components of the revenue requirement formula. Rate of return is the amount of revenue an investment generates in the form of net income. It is typically expressed as a percentage of the amount of an asset base at a particular point in time, which in base rate proceedings, is the projected rate base balance at the end of the FPFTY.

Q. WHAT IS THE REVENUE REQUIREMENT FORMULA?

A. The revenue requirement formula used in base rate cases is as follows:

RR = E + D + T + (RB x ROR)

Where:

RR	=	Revenue Requirement
E	=	Operating Expenses
D	=	Depreciation Expense
T	=	Taxes
RB	=	Rate Base
ROR	=	Overall Rate of Return

In the above formula, the rate of return is expressed as a percentage. The calculation of that percentage is independent of the determination of the appropriate rate base value for ratemaking purposes. As such, the appropriate total dollar return is dependent upon the proper computation of the rate of return and the proper valuation of the Company's rate base.

Q. WHAT CONSTITUTES A FAIR AND REASONABLE OVERALL RATE OF RETURN?

A. A fair and reasonable overall rate of return is one that will allow the utility an opportunity to recover those costs prudently incurred by all classes of capital used to finance the rate base during the prospective period in which its rates will be in effect.

The *Bluefield Water Works & Improvements Co. v. Public Service Comm. of West Virginia,* 262 U.S. 679, 692-93 (1923), and the *Federal Power*

Commission et al v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944) cases set forth the principles that are generally accepted by regulators throughout the country as the appropriate criteria for measuring a fair rate of return:

1. A utility is entitled to a return similar to that being earned by other enterprises with corresponding risks and uncertainties, but not as high as those earned by highly profitable or speculative ventures.
2. A utility is entitled to a return level reasonably sufficient to assure financial soundness.
3. A utility is entitled to a return sufficient to maintain and support its credit and raise necessary capital.
4. A fair return can change (increase or decrease) along with economic conditions and capital markets.

Q. EXPLAIN HOW THE OVERALL RATE OF RETURN IS TRADITIONALLY CALCULATED IN BASE RATE PROCEEDINGS.

A. In base rate proceedings, the overall rate of return is traditionally calculated using the weighted average cost of capital method. To calculate the weighted average cost of capital, a company's capital structure must first be determined by comparing the percentage of each capitalization component which has financed the rate base to total capital. In Columbia's case, the capital components consist of long-term debt, short-term debt, and common equity. Next, the effective cost rate of each capital structure component must be determined. The historical

component of the debt cost rate can be computed accurately, and any future debt issuances are based on estimates. The cost rate of common equity is not fixed and is more difficult to measure. Because of this difficulty, a proxy group is used as discussed later in this testimony. Then, each capital structure component percentage is multiplied by its corresponding effective cost rate to determine the weighted capital component cost rate. The table in the *"I&E Position"* section below demonstrates the interaction of each capital structure component and its corresponding effective cost rate. Finally, the sum of the weighted cost rates produces the overall rate of return. This overall rate of return is multiplied by the rate base to determine the return portion of a company's revenue requirement.

COMPANY'S RATE OF RETURN CLAIM

Q. WHO IS THE COMPANY'S RATE OF RETURN WITNESS?

A. Paul R. Moul is the primary witness addressing the rate of return. Throughout his direct testimony (Columbia Statement No. 8), Mr. Moul provides his analysis for the claimed capital structure, cost of common equity, and overall rate of return for Columbia. Additionally, Mark Kempic, President and Chief Operating Officer of Columbia provides testimony regarding the Company's "Management Effectiveness" claim for a 25-basis point reward or adder in the claimed rate of return on common equity (Columbia Statement No. 1).

Q. PLEASE SUMMARIZE MR. MOUL'S RECOMMENDATIONS FOR THE COMPANY'S RATE OF RETURN CLAIM.

A. Mr. Moul recommends the following rate of return for the Company based on its FPFTY ending December 31, 2025 (Columbia Statement No. 8, p. 2, line 7 and Columbia Exhibit No. 400, Schedule 1, p. 1):

COLUMBIA GAS OF PENNSYLVANIA, INC. Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	43.12%	5.07%	2.19%
Short-Term Debt	2.48%	5.25%	0.13%
Common Equity	54.40%	11.75%	6.39%
Total	**100.00%**		**8.71%**

I&E POSITION

Q. PLEASE SUMMARIZE YOUR RATE OF RETURN RECOMMENDATION FOR THE COMPANY.

A. I recommend the following rate of return for the Company (I&E Exhibit No. 2, Schedule 1):

I & E Recommendation Columbia Gas of Pennsylvania, Inc. Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	43.12%	5.07%	2.19%
Short-Term Debt	2.48%	5.25%	0.13%
Common Equity	54.40%	9.93%	5.40%
Total	**100.00%**		**7.72%**

PROXY GROUP

Q. WHAT IS A PROXY GROUP AS USED IN BASE RATE CASES?

A. A proxy group is a set of companies that have similar traits as compared to the subject utility. This group of companies acts as a benchmark for determining the subject utility's rate of return in a base rate case.

Q. WHAT ARE THE REASONS FOR USING A PROXY GROUP?

A. A proxy group's cost of equity is used as a benchmark to satisfy the long-established guideline of utility regulation that seeks to provide the subject utility with the opportunity to earn a return similar to that of enterprises with corresponding risks and uncertainties.

A proxy group is typically utilized since the use of data exclusively from one company may be less reliable. The lower reliability occurs because the data for one company may be subject to events that can cause short-term anomalies in the marketplace. The rate of return on common equity for a single company could become distorted in these circumstances and would therefore not be representative of similarly situated companies. Therefore, a proxy group has the effect of smoothing out potential anomalies associated with a single company.

Q. WHAT CRITERIA DID YOU USE IN SELECTING YOUR GAS UTILITY PROXY GROUP?

A. The criteria for my proxy group was designed to select companies that are

representative of Columbia. I applied the following criteria to Value Line's "Natural Gas Utility" company group:

1. Fifty percent or more of the company's revenues must be generated from the regulated gas utility industry.
2. The company's stock must be publicly traded.
3. Investment information for the company must be available from more than one source, which includes Value Line.
4. The company must not be currently involved in an announced merger or the target of an acquisition.
5. The company must have four consecutive years of historic earnings data.
6. The company must be operating in a state that has a deregulated gas utility market.

Q. WHAT CRITERIA DID MR. MOUL USE IN SELECTING THE COMPANIES THAT FORMULATE HIS GAS GROUP?

A. Mr. Moul began with the gas utilities contained in Value Line's Investment Survey. From there, he eliminated two companies, including UGI Corp. (UGI), due to its diversified businesses, which includes six reportable segments. These various business segments include propane, international liquefied petroleum gas segments, natural gas utility, energy services, and electric generation. Beyond his rationale for excluding UGI, Mr. Moul has not provided a list of criteria used to

determine the remainder of his Gas Group (Columbia Statement No. 8, p. 4, lines 4-13).

Q. WHAT PROXY GROUP DID YOU USE IN YOUR ANALYSIS?

A. I included the following seven companies in my proxy group:

Company	Stock Ticker
Atmos Energy Corp.	ATO
Chesapeake Utilities	CPK
NiSource Inc.	NI
New Jersey Resources Corp.	NJR
Northwest Natural Gas Co.	NWN
One Gas Inc.	OGS
Spire Inc.	SR

Q. WHAT PROXY GROUP DID MR. MOUL USE IN HIS ANALYSIS?

A. Mr. Moul's Gas Group consists of the following eight companies (Columbia Exhibit No. 400, Schedule 3, p. 2):

Company	Stock Ticker
Atmos Energy Corp.	ATO
Chesapeake Utilities	CPK
New Jersey Resources Corp.	NJR
NiSource Inc.	NI
Northwest Natural Gas Co.	NWN
One Gas Inc.	OGS
Southwest Gas Holdings Inc.	SWX
Spire Inc.	SR

Q. DO YOU AGREE WITH MR. MOUL'S GAS PROXY GROUP?

A. Not entirely. While Mr. Moul's Gas Group included all seven companies of my proxy group, I have excluded one of the companies he uses.

Q. PLEASE IDENTIFY THE COMPANY MR. MOUL HAS INCLUDED THAT YOU DO NOT AND EXPLAIN WHY YOU HAVE EXCLUDED IT FROM YOUR PROXY GROUP.

A. Mr. Moul included Southwest Gas Holdings, Inc. in his Gas Group that I have excluded from my proxy group as this company did not meet my first criterion that fifty percent or more of the company's revenues must be generated from the regulated gas utility industry. This is important because revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If less than fifty percent of revenues come from the regulated gas sector, the companies are not comparable to the subject utility as they do not provide a similar level of regulated business. Therefore, I did not include Southwest Gas Holdings, Inc. in my proxy group.

CAPITAL STRUCTURE

Q. WHAT IS A CAPITAL STRUCTURE?

A. A capital structure represents how a firm has financed its rate base with different sources of funds. The primary sources of funding are long-term debt and common

equity. A capital structure may also include preferred stock and/or short-term debt.

Q. WHAT IS THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. The Company's claimed capital structure is summarized in the table below (Columbia Statement No. 8, p. 18, lines 7-8 and Columbia Exhibit No. 400, Schedule 5):

COLUMBIA GAS OF PENNSYLVANIA, INC. Projected Capital Structure as on December 31, 2025	
Type of Capital	**Capitalization Ratio**
Long-Term Debt	43.12%
Short-Term Debt	2.48%
Common Equity	54.40%
Total	**100.00%**

Q. WHAT IS THE BASIS FOR THE COMPANY'S CLAIMED CAPITAL STRUCTURE?

A. Mr. Moul states that the Company's capitalization and capital structure ratios reflect the new long-term debt issuances of $150 million and maturities of $54.51 million long-debt in the future test year (FTY) and the FPFTY (Columbia Statement No. 8, p. 17, lines 21-24). He opines that his recommended capital structure represents the best approximation of the mix of capital the Company will employ to finance its rate base during the period when new rates are in effect

(Columbia Statement No. 8, p. 18, lines 11-13). Mr. Moul's recommended common equity ratio falls within his Gas Group range of 34.7% to 58.2%. He ultimately reasons that since rate setting is prospective, the rate of return should reflect known and reasonably foreseeable changes throughout the course of the FPFTY (Columbia Statement No. 8, p. 18, lines 5-6).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S CAPITAL STRUCTURE?

A. I recommend using the Company's claimed capital structure as presented in the table above.

Q. WHAT IS THE BASIS FOR YOUR CAPITAL STRUCTURE RECOMMENDATION?

A. I believe a capital structure of 50% long-term debt and 50% common equity is optimal when trying to balance the financial integrity of a utility as well as trying to control costs to ratepayers in this proceeding. However, I recommend using the Company's claimed capital structure as it falls within the range of my proxy group's 2023 (most recently available) capital structures. The most recent five-year average ranges of my proxy group companies' capital structure ratios are from 38.19% to 56.62% long-term debt and 34.74% to 59.95% common equity, with an overall five-year average of 46.21% long-term debt, 8.61% short-term debt, and 45.18% common equity (I&E Exhibit No. 2, Schedule 2).

It is worth noting that the Company's equity ratio is well above the five-year average of my proxy group's equity ratios. In fact, six of seven companies including NiSource, Inc. (the parent company) in my proxy group have a capital structure wherein the equity ratio is less than 50% for the most recent five-year average (I&E Exhibit No. 2, Schedule 2). This equity heavy capital structure must be recognized when considering Columbia's financial risk associated with the capital expenditure program and higher equity ratios generally correspond with lower financial risk as Mr. Moul himself concedes (I&E Exhibit No. 2, Schedule 3).

For consideration when examining the Company's overall financial risk, the example below illustrates the cost savings to ratepayers if the Company were to employ a 50% long-term debt and 50% common equity capital structure in its cost of capital while maintaining its claimed return on equity and rate base:

COLUMBIA GAS OF PENNSYLVANIA, INC. As-filed Capital Structure and Cost Rates			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	43.12%	5.07%	2.19%
Short-Term Debt	2.48%	5.25%	0.13%
Common Equity	54.40%	11.75%	6.39%
Total	**100.00%**		**8.71%**
50/50 Optimal Capital Structure and Cost Rates			
Long-Term Debt	47.52%	5.07%	2.41%
Short-Term Debt	2.48%	5.25%	0.13%
Common Equity	50.00%	11.75%	5.87%
Total	**100.00%**		**8.41%**

Difference in the Overall Rate of Return (8.71% - 8.41%)	0.30%
Impact Prior to Gross Up (Claimed Rate Base* x Difference in the Overall Rate of Return ($3,489,087,567 x 0.0030)	$10,467,263
Gross Revenue Conversion Factor*	1.37884083
Total Impact to Ratepayers	**$14,432,690**

* Columbia Exhibit No. 102, Schedule 3, p. 5.

In this example, if the Company were to employ a 50/50 capital structure and make no change to the requested return on equity (with which I do not agree and discuss in more detail below), the cost savings to ratepayers would be $14,432,690. While I understand achieving and maintaining an exact 50/50 capital structure is not always feasible, this example is intended to demonstrate Columbia's financial security despite the capital expenditure program as compared to its peers and prove that Mr. Moul's various "add-ons" or "adjustments" to his cost of equity calculations (Columbia Exhibit No. 400, Schedule 1, p. 2) and 0.25% management performance reward are unnecessary and unreasonably inflate the rate of return.

COST OF DEBT

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S COST OF SHORT-TERM AND LONG-TERM DEBTS?

A. I recommend using the Company's FPFTY claimed short-term debt cost rate of 5.25% and long-term debt cost rate of 5.07% (Columbia Statement No. 8, p. 19, lines 5-10 and Columbia Exhibit No. 400, Schedule 1, p. 1)

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION TO USE THE COMPANY'S CLAIMED COST RATES OF SHORT-TERM AND LONG-TERM DEBTS?

A. The Company obtains its short-term debt from the NiSource money pool, which has commercial paper as its source. The interest rate is established on the basis of the forecast of the Fed Funds rate of 4.38%, plus an additional 0.50%, which reflects the recent historical yield differential between the Fed Funds rate and commercial paper borrowing rate for a 75-day duration, plus a 0.25% risk premium to reflect the credit quality of NiSource (Columbia Statement No. 8, p. 19, lines 12-16).

The Company's FPFTY claimed cost rate of long-term debt is based on the 2023 long term cost rate and the projected cost rates of new debt issuances in the FTY and FPFTY. The 5.07% long-term debt cost rate falls within my proxy group's 2023 implied long-term debt cost range of 2.24% to 5.57%, with an average implied long-term debt cost of 4.28%. The Mergent Bond Record shows an average yield of 5.65% (May 2023 through April 2024) for A-rated public utility bond (I&E Exhibit No. 2, Schedule 4). Given the upward trend in interest rates, I believe that the Company's claim is representative of the utility industry.

COST OF COMMON EQUITY

COMMON METHODS

Q. WHAT METHODS ARE COMMONLY PRESENTED BY UTILITIES IN DETERMINING THE COST OF COMMON EQUITY?

A. Four methods commonly presented to estimate the cost of common equity are the Discounted Cash Flow (DCF), the Capital Asset Pricing Model (CAPM), the Risk Premium (RP) Method, and the Comparable Earnings (CE) Method.

Q. WHAT IS THE THEORETICAL BASIS FOR THE DCF METHOD?

A. The DCF method is the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. The DCF method assumes that investors evaluate stocks in the traditional economic framework, which maintains that the value of a financial asset is determined by its earning power, or its ability to generate future cash flows. The DCF method is also considered a forward-looking model to estimate the cost of common equity.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CAPM?

A. The CAPM describes the relationship of a stock's investment risk and its market rate of return. It identifies the rate of return investors expect so that it is comparable with returns of other stocks of similar risk. This method hypothesizes that the investor-required return on a company's stock is equal to the return on a

"risk free" asset plus an equity premium reflecting the company's investment risk. In the CAPM, two types of risk are associated with a stock: (1) firm-specific risk (unsystematic risk); and (2) market risk (systematic risk), which is measured by a firm's beta. The CAPM allows for investors to receive a return only for bearing systematic risk. Unsystematic risk is assumed to be diversified away, and therefore, does not earn a return.

Q. WHAT IS THE THEORETICAL BASIS FOR THE RP METHOD?

A. The theoretical basis for the RP method is a simplified version of the CAPM. The RP method's theory is that common stock is riskier than debt, thus, investors require a higher expected return on stocks than bonds. In the RP approach, the cost of equity is made up of the cost of debt and a risk premium. While the CAPM uses the market risk premium, it measures the systematic risk of a company or proxy group through the use of beta. The RP method does not measure the specific risk of a company.

Q. WHAT IS THE THEORETICAL BASIS FOR THE CE METHOD?

A. The CE method utilizes the concept of opportunity cost. This means that investors will likely dedicate their capital to the investment offering the highest return with similar risk to alternative investments. Unlike the DCF, CAPM, and the RP methods, the CE method is not market-based and relies upon historic accounting data. Like the RP method, the CE method does not measure the specific risk of a

company. The most problematic issue with the CE method is determining what constitutes comparable companies.

I&E RECOMMENDED METHOD TO EMPLOY

Q. WHAT METHOD DO YOU RECOMMEND USING TO DETERMINE AN APPROPRIATE COST OF COMMON EQUITY FOR COLUMBIA?

A. I recommend using the DCF method as the primary method to determine the cost of common equity. Additionally, I provide a CAPM analysis to be used as a comparison, not as a check, to the DCF results. The DCF method has the most wide-spread regulatory acceptance, and the Commission has historically relied mostly upon the DCF results in base rate proceedings, but also as recently as 2017, 2018, 2020, and 2021.[1]

Q. PLEASE EXPLAIN WHY YOU CHOSE TO EMPLOY THE DCF TO DETERMINE YOUR RECOMMENDED RETURN ON EQUITY.

A. I recommend using the DCF for a variety of reasons. The DCF is appealing to investors since it is based upon the concept that the receipt of dividends in addition

[1] *Pa. PUC v. City of DuBois – Bureau of Water*; Docket No. R-2016-2554150 (Order Entered March 28, 2017). *See generally* Disposition of Cost Rate Models, pp. 96-97; *Pa. PUC v. UGI Utilities, Inc. - Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Cost of Common Equity, p. 119; *Pa. PUC v. Wellsboro Electric Company;* Docket No. R-2019-3008208 (Order Entered April 29, 2020). *See generally* Disposition of Primary Methodology to Determine ROE, pp. 80-81; *Pa. PUC v. Citizens Electric Company of Lewisburg, PA;* Docket No. R-2019-3008212 (Order Entered April 29, 2020). *See generally* Disposition of Cost of Common Equity, pp. 91-92. *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.;* Docket No. R-2020-3018835 (Order Entered February 19, 2021). *See generally* Disposition of Cost of Common Equity, p. 131; Pa. PUC v. PECO Energy Company – Gas Division; Docket No. R-2020-3018929 (Order Entered June 22, 2021). See generally Disposition of Return of Rate on Common Equity, p. 171.

to expected appreciation is the total return requirement determined by the market.[2] The use of a growth rate and expected dividend yield are also strengths of the DCF, as this recognizes the time value of money and is forward-looking. The use of the utilities' own, or in this case the proxy group's, stock prices and growth rates directly in the calculation also causes the DCF to be industry and company specific. Finally, the current inflationary and economic trends are most certainly reflected in a stock's price, which is used in determining the dividend yield, and by independent professional analysts who generate forecasted earnings growth rates. Therefore, the DCF contains the most up-to-date projected information of any model and is the superior method for determining the rate of return for the current economic market because it measures the cost of equity directly.

Q. PLEASE EXPLAIN WHY YOU CHOSE TO USE THE CAPM AS A COMPARISON TO THE DCF IN YOUR ANALYSIS.

A. I have included a CAPM analysis only as a comparison, and not as a basis, for my recommendation because both the CAPM and the DCF include inputs that allow the results to be specific to the utility industry. However, the CAPM is based on the performance of U.S. Treasury bonds and the performance of the market as measured through the S&P 500 and is company-specific only through the use of beta. Beta reflects a stock's volatility relative to the overall market, thereby

[2] David C. Parcell, "The Cost of Capital – A Practitioner's Guide," 2020 Edition, p. 153.

incorporating an industry-specific aspect to the CAPM, but only as a measure of how reactive the industry is compared to the market as a whole. Although changes in the utility industry are more likely to be accurately reflected in the DCF, which uses the companies' actual prices, dividends, and growth rates, I have included the results of my CAPM analysis because changes in the market, whether as a whole or specific to the utility industry, affect the outcome of each method in different ways. I have provided the results of my CAPM analysis only as a comparison, and not as a check, as it has several disadvantages and should not be given comparable weight to the DCF.

Q. EXPLAIN THE DISADVANTAGES OF THE CAPM.

A. The CAPM, and the RP method by virtue of its similarities to the CAPM, give results that indicate to an investor what the equity cost rate should be if current economic and regulatory conditions are the same as those present during the historical period in which the risk premiums were determined. This is because beta, which is the only company-specific variable in the CAPM model, measures the *historical* volatility of a stock compared to the *historical* overall market return. Reliance on historical values is especially problematic now given the recent impact of the COVID-19 pandemic on economic conditions. Although the CAPM and RP results can be useful to investors in making rational buy and sell decisions within their portfolios, the DCF method is the superior method for determining the rate of return for the current economic market and measuring the cost of equity

directly. The CAPM and the RP methods are less reliable indicators because they measure the cost of equity indirectly and risk premiums vary depending on the debt and equity being compared. Also, regulators can never be certain that economic and regulatory conditions underlying the historical period during which the risk premiums were calculated are the same today or will be the same in the future.

Q. IS THERE ANY ACADEMIC EVIDENCE THAT QUESTIONS THE CREDIBILITY OF THE CAPM MODEL?

A. Yes. An article, "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory," which appeared in the *New York Times* on February 18, 1992, summarized a CAPM study conducted by professors Eugene F. Fama and Kenneth R. French.[3] Their study examined the importance of beta, CAPM's risk factor, in explaining returns on common stock. In CAPM theory a stock with a higher beta should have a higher expected return. However, they found that the model did not do well in predicting actual returns and suggested the use of more elaborate multi-factor models.

A more recent article, "The Capital Asset Pricing Model: Theory and Evidence," which appeared in the *Journal of Economic Perspectives,* states that "the attraction of the CAPM is that it offers powerful and intuitively pleasing

[3] Berg, Eric N. "Market Place; A Study Shakes Confidence in the Volatile-Stock Theory" *The New York Times*, 18 Feb 1992: *nytimes.com* Web. 23 Mar 2016.

predictions about how to measure risk and the relation between expected return and risk. Unfortunately, the empirical record of the model is poor - poor enough to invalidate the way it is used in applications."[4] As a result, I conclude that the CAPM's relevance to the investment decision making process does not carry over into the regulatory rate setting process.

Q. PLEASE EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE RP METHOD FROM YOUR ANALYSIS.

A. The RP method is excluded because it is a simplified version of the CAPM and is subject to the same faults explained above. Most importantly, unlike the CAPM, the RP method does not recognize company-specific risk through beta.

Q. EXPLAIN WHY YOU HAVE CHOSEN TO EXCLUDE THE CE METHOD IN YOUR ANALYSIS.

A. The CE method is excluded because the choice of which companies are comparable is highly subjective, and it is debatable whether historic accounting values are representative of the future. Moreover, its historical usage in this regulatory forum has been minimal.

[4] Fama, Eugene F. and French, Kenneth R., "The Capital Asset Pricing Model: Theory and Evidence." *Journal of Economic Perspectives* (2004): Volume 18, Number 3, pp. 25-46.

Q. ARE THERE ANY RECENT COMMISSION ORDERS THAT DEVIATE FROM THE HISTORICAL USE OF THE DCF AS THE PRIMARY METHOD IN DETERMINING A COMPANY'S RETURN ON EQUITY?

A. Yes. The Commission indicated in the 2021 Aqua Pennsylvania, Inc. (Aqua) base rate case order that its method "for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies"[5] and that "I&E's DCF and CAPM produce a range of reasonableness for the ROE…"[6] , which deviates from prior Commission practice of primarily relying on the DCF. Most recently, the Commission's Columbia Water Company (Columbia Water) base rate case order relied on the results of I&E's DCF and CAPM analyses for determining Columbia Water's ROE.[7]

Q. SHOULD THE COMMISSION'S USE OF THE CAPM AS A CEILING FOR A "RANGE OF REASONABLENESS" APPLY IN THIS PROCEEDING?

A. No. In a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[8] Aqua's ROE of 10.00% was stated as being above the national average for water utility base rate cases and above the Distribution

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5 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 154 (Order entered May 16, 2022).

6 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order entered May 16, 2022).

7 *Pa. PUC v. Columbia Water Company,* Docket Nos. R-2023-3040258, p. 105 (Order entered January 18, 2024).

8 Regulatory Research Associates, "Commission authorizes management performance bonus for Aqua Pennsylvania," *S&P Global Market Intelligence*, May 16, 2022. CIQ Pro: RRA Regulatory Focus: Commission authorizes management performance bonus for Aqua Pennsylvania (spglobal.com) (Accessed April 23, 2024).

System Improvement Charge (DSIC) rate authorized by the Commission of 9.80%[9] for water and wastewater utilities for the year ended December 31, 2021. This DSIC rate for water and wastewater utilities has since dropped 5 basis points to 9.75% for the year ended March 31, 2023[10] and dropped a further 10 basis points to 9.65% for the year ended June 30, 2023[11] and remained at the same level 9.65% for the year ended December 31, 2023.[12] The above referenced S&P report, which directly reviews Aqua's ROE of 10.00% on the very date the Commission entered its order in Aqua's base rate proceeding demonstrated that the ROE awarded to Aqua was higher than average. Specifically, the S&P report determined that the average ROE for water utility base rate cases that have been completed during the first four months of 2022 was 9.63% and for the twelve months ended April 30, 2022 was 9.53%, each of which were well below the 10.00% ROE authorized by the Commission for Aqua. This demonstrates the unreasonable skewing of results associated with using the CAPM as a ceiling for determining a utility's ROE.

[9] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended December 31, 2021, approved at Public Meeting on June 16, 2022, at Docket No. M-2022-3032405.

[10] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended March 31, 2023, approved at Public Meeting on July 13, 2023 at Docket No. M-2023-3041106.

[11] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended June 30, 2023, approved at Public Meeting on October 19, 2023 at Docket No. M-2023-3042679.

[12] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended December 31, 2023, approved at Public Meeting on May 9, 2024 at Docket No. M-2024-3048688.

In the Columbia Water order, the Commission noted that I&E's DCF and CAPM produced a range of reasonableness for the ROE from 7.84% to 11.09% and approved an ROE of 9.75% as reasonable and appropriate for that company, which is based upon consideration of a variety of factors such as increasing inflation leading to increases in interest rates and capital costs.[13] I respectfully disagree with the Commission's basis (current inflation and interest rates) for determining Columbia Water's ROE of 9.75%. I have presented and discussed below the forecasted lower-level inflation rates, and the Federal Reserve's intention to cut interest rates in 2024-2025, which would have the effect of reducing potential inflation and interest rate risks in the capital costs during 2025, when Columbia's new rates will be in effect.

Additionally, as explained above, the CAPM should not be used as a primary method, and it should only be used as a comparison (not as a check) of the DCF. Also, as demonstrated below, the use of the CAPM in this proceeding would result in a significant burden to ratepayers during a time of increased levels of inflation. Therefore, I disagree with providing the CAPM comparable weight to the DCF method.

Q. PLEASE COMMENT ON CURRENT INFLATION AND INTEREST RATE CONCERNS.

A. First, I cannot dispute the current economic conditions with respect to increased

[13] *Pa. PUC v. Columbia Water Company,* Docket Nos. R-2023-3040258, pp.108-109 (Order entered January 18, 2024).

interest rates and government bond yields, however, it is important to note that all companies, including regulated utilities, are impacted by high interest rates. Per the latest news article,[14] Fed Reserve officials now expected to lower the interest rates more rapidly next year, to make four rate cuts in 2025, up from three previously. Considering Chairman Powell's indication, it is my understanding that most likely the Federal Reserve will consider a series of interest rate cuts in 2025, which covers Columbia's FPFTY when the new rates will be in effect.

Per the most recent monthly Blue Chip Financial Forecasts (May 31, 2024),[15] the 2024-2025 inflation rates by two measures are forecasted to be slightly over 2% as shown in the table below:

	Q2 2024	**Q3 2024**	**Q4 2024**	**Q1 2025**	**Q2 2025**	**Q3 2025**
Consumer Price Index	3.5%	2.7%	2.5%	2.4%	2.4%	2.4%
PCE Price Index	2.9%	2.3%	2.2%	2.3%	2.2%	2.2%

The Federal Reserve's commitment to an interest rate reduction would have the effect of reducing potential inflation and interest rate risks in the capital costs in 2025, when Columbia's new rates will be in effect. Lastly, it is important to note that unlike unregulated companies, public utilities may file rate cases to address unforeseen or increased expenses and/or revenue shortfalls due to changes in market conditions.

[14] Fed Meeting Live Updates: Powell Speaks on Rates and Inflation Report - The New York Times (nytimes.com) (accessed on June 12, 2024).

[15] Blue Chip Financial Forecasts, Vol. 43, No. 6, May 31, 2024, p. 2.

SUMMARY OF THE COMPANY'S RESULTS

Q. WHAT ARE THE RESULTS OF THE COMPANY'S COST OF EQUITY ANALYSES?

A. Mr. Moul employed the DCF, CAPM, RP, and CE methods in analyzing the Company's cost of equity. He adjusts his results through various methods including a financial risk leverage adjustment to his DCF results, use of the inflated beta in the CAPM analysis, and applying a size premium adjustment/adder to the CAPM results (Columbia Exhibit No. 400, Schedule 1, p. 2). Ultimately, Mr. Moul opines that a cost of equity of 11.75% including an increment/adder of 0.25% for management performance is warranted due to Columbia's risk relative to the Gas Group and the S&P Public Utilities companies (Columbia Statement No. 8, p. 19, lines 23-24 and p. 20, lines 9-11). He believes his recommended return on common equity would be appropriate to assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms (Columbia Statement No. 8, p. 3, lines 22-24).

I&E RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDED COST OF COMMON EQUITY FOR COLUMBIA?

A. Based upon my analysis, I recommend a cost of common equity of 9.93% for Columbia (I&E Exhibit No. 2, Schedule 1).

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. My recommendation is based on the use of the DCF method. As explained above, I used my CAPM result only to present to the Commission a comparison to my DCF results. My DCF analysis uses the proxy group companies' spot dividend yield, a 52-week dividend yield, and five-year earnings growth forecasts.

DISCOUNTED CASH FLOW

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS.

A. My analysis employs the constant growth DCF model as portrayed in the following formula:

$$K = D_1/P_0 + g$$

Where:

K	=	Cost of equity
D_1	=	Dividend expected during the year
P_0	=	Current price of the stock
g	=	Expected growth rate

When a forecast of D_1 is not available, D_0 (the current dividend) must be adjusted by one half of the expected growth rate to account for changes in the dividend paid in period one. As forecasts for each company in my proxy group are available from Value Line, no dividends are adjusted for the purpose of my analysis.

Q. PLEASE EXPLAIN HOW YOU DEVELOPED THE DIVIDEND YIELDS USED IN YOUR DCF ANALYSIS.

A. A representative dividend yield must be calculated over a time frame that avoids the problems of both short-term anomalies and stale data series. For my DCF analysis, the dividend yield calculation places equal emphasis on the most recent spot and the 52-week average dividend yields. The following table summarizes my dividend yield computations for the proxy group (I&E Exhibit No. 2, Schedule 5):

Proxy Group - Average Dividend Yields	
(a) Spot Dividend Yield	4.09%
(b) 52-week Average Dividend Yield	3.86%
(c) Average ((a +b) ÷ 2)	3.98%

Q. WHAT INFORMATION DID YOU RELY UPON TO DETERMINE YOUR EXPECTED GROWTH RATE?

A. I have used five-year projected growth rate estimates from Value Line, Yahoo! Finance, and Zacks.

Q. WHAT WERE THE RESULTS OF YOUR FORECASTED EARNINGS GROWTH RATES?

A. The expected average growth rates for my gas proxy group ranged from 4.65% to 7.60% with an overall average growth rate of 5.95% (I&E Exhibit No. 2,

Schedule 6).

Q. WHAT IS THE RESULT OF YOUR DCF ANALYSIS BASED ON YOUR RECOMMENDED DIVIDEND YIELD AND GROWTH RATE?

A. The results of my DCF analysis are calculated as follows (I&E Exhibit No. 2, Schedule 7):

K	**=**	**D_1/P_0**	**+**	**g**
9.93%	=	3.98%	+	5.95%

CAPITAL ASSET PRICING MODEL

Q. PLEASE EXPLAIN YOUR CAPM ANALYSIS.

A. My analysis employs the traditional CAPM as portrayed in the following formula:

$$K = R_f + \beta(R_m - R_f)$$

Where:

K = Cost of equity

R_f = Risk-free rate of return

R_m = Expected rate of return on the overall stock market

β = Beta measures the systematic risk of an asset

Q. WHAT IS BETA AS EMPLOYED IN YOUR CAPM ANALYSIS?

A. Beta is a measure of the systematic risk of a stock in relation to the rest of the

stock market. A stock's beta is estimated by calculating the linear regression of a stock's return against the return on the overall stock market. The beta of a stock with a price pattern identical to that of the overall stock market will equal one. A stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Conversely, a stock with a price movement that is less than the overall stock market will have a beta of less than one and would be described as having less investment risk than the overall stock market.

Q. HOW DID YOU DETERMINE YOUR BETA FOR YOUR CAPM ANALYSIS?

A. In estimating an equity cost rate for my proxy group of seven companies, I used the average of the betas for the proxy group companies as provided in the Value Line Investment Survey. The average beta for my proxy group is 0.86 (I&E Exhibit No. 2, Schedule 8).

Q. WHAT RISK-FREE RATE OF RETURN HAVE YOU USED FOR YOUR FORECASTED CAPM ANALYSIS?

A. I have chosen to use the risk-free rate of return (R_f) from the projected yield on 10-year Treasury Notes. While the yield on the short-term T-Bill is a more theoretically correct parameter to represent a risk-free rate of return, it can be extremely volatile. The volatility of short-term T-Bills is directly influenced by

Federal Reserve policy. At the other extreme, the 30-year Treasury Bond exhibits more stability but is not risk-free. Long-term Treasury Bonds have substantial maturity risk associated with market risk and the risk of unexpected inflation. Long-term treasuries normally offer higher yields to compensate investors for these risks. As a result, I chose to use the yield on the 10-year Treasury Note because it mitigates the shortcomings of the other two alternatives. Additionally, the Commission has historically agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[16]

The forecasted yield on the 10-year Treasury Note, as seen in Blue Chip Financial Forecasts, is expected to range between 3.80% and 4.00% from the third quarter of 2024 through the third quarter of 2025, and it is forecasted to be 3.90% from 2025-2029. For my CAPM analysis, I used 3.88%, which is the average of all the yield forecasts I observed (I&E Exhibit No. 2, Schedule 9).

Q. HOW DID YOU DETERMINE THE ESTIMATED RETURN ON THE OVERALL STOCK MARKET EMPLOYED IN YOUR CAPM ANALYSIS?

A. To arrive at an estimated return on the overall stock market, I observed Value Line's 1700 stocks and the S&P 500. Value Line expects its universe of approximately 1700 stocks to have an average yearly return of 11.83% over the

[16] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 99; *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, p. 154 (Order entered May 16, 2022); *Pa. PUC v. Columbia Water Company*; Docket No. R-2023-3040258 (Order Entered January 18, 2024). See generally Disposition of Cost of Common Equity, pp. 107-108.

next three to five years based on a forecasted dividend yield of 2.10% and a yearly index appreciation of 45% (I&E Exhibit No. 2, Schedule 11). The S&P 500 Index has an average return of 12.16% over the past 98 years (1926-2023) and the trendline for the returns over the past 98 years has been relatively flat (I&E Exhibit No. 2, Schedule 10). I have averaged these two figures which results in an estimated market return of 12.00% (I&E Exhibit No. 2, Schedule 11).

Q. WHAT IS THE COST OF EQUITY RESULT FROM YOUR CAPM ANALYSIS?

A. The result of my analysis is as follows (I&E Exhibit No. 2, Schedule 12).

K	$=$	R_f	$+$	$\beta(R_m - R_f)$
10.86%	=	3.88%	+	0.86 (12.00% - 3.88%)

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR CAPM ANALYSIS?

A. Yes. As discussed earlier in my testimony, my recommended cost of equity is based upon my DCF analysis. I only present a CAPM analysis to the Commission as a comparison and not for recommendation purposes as the inputs are highly subjective, and other than beta, not company or industry specific.

Q. IS IT NECESSARY TO APPLY THE CAPM WITH SIMILAR WEIGHT TO THE DCF WHEN DETERMINING A SPECIFIC RETURN ON EQUITY DUE TO RECENT INFLATIONARY TRENDS?

A. No. My use of the DCF as a primary method in determining an appropriate return on equity already sufficiently takes inflationary trends into consideration. As mentioned above, the DCF includes a spot stock price in the dividend yield calculation and analysts who generate forecasted earnings growth almost certainly take inflation into consideration as well, so it contains the most up-to-date projected information of any model. In other words, the inputs of the DCF capture all known economic factors, including inflation.

Q. DID YOU QUANTIFY THE NUMBER OF BASIS POINTS DIFFERENCE BETWEEN YOUR DCF AND CAPM RESULTS TO ILLUSTRATE THE FINANCIAL IMPACT BETWEEN USING EACH MODEL?

A. Yes. The difference between my DCF and CAPM analysis is 93 basis points (CAPM result of 10.86% - DCF result of 9.93% = 0.93% difference). As demonstrated below, relying on the results of the CAPM is unnecessary and creates undue hardship for Columbia's ratepayers.

Q. BASED ON THE COMPANY'S FILED RATE BASE AND CLAIMED CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 93 BASIS POINTS TO THE COST OF EQUITY BASED ON THE DIFFERENCE IN RESULTS BETWEEN YOUR CAPM ANALYSIS (10.86%) AND YOUR DCF ANALYSIS (9.93%)?

A. The example below illustrates the impact of 93 additional basis points to the Company's cost of equity if the results of my CAPM analysis, rather than my DCF results were applied to the Company's total claimed rate base and capital structure:

Columbia's Claimed Equity Percentage of Capital Structure*	54.40%
Difference in Return on Equity between I&E's CAPM and DCF Analysis (10.86% – 9.93% = 0.93%)	0.93%
Claimed Rate Base**	$3,489,087,567
Impact Prior to Gross Up (0.5440 x 0.0093 x $3,489,087,567)	$17,651,992
Gross Revenue Conversion Factor**	1.37884083
Total Impact to Ratepayers ($17,651,992 x 1.37884083)	**$24,339,287**

*Columbia Exhibit No. 400, Schedule 1, p. 1.
**Columbia Exhibit No.102, Schedule 3, p. 5.

In this example, an addition of 93 basis points to the cost of equity would burden ratepayers to fund an additional amount of $24,339,287 annually to cover the increase of the inflated rate of return along with the associated impact resulting from increases to income taxes and uncollectibles.

Q. DOES THE DEMONSTRATED FINANCIAL IMPACT THAT RATEPAYERS WOULD BEAR TO FUND AN ADDITIONAL $24,339,287 ANNUALLY DEMONSTRATE THAT IT IS INAPPROPRIATE TO USE THE CAPM TO ESTABLISH A "ZONE OF REASONABLENESS" IN THIS PROCEEDING?

A. Yes. In my opinion it is inappropriate to use the CAPM as the top end of a range in this proceeding for determining an ROE. In this instance, the $24,339,287 additional revenue impact is 19.61% of Columbia's total revenue increase request of $124,138,477. This would result in an additional burden on Columbia's ratepayers. In my opinion, and as demonstrated by my analysis, any amount granted above the DCF (9.93% based on my recommendation) is not justified and places an unreasonable burden on ratepayers.

CRITIQUE OF MR. MOUL'S PROPOSED COST OF EQUITY

Q. DO YOU AGREE WITH MR. MOUL'S PROPOSED COST OF EQUITY?

A. No. I disagree with Mr. Moul's proposed cost of equity for several reasons. First, I disagree with the weights given to the results of Mr. Moul's CAPM, RP, and CE analyses in his recommendation. Second, I take issue with certain aspects of Mr. Moul's risk analysis of Columbia. Third, I disagree with his application of the DCF including the forecasted growth rate and leverage adjustment he uses. Fourth, I disagree with his use of the 30-year Treasury Bond in place of the 10-

year Treasury Note, use of an inflated beta, and his inclusion of a size adjustment in his CAPM analysis. Finally, I disagree with Mr. Moul's recommendation to include an adjustment to the cost of equity for recognition of exemplary management performance.

WEIGHTS GIVEN TO THE CAPM, RP, AND CE METHODS

Q. DO YOU AGREE WITH MR. MOUL'S RELIANCE ON THE CAPM AND RP MODELS?

A. No. While I am not opposed to providing the Commission with the results of the CAPM methodology for a point of comparison to the results of the DCF calculation, I am opposed to giving the CAPM and RP considerable weight. For the reasons previously discussed in this testimony, including my reference to recent Commission orders, it is inappropriate to give the CAPM, RP, and CE models similar weight to the DCF as Mr. Moul has done in creating his recommended cost of equity range of 11.50% to 13.86% (Columbia Statement No. 8, p. 6, lines 1-7). As discussed above, the CAPM measures the cost of equity indirectly and can be manipulated by the time period chosen. Since the RP is a simplified version of the CAPM, it suffers these same flaws.

Q. DO YOU AGREE WITH MR. MOUL'S USE OF THE CE METHOD?

A. No. The companies in Mr. Moul's analysis are not utilities, and therefore, they are too dissimilar to be used in a CE analysis. Mr. Moul's CE proxy group is

comprised of unregulated industries like Chemicals, Retail Stores, Financial Services, Telecom, Food, IT Services, Industrials, Machinery, Trucking, Diversified Business, Banking, Petroleum, Aerospace/Defense, Railroad, etc. (Columbia Exhibit No. 400, Schedule 14, pp. 1-2). These non-utility companies with unrelated or entirely dissimilar business segments are simply not comparable to gas distribution utilities in terms of business risk and financial risk profiles. Natural gas distribution utilities are monopolies, which are subject to very little competition, if any at all. Due to this minimal competition, utilities in general have very low business risk and can maintain higher financial risk profiles by employing more leverage. Conversely, since the companies in Mr. Moul's CE proxy group operate in an unregulated competitive environment with a higher level of business risk, they must maintain lower financial risk profiles by employing a smaller amount of leverage.

Further, in his CE analysis, Mr. Moul states, "I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach" (Columbia Statement No. 8, p. 42, line 25 through p. 43, line 2). I do not believe this arbitrary use of 20% is justified, as I am unaware of any natural gas utility company that has been granted a Commission authorized return or regularly earns a 20% or greater return on equity.

RISK ANALYSIS

Q. PLEASE SUMMARIZE MR. MOUL'S CLAIMS REGARDING THE RISK FACTORS THE COMPANY FACES.

A. Mr. Moul described the Company's claimed risk factors in two different sub-sections. In the first section, labeled "Natural Gas Risk Factors," he described the gas utility specific risk factors. In this section, Mr. Moul discusses various business risks such as the potential risks arising from bypass threat, economic regulation, business cycle, customer usage patterns, and the Company's construction program (Columbia Statement No. 8, pp. 7-11). In the second section of his risk analysis labeled "Fundamental Risk Analysis," he described the quantitative risk factors. In this section, Mr. Moul discusses the Company's credit quality (rating), as well as many different financial metrics including size, market ratios, common equity ratios, return on book equity, operating ratios, pre-tax interest coverage, quality of earnings, internally generated funds (IGF), and betas relative to the S&P Public Utilities and his Gas Group (Columbia Statement No. 8, pp. 12-16).

Q. WHAT IS MR. MOUL CLAIMING REGARDING THE POTENTIAL RISK OF BYPASS?

A. Mr. Moul opines that large volume users have the potential to bypass the Company's system as they may be located close enough to interstate pipelines to use those sources. Mr. Moul claims a potential bypass risk for fifty-two major

accounts of large industrial and commercial customers, which are also exposed to alternative energy sources (Columbia Statement No. 8, p. 9, lines 15-18). All of these risks put fixed cost recovery for this class of customers at risk.

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIMED BUSINESS RISKS INCLUDING POTENTIAL BYPASS RISK FOR COLUMBIA?

A. Most companies in the natural gas utility sector face similar potential risks of bypass or competition with other suppliers and alternative energy sources. In this regard, the companies within my proxy group provide a good measurement of the risk associated with competition from alternate suppliers. Mr. Moul agrees that all companies in his Gas Group have business risks arising from competition, economic regulation, the business cycle, pipeline safety regulations, and customer usage patterns to varying degrees (I&E Exhibit No. 2, Schedule 13, p. 1). Additionally, though Mr. Moul admits to not studying the risk of by-pass threat of each company in his Gas Group, he acknowledges that he is aware that bypass is usually a threat to Local Distribution Companies (LDCs) when there are a number of interstate pipelines in close proximity to large volume users served by an LDC or when customers of the LDC are in close proximity to gas producing wells. He agrees that most LDCs, including the companies in his Gas Group, are faced with threat of bypass risk due to interstate pipelines (I&E Exhibit No. 2, Schedule 13, p. 2).

Q. WHAT IS MR. MOUL'S CLAIM REGARDING ADDITIONAL RISK DUE TO THE COMPANY'S CONSTRUCTION PROGRAM FOR AGING INFRASTRUCTURE?

A. Mr. Moul claims that the Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities including replacement of aging pipeline in its service territory to maintain safe and reliable service to existing customers. Therefore, the Company must invest to upgrade its infrastructure and anticipates that gross construction expenditures will be approximately $2.29 billion (average annual expenditure of $457.80 million) during the 2024-2028 period (Columbia Statement No. 8, p. 11, lines 1-4). He expresses concern that these large expenditures are not paired with new customers or additional revenues (Columbia Statement No. 8, p. 10, lines 12-22).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIM REGARDING THE COMPANY'S CONSTRUCTION PROGRAM AND REPLACEMENT OF AGING INFRASTRUCTURE?

A. Every gas utility faces the same issues of upgrading or replacing infrastructure. Mr. Moul agrees that all members of his Gas Group are engaged in capital expenditure programs and are susceptible to the associated risk to varying degrees (I&E Exhibit No. 2, Schedule 13, p. 3). As costs for replacing infrastructure increase, Columbia, like any other regulated gas utility, has the option to file a base rate case at any time to address revenue inadequacy due to increasing costs,

infrastructure replacement, or any other associated issues. Base rate cases allow a utility to recover its costs and provide it with the *opportunity* to earn a reasonable return on capital investments. Additionally, the Commission offers risk reducing mechanisms such as the DSIC and the FPFTY to help reduce any regulatory lag in recovery of infrastructure investment or other unforeseen expenditures. It should be noted that these mechanisms were not designed to eliminate the need for periodic base rate case filings, but only to mitigate regulatory lag and support increasing infrastructure replacement needs.

It is also important to note that Columbia has consistently filed base rate cases using the FPFTY to primarily recover the capital cost of its pipeline infrastructure replacement program and O&M expenses, which have consistently increased customers' rates. The following table summarizes base rate cases (BRC) filed since 2012 and the corresponding requested revenue increases:[17]

Docket No.	FPFTY ended	Revenue Increase Request	Annual Revenue Increase
R-2012-2321748	June 30, 2014	$77.31 M	20.61%
2013	BRC not filed	-	-
R-2014-2406274	December 31, 2015	$54.11 M	11.09%
R-2015-2468056	December 31, 2016	$46.17 M	8.63%
R-2016-2529660	December 31, 2017	$55.26 M	11.23%
2017	BRC not filed	-	-
R-2018-2647577	December 31, 2019	$46.94 M	8.16%
2019	BRC not filed	-	-

[17] Commission orders entered in the respective docket numbers (except for this base rate case at Docket No. R-2024-3046519) listed in the table.

R-2020-3018835	December 31, 2021	$100.44 M	17.50%
R-2021-3024296	December 31, 2022	$98.28 M	19.91%
R-2022-3031211	December 31, 2023	$81.51 M	10.09%
2023	BRC not filed	-	-
R-2024-3046519	December 31, 2025	$124.14 M	15.79%

The above table shows that Columbia has filed nine base rate cases in a span of thirteen years requesting total additional revenue of $684.16 million.

Lastly, I disagree with Mr. Moul's assertion that the Commission should recognize and consider the proposed capital expenditures program in determining the cost of capital because historically Columbia has been making significant capital expenditures for infrastructure improvement and ratepayers have funded these capital expenditures with every rate increases. It should be noted that at Columbia's filing frequency, new cases are often filed before the Company has even completed the plant investments for which they were previously granted rate recovery.

Q. ACCORDING TO MR. MOUL, WHAT ADDITIONAL BUSINESS RISKS AFFECT THE COMPANY?

A. Mr. Moul suggests that the Company faces business risks such as economic regulation, business cycle, and customer usage patterns.

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIMS REGARDING THE VARIOUS BUSINESS RISKS HE MENTIONS?

A. The issues referenced by Mr. Moul affect the entire gas utility industry, therefore, Columbia faces the same exposure to these issues as do all the other companies in our proxy groups. Investors voluntarily buy and hold shares of stocks in natural gas utility companies, indicating they are aware of these risks and the returns. The cost of equity I recommend in this proceeding is adequately measured by my proxy group and adequately compensates for these risks.

Q. PLEASE COMMENT ON THE COMPANY'S PROPOSED REVENUE NORMALIZATION ADJUSTMENT (RNA) MECHANISM AND CHANGES IN THE CURRENT WEATHER NORMALIZATION ADJUSTMENT (WNA) MECHANISM AND ITS CLAIM REGARDING THE POTENTIAL IMPACT ON THE COMPANY'S COST OF EQUITY.

A. Mr. Moul claims that all of the companies in his Gas Group have some form WNA mechanism and in some cases, other forms of revenue decoupling. He argues that his analysis reflects the impacts of WNA and RNA mechanisms on investor expectations through the use of market-determined models. He opines that if the Company is unable to obtain the proposed RNA mechanism, its risk will increase above that of the Gas Group and the Gas Group's cost of equity will then understate the return that is used as a measure for Columbia's cost of equity (Columbia Statement No. 8, p. 8 line 18 through p. 9, line 2).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S CLAIM REGARDING THE COMPANY'S PROPOSED RNA MECHANISM?

A. The Commission allows utilities the opportunity to propose alternative ratemaking mechanisms such as the WNA and RNA. Columbia has already implemented a WNA and is now proposing the RNA mechanism in this proceeding. The RNA proposal is designed to be an additional revenue stabilization mechanism providing guaranteed recovery of all costs associated with benchmarked distribution revenue via an RNA Rider. If the Commission approves the Company's RNA proposal, the benefits of revenue decoupling would certainly reduce the Company's overall risk profile. Instead, it would shift the risk and the burden directly onto the ratepayers. I&E's position recommending that the Commission deny Columbia's specific request for an RNA is addressed more directly in the testimony of I&E witness Esyan Sakaya (I&E Statement No. 3).

Q. PLEASE DISCUSS THE CLAIMS MR. MOUL MAKES REGARDING QUANTITATIVE RISK FACTORS DESCRIBED IN THE "FUNDAMENTAL RISK ANALYSIS" SECTION.

A. Mr. Moul states that it is necessary to establish a company's relative risk position within its industry through an analysis of quantitative and qualitative factors. In this section, Mr. Moul uses various financial metrics to compare Columbia to the S&P Public Utilities and his Gas Group companies (Columbia Statement No. 8, p. 12, lines 4-11).

Q. WHAT ARE YOUR COMMENTS REGARDING MR. MOUL'S "FUNDAMENTAL RISK ANALYSIS?"

A. Two of the points he examines, size risk and betas, are discussed and disputed in the latter part of my direct testimony below. Throughout the remainder of his "fundamental risk analysis," Mr. Moul makes several statements to indicate that Columbia has lower or similar risk than any other company in his Gas Group (Columbia Statement No. 8, p. 17, lines 7-9).

First, although Columbia is not individually rated by credit rating agencies, Mr. Moul notes that Moody's Investors Service (Moody's) offers a long-term issuer credit quality rating of A3 for both his Gas Group and the S&P Public Utilities companies (comprising electric power and natural gas companies). This rating is categorized as upper-medium investment grade with low credit risk. Additionally, S&P Global Ratings offers corporate credit ratings of A- for Mr. Moul's Gas Group and BBB+ for the S&P Public Utilities companies (Columbia Statement No. 8, p. 13, lines 5-14). These ratings are categorized as investment grade and imply an adequate/strong capability to meet financial commitments. From this information, one can extrapolate that Mr. Moul's Gas Group, which is used to develop his return on equity recommendation, possesses low financial risk.

Second, while discussing common equity ratios, Mr. Moul notes that the five-year average common equity ratios, based on permanent capital, were 49.0% for the Gas Group and 40.5% for the S&P Public Utilities (Columbia Statement No. 8, p. 14, lines 18-19). These ratios are much lower than the 54.14% he is

recommending for Columbia in this proceeding. Mr. Moul acknowledges that a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk (Columbia Statement No. 8, p. 14, lines 16-18). This confirms that Columbia, with a high common equity ratio, has lower financial risk as compared to Mr. Moul's Gas Group companies.

Third, pertaining to operating ratios, Mr. Moul affirms that the five-year average operating ratios were 72.2% for the Company, 82.79% for the Gas Group, and 81.0% for the S&P Public Utilities. As Mr. Moul explains, the operating ratio illustrates the percentage of revenue required to cover operating expenses, depreciation, and taxes other than income (Columbia Statement No. 8, p. 15, lines 9-12). The lower the operating ratio is, the higher the operating margin becomes and vice versa. In this case, Columbia's operating ratios are lower than the Gas Group companies indicating lower risk levels (Columbia Statement No. 8, p. 15, lines 12-13).

Fourth, regarding coverage for fixed charges such as interest expense, he explains that excluding the Allowance for Funds Used During Construction, the five-year average pre-tax interest coverage was 4.27 times for the Company, 4.33 times for the Gas Group, and 2.94 times for the S&P Public Utilities. Mr. Moul acknowledges that "[t]he interest coverages were fairly similar for the Company and the Gas Group, thereby indicating similar risk (Columbia Statement No. 8, p. 15, lines 18-22).

Fifth, related to quality of earnings, Mr. Moul concludes, "[q]uality of earnings has not been a significant concern for the Company, the Gas Group, and the S&P Public Utilities" (Columbia Statement No. 8, p. 16, lines 5-6).

Finally, Mr. Moul identifies the five-year average percentage of IGF to capital expenditures was 62.0% for the Company, 56.3% for the Gas Group and 62.3% for the S&P Public Utilities. The Company's average IGF to construction percentage has been slightly stronger than the Gas Group (Columbia Statement No. 8, p. 16, lines 9-13).

Q. PLEASE CONTINUE.

A. Mr. Moul summarizes his fundamental risk analysis by stating, "[o]n balance, the cost of equity measured with the Gas Group data will provide a reasonable representation of the Company's cost of equity (Columbia Statement No. 8, p. 17, lines 9-10). Overall, through his own analysis and testimony, Mr. Moul substantiates that the Company has lower, or similar risk as compared to that of his Gas Group except for Columbia's smaller size risk as compared to the Gas Group companies (Columbia Statement No. 8, p. 17, lines 7-9). Therefore, any additional consideration for the Company's risk profile in determination of the cost of equity is unnecessary.

COST OF EQUITY ADJUSTMENTS

INFLATED GROWTH RATES USED IN DCF ANALYSIS

Q. WHAT GROWTH RATE HAS MR. MOUL USED IN HIS DCF ANALYSIS?

A. Mr. Moul has chosen a growth rate of 6.75% (Columbia Statement No. 8, p. 27, lines 12-13).

Q. WHAT IS THE BASIS FOR MR. MOUL'S GROWTH RATE?

A. Mr. Moul indicates that Schedule 9 of his Exhibit No. 400 shows the prospective five-year earnings per share growth rates projected for the Gas Group to be 5.87% from IBES/First Call, 5.69% from Zacks, and 7.31% from Value Line (Columbia Statement No. 8, p. 26, lines 16-17). Although the average of his sources for the growth rate is 6.29% [(5.87% + 5.69% + 7.31%) ÷ 3], Mr. Moul arbitrarily chooses to use a 6.75% growth rate claiming that DCF growth rates should not be established by mathematical formulation and that the reasonableness of his chosen growth rate is supported by the expected continuation of gas utility infrastructure spending and it is within the analysts' forecasts of five-year earnings per share growth rates (Columbia Statement No. 8, p. 27, lines 10-16).

Q. DO YOU AGREE WITH MR. MOUL'S GROWTH RATE ANALYSIS?

A. No. Contrary to Mr. Moul's belief that DCF growth rates *should not* be established by mathematical formulation, any alternative is subjective and

introduces additional and unnecessary bias and should be avoided when possible. The use of a higher growth rate than the average of his proxy group ignores the fact that analysts making earnings per share growth forecasts are already aware of the economic conditions and the state of the gas utility industry. The reasons Mr. Moul has given for choosing a growth rate of 6.75% above his calculated average rate of 6.29% are factors already included in the earnings per share growth forecasts and the future infrastructure spending as confirmed by him in his response to I&E-RR-09-D that analysts consider all factors that they believe impact future growth, which for the members of the Gas Group would include growth associated with infrastructure spending (I&E Exhibit No. 2, Schedule 14, pp. 1-2). Thus, Mr. Moul's arbitrarily choosing a higher growth rate than the average of his Gas Group is inappropriate, unsupported, and would account for the same factor twice. Mr. Moul's inflated growth rate inappropriately increases his DCF results by 0.46% (6.75% - 6.29%).

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING THE RESULTS OF MR. MOUL'S PROJECTED GROWTH RATES?

A. Yes. While the five-year projected growth rates can be used in analyses, one must be aware that analysts' estimates may be biased. This bias has been observed in literature. An article authored by Professors Ciciretti, Dwyer, and Hasan in 2009

observed strong support of earnings forecasts being higher than actual earnings.[18] In spring of 2010, McKinsey on Finance presented an article reporting that after a decade of stricter regulation analysts' forecasts are still overly optimistic.[19]

Analysts' estimates are an attempt to forecast future cash flows and thus expected earnings growth. However, it should be kept in mind that prudent judgment must be exercised as to the sustainability of forecasted growth rates with respect to the base earnings. If the base year earnings are abnormally high, the growth rates from which they are calculated will be biased downward. Similarly, if the base year earnings are abnormally low, the growth rates from which they are calculated will be biased upward. As a result, it is typically necessary to employ a methodology to smooth out the abnormally high or low base year earnings.

In summary, since analysts' projected growth forecasts are most often overly optimistic, there is no need to arbitrarily and non-formulaically increase the estimates used in a DCF analysis.

LEVERAGE ADJUSTMENT APPLIED TO DCF ANALYSIS

Q. HAS MR. MOUL MADE ANY ADDITIONAL ADJUSTMENTS TO THE RESULT OF HIS DCF ANALYSIS?

A. Yes. Mr. Moul proposes to make a 131-basis point (1.31%) "leverage" adjustment

[18] Ciciretti, Rocco; Dwyer, Gerald R; and Iftekhan Hasan. "Investment Analysts' Forecasts of Earnings" Federal Reserve Bank of St. Louis *Review*, September/October 2009, 91 (5, part 2) pp. 545-67.

[19] Goedhart, Marc J; Raj, Rishi; and Abhishek Saxena. "Equity analyst: Still too bullish" McKinsey on Finance Number 35 Spring 2010, pp. 14-17.

to the results of his DCF analysis to account for applying a market-determined cost of equity to a book value capital structure (Columbia Statement No. 8, p. 31, lines 4-7).

Q. WHAT IS FINANCIAL LEVERAGE?

A. Financial leverage is the use of debt capital to supplement equity capital. A firm with significantly more debt than equity is considered highly leveraged.

Q. WHAT IS A MARKET-TO-BOOK (M/B) RATIO?

A. A market-to-book ratio is used to evaluate a public firm's equity value by comparing the market value and book value of a company's equity. One way of doing this is to divide the current market price per share of stock by the book value per share. A M/B result of above one (1) is desired.

Q. HAS MR. MOUL PROPOSED TO ADJUST THE RESULT OF HIS DCF ANALYSIS TO RECOGNIZE HOW THE COMPANY IS LEVERAGED?

A. No. Mr. Moul does not propose to change the capital structure of the utility (a leverage adjustment), nor does he propose to apply the market-to-book ratio to the DCF model (a market-to-book adjustment). Instead, Mr. Moul proposes to make an adjustment to account for applying the market determined cost rate of equity to the book value of the utility's equity. I am not aware of any term in academic journals, textbooks, or other literature that describes this type of adjustment.

Q. WHAT IS THE BASIS FOR MR. MOUL'S PROPOSED LEVERAGE ADJUSTMENT?

A. As stated above, Mr. Moul theorizes that to make the DCF results relevant to the capitalization measured at book value, the market-derived cost rate must be adjusted to account for this difference in financial risk (Columbia Statement No. 8, p. 28, lines 11-13). Mr. Moul opines that such financial risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization (Columbia Statement No. 8, p. 28, lines 5-8).

Q. HOW DOES MR. MOUL CALCULATE THE LEVERAGE ADJUSTMENT USED IN HIS ANALYSIS?

A. Mr. Moul simply states,

> What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting (Columbia Statement No. 8, p. 30, lines 13-16).

> I know of no means to mathematically solve for the 1.31% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.31% adjustment is merely a convenient way to compare the 12.05% return computed using the Modigliani & Miller formulas to the 10.74% return generated by the DCF model based on a market-value capital structure (Columbia Statement No. 8, p. 31, lines 7-12).

Q. DO YOU AGREE WITH MR. MOUL'S "LEVERAGE ADJUSTMENT"?

A. No. Mr. Moul's financial risk adjustment to the market determined DCF results is inappropriate and unsupported for a couple of reasons, including the characterization of financial risk and its inconsistency with the Commission's recent orders discussed below rejecting such adjustments.

Q. EXPLAIN HOW RATING AGENCIES ASSESS FINANCIAL RISK.

A. Rating agencies assess financial risk based upon a company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations. The agencies use a company's financial statements for their analysis, not market capital structure. The income statement reflects the financial risk of a company because it represents the performance of the company over a certain period. A change in the market value of the stock is not reflected in the income statement nor is a change in market value capital structure reflected in the book value capital structure unless treasury stock is purchased. It is a company's financial statements that affect the market value of the stock, and therefore, the financial statements and the book value capital structure are relied upon in an analysis such as that done by rating agencies. Additionally, investors are aware of the difference in the return on book value and market value of a stock while making the investment decision.

Q. WHAT ARE THE MOST RECENT COMMISSION DECISIONS REGARDING A LEVERAGE ADJUSTMENT?

A. The following cases are recent instances where the Commission has addressed the use of a "leverage adjustment." In these cases, the leverage adjustment has been rejected.

First, in *Pennsylvania Public Utility Commission v. Aqua Pennsylvania, Inc.*, at Docket No. R-00072711 (Order Entered July 31, 2008), pp. 38-39, the Commission rejected the ALJ's recommendation for a leverage adjustment stating, "[t]he fact that we have granted leverage adjustments in the past does not mean that such adjustments are indicated in all cases." In this proceeding, the Commission determined that there was no viable support for an upwards adjustment to compensate for any perceived risk.

Second, in *Pennsylvania Public Utility Commission, et al v. City of Lancaster – Bureau of Water*, at Docket No. R-2010-2179103 (Order Entered July 14, 2011), p. 101, the Commission agreed with the I&E position and stated, "any adjustment to the results of the market based DCF are unnecessary and will harm ratepayers. Consistent with our determination in *Aqua 2008* there is no need to add a leverage adjustment. . ."

Third, in *Pennsylvania Public Utility Commission, et al v. UGI Utilities, Inc. – Electric Division*, at Docket No. R-2017-2640058 (Order Entered October 25, 2018), pp. 93-94, the Commission agreed with the I&E position and stated, "we conclude that an artificial adjustment in this proceeding is unnecessary

and contrary to the public interest. Accordingly, we decline to include a leverage adjustment in our calculation of the DCF cost of equity."

Fourth, in *Pennsylvania Public Utility Commission, et. al v. Columbia Gas of Pennsylvania, Inc*., at Docket No. R-2020-3018835 (Order Entered February 19, 2021), pp. 137-141, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded Columbia's application of a leverage adjustment.

Fifth, in *Pennsylvania Public Utility Commission, et. al v. PECO Energy Company – Gas Division*, at Docket No. R-2020-3018929 (Order Entered June 22, 2021, Public Version), pp. 172-173, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded PECO's application of a leverage adjustment.

Finally, in the most recent case of *Pennsylvania Public Utility Commission, et. al v. Aqua Pennsylvania, Inc.*, at No. Docket R-2021-3027385 (Order Entered June 22, 2021), pp. 154-155, the Commission adopted the ALJ's recommendation to use I&E's DCF methodology, which excluded Aqua's application of a leverage adjustment.

Q. BASED ON THE COMPANY'S RATE BASE AND CAPITAL STRUCTURE CLAMS, WHAT IS THE VALUE OF AN ADDITIONAL 131 BASIS POINTS FOR MR. MOUL'S LEVERAGE ADJUSTMENT TO THE COST OF EQUITY?

A. The example below illustrates the impact of 131 additional basis points (1.31%) for the leverage adjustment to the Company's cost of equity:

Columbia's Claimed Equity Percentage of Capital Structure*	54.40%
Financial Risk Leverage Adjustment to DCF Results	1.31%
Claimed Rate Base**	$3,489,087,567
Impact Prior to Gross Up (0.5440 x 0.0131 x $3,489,087,567)	$24,864,634
Gross Revenue Conversion Factor**	1.37884083
Total Impact to Ratepayers ($24,864,634 x 1.37884083)	**$34,284,373**

*Columbia Exhibit No. 400, Schedule 1, p. 1.
**Columbia Exhibit No.102, Schedule 3, p. 5.

In this example, an addition of 131 basis points for the leverage adjustment to the cost of equity would force ratepayers to fund an unwarranted additional amount of $34,284,373 annually to cover the increase of the inflated rate of return along with the associated impact resulting from increases to income taxes and uncollectibles. This additional revenue recovery of $34,284,373 is 27.62% of Columbia's total revenue increase request of $124,138,477 (Columbia Exhibit No. 102, Schedule 3,

p. 3), which signifies an exorbitant impact and unreasonable burden on ratepayers if the Commission were to approve this adjustment in the cost of equity.

Q. SUMMARIZE YOUR RECOMMENDATION REGARDING THE PROPOSED LEVERAGE ADJUSTMENT.

A. I recommend that Mr. Moul's proposed 131-basis point leverage adjustment to the DCF results be rejected because true financial risk is a function of the amount of interest expense, and capital structure information provided to investors through Value Line is that of book value, and not market value. This demonstrates that investors base their decisions on book value debt and equity ratios for the regulated utilities; therefore, no adjustment is needed. Mr. Moul's proposed adjustment serves only to manipulate the DCF's market-based methodology and causes undue harm to ratepayers as illustrated above.

Q. DO YOU HAVE ANY FURTHER COMMENTS REGARDING MR. MOUL'S DCF CALCULATION?

A. Yes. While I am not directly disputing Mr. Moul's adjusted dividend yields, it is important to recognize that, as cited above, the Commission has recently agreed with I&E's DCF methodology which includes the appropriate calculation of dividend yields. Although it is acceptable to adjust historical dividend yields as Mr. Moul has done, it is preferable to use forecasted dividends to calculate the

dividend yields when available, such as the ones offered by Value Line that I have employed.

Q. WHAT WOULD MR. MOUL'S DCF BE WITHOUT ANY ADJUSTMENTS?

A. Without Mr. Moul's use of inflated growth rates and a leverage adjustment, his DCF would consist of an adjusted dividend yield of 3.99% and an average growth rate of 6.29%, which results in a 10.28% cost of equity. This result is lower than his originally calculated and inappropriately inflated result of 12.05% (Dividend Yield 3.99% + Growth Rate 6.75% + Leverage Adjustment 1.31%) (Columbia Statement No. 8, p. 32, line 2 and Columbia Exhibit No. 400, Schedule 2, p. 2).

RISK-FREE RATE OF RETURN

Q. HOW HAS MR. MOUL CALCULATED HIS RISK-FREE RATE FOR USE IN HIS CAPM MODEL?

A. Mr. Moul's calculation of his risk-free rate is similar to mine. He considers Treasury yield estimates published by Blue Chip Financial Forecasts over the next six quarters, from the time of his analysis, as well as long-range, five-year averages. However, he uses the 30-year Treasury Bond while I employed the 10-year Treasury Note. Also, where I used a long-range, five-year average, future data point accounting for years 2025-2029 predictions, Mr. Moul uses two future data points accounting for not only years 2025-2029, but also includes an estimate

for years 2030-2034. He recommends using a 3.75% risk-free rate (Columbia Statement No. 8, p. 38, line 24 through p. 39, line 2), which is comparable to the 3.88% I used (I&E Exhibit No. 2, Schedule 9).

Q. WHAT COMMENTS DO YOU HAVE REGARDING MR. MOUL'S CALCULATION OF THE RISK-FREE RATE?

A. Although Mr. Moul and I disagree on the method and inputs to determine the risk-free rate, his result is comparable to my own. However, I must reiterate my earlier statements that long-term Treasury Bonds have substantial maturity risk associated with the market risk and the risk of unexpected inflation and normally offer higher yields to compensate investors for these risks. Using the 10-year Treasury Note is more appropriate to balance the short-term volatility risk and the long-term inflation risk.

The Commission has recognized the 10-year Treasury Note as the superior measure for the risk-free rate by stating the following,[20]

> We agree with I&E and the ALJs that using the yield on the 10-year Treasury Note provides a better measure of the risk-free rate of return than using the yield on the 30-year Treasury Bond, as recommended by UGI. In our view, using the 10-year Treasury Note balances the shortcomings of the short-term T-Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with the market risk. In addition, long-term Treasury Bonds bear the risk of unexpected inflation.

[20] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order entered October 25, 2018), p. 99. (Disposition of Capital Asset Pricing Model (CAPM)).

Additionally, the further out into the future one projects, the less reliable the information becomes. Using the projection for 2030-2034 is an unreliable measure and this should not be included in the risk-free rate. The Company's FPFTY ends December 31, 2025, and in my opinion using an estimated risk-free rate that is up to nine years beyond the FPFTY is unreasonable and unnecessary.

INFLATED BETA USED IN CAPM ANALYSIS

Q. HOW HAS MR. MOUL INFLATED THE BETAS EMPLOYED IN HIS CAPM ANALYSIS?

A. Mr. Moul uses the same logic for inflating Value Line average betas from 0.87 to 1.10 in the CAPM analysis that he uses to enhance his DCF results, through a financial risk adjustment or "leverage" adjustment to account for the alleged financial risk associated with the book value capital structure using the Hamada formula (Columbia Statement No. 8, p. 37, lines 2-21 and Columbia Exhibit No. 400, Schedule 10).

Q. DO YOU AGREE WITH MR. MOUL'S USE OF LEVERAGED OR ADJUSTED BETAS?

A. No. Such enhancements are unwarranted for beta in a CAPM analysis for the same reasons that the "leverage" adjustment is unwarranted for DCF results.

Additionally, if the *Value Line* betas do not reflect an accurate investment risk as Mr. Moul contends, the question naturally arises as to why *Value Line* does not publish betas that are adjusted for leverage.

Finally, as described in my CAPM analysis above, a stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Due to being regulated and the monopolistic nature of utilities, very rarely do they have a beta equal to or greater than one. Therefore, in this case, to apply an adjusted beta of 1.10 of gas group in the CAPM analysis to inflate the CAPM results is irrational and unsupported in the traditional ratemaking process. Thus, I recommend rejecting Mr. Moul's application of an adjusted beta of 1.10 in the CAPM analysis.

SIZE ADJUSTMENT APPLIED TO CAPM ANALYSIS

Q. PLEASE EXPLAIN MR. MOUL'S PROPOSED SIZE ADJUSTMENT.

A. Mr. Moul adds 102 basis points (1.02%) to his CAPM indicated cost of common equity of 12.84% resulting in 13.86% CAPM results (Columbia Statement No. 8, p. 40, lines 7-9 and Columbia Exhibit No. 400, Schedule 13, p. 3 and Schedule 1, p. 2). He asserts that as the size of a firm decreases, its risk and required return increases. Mr. Moul relies upon technical literature including a Fama and French study entitled "The Cross-Section of Expected Stock Returns," an article published in Public Utilities Fortnightly entitled "Equity and the Small-Stock

Effect," and the Stocks, Bonds, Bills, and Inflation Yearbook (Columbia Statement No. 8, p. 39, lines 19-25 and Columbia Exhibit No. 400, Schedule 13, p. 3).

Q. DO YOU AGREE WITH MR. MOUL'S SIZE ADJUSTMENT?

A. No. Mr. Moul's proposed size adjustment of 1.02% is unnecessary because the technical literature he cites supporting investment adjustments relating to the size of a company is not specific to the utility industry, and therefore, has no relevance in this proceeding.

Q. IS THERE ACADEMIC EVIDENCE THAT SUPPORTS YOUR CONCLUSION THAT THE SIZE ADJUSTMENT FOR RISK IS NOT APPLICABLE TO UTILITY COMPANIES?

A. Yes. In the article "Utility Stocks and the Size Effect: An Empirical Analysis," Dr. Annie Wong concludes,

> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for utility stocks. This implies that although the size phenomenon has been strongly documented for the industriales, the findings suggest that there is no need to adjust for the firm size in utility rate regulation.[21]

[21] Dr. Annie Wong, "Utility Stocks and the Size Effect: An Empirical Analysis," *Journal of Midwest Finance Association* 1993, pp. 95-101.

Columbia presents no evidence to support application of a non-utility study regarding a size adjustment for risk to a utility setting. Absent any credible article to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected. The size premium data based on market capitalization is not reliable because for certain periods, large-capitalization stocks outperform mid-capitalization stocks and vice-versa, and it is difficult to establish a sufficient correlation to prove that size is a specific risk for utilities.

Furthermore, any expense impact resulting from the lesser buying power of a small utility is reflected in the revenue requirement and the dollar-for-dollar recovery that applies to expenses. To apply an additional size adjustment to a smaller regulated utility would only duplicate the burden to ratepayers.

Additionally, the Commission has recently rejected the application of a size adjustment to the CAPM cost of equity calculation where it agreed that the same literature the Company cites is not specific to the utility industry.[22]

Q. BASED ON THE COMPANY'S CLAIMED RATE BASE AND CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 102 BASIS POINTS FOR MR. MOUL'S SIZE ADJUSTMENT TO THE COST OF EQUITY?

A. The example below illustrates the impact of 102 additional basis points (1.02%)

[22] *Pa. PUC v. UGI Utilities, Inc. – Electric Division;* Docket No. R-2017-2640058 (Order Entered October 25, 2018), p. 100 (Disposition of Cost of Common Equity).

for the size adjustment to the Company's cost of equity:

Columbia's Claimed Equity Percentage of Capital Structure*	54.40%
Size Adjustment to CAPM Results	1.02%
Claimed Rate Base**	$3,489,087,567
Impact Prior to Gross Up (0.5440 x 0.0102 x $3,489,087,567)	$19,360,249
Gross Revenue Conversion Factor**	1.37884083
Total Impact to Ratepayers ($19,360,249 x 1.37884083)	**$26,694,702**

*Columbia Exhibit No. 400, Schedule 1, p. 1.

**Columbia Exhibit No.102, Schedule 3, p. 5.

In this example, an addition of 102 basis points for the size adjustment to the cost of equity would force ratepayers to fund an unwarranted additional amount of $26,694,702 annually to cover the increase of the overstated rate of return along with the associated impact resulting from increases to income taxes and uncollectibles.

Q. WHAT WOULD MR. MOUL'S CAPM RESULT BE WITHOUT INFLATED BETAS AND HIS SIZE ADJUSTMENT?

A. Mr. Moul's CAPM result would be 10.94%. This is 292 basis points (2.92%) lower than his originally calculated 13.86% result and close to my CAPM result of 10.86% (eight basis points higher). The calculation is repeated below without Mr. Moul's unnecessary adjustment to bata and size adjustment:

K	=	R_f	+	$\beta(R_m - R_f)$	+	Size Adjustment
10.94%	=	3.75%	+	0.87 (8.26%)	+	0%

MANAGEMENT PERFORMANCE

Q. DISCUSS THE COMPANY'S CLAIM SPECIFIC TO EXEMPLARY MANAGEMENT PERFORMANCE.

A. Mr. Moul proposes that 25 basis points (0.25%) be added to his recommended 11.50% cost of equity in recognition of the Company's exemplary management performance. He primarily relies upon the direct testimony of Company witness Mark Kempic, President (Columbia Statement No. 1) to support the consideration of additional basis points for Columbia's management performance (Columbia Statement No. 8, p. 1, line 18 through p. 2, line 2).

Q. WHAT INFORMATION DOES MR. KEMPIC PROVIDE TO SUPPORT THE COMPANY'S CLAIM OF EXEMPLARY MANAGEMENT PERFORMANCE?

A. Mr. Kempic claims that Columbia has exhibited exceptional management performance demonstrated by its efforts which include the Company's high level of customer services, lower level of customer complaints, call center performance, customer billing, universal services and customer payment assistance programs, safety initiatives, community engagement, and charitable donations (Columbia

Statement No. 1, pp. 30-56). He reasons that all these efforts provide significant value to Columbia's customers and the community.

Q. DO YOU AGREE WITH THE COMPANY'S CLAIMS REGARDING MANAGEMENT PERFORMANCE?

A. No. First, many of the topics presented by the Company witness fall within the categories of safe and reliable customer services and satisfaction that are required of every public utility company under 66 Pa C.S.A. §1501. There is no basis for quantification of 25 basis points for exemplary management performance. Additionally, the Company passes capital expenditure program costs to its ratepayers via base rates, or it can utilize a DSIC for capital expenditure recovery. Further, if the Company is effective at controlling operating and maintenance costs, those savings should flow through to ratepayers and/or investors. These savings would likely be offset by the addition of basis points for management performance as ratepayers would have to fund the additional costs. This defeats the purpose of any cost cutting measures to benefit ratepayers.

Q. ARE YOU AWARE OF ANY COMPANIES THAT HAVE RECENTLY RECEIVED ADDITIONAL BASIS POINTS IN RECOGNITION OF MANAGEMENT PERFORMANCE?

A. Yes. Most recently, the Commission awarded Aqua an addition of 25 basis points

for its management performance efforts.[23] However, it is important to recognize that this addition was based specifically on Aqua rescuing troubled water and wastewater systems at the Commission's request. The Commission stated: [24]

> We specifically recognize Aqua's efforts and willingness to quickly provide emergency aid to various water and wastewater systems that needed substantial improvement. Aqua has often provided this emergency aid on short notice and at the request of the Commission or other parties to protect the public from egregious health and safety threats and to protect the Commonwealth's drinking water resources from catastrophic damage.

Q. DOES THE COMMISSION'S PAST ISSUANCE OF ADDITIONAL EQUITY POINTS TO RECOGNIZE MANAGEMENT PERFORMANCE MEAN THAT COLUMBIA SHOULD ALSO RECEIVE AN ADJUSTED RETURN ON EQUITY?

A. No. The issuance of equity points to recognize management performance should be done on a case-by-case basis. The situation in the Aqua proceeding as discussed above was very specific to Aqua rescuing troubled water and wastewater systems and preventing health and safety concerns regarding drinking water. This scenario does not apply to Columbia.

[23] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 168-173 (Order entered May 16, 2022).

[24] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, p. 169 (Order entered May 16, 2022).

Q. BASED ON THE COMPANY'S CLAIMED RATE BASE AND CAPITAL STRUCTURE, WHAT IS THE VALUE OF AN ADDITIONAL 25 BASIS POINTS FOR THE CONSIDERATION OF MANAGEMENT PERFORMANCE TO THE COST OF EQUITY?

A. The example below illustrates the impact of 25 additional basis points for the consideration of management performance to the Company's claimed cost of equity:

Columbia's Claimed Equity Percentage of Capital Structure*	54.40%
Additional Basis Points to Calculated Cost of Equity	0.25%
Claimed Rate Base**	$3,489,087,567
Impact Prior to Gross Up (0.5440 x 0.0025 x $3,489,087,567)	$4,745,159
Gross Revenue Conversion Factor**	1.37884083
Total Impact to Ratepayers ($4,745,159 x 1.37884083)	**$6,542,819**

*Columbia Exhibit No. 400, Schedule 1, p. 1.
**Columbia Exhibit No.102, Schedule 3, p. 5.

In this example, an addition of 25 basis points to the cost of equity in consideration of management performance would force ratepayers to fund an unwarranted additional amount of $6,542,819 annually to cover the increase of the inflated rate of return along with the associated impact resulting from increases to income taxes and uncollectibles. This additional revenue recovery of $6,542,819 is 5.27% of Columbia's total revenue increase request of $124,138,477 (Columbia Exhibit No. 102, Schedule 3, p. 3).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE CONSIDERATION OF ADDITIONAL BASIS POINTS FOR THE COMPANY'S MANAGEMENT PERFORMANCE?

A. Ultimately, as alluded to above, true strong management performance is earning a higher return through efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to both ratepayers and shareholders. I do not believe that Columbia, or any utility should be gifted additional basis points for doing what they are required to do to provide adequate, efficient, safe, and reasonable service under 66 Pa C.S.A. §1501.

For these reasons, I recommend that the addition of any basis points to the cost of equity for management performance be disallowed.

OVERALL RATE OF RETURN RECOMMENDATION

Q. WHAT IS THE COMPANY'S PROPOSED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. The Company recommends a cost of equity of 11.75% and an overall rate of return of 8.71%.

Q. WHAT IS I&E'S RECOMMENDED COST OF EQUITY AND OVERALL RATE OF RETURN?

A. I&E Exhibit No. 2, Schedule 1, shows the calculation of an appropriate cost of

equity to be 9.93% with an overall rate of return for Columbia to be 7.72%.

Q. DO YOU HAVE ANY FINAL COMMENTS REGARDING THE COMPANY'S PROPOSED RETURN ON EQUITY?

A. Yes. First, a report issued by Regulatory Research Associates, a group within S&P Global Market Intelligence,[25] illustrates that Columbia's 11.75% requested return on equity is a significant 197 basis points (1.97%) higher than the average return on equity of 9.78% of all gas utility rate cases decided/approved by the state regulatory authorities in the first quarter of 2024. It is also important to note here that Pennsylvania is a deregulated state, which would indicate less risk.

Second, when asked, Mr. Moul indicated he has not researched (is unaware) whether any natural gas distribution utilities throughout the United States were granted a Commission authorized return of 11.75% or higher cost of common equity in the past three years despite the high interest rate environment since March 2022 (I&E Exhibit No. 2, Schedule 15).

Third, the Company's requested return on common equity is 182 basis points higher than the Commission's approved DSIC rate of 10.15% (Q4 2023 Quarterly Earnings Summary Report[26]) for gas distribution companies. The DSIC rate is designed to encourage its use and to incentivize accelerated pipeline

[25] S&P Global, RRA Regulatory Focus, "Major energy rate case decisions in US – January-March 2024, Quarterly update on decided rate cases," April 19, 2024.

[26] PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended December 31, 2023, approved at Public Meeting on May 9, 2024 at Docket No. M-2024-3048688.

replacement and infrastructure upgrades to bring the existing aging infrastructure closer to meeting safety and reliability requirements in between base rate filings. Additionally, it is my understanding that the DSIC rate establishes a benchmark above which a utility company is considered "overearning." As such, the DSIC rate does not serve as a proper measurement or proxy of a subject utility's cost of equity in a rate case proceeding. To suggest the cost of equity must be at or above the DSIC rate in this base rate proceeding is inappropriate and not in the public interest.

Finally, while I am aware of the rising costs of capital due to the after-effects of the pandemic and inflation, I believe it is equally important not to over burden ratepayers. Despite current economic conditions, Columbia is requesting a record return on equity to apply to its equity heavy capital structure and consistently expanding rate base and increases in customers rates. As detailed in various charts above, the effect of Mr. Moul's adjustments to the market-determined cost of common equity are an enormous burden to ratepayers and are completely unwarranted and unnecessary. Although they are not cumulative, the impact to ratepayers of each of the disputed adjustments is summarized as follows:

Leverage Adjustment of 1.02% to DCF Results	$34,284,373
Size Adjustment of 1.02% to CAPM Results	$26,694,702
Management Performance Adder of 0.25%	$6,542,819

EFFECTIVE DATE OF NEW RATES

Q. WHAT IS THE FIRST DAY OF COLUMBIA'S CLAIMED FPFTY?

A. The first day of Columbia's FPFTY is January 1, 2025.

Q. WHAT IS THE EFFECTIVE DATE ON WHICH COLUMBIA PROPOSES TO MAKE AN INCREASE IN RATES IN THIS PROCEEDING?

A. In response to I&E-RR-30-D, the Company indicates that the effective date of new rates will be December 14, 2024 as the Commission suspended the Supplemental No. 374 to Tariff Gas Pa. P.U.C. No. 9 until December 14, 2024 (I&E Exhibit No. 2, Schedule 16, p. 1).

Q. WHAT IS THE COMPANY'S RATIONALE FOR PROPOSING THAT RATES SHOULD GO INTO EFFECT ON DECEMBER 14, 2024?

A. Columbia states that by regulation, an historic test year is to be the twelve-month period ending no later than 120 days prior to the date of the rate filing and the FTY is to be the twelve-month period immediately following the historic test year. Additionally, Columbia avers that the FPFTY should be the twelve-month period beginning with the first month that new rates will be placed into effect after the full suspension period. Per Columbia, since the full statutory suspension period concludes in December 2024, the FPFTY is the twelve-month period beginning January 1, 2025 (I&E Exhibit No. 2, Schedule 16, p. 2).

Q. DO YOU AGREE THAT RATES SHOULD GO INTO EFFECT BEFORE THE BEGINNING OF THE FPFTY (JANUARY 1, 2025) IN THIS PROCEEDING?

A. No. I recommend the Commission to direct Columbia to make new rates effective on January 1, 2025, the first day of the FPFTY and not allow Columbia to make the new rates effective on December 14, 2024, which falls in the FTY ending December 31, 2024 and before the beginning of the FPFTY.

Q. WHY DO YOU BELIEVE THAT NEW RATES BECOMING EFFECTIVE ON DECEMBER 14, 2024 AND BEFORE JANUARY 1, 2025, THE BEGINNING OF THE FPFTY, WOULD BE IMPROPER?

A. It would be unjust and unreasonable for the Commission to allow Columbia to make new rates effective on December 14, 2024 because the ratemaking calculations or claims in this base rate filing are based on projected changes that will occur in the FPFTY (January 1, 2025 - December 31, 2025) and not in the FTY ending December 31, 2024. The higher new rates should not be made applicable during the period December 14, 2024 through December 31, 2024 (an 18-day period) as it is not supported by Columbia's FPFTY ratemaking calculation.

If Columbia is permitted to charge new rates effective on December 14, 2024 instead of January 1, 2025, then at the full revenue increase request of $124,138,477 (Columbia Exhibit No. 102, Schedule 3, p. 3), the Company would

recover an unsupported and unreasonable additional revenue increase of $6,121,897 (($124,138,477 ÷ 365) x 18) for that 18-day period from ratepayers. My recommendation is more appropriate, just, and reasonable because the ratemaking calculation (projection) for new rates includes the 12-month FPFTY beginning January 1, 2025 and not December 14, 2024. If the Commission approves a new rate effective date beginning December 14, 2024, then it would represent retroactive approval of new rates for the FPFTY effective from December 14, 2024 through December 31, 2025 (a 383-day period rather than the 12-month period (365 days)) for the FPFTY.

Q. PLEASE CONTINUE.

A. It is important to note that the company has used the twelve-month period ended November 30, 2023 as the historic test year (HTY), the twelve-month period ending November 30, 2024 as the FTY, and the twelve-month period ending December 31, 2025 (January 1, 2025 - December 31, 2025) as the FPFTY (Columbia Statement No. 4, p. 3, lines 8-11). If the Company has an intention to make new rates effective in December 2024, it should have used the twelve-month period ending November 30, 2025 (December 1, 2024 - November 30, 2025) as the FPFTY consistent with the HTY ended on November 30, 2023 and FTY ending on November 30, 2024 and should have filed this base rate case appropriately on or before March 1, 2024.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION.

A. Considering the above discussion and in the interest of ratepayers, I recommend that Columbia should agree to make the new rates effective January 1, 2025 (the first day of the FPFTY) instead of December 18, 2024, to avoid any unreasonable and unjustified impact on ratepayers.

If Columbia does not agree with the above recommendation, I recommend the Commission direct Columbia: (1) to make the new rates effective January 1, 2025 (the first day of the FPFTY) instead of on December 14, 2024 and file an updated tariff rates and rules (Supplement to Tarriff Gas) pursuant to the provisions of 52 Pa. Code §§ 53.1, et seq., and 53.101, designed to produce the approved annual distribution rate/revenue increase to become effective for service rendered *on and after January 1, 2025*; and (2) to file all subsequent base rate cases that should have new rates effective date beginning with the first day or later of the claimed FPFTY.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

D. C. PATEL

PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

- Pennsylvania Public Utility Commission, Harrisburg, Pennsylvania
  June 2015 to present
  Fixed Utility Financial Analyst, Bureau of Investigation and Enforcement
- Pennsylvania Insurance Department, Harrisburg, Pennsylvania
  March 2013 - June 2015
  Insurance Company Financial Analyst, Bureau of Company Licensing & Financial Analysis
- Pennsylvania Department of Revenue, Harrisburg, Pennsylvania
  November 2010 - March 2013
  Accounting Assistant, Bureau of Corporation Taxes (Accounting)
- Hersha Hospitality Management, Harrisburg, Pennsylvania
  June 2007 - November 2010
  Staff Accountant (Taxes), Accounting Department
- Corporate Experience-India
  February 1987 - April 2007
  Worked as Company Secretary for three different companies during this period, which were listed on the Stock Exchanges.

EDUCATION/CERTIFICATION:

- Gujarat State University, Ahmedabad, India:
  - Bachelor of Commerce (Major concentration: Accounting)
    June 1980 - April 1983
  - Bachelor of Law
    June 1983 - December 1988

- The Institute of Company Secretaries of India, New Delhi, India:
  Post Graduate Professional Degree: Company Secretary
  June 1983 - December 1985

RATE CASE TRAINING:

- Attended SURFA – 54th Financial Forum (ROR) in April 2023
- Attended 37th Western NARUC Utility Rate School in May 2016

D. C. PATEL

PROFESSIONAL EXPERIENCE AND EDUCATION

WORKED ON THE FOLLOWING CASES (Testimony not required):

- R-2022-3032167 - Columbia Gas of Pennsylvania, Inc. (Green Path Rider)
- R-2022-3031172 - Columbia Gas of Pennsylvania, Inc. (1307(f))
- R-2021-3024349 - Columbia Gas of Pennsylvania, Inc. (1307(f))
- R-2021-3023541 - National Fuel Gas Distribution Corporation (§ 1307(f))
- A-2020-3021460 - PA American Water Co.-Upper Pottsgrove-Wastewater (1329)
- A-2020-3020178 - PA American Water Co.-Valley Township-Wastewater (1329)
- A-2020-3019859 - PA American Water Co.-Valley Township-Water (1329)
- R-2020-3019661 - PECO Energy Co. - Gas Operations (1307(f))
- U-2020-3015258 - Pittsburgh Water and Sewer Authority
- R-2019-3008255 - Columbia Gas of Pennsylvania, Inc. (1307(f))
- R-2018-3001568 - PECO Energy Co. - Gas Operations (1307(f))
- R-2018-3000253 - Columbia Gas of Pennsylvania, Inc. (1307(f))
- R-2017-2631441 - Reynolds Water Co.
- A-2017-2629534 - PPL Electric Utilities (Restructuring Plan)
- R-2017-2602611 - PECO Energy Co. - Gas Operations (1307(f))
- R-2016-2567893 - Andreassi Gas Co.
- R-2016-2525128 - Columbia Water Co. - Marietta Division
- R-2015-2493905 - Sands, Inc.
- R-2015-2479962 - Corner Water Supply and Service Corporation
- R-2015-2479955 - Allied Utility Services, Inc.

SUBMITTED TESTIMONY IN THE FOLLOWING CASES:

- R-2023-3042804 et al. Community Utilities of Pennsylvania, Inc.
- R-2023-3043189 et al. PA American Water Co.
- R-2023-3038630 Columbia Gas of Pennsylvania, Inc. (1307(f))
- R-2023-3037933 Philadelphia Gas Works
- R-2022-3037368 UGI Electric, Inc. - Electric Division
- A-2022-3034143 Aqua Pennsylvania, Inc. - Borough of Shenandoah (Water System) (1329)
- R-2022-3031672 and R-2022-3031673 - PA American Water Co.
- R-2022-3031211 - Columbia Gas of Pennsylvania, Inc.
- R-2021-3024773 et al. - Pittsburgh Water and Sewer Authority
- A-2021-3024058- PA American Water Co. - Borough of Brentwood (Wastewater System) - 1329
- A-2021-3024681 - PA American Water Co. - York City Sewer Authority/City of York (Wastewater System) (1329)

D. C. PATEL

PROFESSIONAL EXPERIENCE AND EDUCATION

- R-2021-3024601 - PECO Energy Co. - Electric Operations
- A-2021-3024267 - Aqua Pennsylvania Wastewater, Inc. - Lower Makefield (WW) (1329)
- A-2020-3019634 - PA American Water Co. - Royersford Wastewater (1329)
- R-2020-3018993 - Columbia Gas Pennsylvania, Inc. (1307(f))
- R-2020-3018929 - PECO Energy Co. - Gas Operations
- R-2020-3017951 et al. - Pittsburgh Water and Sewer Authority
- A-2019-3008491 - Aqua Pennsylvania Wastewater, Inc.
- R-2019-3008212 - Citizens Electric Company of Lewisburg, PA
- R-2019-3008208 - Wellsboro Electric Company
- R-2018-3006814 - UGI Utilities, Inc. (Gas Division)
- R-2018-3002645 and 3002647 - Pittsburgh Water and Sewer Authority
- R-2018-3000834 - Suez Water Pennsylvania, Inc.
- R-2018-2647577 - Columbia Gas of Pennsylvania, Inc.
- M-2018-2640802 and M-2018-2640803 - Pittsburgh Water and Sewer Authority (Compliance Plan Stage 2)
- R-2017-2595853 - Pennsylvania American Water Co.
- R-2016-2580030 - UGI Penn Natural Gas, Inc.
- R-2016-2554150 - City of DuBois - Bureau of Water
- R-2016-2529660 - Columbia Gas of Pennsylvania, Inc.
- P-2016-2526627 - PPL Electric Utilities Corp. (DSP IV)

I&E Exhibit No. 2
Witness: D. C. Patel

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2024-3046519

Exhibit to Accompany

the

Direct Testimony

of

D. C. Patel

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

Effective Date of New Rates

I&E
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost
	Columbia Gas of Pennsylvania, Inc.		
Long-Term Debt	43.12%	5.07%	2.19%
Short-Term Debt	2.48%	5.25%	0.13%
Common Equity	54.40%	9.93%	5.40%
Total	100.00%		7.72%

Proxy Group Capital Structure

	2023		2022		2021		2020		2019		Average
Atmos Energy Corp.											
Long-term Debt	$ 6,833.663	38.08%	$ 5,944.945	38.23%	$ 5,124.950	39.33%	$ 4,732.850	41.07%	$ 3,529.452	36.22%	38.59%
Short-term Debt	241.933	1.35%	184.967	1.19%	-	0.00%	-	0.00%	464.915	4.77%	1.46%
Common Equity	10,870.064	60.57%	9,419.091	60.58%	7,906.889	60.67%	6,791.203	58.93%	5,750.223	59.01%	59.95%
	17,945.660	100.00%	15,549.003	100.00%	13,031.839	100.00%	11,524.053	100.00%	9,744.590	100.00%	100.00%
Chesapeake Utilities											
Long-term Debt	1,197.625	45.65%	590.780	36.34%	558.474	35.93%	518.371	37.26%	450.064	35.75%	38.19%
Short-term Debt	179.853	6.86%	202.157	12.43%	221.634	14.26%	175.644	12.63%	247.371	19.65%	13.16%
Common Equity	1,246.104	47.50%	832.801	51.23%	774.130	49.81%	697.085	50.11%	561.577	44.60%	48.65%
	2,623.582	100.00%	1,625.738	100.00%	1,554.238	100.00%	1,391.100	100.00%	1,259.012	100.00%	100.00%
NiSource Inc.											
Long-term Debt	11,081.300	50.57%	9,555.500	55.09%	9,211.300	60.71%	9,249.700	63.25%	7,907.800	53.48%	56.62%
Short-term Debt	3,048.600	13.91%	1,761.900	10.16%	560.000	3.69%	503.000	3.44%	1,773.200	11.99%	8.64%
Common Equity	7,783.500	35.52%	6,028.900	34.76%	5,400.800	35.60%	4,872.200	33.31%	5,106.700	34.53%	34.74%
	21,913.400	100.00%	17,346.300	100.00%	15,172.100	100.00%	14,624.900	100.00%	14,787.700	100.00%	100.00%
New Jersey Resources Corp.	-										
Long-term Debt	2,916.040	56.52%	2,623.784	53.93%	2,303.527	53.43%	2,354.496	54.45%	1,537.177	49.36%	53.54%
Short-term Debt	252.100	4.89%	423.950	8.71%	377.300	8.75%	125.350	2.90%	25.450	0.82%	5.21%
Common Equity	1,990.735	38.59%	1,817.210	37.35%	1,630.862	37.82%	1,844.692	42.66%	1,551.717	49.82%	41.25%
	5,158.875	100.00%	4,864.944	100.00%	4,311.689	100.00%	4,324.538	100.00%	3,114.344	100.00%	100.00%
Northwest Natural Gas Co.											
Long-term Debt	1,502.602	52.24%	1,325.132	48.03%	1,124.055	45.90%	940.702	44.08%	806.796	44.28%	46.91%
Short-term Debt	89.780	3.12%	258.200	9.36%	389.500	15.91%	304.525	14.27%	149.100	8.18%	10.17%
Common Equity	1,283.838	44.64%	1,175.441	42.61%	935.146	38.19%	888.730	41.65%	865.999	47.53%	42.92%
	2,876.220	100.00%	2,758.773	100.00%	2,448.701	100.00%	2,133.957	100.00%	1,821.895	100.00%	100.00%
One Gas Inc.											
Long-term Debt	2,174.701	43.24%	2,679.143	46.07%	3,707.778	56.60%	1,613.228	37.83%	1,314.064	33.18%	43.38%
Short-term Debt	88.500	1.76%	552.000	9.49%	494.000	7.54%	418.225	9.81%	516.500	13.04%	8.33%
Common Equity	2,765.877	55.00%	2,584.426	44.44%	2,349.532	35.86%	2,233.311	52.37%	2,129.390	53.77%	48.29%
	5,029.078	100.00%	5,815.569	100.00%	6,551.310	100.00%	4,264.764	100.00%	3,959.954	100.00%	100.00%
Spire Inc.											
Long-term Debt	3,624.200	49.95%	3,032.200	45.62%	2,992.800	49.22%	2,482.100	45.88%	2,082.600	40.62%	46.26%
Short-term Debt	955.500	13.17%	1,037.500	15.61%	672.000	11.05%	648.000	11.98%	743.200	14.50%	13.26%
Common Equity	2,675.300	36.88%	2,576.500	38.77%	2,416.200	39.73%	2,280.300	42.15%	2,301.000	44.88%	40.48%
	7,255.000	100.00%	6,646.200	100.00%	6,081.000	100.00%	5,410.400	100.00%	5,126.800	100.00%	100.00%

Five-Year Average Capital Structure					
Long-term Debt	**46.21%**	**Maximum**	56.62%	**Minimum**	38.19%
Short-term Debt	**8.61%**				
Common Equity	**45.18%**	**Minimum**	34.74%	**Maximum**	59.95%
	100.00%				

Source:
Compustat (S&P Global Market Intelligence - Data Management Solutions)
Yearly data updates typically provided late April of each year
(data in millions)

I&E Exhibit No. 2
Schedule 2

I&E Exhibit No. 2
Schedule 3

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. Staff RR-027-D:

Reference Columbia Statement No. 8, p. 18, lines 6-10 and p. 14, lines 18-22, and Columbia Exhibit 400, Schedule 3 regarding the Company's, and the Gas Group's capital structures:

A. Confirm whether Mr. Moul agrees that his 54.40% common equity recommendation as compared to the 49.0% five-year average for his Gas Group's permanent capital ratio results in less financial risk for the Company. If not, please explain.

B. Explain why Mr. Moul asserts that the Company's claimed common equity ratio of 54.40% is within the range of other gas distribution utilities thereby making it reasonable for setting rates in this case, when the Gas Group's permanent capital ratio range is 44.2% - 53.60%.

Response:

A. Higher common equity ratios are associated with less financial risk than lower common equity ratios.

B. The range of common equity ratios for the Gas Group are 34.7% to 58.2% for the year 2022. The Value Line forecast of common equity ratios is 40% to 60%.

Long-Term Debt Cost

Company	2023 Interest Charges	2023 Long-Term Debt	2023 Debt Cost
Atmos Energy Corp.	$ 153.09	$ 6,833.66	2.24%
Chesapeake Utilities	32.85	1,197.63	2.74%
NiSource Inc.	514.90	11,081.30	4.65%
New Jersey Resources Corp.	126.56	2,916.00	4.34%
Northwest Natural Gas Co.	76.57	1,502.60	5.10%
One Gas Inc.	121.04	2,174.70	5.57%
Spire Inc.	194.30	3,624.20	5.36%
	Range:	**Low**	**2.24%**
		High	**5.57%**
		Average	**4.28%**

Source:
Compustat (S&P Global Market Intelligence - Data Management Solutions)
Yearly data updates typically provided late April of each year
(data in millions)

Mergent Bond Record A-Rated Public Utility Bond Yields	
Month	Yield
May-23	5.36%
Jun-23	5.38%
Jul-23	5.41%
Aug-23	5.71%
Sep-23	5.86%
Oct-23	6.34%
Nov-23	5.96%
Dec-23	5.42%
Jan-24	5.48%
Feb-24	5.56%
Mar-24	5.55%
Apr-24	5.79%
	5.65%

Source:
Mergent Bond Record, p. 22 - 5/1/2024

Dividend Yields of the Proxy Group							
Company	**Atmos Energy Corp.**	**Chesapeake Utilities**	**NiSource Inc.**	**New Jersey Resources Corp.**	**Northwest Natural Gas Co.**	**One Gas Inc.**	**Spire Inc.**
Symbol	*ATO*	*CPK*	*NI*	*NJR*	*NWN*	*OGS*	*SR*
Expected Div	3.46	2.60	1.12	1.76	1.96	2.68	3.16
52-wk low	101.00	83.80	22.86	38.92	34.95	55.50	53.77
52-wk high	125.28	132.91	28.95	55.84	49.09	83.89	72.07
Spot Price	116.23	103.22	27.19	42.78	36.41	63.72	59.34
Spot Div Yield	2.98%	2.52%	4.12%	4.11%	5.38%	4.21%	5.33%
52-wk Div Yield	3.06%	2.40%	4.32%	3.71%	4.66%	3.85%	5.02%
Average	**3.02%**	**2.46%**	**4.22%**	**3.91%**	**5.02%**	**4.03%**	**5.17%**

	Average
Spot Div Yield	**4.09%**
52-wk Div Yield	**3.86%**
Average	**3.98%**

Source: Barrons 4/8/2024 & 2/23/2024
Value Line 02/23/24

Five-Year Growth Estimate Forecast for Proxy Group (Actual)

Company	Symbol	Yahoo!	Zacks	Value Line	Average
		Source			
Atmos Energy Corp.	ATO	7.50%	7.00%	7.00%	7.17%
Chesapeake Utilities	CPK	7.60%	NA	5.00%	6.30%
NiSource Inc.	NI	7.30%	6.00%	9.50%	7.60%
New Jersey Resources Corp.	NJR	6.00%	NA	5.00%	5.50%
Northwest Natural Gas Co.	NWN	2.80%	NA	6.50%	4.65%
One Gas Inc.	OGS	5.00%	5.00%	4.00%	4.67%
Spire Inc.	SR	6.36%	5.00%	4.50%	5.29%
Average					**5.95%**

Sources date:
4/8/2024 & 2/23/2024

Expected Market Cost Rate of Equity for the Proxy Group

5-Year Forecasted Growth Rates

	Time Period	Adjusted Dividend Yield (1)	Growth Rate (2)	Expected Return on Equity (3=1+2)
(1)	**52-Week Average** **Ending:** 4/8/2024 & 2/23/2024	3.86%	5.95%	9.81%
(2)	**Spot Price** **Ending:** 4/8/2024 & 2/23/2024	4.09%	5.95%	10.04%
(3)	**Average:**	**3.98%**	**5.95%**	**9.93%**

Sources: Value Line 02/23/24
Barrons 4/8/2024 & 2/23/2024

Company	**Beta**
Atmos Energy Corp.	0.85
Chesapeake Utilities	0.80
NiSource Inc.	0.90
New Jersey Resources Corp.	0.95
Northwest Natural Gas Co.	0.85
One Gas Inc.	0.85
Spire Inc.	0.85
Average beta for CAPM	**0.86**

Source:
Value Line
02/23/24

Risk-Free Rate

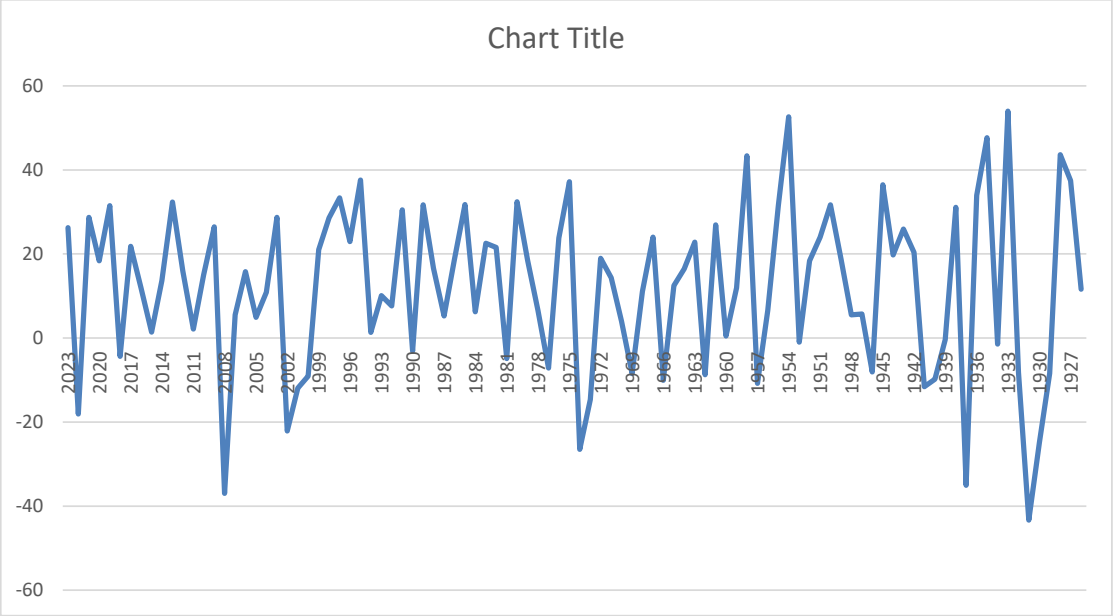
10-Year Treasury Note	Yield
3Q 2024	4.00
4Q 2024	3.90
1Q 2025	3.90
2Q 2025	3.80
3Q 2025	3.80
2025-2029	3.90
Average	**3.88**

Source:
Blue Chip
12/1/2023 & 4/1/2024

S&P 500 Market Return

Year	% Return
2023	26.29
2022	-18.11
2021	28.71
2020	18.4
2019	31.49
2018	-4.38
2017	21.83
2016	11.96
2015	1.38
2014	13.69
2013	32.39
2012	16
2011	2.11
2010	15.06
2009	26.46
2008	-37
2007	5.49
2006	15.79
2005	4.91
2004	10.88
2003	28.68
2002	-22.1
2001	-11.89
2000	-9.1
1999	21.04
1998	28.58
1997	33.36
1996	22.96
1995	37.58
1994	1.32
1993	10.08
1992	7.62
1991	30.47
1990	-3.1
1989	31.69
1988	16.61
1987	5.25
1986	18.67
1985	31.73
1984	6.27
1983	22.56
1982	21.55
1981	-4.91
1980	32.42
1979	18.44
1978	6.56
1977	-7.18
1976	23.84
1975	37.2
1974	-26.47
1973	-14.66
1972	18.98
1971	14.31
1970	4.01
1969	-8.5
1968	11.06
1967	23.98
1966	-10.06

1965	12.45
1964	16.48
1963	22.8
1962	-8.73
1961	26.89
1960	0.47
1959	11.96
1958	43.36
1957	-10.78
1956	6.56
1955	31.56
1954	52.62
1953	-0.99
1952	18.37
1951	24.02
1950	31.71
1949	18.79
1948	5.5
1947	5.71
1946	-8.07
1945	36.44
1944	19.75
1943	25.9
1942	20.34
1941	-11.59
1940	-9.78
1939	-0.41
1938	31.12
1937	-35.03
1936	33.92
1935	47.67
1934	-1.44
1933	53.99
1932	-8.19
1931	-43.34
1930	-24.9
1929	-8.42
1928	43.61
1927	37.49
1926	11.62
Average	**12.16**



Source:
https://www.slickcharts.com/sp500/returns

Estimated Rate of Return on Market as a Whole

	Dividend Yield	+	Growth Rate	=	Market Return
Value Line Estimate	2.10%		9.73%	(a)	11.83%
S&P 500 Historical Return					12.16%
Average					**12.00%**

(a) Value Line forecast for the 3 to 5 year index appreciation is 45% ((1+45%)^.25)-1)

Sources:

Value Line Dividend Yield	4/5/2024	2.10%
Value Line Appreciation Potential	4/5/2024	45.00%

CAPM

Re		Required return on individual equity security
Rf		Risk-free rate
Rm		Required return on the market as a whole
Be		Beta on individual equity security
Re	**=**	Rf+Be(Rm-Rf)
Rf	**=**	3.88
Rm	**=**	12.00
Be	**=**	0.86
Re	**=**	**10.86**

Sources: Value Line 02/23/24
Blue Chip 12/1/2023 & 4/1/2024

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. Staff RR-021-D:

Reference Columbia Statement No. 8, pp. 7-8 concerning Mr. Moul's discussion regarding natural gas utilities business risks arising from competition, economic regulation, the business cycle, pipeline safety regulations, and customer usage patterns. List the companies in Mr. Moul's Gas Group that are not susceptible to these business risks.

Response:

All of the members of the Gas Group have those characteristics to varying degrees.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. Staff RR-022-D:

Reference Columbia Statement No. 8, p. 9, lines 15-20 concerning large industrial and commercial customers' bypass risk:

A. Identify all large industrial and commercial customers lost and gained by year in 2021, 2022, and 2023.

B. List the companies in Mr. Moul's Gas Group that are not susceptible to competition and alternative energy sources or bypass risks.

Response:

Mr. Moul did not study in detail the bypass threat of each company in his proxy group. However, he is aware that bypass is usually a threat to LDCs when there are a number of interstate pipelines in close proximity to large volume users served by an LDC or when customers of the LDC are in close proximity to gas producing wells. As to the issue of bypass by interstate pipelines, most LDCs, including companies in the Gas Group, are faced with this threat, which can be greater or less than the risk experienced by CPA. Relevant here, CPA has six interstate pipelines traversing its service territory. As to bypass that might be associated in proximity to producing wells, only one member (i.e., Atmos Energy) has extensive operations in gas producing regions. There is only one company in the Gas Group (i.e., NiSource) that operates in the Marcellus Shale formation like CPA.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. Staff RR-023-D:

Reference Columbia Statement No. 8, pp. 10-11 concerning Mr. Moul's discussion regarding construction programs that affects Columbia's risk. List the companies in Mr. Moul's Gas Group that are not susceptible to risk associated with construction programs.

Response:

All members of the Gas Group are engaged in capital expenditures to varying degrees.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. Staff RR-009-D:

Reference Columbia Statement No. 8, p. 27, lines 10-16 where Mr. Moul opines that his recommended 6.75% five-year projected growth rate is a reasonable investor expected growth rate because it is within the range of 5.69% and 7.31% and expected continuation of gas utility infrastructure spending:

A. Explain whether Mr. Moul believes that the analysts at IBES/First Call, Zacks, and Value Line consider these expectations when formulating their five-year growth projections.

B. Explain whether Mr. Moul believes that all companies in his Gas Group would benefit from the same expectations.

C. Provide the basis for determining a 6.75% growth rate as appropriate for the DCF analysis.

Response:

A. The growth rates published by IBES/FirstCall, Zacks and Value Line are assumed to consider all factors that they believe impact future growth, which for the members of the Gas Group would include growth associated with infrastructure spending. IBES/First Call and Zacks are consensus growth rates that are obtained from a survey of analysts, and as such, the assumptions reflected in the consensus are not revealed by the published growth rates. Hence, there is no ability to determine the weight that an individual analyst assigns to infrastructure spending for each member of the Gas Group. Value Line does reveal the underlying data that supports its growth rates.

B. It cannot be established that "all companies" are affected equally by infrastructure spending, as infrastructure spending varies across the members of the Gas Group. Regardless, there is widespread knowledge for the

proposition that infrastructure spending has been ramping up in recent years for the gas utility industry.

C. As noted on page 27 of Statement No. 8, the 6.75% investor-expected growth rate rests well within the range of analysts' earnings per share growth rates of 5.69% to 7.31%, giving due regard to infrastructure spending of the members of the Gas Group.

I&E Exhibit No. 2
Schedule 15

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. Staff RR-018-D:

Reference Columbia Statement No. 8, p. 43 concerning Mr. Moul's opinion that his recommended 11.75% cost of common equity is reasonable:

A. State whether Mr. Moul is aware of any natural gas distribution utilities throughout the United States that have been granted a Commission authorized 11.75% or higher cost of common equity in the past three years.

B. If the answer to I&E-RR-18-D, Part A is yes, identify which company/companies have been authorized such cost of common equity, in what jurisdiction, and docket numbers associated with each instance.

Response:

A. Mr. Moul has not researched this issue.

B. See the response to (A) above.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. Staff RR-030-D:

Reference Columbia Exhibit 14, Schedule 2, Attachment B, pp. 1-23 concerning the proposed Supplement Tariff No. 374 to Tariff Gas Pa. P.U.C. No. 9 showing the effective date of proposed new rates as May 14, 2024, which will be suspended until December 14, 2024:

A. Provide the targeted effective date of new rates after the rate suspension ending on December 14, 2024 or after the Commission order approving the rate increase request.

B. If the targeted effective date of new rates is on or before December 31, 2024 and not January 1, 2025, the first day of the FPFTY 2025, state whether Columbia will refund the over recovery in rates/revenue from customers with interest for the period starting with December 15, 2024 (new rate effective date) through December 31, 2024.

Response:

A. If the Commission suspends the Company's proposed rates set forth in Supplement No. 374 until December 14, 2024, the effective date of new rates will be December 14, 2024.

B. If the Commission approves the Company's rates and directs them to be implemented on December 14, 2024, there will be no over recovery in rates/revenues from customers.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

BUREAU OF INVESTIGATION AND ENFORCEMENT INTERROGATORIES
Set RR

Question No. Staff RR-029-D:

Reference Columbia Statement No. 8, pp. 3-4 and Exhibit 102, Schedule 3 concerning the Statement of Income at present and proposed rates showing the ratemaking calculation (total revenue requirement and revenue increase adjustment) for the twelve months ended November 30, 2023 (HTY), twelve months ending November 30, 2024 (FTY), and the twelve months ending December 31, 2025 (FPFTY):

A. Explain in detail why the Company projected the FPFTY for the twelve months from January 1, 2025 to December 31, 2025 when the claimed FTY is from December 1, 2023 to November 30, 2024 and the HTY is from December 1, 2022 to November 30, 2023 in the ratemaking calculation.

B. Explain why the Company filed this rate case on March 15, 2024 instead of on March 31, 2024 when Columbia has provided the supporting revenue requirement and revenue increase calculation based on the FPFTY which covers January 1, 2025 to December 31, 2025 and the proposed new rate effective date will be suspended until December 14, 2024.

Response:

A. By regulation, an historic test year is to be the twelve -month period ending no later than 120 days prior to the date of the rate filing. Also, by regulation, the future test year is to be the twelve-month period immediately following the historic test year. By statute, the FPFTY is to be the twelve-month period beginning with the first month that new rates will be placed into effect after the full suspension period. Because the full statutory suspension period concludes in December 2024, the FPFTY is the twelve-month period beginning January 1, 2025.

B. Filing the rate case on March 31, 2024, would not be in compliance with the Commission's regulations regarding the period for an historic test year.

I&E Statement No. 3
Witness: Esyan A. Sakaya

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2024-3046519

Direct Testimony

of

Esyan A. Sakaya

Bureau of Investigation and Enforcement

Concerning:

Fully Projected Future Test Year Reporting Requirements
Hydrogen Blend Pilot Program
Weather Normalization Adjustment
Revenue Normalization Adjustment
Customer Charge
Cost of Service Study
Scale Back of Rates

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Esyan A. Sakaya. My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Bureau of Investigation and Enforcement ("I&E") as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATION AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in the proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My direct testimony relates to Columbia Gas of Pennsylvania, Inc.'s ("Columbia

Gas" or "Company") requested base rate revenue increase of $124,138,477.[1] My testimony specifically addresses the following issues:

- Fully Projected Future Test Year ("FPFTY") Reporting Requirements
- Hydrogen Blend Recovery
- Weather Normalization Adjustment
- Revenue Normalization Adjustment
- Cost of Service Allocation
- Customer Cost Analysis
- Customer Charge
- Scale Back of Rates

Q. DOES YOUR DIRECT TESTIMONY INCLUDE AN EXHIBIT?

A. No.

FPFTY REPORTING REQUIREMENTS

Q. WHAT TEST YEARS DID THE COMPANY ELECT TO USE IN THIS PROCEEDING?

A. Columbia elected to base its rates on an FPFTY ending December 31, 2025. The Company also addressed a historic test year ("HTY") ended November 30, 2023

[1] Columbia Gas Statement No. 4, pp. 3-4.

and future test year ("FTY") ending November 30, 2024 (Columbia St. No. 4, p. 3).

Q. WHAT AMOUNT OF ADDITIONAL RATE BASE WILL BE ASSOCIATED WITH COLUMBIA'S INCLUSION OF THE FPFTY ENDING DECEMBER 31, 2025?

A. The Company's claimed FPFTY rate base is $3,489,087,567 (Columbia Ex. No. 108, p. 3, col. 5). Columbia's FTY rate base is $3,181,524,560 (Columbia Ex. No. 108, p. 3, col. 3). Therefore, $307,563,007 ($3,489,087,567 - $3,181,524,560) of rate base additions are associated with the thirteen months between the end of FTY and the end of the FPFTY.

Q. DID THE COMPANY PROVIDE A SCHEDULE SHOWING PLANT ADDITIONS AND RETIREMENTS THAT SUPPORT THE PROJECTED LEVEL OF TOTAL PLANT IN THE FTY AND FPFTY RATE BASE?

A. Yes. The Company provided Columbia Ex. No. 108, Sch. 1 showing detailed plant additions and retirements for the FTY and FPFTY.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT COLUMBIA PROJECTS TO BE IN SERVICE DURING THE FTY AND THE FPFTY?

A. Yes. I recommend that the Company provide the Bureau of Investigation and

Enforcement and the Office of Consumer Advocate with an update to Columbia Exhibit No. 108, Schedule 1 no later than April 1, 2025, under this docket number, which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending November 30, 2024. An additional update should be provided for actuals through December 31, 2025, no later than April 1, 2026.

Q. WHY DO YOU RECOMMEND THAT COLUMBIA PROVIDE THESE UPDATES?

A. There is value in determining how closely Columbia's projected investments in future plant align with the actual investments that are made by the end of the FTY and FPFTY. Determining the correlation between Columbia's projected and actual results will help inform the Commission and the parties in Columbia's future rate cases as to the validity of Columbia's projections.

Using an FPFTY, Columbia is requesting that ratepayers pre-pay a return on its projected investment in future plant that is not in place and providing service at the time the new rates take effect, but also is not subject to any guarantee of being completed and placed into service. While the FPFTY provides for such projections, there should be verification of the projections. Therefore, requiring the Company to provide updates demonstrating that actual investments align with projections used in setting rates via an FPFTY provides the Commission with

actual data to determine the accuracy of Columbia's projected investments in future proceedings.

HYDROGEN BLENDING RECOVERY

Q. WHAT IS HYDROGEN BLENDING?

A. Hydrogen blending helps to decarbonize the gas system and reduce greenhouse gas emissions (Columbia St. No. 9, p. 14). In summary, it is the blending of hydrogen with natural gas.

Q. BRIEFLY EXPLAIN THE COMPANY'S PROPOSED RECOVERY RELATED TO THE PURCHASE OF HYDROGEN.

A. The Company is seeking to recover $54,000 in operating and maintenance expenses in the FPFTY related to the purchase of hydrogen for its Hydrogen Blending Skid at the Columbia Gas training center in Monaca, Pennsylvania (Columbia St. No. 9, p. 15 and Columbia Ex. No. 104, Sch No. 2, p. 18).

Q. WHY HAS COLUMBIA CONSIDERED PURCHASING HYDROGEN?

A. Columbia asserted that as more and more Columbia customers become aware of low carbon solutions, the interest in hydrogen blending is expected to grow. The Company is predicting that customers will begin to request or want to purchase hydrogen-blended natural gas (Columbia St. No. 9, p. 14).

Q. DO YOU HAVE ANY CONCERNS ABOUT THE HYDROGEN BLENDING RECOVERY?

A. Yes.

Q. PLEASE EXPLAIN YOUR CONCERN.

A. I have one concern. Ratepayers should not have to pay for the Company's $54,000 purchase of hydrogen as it is not currently being blended into Columbia's operating system serving customers (Columbia St. No. 9, p. 13). Therefore, hydrogen blending cannot be considered used and useful in Columbia's distribution system.

Q. WHAT DO YOU RECOMMEND CONCERNING THE HYDROGEN BLENDING RECOVERY?

A. I recommend that the $54,000 in hydrogen recovery for the FPFTY be denied as it is not servicing any current Columbia natural gas customers because the Company is proposing the purchase of hydrogen as a research-only project exclusively for use in a model home located inside its training facility in Monaca, Pennsylvania (Columbia St. No. 9, pp. 13-15 and Columbia Ex. No. 104, Sch No. 2).

WEATHER NORMALIZATION ADJUSTMENT

Q. WHAT IS THE WEATHER NORMALIZATION ADJUSTMENT?

A. The Weather Normalization Adjustment ("WNA") is a pilot program established

by the Company after Commission approval in the 2012 Columbia base rate case and made a permanent rider after the 2018 Columbia base rate case. The purpose of the WNA is to adjust the temperature sensitive portion of a customer's bill to mitigate the impacts of warmer or colder than normal weather (Columbia St. No. 3, pp. 3-4). In summary, customers are billed less than what a traditional bill calculation would require during colder than normal heating seasons and billed more during warmer than normal heating seasons.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE WNA?

A. Yes. The Company is proposing to use its current WNA in conjunction with a proposed Revenue Normalization Adjustment ("RNA") to establish a benchmark revenue level that remains intact regardless of a customer's actual usage (Columbia St. No. 6, p. 36).

Q. HOW IS THE COMPANY PLANNING TO IMPLEMENT ITS RNA PROPOSAL WITH THE WNA?

A. The Company is looking to eliminate the 3% deadband currently in effect in its WNA and replace it with an RNA (Columbia St. No. 6, p. 35).

Q. WHY DOES THE COMPANY PROPOSE ELIMINATING THE 3% DEADBAND IN THE WNA?

A. In summary, the Company thinks its current WNA with a 3% deadband is

insufficient in recovering revenue from customers during a period where temperatures are - 3% colder than usual in which customers receive a credit towards their bill, or + 3% warmer than usual in which customers receive a surcharge on their bill. Columbia believes fluctuations in temperature that are 2.5% colder or warmer than their current 3% in their WNA will not provide the Company a stable amount of revenue and would best be supplemented with a Revenue Normalization Adjustment ("RNA") (Columbia St. No. 6, p. 35).

Q. WHAT DO YOU RECOMMEND REGARDING THE COMPANY'S WNA PROPOSAL?

A. I recommend that the proposal to remove the 3% deadband be denied.

Q. WHY DO YOU RECOMMEND THAT THE 3% DEADBAND BE RETAINED?

A. A WNA is a departure from traditional ratemaking in that it allows the Company to actually adjust a customer's base rate bill, which was calculated based on Commission approved rates, outside the scope of a base rate case. Such a departure from traditional ratemaking should only occur due to circumstances that are an extraordinary departure from normal operating conditions, such as abnormal weather. There is no need to reconcile the day-to-day temperature variations that can be considered a normal part of doing business. Therefore, a 3% deadband is a reasonable provision, because it allows for a range of what is

considered "normal" weather in which the Company's Commission-approved rates would be applied without adjustment.

The WNA with the 3% deadband is a reasonable provision because it serves to protect both the Company and customers from the effects of abnormal weather, which cannot be predicted or controlled. However, as stated above, there is no need to reconcile day-to-day weather changes; therefore, I recommend that the 3% deadband which is currently in place become permanent.

REVENUE NORMALIZATION ADJUSTMENT

Q. WHAT IS A REVENUE NORMALIZATION ADJUSTMENT?

A. Columbia is arguing that a revenue normalization adjustment ("RNA") is a tariff provision that is "designed to 'break the link' between residential non-gas revenue received by the Company and gas consumed by non-CAP residential customers." (Columbia St. No. 6, p. 36). In other words, the Company is proposing to stabilize its revenue level received from customers by enacting a "benchmark distribution revenue level" and adjusting revenues to that point regardless of actual usage levels.

Q. IS THE COMPANY PROPOSING AN RNA IN THIS PROCEEDING?

A. Yes. The Company is proposing to apply an RNA to its non-CAP residential customers (Columbia St. No. 6, p. 36).

Q. HOW DOES THE COMPANY PROPOSE TO ENACT THE RNA?

A. The Company proposes to set the benchmark distribution revenue levels by month for the peak period, October through March, and off-peak period, April through September, separately, based on the revenue requirement approved in the instant proceeding (Columbia St. No. 6, pp. 40-41).

Q. IS THIS THE FIRST PROCEEDING IN WHICH THE COMPANY HAS PROPOSED TO ENACT THE RNA?

A. No. The Company has proposed to enact the RNA in several previous rate cases. Most recently, the Company proposed to enact the RNA in its prior 2020, 2021, and 2022 rate cases at Docket Nos. R-2020-3018835, R-2021-3024296 and R-2022-3031211.

Q. DID THE COMPANY MAKE ANY CHANGES TO ITS PROPOSED RNA BETWEEN THE LAST PROCEEDING AND THE INSTANT PROCEEDING?

A. Yes. The Company is proposing to eliminate its present 3% WNA deadband in the present tariff and replace it with an RNA in the proposed tariff.

Q. DO YOU RECOMMEND THAT THE RNA BE APPROVED?

A. No, Columbia's proposed RNA should be denied.

Q. WHY DO YOU RECOMMEND THAT THE RNA BE DENIED?

A. I recommend that the proposed RNA be denied for the following reasons. First, the Commission determined the RNA was unnecessary in the Company's 2020 base rate proceeding. Second, the policy statement cited by the Company does not allow Columbia to abandon the necessity to charge just and reasonable rates. Third, the use of the FPFTY already provides projected lower usage levels.

Q. WHICH CUSTOMERS WOULD BE SUBJECT TO THE PROPOSED RNA?

A. The Company is proposing to apply an RNA to its non-CAP residential customers (Columbia St. No. 6, p. 36).

Q. WHAT DID THE COMMISSION DETERMINE REGARDING THE RNA IN COLUMBIA'S 2020 BASE RATE PROCEEDING?

A. The Commission determined that the RNA, as presented in Columbia's 2020 base rate case, was not needed nor reasonable and would not produce rates that are just, reasonable, and in the public interest. (*Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, OPINION AND ORDER, pp. 264-265, Order entered February 19, 2021).

Q. DOES THE REFERENCE TO THE STATEMENTS OF POLICY IN THE ALTERNATIVE RATEMAKING DOCKET NEGATE THE OBLIGATION OF A COMPANY TO CHARGE RATES THAT ARE JUST, REASONABLE, AND IN THE PUBLIC INTEREST?

A. No. The Statements of Policy as outlined by the Commission in the alternative ratemaking Docket No. M-2015-2518883 does not negate the obligation of a Company to charge rates that are just and reasonable (Columbia St. No. 6, pp. 36 - 40). Moreover, Columbia seeks to point to the 2015 Policy Statement as justification for the RNA but disregards the Commission's February 19, 2021 Order denying Columbia's RNA proposal.

Q. DOES THE USE OF THE FPFTY ALREADY INCLUDE PROJECTED ADJUSTMENTS FOR DECLINES IN USAGE?

A. Yes. Through Act 11 and the FPFTY, the Company is permitted to build into its revenue requirement and future rates an adjustment for revenues lost due to a projected decline in usage that is projected to occur up to a year after new rates go into effect. The Company did so in this proceeding as it is projecting a reduction in customer usage over the FPFTY and included an adjustment to revenues to account for that reduction, as discussed below.

Q. HAS THE COMPANY DEMONSTRATED A NEED FOR REVENUE STABILIZATION?

A. No. The purpose of revenue stabilization is to remove the inherent risk of not recovering the full amount of revenue requirement allowed by the Commission due to changes in usage. Between the frequent base rate cases filed by the Company, staying out no more than two years, the FPFTY, the DSIC, and the WNA, the Company has demonstrated no need for further revenue stabilization measures. Additionally, the Company has not indicated that the RNA will result in fewer base rate cases, thus removing any benefit from the residential customers. Furthermore, as stated above, the Company did not add any additional information or support that would cause the Commission to reverse its previous decision that the RNA does not provide rates that are just, reasonable, and in the public interest. Finally, it can be argued that the RNA will having a chilling effect on voluntary conservation by the ratepayers.

COST OF SERVICE ALLOCATION

Q. WHAT IS AN ALLOCATED COST OF SERVICE ("ACOS") STUDY?

A. A utility provides service to a defined set of customer classes that are different in terms of demand and usage patterns. An ACOS allocates or assigns a utility's revenue requirement based on those service differences. In other words, an ACOS is a formalized analysis of costs that attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the

Company's total revenue requirement). The results of such a study can be utilized to determine the relative cost of service for each class and help determine the individual class revenue requirements, and to the extent a particular class is above or below the system average rate of return, show the additional revenues each class receives or conversely the additional revenues that each class contributes to the Company's overall revenues. In addition to the relative provision of revenues, a relative rate of return is also provided, which shows how the rate of return for each class compares to the system average rate of return.

Q. WHAT ARE RATES OF RETURN AND RELATIVE RATES OF RETURN?

A. The rate of return is the Commission authorized return on rate base that is determined in a base rate proceeding. A relative rate of return indicates how the rate of return of each customer class compares to the system average rate of return. In general, a relative rate of return that provides revenue equal to its cost to serve would have a relative rate of return equal to 1.0. If a class of service has a relative rate of return below 1.0, the revenue received from that class does not cover the cost of providing service to that class. If a class of service has a relative rate of return above 1.0, the revenue received from that class exceeds the cost of providing service to that class.

Q. DID THE COMPANY PROVIDE AN ACOS STUDY IN THIS PROCEEDING?

A. Yes. The Company performed and provided three ACOS studies in its filing sponsored by Columbia witness Kevin L. Johnson as described on Columbia Statement No. 6, p. 4. The first is a customer-demand ACOS study (Columbia Exhibit No. 111, Schedule 1), the second is a peak and average ACOS study (Columbia Exhibit No. 111, Schedule 2), and the third ACOS study is an average of the customer-demand studies and the peak and average studies (Columbia Exhibit No. 111, Schedule 3).

Q. WHAT IS THE LARGEST CAPITAL COST FOR COLUMBIA?

A. On Columbia Statement No. 6, p. 9, Mr. Johnson states that "[m]ains and services account for the majority of the Company's gross plant investment and distribution O&M expenses."

Q. WHAT IS THE MAIN DIFFERENCE BETWEEN THE CUSTOMER-DEMAND AND THE PEAK AND AVERAGE ACOS STUDIES?

A. The difference between the customer-demand ACOS and the peak and average ACOS studies presented by Mr. Johnson in Company Exhibit No. 111 is in the way that each study allocates the costs of mains. Consequently, the two ACOS studies yield different relative rates of return for each rate class.

The customer-demand methodology classifies distribution mains as partially customer related and partially demand related. The customer portion of mains is then allocated to the various customer classes based on the total number of customers, while the demand portion of mains is allocated to classes based on peak day contributions or demand. This methodology was rejected by the Commission in the Company's 2020 base rate case (*Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, OPINION AND ORDER, pp. 217-218, Order entered February 19, 2021).

The peak and average ACOS, however, allocates distribution mains to classes based partially on contributions to peak day demand and partially on annual consumption (average demand). This methodology was accepted by the Commission in the Company's 2020 base rate case referenced above.

Q. WHICH OF THE THREE ACOS STUDIES SPONSORED BY MR. JOHNSON DID THE COMPANY UTILIZE TO ALLOCATE THE PROPOSED REVENUE INCREASES?

A. Consistent with the Commission's Order from Columbia's 2020 base rate case, discussed above, the Company utilized the second ACOS study sponsored by Mr. Johnson, which is the peak and average study, presented on Columbia Exhibit No. 111, Schedule No. 2 to allocate the proposed revenue increases (Columbia St. No. 6, p. 4).

Q. DO YOU AGREE WITH THE COMPANY'S PROPOSED USE OF THE PEAK AND AVERAGE METHODOLOGY TO ALLOCATE THE REVENUE INCREASES AMONG THE DIFFERENT CUSTOMER CLASSES IN THIS PROCEEDING?

A. Yes.

Q. DID THE COMPANY ALSO ELECT TO SHOW THE FLEX RATE CUSTOMERS UNDER THEIR OWN RATE CLASS IN THE COST OF SERVICE STUDY?

A. Yes, and I agree with the Company's decision to do this. This is important so that the Commission can determine the cost to provide service to the flex and non-flex customers and the subsidy being provided by tariff rate customers. With this information, the Commission can establish fair and reasonable rates for all other non-flex customers in non-flex classes.

Q. WHAT DO YOU RECOMMEND CONCERNING FUTURE COLUMBIA BASE RATE CASES?

A. I recommend two things in future base rate cases. First, I recommend the Company continue to utilize the peak and average cost of service study to establish rates. Second, I recommend that the Company continue to classify flex rate customers as a separate class in future cost of service studies.

CUSTOMER COST ANALYSIS

Q. WHAT IS A CUSTOMER COST ANALYSIS AND HOW IS IT USED?

A. A customer cost analysis is a part of a COSS that is used to determine the appropriate fixed customer charges for the various classes and meter sizes. It includes customer costs only.

Q. WHY IS IT NECESSARY TO PERFORM A CUSTOMER COST ANALYSIS?

A. A fixed customer charge represents the revenue that the Company is guaranteed to receive each month, regardless of the level of usage. As acknowledged in the seventh edition of the American Water Works Association M1 Manual, there is a tradeoff between revenue stability from a high customer charge, and affordability and conservation from a low customer charge and higher usage rates.[2]

Q. WHAT IS A DIRECT CUSTOMER COST?

A. A direct customer cost is a cost that changes with the increase or decrease of a single customer.

Q. WHAT IS AN INDIRECT CUSTOMER COST?

A. An indirect customer cost is a customer related cost that does not change with the

[2] AWWA Manual of Water Supply Practices M1 Principles of Water Rates, Fees, Charges, Seventh Edition. pp. 154-155.

increase or decrease of a single customer. The Commission has allowed, in past instances, only certain indirect customer costs to be included in a customer cost analysis and thus recovered in a customer charge. As an example, in previous cases, the Commission has allowed the indirect cost of Employee Pension and Benefits.

Q. DID COLUMBIA PREPARE A CUSTOMER COST ANALYSIS TO SUPPORT THE PROPOSED CUSTOMER CHARGE INCREASES IN THIS PROCEEDING?

A. Yes. The Company prepared two customer cost analyses presented in Columbia Exhibit No. 111, Schedule 1, pages 17 and 25. The Company's first customer cost analyses allocates a portion of the cost of mains to customers. The Company's second customer cost analyses does not allocate any portion of the cost of mains to customers. The results of each customer cost analysis are presented in the following table:

Customer Class	Including Mains (Columbia Ex. No. 111, Sch. 2, p. 17, line 43)	Excluding Mains (Columbia Ex. No. 111, Sch. 2, p. 25, line 39)
RSS/RDS	$72.67	$28.71
SGS/DS-1	$81.63	$31.68
SGS/DS-2	$177.85	$59.53
SDS/LGSS	$926.85	$300.62
LDS/LGSS	$6,174.02	$1,711.06
MLDS	$801.24	$675.21
FLEX	$27,645.21	$5,195.54

Q. HOW DID COLUMBIA DETERMINE THE FIXED MONTHLY COSTS BY CUSTOMER CLASS ABOVE?

A. According to Columbia witness Johnson, the Company designed its rates to include the principles of efficiency, simplicity, continuity, fairness, and earnings stability (Columbia St. No. 6, p. 16).

Q. SHOULD THE COMPANY'S CUSTOMER COST ANALYSIS THAT INCLUDES THE COST OF MAINS BE CONSIDERED?

A. No. The Commission has established in Columbia's 2020 base rate case that mains are not properly included as a customer cost (*Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, OPINION AND ORDER, p. 218, Order entered February 19, 2021). Therefore, the Company's customer cost analysis that includes the cost of mains should not be utilized in this proceeding.

<u>CUSTOMER CHARGES</u>

Q. WHAT CUSTOMER CHARGES ARE THE COMPANY PROPOSING FOR EACH RATE CLASS?

A. The customer charges for each rate class that received a proposed increase are shown in the table below (Columbia Ex. No. 103, Sch. No. 8, pp. 5-9).

Rate Schedule (Therms, annually)	Present Rate	Change	Proposed Rate	Percent Increase
RS, RDS, RC2				
All Usage	$16.75	$10.28	$26.00	61.3%
SGSS1, SCD1, SGDS1				
≤6,440	$29.92	$6.63	$36.55	22.1%
SGSS2, SCD2, SGDS2				
>6,440 to ≤64,440	$57.00	$12.63	$69.63	22.1%
SDS/LGSS				
>64,400 to ≤110,000	$267.11	$58.98	$326.09	22.1%
>110,000 to ≤540,000	$1211.59	$267.54	$1,479.13	22.1%
LDS				
>540,000 to ≤1,074,000	$2,986.82	$662.68	$3,649.50	22.1%
>1,074,000 to ≤3,400,000	$4645.73	$1030.73	$5,676.46	22.1%
>3,400,000 to ≤7,500,000	$8,959.14	$1,987.74	$10,946.88	22.1%
>7,500,000	$13,272.55	$2,944.74	$16,217.29	22.1%

Q. ARE YOU RECOMMENDING ADJUSTMENTS TO ANY OF THE COMPANY'S PROPOSED CUSTOMER CHARGES?

A. Yes. Based on the customer cost analysis that does not include the cost of mains, as described above, the customer charges for the RS, RDS, and RC2 classes are too high. I am not recommending an adjustment to the proposed customer charges for the LDS customers because higher usage customers generally favor a higher fixed charge and lower usage charges. I am also not recommending adjustments to the proposed customer charges for SGS1, SGS2, and SDS/LGSS customers as the proposed charges are consistent with the customer cost analysis.

Q. WHAT CUSTOMER CHARGES ARE YOU RECOMMENDING FOR THE RS, RDS, AND RC2 CLASSES?

A. I am recommending the customer charges for the RS, RDS and RC2 classes be adjusted to be consistent with the customer cost analysis below:

Rate Schedule (Therms, annually)	Customer Cost Analysis	Company Proposed Rate	Change	I&E Proposed Rate	Percent Increase
RS, RDS, RC2					
All Usage	$25.47	$26.00	$5.14	$20.46	22.1%

Q. WHAT JUSTIFICATION DO YOU HAVE FOR RECOMMENDING YOUR PROPOSED CUSTOMER CHARGES FOR THE RS, RDS, AND RC2 CLASSES?

A. My justification for the 22.1% increase in the customer charge for the RS, RDS and RC2 customer classes is based upon the proposed rate increases across all other classes being at 22.1%. Columbia proposes a 61.3% revenue allocation increase to RS, RDS and RC2 customer classes (Columbia Ex. No. 103, Sch. No. 8, p. 5). However, this proposed increase is excessive, and violates the concept of gradualism.

Q. WHAT IS GRADUALISM?

A. Gradualism is a well-established ratemaking concept that seeks to limit the immediate increases customers receive when rates are increased and implement

significant rate changes on a more gradual basis over time.

SCALEBACK OF RATES

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommend that all customer charges and usage rates that have a proposed increase be scaled back proportionately based on the ACOSS that is ultimately approved by the Commission.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Esyan A. Sakaya

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION
400 North Street
HARRISBURG, PA 17120

Education:

National Association of Regulatory Utility Commissioners, Clearwater, FL
Utility Rate School; Utility Rate Making Basics, October 2019

Society of Depreciation Professionals, Philadelphia, PA
Introduction to Depreciation; Depreciation Fundamentals, September 2019

Temple University, Philadelphia, PA
Bachelor of Science; Major in Engineering Technology, 2015

Community College of Philadelphia, Philadelphia, PA
Associate of Applied Science; Major in Construction Management Technology, 2011

Island School of Building Arts, Gabriola Island, BC-Canada
Certificate Graduate: Heavy Timber Construction August 2002-November 2002

Solar Energy International, Carbondale, CO
Certificate Graduate: Basic and Advanced Photovoltaic Design, April 2002-May 2002

Experience:

12/2018-Present
Pennsylvania Public Utility Commission-Harrisburg, PA

Fixed Utility Valuation Engineer - Assist in engineering related studies related to valuation, depreciation, cost of service, quality of service as they apply to regulated utilities. Contribute in evaluating, contrasting and conducting performance analyses in distinctive sections of valuation engineering and rate structure involving valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design. Provide expert testimony in rate related utility cases.

4/2018-12/2018
Pennsylvania Department of Transportation-Harrisburg, PA

Photogrammetry Technician I - Created three-dimensional mapping layouts of natural and man-made features from stereoscopic images on a computer workstation. Assisted in the field placement of ground based surveyed control-points prior to aerial photography acquisition. Provided field support in the use of laser scans for comprehensive digital surveying data. Operated global positioning satellite surveying equipment to obtain accurate geodetic coordinates of pre-established benchmarks.

8/2017-4/2018
Pennoni and Associates. Consulting Engineers-King of Prussia, PA

Construction Inspector – Provided quality assurance in the onsite material testing of concrete, soils, and asphalt. Read and interpreted construction drawings and specifications of materials and components. Completed daily reports regarding project progress to engineers, project managers/superintendents, contractors, and clients.

TESTIMONY SUBMITTED:

I have assisted and/or submitted testimony in the following proceedings:

NO.	Case
1.	UGI Gas Utilities - Gas Division, Docket No. R-2018-3006814
2.	Newtown Artesian Water Company, Docket No. R-2018-3006904
3.	Pittsburgh Wastewater, Docket No. M-2018-2640803
4.	PAWC Purchase of Steelton, Docket No. A-2019-3006814
5.	Philadelphia Gas Works, Docket Nos. R-2019-3009016 & R-2019-3007636
6.	Community Utilities Water, Docket No. R-2019-3008947
7.	Aqua Purchase of Cheltenham, Docket No. A-2019-3008491
8.	UGI North, Docket No. R-2019-3009647
9.	UGI Central, Docket No. R-2019-3009647
10.	UGI South, Docket No. R-2019-3009647
11.	Twin Lakes Utilities, Docket No. R-2019-3010958
12.	Penn Power Company, Docket No. P-2019-3012628
13.	UGI Gas Utilities, Docket No. R-2019-3015162
14.	National Fuel and Gas Distribution, Docket No. R-2020-3015251
15.	Columbia Gas of PA, Docket Nos. R-2020-3018993 & R-2020-3018835
16.	Duquesne Light Company, Docket No. P-2020-3019522
17.	PA American Water Co., Docket Nos. R-2020-3019369 & R-2020-3010937

18. Bethlehem Water Company, Docket No. R-2020-3020256
19. Audubon Water Company, Docket No. R-2020-3020919
20. Twin Lakes Utilities, Docket No. P-2020-3020914
21. Pike County Light and Power-Gas, Docket No. R-2020-3022134
22. Pike County Light and Power-Electric, Docket No. R-2020-3022135
23. Duquesne Light Company, Docket No. R-2021-3024750
24. Community Utilities Water, Docket No. R-2021-3025206
25. Community Utilities Wastewater, Docket No. R-2021-3025206
26. Hanover Municipal Water Works, Docket No. R-2021-3026116
27. Aqua Pennsylvania, Inc., Docket Nos. R-2021-3027385 & R-2021-3027386
28. Aqua Purchase of Willistown, Docket No. A-2021-3027268
29. National Fuel and Gas Distribution, Docket No. R-2022-3030235
30. UGI Gas Utilities, Docket No. R-2021-3030218
31. PECO Energy Company – Gas, Docket No. R-2022-3031113
32. Valley Energy, Inc., Gas, Docket No. R-2022-3032300
33. Citizens' Electric Company, Docket No. R-2022-3032369
34. Leatherstocking Gas Company, LLC Docket No. R-2022-303276
35. National Fuel and Gas Distribution, Docket No. R-2022-3035730
36. Aqua Purchase of Shenandoah, Docket No. A-2022-3034143
37. UGI Electric Utilities, Docket No. R-2022-3037368
38. Philadelphia Gas Works, Docket No. R-2023-3037933
39. Columbia Water, Docket No. R-2023-3040258
40. Community Utilities Water, Docket No. R-2023-3042804
41. Community Utilities Wastewater, Docket No. R-2023-3042805
42. CAN DO, Inc., Docket Nos. R-2023-3040153 & R-2023-3040151
43. Veolia Water, Inc., Docket No. R-2024-3045192
44. Veolia Wastewater, Inc., Docket No. R-2024-3045193

I&E Statement No. 1-R
Witness: Christian Yingling

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2024-3046519

Rebuttal Testimony

of

Christian Yingling

Bureau of Investigation & Enforcement

Concerning:

LOW-INCOME USAGE REDUCTION PROGRAM

HARDSHIP FUND

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INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christian Yingling, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME CHRISTIAN YINGLING WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 1 AND THE SCHEDULES IN I&E EXHIBIT NO. 1?

A. Yes.

Q. DOES YOUR REBUTTAL TESTIMONY INCLUDE AN ACCOMPANYING EXHIBIT?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address the direct testimony of the Pennsylvania Weatherization Providers Task Force (PWPTF) witness Jennifer

Warabak concerning her recommended increase to Columbia Gas of Pennsylvania, Inc.'s (Columbia or Company) Low Income Usage Reduction Program (LIURP) budget commensurate to the increase in rates for the residential class in this proceeding (PWPTF Statement No. 1, p. 6), and her recommended increase to the Company's contribution to the Hardship Fund commensurate with the percentage increase in residential rates that result from this proceeding (PWPTF Statement No. 1, p. 7).

LIURP

Q. SUMMARIZE MS. WARABAK'S DIRECT TESTIMONY CONCERNING COLUMBIA'S LIURP BUDGET.

A. Ms. Warabak states that the Company is not proposing any increase to LIURP funding. However, she proposes to, at a minimum, increase LIURP funding by the commensurate increase in rates resulting from this proceeding for the residential class (PWPTF Statement No. 1, pp. 6-7).

Q. WHAT IS THE BASIS FOR MS. WARABAK'S RECOMMENDATION?

A. Ms. Warabak states that despite the expected rate increase that will likely result from this proceeding, the Company is not proposing any increase to LIURP funding. She then states that her recommendation will help customers deal with a rate increase in these difficult economic times (PWPTF Statement No. 1, pp. 6-7).

Q. DO YOU AGREE WITH MS. WARABAK'S RECOMMENDATION?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that no increase in the budgeted LIURP amount be approved in this proceeding.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. While Ms. Warabak's recommendation is well-intentioned, it is inappropriate to consider an increase in the LIURP budget in this base rate proceeding. Any potential increase should be addressed in the Company's USECP proceeding, where consideration and evaluation of all other related programs and comments from all stakeholders and interested parties can occur.

Q. WHEN WAS COLUMBIA'S USECP MOST RECENTLY ADDRESSED?

A. The Company filed its 2024 USECP and a Petition for Reconsideration at Docket No. M-2023-3039487, and modifications to the LIURP funding were detailed.[1] In that proceeding the Commission did not direct Columbia to make changes to its LIURP funding level.[2]

[1] *Columbia Gas of Pennsylvania Inc. Universal Service and Energy Conservation Plan for 2024-2028 Submitted in Compliance with 52 Pa. Code § 62.4*, p. 14 (Order Entered April 4, 2024).

[2] *Id.*, p. 105.

Q. ARE THERE ANY RECENT COMMISSION DECISIONS THAT SUPPORT YOUR RECOMMENDATION?

A. Yes. Most recently, the Commission stated the following related to a decision concerning universal service issues in the Aqua, Pennsylvania, Inc. base rate case,[3]

> Our decision on this issue is consistent with prior decisions in which we have determined that it was not appropriate to consider proposals relating to a public utility's energy burdens, CAP, and other universal service program issues within the context of a base rate proceeding, finding that such proposals are more properly considered in a public utility's Universal Service and Energy Conservation Plan (USECP) proceeding.

Additionally, in the recent PECO Energy Company – Gas Division proceeding, the Commission did not consider CAUSE-PA's proposals related to CAP and other universal service program issues within the context of the base rate proceeding because they would be more properly considered in its USECP proceeding.[4] In that proceeding, the Commission also referenced Columbia's 2020 base rate proceeding[5] where it concluded, "that energy burdens should not be considered separately from other parts of the Company's CAP and universal service programs but should be considered as part of the Company's entire universal service plan, including the need for changes and associated costs."[6]

It should also be noted that in the 2020 Columbia Gas proceeding, the

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3 *PA Public Utility Commission et al. v. Aqua Pennsylvania, Inc.*, Docket No. R-2021-3027386, p. 333 (Order Entered May 16, 2022.

4 *PA PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, pp. 195-196 (Order Entered June 22, 2021).

5 *PA PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835 (Order Entered February 19, 2021).

6 *PA PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, p. 195 (Order Entered June 22, 2021).

Commission rejected a similar proposal related to the Health and Safety Pilot Program from CAUSE-PA.[7] In that proceeding the Commission agreed with the Administrative Law Judge's recommended decision denying any change to the pilot program until its effectiveness could be evaluated.[8]

Q. IS THERE ANY ADDITIONAL GUIDANCE THAT SUPPORTS YOUR RECOMMENDATION?

A. Yes. The Notice of Proposed Rulemaking for the *Initiative to Review and Revise the Exhibit Low-Income Usage Reduction Program (LIURP) Regulations at 52 Pa. Code §§ 58.1-58.18*, states,

> [A] LIURP budget can only be revised through a USECP proceeding initiated pursuant to the periodic USECP review process or in response to a petition to amend a USECP earlier than the periodic USECP review process.[9]

Further, it states as follows,

> As LIURP is a ratepayer-funded program, considerations impacting its budget determination should be open to scrutiny and comment. USECP proceedings allow all interested parties to provide comments, raise questions, and review information justifying the proposed change to the LIURP budget in an on-the-record proceeding. [10]

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7 *PA PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, pp. 160-161 and 173-174 (Order Entered February 19, 2021).

8 *Id.,* p. 174.

9 Notice of Proposed Rulemaking for the *Initiative to Review and Revise the Exhibit Low-Income Usage Reduction Program (LIURP) Regulations at 52 Pa. Code §§ 58.1-58.18*, p. 36 (Order Entered May 18, 2023).

10 Notice of Proposed Rulemaking for the *Initiative to Review and Revise the Exhibit Low-Income Usage Reduction Program (LIURP) Regulations at 52 Pa. Code §§ 58.1-58.18*, p. 37 (Order Entered May 18, 2023).

Q. ARE THERE ANY RECENT STATEMENTS THAT SUPPORT YOUR RECOMMENDATION HEREIN?

A. Yes. In a recent UGI Utilities, Inc. Electric Division base rate proceeding, Commissioner John F. Coleman stated the following,[11]

> In addition to my concerns about the lawfulness and reasonableness of the automatic enrollment modifications in this specific Settlement, I am becoming increasingly uncomfortable with the modification of universal service programs within base rate cases, especially in base rate cases that result in black box settlements.

In that same statement, he asserted that, "This complexity and the need for balance are best addressed in USECP proceeding."[12]

HARDSHIP FUND

Q. SUMMARIZE MS. WARABAK'S TESTIMONY CONCERNING COLUMBIA'S HARDSHIP FUND BUDGET.

A. Ms. Warabak recommends that the Company's contribution to its Hardship Fund be increased commensurate with the percentage increase in rates of the residential class that would result from this proceeding. She then states that a modest increase in comparison to other universal service funding will help customers deal with a rate increase in these difficult economic times (PWPTF Statement No. 1, pp. 6-7).

[11] *PA Public Utility Commission, et al. v. UGI Utilities, Inc. Electric Division*, Docket No. R-2022-3037368, et al., Statement of Commissioner John F. Coleman, Jr., p. 2.

[12] *Id.*, p. 2.

Q. DO YOU AGREE WITH MS. WARABAK'S RECOMMENDATION THAT THE COMPANY SHOULD INCREASE ITS CONTRIBUTION TO THE HARDSHIP FUND?

A. No.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that no increase to the Company's contribution to its hardship fund be approved in this proceeding.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDATION?

A. Like Ms. Warabak's LIURP recommendation mentioned above, although well-intentioned, it is also inappropriate to consider an increase in the Hardship Fund in this base rate case proceeding, regardless of the source of the funding. Columbia's Hardship Fund is funded by shareholders, customer contributions, fundraising activities, and natural gas supplier refunds and penalty credits. In the absence of any analysis of funding sources or the historic spending level of the Hardship Fund, it is inappropriate to consider any increase in this base rate proceeding. Any potential increase should be addressed in the Company's USECP proceeding, where consideration and evaluation of all other related programs and comments from all stakeholders and interested parties can occur.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 1-SR
Witness: Christian Yingling
NON-PROPRIETARY

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2024-3046519

Surrebuttal Testimony

of

Christian Yingling

Bureau of Investigation & Enforcement

Concerning:

OPERATING AND MAINTENANCE EXPENSES

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christian Yingling, and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME CHRISTIAN YINGLING WHO SUBMITTED DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes. I submitted I&E Statement No. 1 – PROPRIETARY and NON-PROPRIETARY, I&E Exhibit No. 1 PROPRIETARY and NON-PROPRIETARY, and I&E Statement No. 1-R.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN ACCOMPANYING EXHIBIT?

A. No.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to Columbia Gas of Pennsylvania, Inc's. (Columbia or Company) rebuttal testimony of the following witnesses: Brittany Komenda (Columbia Statement No. 4-R), Nicholas Bly (Columbia Statement No. 15-R), Kimberly Cartella (Columbia Statement No. 19-R), and Jason Leal (Columbia Statement No. 21-R).

Q. HAS COLUMBIA UPDATED ITS OVERALL REVENUE REQUIREMENT CLAIM IN REBUTTAL TESTIMONY?

A. Yes. Columbia provided a revised requested increase of $123,640,376 compared to the originally proposed increase of $124,138,477.[1] This change was necessary to reflect an updated claim for NCSC expense.

SUMMARY OF RECOMMENDED ADJUSTMENTS

Q. PLEASE SUMMARIZE YOUR RECOMMENDED ADJUSTMENTS AS UPDATED IN THIS SURREBUTTAL TESTIMONY.

A. My updated recommended adjustments are shown below:

[1] Columbia Statement No. 4-R, p. 2.

	Company Claim	Updated I&E Recommended Allowance	Updated I&E Adjustment
O&M Expenses:			
Rate Case Expense	$1,008,000	$558,079	($449,921)
Other Employee Benefits	$8,527,000	$7,645,486	($881,514)
Injuries and Damages	$398,074	$298,705	($99,369)
Employee Expense	$1,563,000	$1,375,352	($187,648)
Advertising Expense	$610,332	$599,530	($10,802)
NCSC Allocated Compensation – Profit Sharing & Stock Rewards	$3,735,123	$230,925	($3,504,198)
Total O&M Expense Adjustments			**($5,133,452)**

SUMMARY OF OVERALL I&E UPDATED POSITION

Q. WHAT IS I&E'S TOTAL UPDATED RECOMMENDED REVENUE REQUIREMENT?

A. I&E's total recommended revenue requirement for the Company is $856,858,367. This recommended revenue requirement represents an increase of $70,751,288 to the Company's claimed present rate revenues of $786,107,079. This total recommended allowance incorporates my adjustments made in this surrebuttal testimony to O&M expenses, and those recommended adjustments made in the surrebuttal testimony of I&E witnesses DC Patel (I&E Statement No. 2-SR), and Esyan Sakaya (I&E Statement No. 3-SR). A calculation of the I&E recommended revenue requirement is shown below:

Columbia Gas of PA, Inc.		TABLE I			
R-2024-3046519		INCOME SUMMARY			
	12/31/25	INVESTIGATION & ENFORCEMENT			
	Proforma	[---]			
	Present Rates	Adjustments	Present Rates	Allowances	Proposed
	$	$	$	$	$
Operating Revenue	786,107,079	0	786,107,079	70,751,288	856,858,367
Deductions:					
O&M Expenses	392,998,515	-5,187,452	387,811,063	1,019,109	388,830,172
Depreciation	141,404,702	0	141,404,702		141,404,702
Taxes, Other	4,630,755	0	4,630,755	0	4,630,755
Income Taxes:					
Current State	450,738	355,342	806,080	4,776,654	5,582,734
Current Federal	3,574,295	1,014,743	4,589,038	13,640,660	18,229,698
Deferred Taxes	28,943,957	0	28,943,957		28,943,957
ITC	-121,211	0	-121,211		-121,211
Total Deductions	571,881,751	-3,817,367	568,064,384	19,436,423	587,500,807
Income Available	214,225,328	3,817,367	218,042,695	51,314,865	269,357,560
Rate Base	3,489,087,567	0	3,489,087,567	0	3,489,087,567
Rate of Return	6.14%		6.25%		7.72%

RATE CASE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR RATE CASE EXPENSE.

A. I recommended the Company's total rate case expense first be adjusted based on the 2020 fully litigated rate case (the most recently litigated Columbia rate case) actual expense and then normalized over a period of 16 months resulting in the FPFTY allowance of $558,079 ((adjusted expense of $744,106 ÷ 16 months) x 12 months), or a reduction of $449,921 ($1,008,000 - $558,079) to the Company's claim (I&E Statement No. 1, p. 6). My recommendation was comprised of two

parts: (1) adjusting rate case expense based on the 2020 fully litigated rate case actual expense; and (2) normalizing the adjusted rate case expense over a period of 16 months based on Columbia's historic rate case filing frequency in contrast to Columbia's claimed 12-month normalization period as discussed in my direct testimony (I&E Statement No. 1, pp. 6-9).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Columbia witness Brittany Komenda disagrees with my recommended adjustment to rate case expense (Columbia Statement No. 4-R, pp. 4-5).

Q. PLEASE SUMMARIZE MS. KOMENDA'S RESPONSE.

A. First, Ms. Komenda disagrees with my recommended 16-month normalization period in contrast to the Company's 12-month normalization period for rate case expense because Columbia anticipates a need to file annual rate cases for the foreseeable future, and in recent years, the Company has filed annual rate cases with only a few exceptions (Columbia Statement No. 4-R, p. 4). Second, she states that Columbia's budgeted expenses for this rate case reflect anticipated costs for a fully litigated case. She then asserts that basing a rate case expense adjustment on only one historical occurrence, the 2020 litigated base rate case, is inappropriate and not reflective of the level of expenses that are expected, and that every case presents different issues, such as the Office of Consumer Advocate's

"novel" depreciation adjustment in this proceeding, which can affect the litigation costs incurred (Columbia Statement No. 4-R, p. 4).

Q. WHAT IS YOUR RESPONSE TO MS. KOMENDA'S ASSERTIONS?

A. First, I disagree with Ms. Komenda because the Commission has cited the importance of considering the involved utility's historic filing frequency as an essential element to determine the normalized level of rate case expense for ratemaking purposes in several base rate cases (I&E Statement No. 1, p. 5). The Company's proposed normalization period fails to properly rely upon the historic data of three filing intervals (I&E Statement No. 1, pp. 5-6). Additionally, Columbia's anticipated need to file annual rate cases for the foreseeable future is speculative in nature and is not supported by the historic filing intervals as shown in my direct testimony (I&E Statement No. 1, pp. 6-8). Finally, as discussed in my direct testimony, the outcome of PPL Electric's claimed 24-month normalization period in 2012 supports my recommendation. In that proceeding, PPL Electric's claim was based on the expected timing of future base rate case filings, where that utility did not file its next rate case until March 31, 2015, which was 36 months after the 2012 rate case filing (I&E Statement No. 1, p. 9).

Second, I disagree with Ms. Komenda that basing a rate case expense adjustment on only one historical occurrence, the 2020 litigated base rate case, is inappropriate and not reflective of the level of expenses to be incurred. In my direct testimony I presented Columbia's budgeted/claimed versus actual rate case

expense for the last three rate cases and there was only one litigated rate case (2020) that depicted a 73.82% actual expense incurred as compared to the budgeted claim, while two other cases were settled. Therefore, it is more appropriate and reasonable to base the 2024 rate case expense allowance on the 2020 actual expense (at 73.82%) since it is the most recently litigated rate case. Finally, one novel issue in this case is not a persuasive reason to change my recommendation.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR RATE CASE EXPENSE?

A. No. I continue to recommend basing the FPFTY rate case expense allowance on 2020 actual rate case expense (percentage of estimated expenses incurred) and applying a 16-month normalization period to the adjusted expense.

PAYROLL EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR PAYROLL EXPENSE.

A. In direct testimony, I recommended an allowance of $35,180,705 for payroll expense, or a reduction of $3,046,726 ($38,227,431 - $35,180,705) to the Company's claim (I&E Statement No. 1, p. 13). As discussed in direct testimony, my recommendation consisted of a payroll expense adjustment of $3,046,726 for

{BEGIN PROPRIETARY} [redacted] **{END PROPRIETARY}** (I&E Statement No. 1, pp. 14-15).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Columbia witnesses Jason Leal disagrees with my recommendation for the payroll expense adjustment of $3,046,726 for normal employee vacancies (Columbia Statement No. 15-R, pp. 4-5).

Q. PLEASE SUMMARIZE MR. LEAL'S RESPONSE REGARDING YOUR RECOMMENDED EMPLOYEE VACANCY ADJUSTMENT.

A. Mr. Leal disagrees with my vacancy adjustment because, he opines, my recommendation was based on an incorrect assumption that the Company's payroll expense claim is based upon a full authorized complement of employees. He then states that in past cases the Company has made its payroll expense claim based upon its full authorized complement of employees, which included vacant positions in the employee complement. However, the Company has changed its approach, now adjusting the payroll expense claim for vacant positions since its 2022 rate case and continuing to use the same method in this case (Columbia Statement No. 21-R, p. 5). Considering the above, the Company rejects the vacancy adjustment and all other adjustments to O&M resulting from the impact of this adjustment (Columbia Statement No. 21-R, p. 6).

Q. WHAT IS YOUR RESPONSE TO MR. LEAL'S ASSERTION?

A. Mr. Leal puts forth new information that the Company's FPFTY employee complement (total headcount) of 728 in the current case already excludes vacant positions. My original recommendation based on information received in response to I&E-RE-11-D (I&E Exhibit No. 1, Schedule 3, pp. 1-2) did not make clear that vacant positions were excluded from the claim, as Mr. Leal asserts in his rebuttal testimony. Additionally, per SDR-GAS-RR-026, the FPFTY headcount is shown as 728 total employees, and in the next line, budgeted total payroll expense claim of $38,227,431 is identified with reference to the total headcount of 728. However, I recognize that Columbia's payroll expense has remained generally flat over the most recent three historic years in comparison to its FPFTY claim. I also acknowledge that Columbia has incorporated a vacancy adjustment in its 2022 rate case.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR PAYROLL EXPENSE?

A. Yes. I withdraw my vacancy adjustment for payroll expense and for all the expenses it would have otherwise impacted due to Mr. Leal's explanation in rebuttal testimony along with reexamination of the FPFTY claim in comparison to prior years' actual expense levels.

INCENTIVE COMPENSATION

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR INCENTIVE COMPENSATION.

A. In direct testimony, I recommended an allowance of $2,357,107 for incentive compensation, or a reduction of $204,893 ($2,562,000 - $2,357,107) to the Company's claim (I&E Statement No. 1, p. 17). As discussed, my recommendation was based on the Company's claimed target of a 6.70% payout factor along with an adjustment for **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** (I&E Statement No. 1, pp. 17-18).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Columbia witnesses Jason Leal and Kimberly Cartella disagree with my recommendation to adjust the FPFTY incentive compensation claim (Columbia Statement No. 19-R, pp. 3-4). Mr. Leal's disagreement with my incentive compensation is covered in the payroll expense section above (Columbia Statement No. 21-R, p. 6).

Q. PLEASE SUMMARIZE MS. CARTELLA'S RESPONSE.

A. Ms. Cartella states that incentive compensation expense is calculated on the anticipated base salary of employees during the period and the assumption of achieving the target performance levels described in the incentive plan, which is

the anticipated level of achievement. Thus, she disagrees with using historical data as the basis for ratemaking, rather than the use of a FPFTY. (Columbia Statement No. 19-R, p. 4). Additionally, she points to Mr. Leal's disagreement with my vacancy adjustment to payroll expense and all other related expenses (Columbia Statement No. 21-R, p. 6).

Q. WHAT IS YOUR RESPONSE TO MS. CARTELLA'S ASSERTION?

A. As stated in the payroll expense section above, I am withdrawing my recommended vacancy adjustment to payroll expense and all related expenses. This incentive compensation recommendation was a resulting adjustment and thus must be withdrawn consistent with my other vacancy-related adjustment as explained in the section above.

<u>OTHER EMPLOYEE BENEFITS EXPENSE</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR OTHER EMPLOYEE BENEFITS.

A. In direct testimony, I recommended an allowance of $6,475,569 for other employee benefits expense, or a reduction of $2,051,431 ($8,527,000 - $6,475,569) to the Company's claim (I&E Statement No. 1, p. 19). As discussed in my direct testimony, my recommendation is comprised of three parts: (1) removal of the Profit-Sharing cost of $413,427 from other employee benefits expense; (2) an adjustment to the remaining benefits expense claim of $8,113,573

($8,527,000 - $413,427) based on a benefits to payroll expense factor of 20%; and (3) an adjustment for **{BEGIN PROPRIETARY}** [redacted] **{END PROPRIETARY}** (I&E Statement No. 1, pp. 20-23).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Columbia witnesses Kimberly Cartella and Nicholas Bly disagree with my recommendation.

Q. PLEASE SUMMARIZE MS. CARTELLA'S RESPONSE, WHICH RELATES SPECIFICALLY TO PROFIT SHARING EXPENSE AS A COMPONENT OF OTHER EMPLOYEE BENEFITS EXPENSE.

A. Ms. Cartella states that as part of the total rewards package to attract, retain, and motivate employees who are qualified to perform the functions needed by the Company, profit sharing is an element of the Company's 401(k)/Retirement Savings Plan, not the Omnibus Incentive Plan, and supports all employees' saving for retirement. She states that not just certain high-level executives are eligible for the retirement savings plan. The Company's contributions for profit sharing are deposited into employees' retirement accounts, which supplements employees' individual contributions to their retirement accounts (Columbia Statement No. 19-R, p. 7).

Q. WHAT IS YOUR RESPONSE TO MS. CARTELLA?

A. I accept Ms. Cartella's response because the profit-sharing plan supplements all employees' contributions to their retirement accounts (Columbia Statement No. 19-R, p. 7). Therefore, I withdraw my recommendation to remove profit-sharing expense of $413,427.

Q. PLEASE SUMMARIZE MR. BLY'S RESPONSE CONCERNING OTHER EMPLOYEE BENEFITS EXPENSE.

A. Mr. Bly disagrees with my recommendation to adjust other employee benefits expense based on the benefits expense to payroll expense factor of 20% stating that it would be an oversimplification and incorrect way to budget employee benefits. He asserts that employee benefits require the use of an actuary capable of considering all relevant factors such as but not limited to high-cost claimants, company-specific and nationwide claims trends, and inflation specific to health benefits (Columbia Statement No. 15-R, p. 4).

Q. WHAT IS YOUR RESPONSE TO MR. BLY'S ASSERTION?

A. As discussed in my direct testimony, Columbia's 2021-2023 average benefits expense to payroll expense factor was 19.34% ((19.33 + 17.77 + 20.91) ÷ 3), and the Company underspent its budgeted benefits expense by an average of 10.01% ((13.69 + 10.33 + 6.02) ÷ 3) in the last three years as shown in my direct testimony (I&E Statement No. 1, pp. 21-22 and I&E Exhibit No. 1, Schedule 4, p. 3).

Therefore, my recommendation, which is based on a benefits to payroll expense factor of 20% (I&E Statement No. 1, pp. 21-22), is more appropriate and reasonable in contrast to the Company's FPFTY claimed 22.31% benefits expense factor.

Q. DO YOU HAVE ANY CHANGES TO YOUR REDUCTION IN OTHER EMPLOYEE BENEFITS EXPENSE RELATED TO YOUR RECOMMENDED VACANCY ADJUSTMENT?

A. Yes. Continuing with the prior expense adjustments, I withdraw my vacancy adjustments for all related expense categories, including other employee benefits expense.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR OTHER EMPLOYEE BENEFITS EXPENSE?

A. Yes.

Q. WHAT IS YOUR UPDATED RECOMMENDATION FOR OTHER EMPLOYEE BENEFITS EXPENSE?

A. I recommend an updated allowance of $7,645,486 or a reduction of $881,514 ($8,527,000 - $7,645,486) to the Company's claim.

Q. HOW DID YOU CALCULATE YOUR RECOMMENDATION?

A. The updated calculation of my recommendation for other employee benefits expense adjustment and allowance are summarized in the table below based on 20% of payroll expense as explained above:

1. FPFTY Benefits Expense Claim	$8,527,000
2. Company FPFTY Payroll Expense	$38,227,431
3. I&E Recommended Payroll Expense Factor	20%
4. I&E Adjustment at 20% of Payroll Expense Allowance of $38,227,431	$7,645,486
5. I&E Recommended Reduction (1 - 4)	$881,514

<u>INJURIES AND DAMAGES</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR INJURIES AND DAMAGES.

A. In direct testimony, I recommended an allowance of $239,681 for injuries and damages expense, or a reduction of $158,393 ($398,074 - $239,681) to the Company's claim (I&E Statement No. 1, p. 25). As discussed in direct testimony, my recommendation was based on an average of the last three years' (2021 through 2023) actual payments to even out historic highs and lows in actual payments in contrast to Columbia's calculation based on the last five years' average of inflated actual expenses (I&E Statement No. 1, pp. 24-25).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Columbia witness Brittany Komenda disagrees with my recommended adjustment to injuries and damages expense (Columbia Statement No. 4-R, pp. 5-7).

Q. PLEASE SUMMARIZE MS. KOMENDA'S RESPONSE.

A. Ms. Komenda rejects my recommended historic three-year simple average of actual expenses (cash payments) in contrast to the Company's inflated historic actual expense (again, based on cash payments) average method of five years for determining the FPFTY claim for injuries and damages. The primary reason for her rejection is that the cash payments incurred five years ago to repair damaged property will cost more today due to inflation (Columbia Statement No. 4-R, p. 6). She then asserts that I incorrectly averaged the per book accruals for injuries and damages. She asserts that accruals and actual net payments can be substantially different, because accruals represent an estimate for future injuries and damages (Columbia Statement No. 4-R, p. 7).

Q. WHAT IS YOUR RESPONSE TO MS. KOMENDA'S ASSERTION?

A. I disagree with Ms. Komenda applying a historic five-year inflated actual expense (cash payments) average method for determining the FPFTY claim. Regarding Ms. Komenda's assertion, it is generally true that the cash payments incurred five years ago to repair damaged property will cost more today due to inflation.

However, the Company's historic injuries and damages expense (cash payment) shows highs and lows as shown in the table below (Columbia Volume 2, Exhibit 4, Schedule 2, p. 11):

	Actual cash payment	**Columbia's GDP Inflated**
12/2022-11/2023	$367,013	$367,013
12/2021-11/2022	$322,404	$334,149
12/2020-11-2021	$206,698	$229,355
12/2019-11/2020	$441,144	$511,888
12/2018-11/2019	$397,834	$467,680
Total	$1,735,094	$1,910,086
Five-Year Average	$347,019	$382,017

The above table shows that the Company experienced highs and lows in actual cash payments for this expense, and therefore, it is more appropriate and reasonable to use a simple average to even out historic highs and lows of the actual cash payments for determining an appropriate FPFTY allowance. This expense trend does not support applying inflation to the historic expense to determine a FPFTY allowance (I&E Statement No. 1, p. 25).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR INJURIES AND DAMAGES?

A. Yes. As Ms. Komenda points out, I mistakenly averaged accrual amounts rather than cash payments.

Q. WHAT IS YOUR UPDATED RECOMMENDATION?

A. I recommend an updated allowance of $298,705 or a reduction of $99,369 ($398,074 - $298,705) to the Company's claim. My recommendation was calculated based on the most recent three years' cash payments from the table above as obtained from Columbia Volume 2, Exhibit 4, Schedule 2, p. 11, as follows: $298,705 = ($367,013 + $322,404 + $206,697) / 3 years.

EMPLOYEE EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR EMPLOYEE EXPENSE.

A. In direct testimony, I recommended an allowance of $1,375,352 for employee expenses, or a reduction of $187,648 ($1,563,000 - $1,375,352) to the Company's claim (I&E Statement No. 1, p. 26). As discussed in direct testimony, my recommendation was based on an average of the last three years' (2021 through 2023) actual payments due to the fluctuating nature of the expense (I&E Statement No. 1, p. 27).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Columbia witness Jason Leal disagrees with my recommended adjustment to employee expense (Columbia Statement No. 21-R, pp. 6-7).

Q. PLEASE SUMMARIZE MR. LEAL'S RESPONSE.

A. Mr. Leal rejects my recommended historic three-year simple average of actual expenses (cash payment) in contrast to the Company's inflated historic actual expense (cash payments) average method for determining the FPFTY claim for employee expense. He explains that the COVID-19 pandemic implemented travel restrictions, resulting in employee expense as low as $1,057,284, from 2022 to the HTY, except for 2022. He asserts that the increased amounts in the FTY and FPFTY restore the level of spending to pre-pandemic levels, while also accounting for the increased costs of hotels and transportation. He states that Columbia's proposed expenditure level enables the Company to conduct in-person departmental meetings, trainings, and collaborations on-site, which had been either limited or denied since the beginning of the pandemic. Mr. Leal also rejects my recommended adjustment to employee expense because Columbia's FPFTY claim is consistent with the historic expense level in Fiscal Year 2019, a mere 1.3% increase from that year (Columbia Statement No. 21-R, pp. 6-7).

Q. WHAT IS YOUR RESPONSE TO MR. LEAL'S ASSERTION?

A. I disagree with increasing the FTY and FPFTY amounts for employee expense based on restoring the level of spending to pre-pandemic levels. In particular, it is unclear if the higher expense in 2022, driven by $781,840 in discretionary bonuses, and $534,049 in clothing allowance spending (Columbia Statement No.

21-R, p. 7), will become reoccurring costs for future years at the same or higher amounts, or if those were increases exclusive to 2022.

Additionally, although the expenditure level proposed by Columbia could enable the Company to conduct more in-person departmental meetings, trainings, and collaborations on-site, it is not guaranteed that the frequency and/or demands for these events will be utilized at the same or higher amounts in years prior to the COVID-19 pandemic. Lingering effects from the pandemic have changed working conditions across industries for telework demand, availability, and sustainability. Generally, telework remains significantly used and useful as a means for meetings, trainings, and collaborations. The Bureau of Labor and Statistics (BLS) reported that in August–September 2022, Private-Sector Utilities had their employees teleworking at least some of the time at a rate of 21.0%, and at 8.0% all employees teleworked all the time.[2] These utilities' teleworking percentages are consistent with the Total U.S. Private Sector teleworking percentages of 16.4% and 11.1% respectively in 2022 as reported by the BLS.[3]

I continue to recommend a three-year simple average of known and measurable employee expense incurred by the Company. The Company experienced both highs and lows in actual cash payments for this expense, and therefore, it is more appropriate and reasonable to use a simple average to even out

[2] *Employees teleworked at least some of the time at 27.5 percent of private establishments in 2022 : The Economics Daily: U.S. Bureau of Labor Statistics (bls.gov)*.

[3] *Employees teleworked at least some of the time at 27.5 percent of private establishments in 2022 : The Economics Daily: U.S. Bureau of Labor Statistics (bls.gov)*.

historic highs and lows of the actual cash payments for determining an appropriate FPFTY allowance (I&E Statement No. 1, p. 27).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR EMPLOYEE EXPENSE?

A. No.

ADVERTISING EXPENSE

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR ADVERTISING EXPENSE.

A. In direct testimony, I recommended an allowance of $565,128 for advertising expense, or a reduction of $45,204 ($610,332 - $565,128) to the Company's claim (I&E Statement No. 1, p. 28). As discussed in my direct testimony, my recommendation is based on a three-year average of the actual expense to even out the highs and lows in this expense (I&E Statement No. 1, pp. 28-29).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Columbia witness Jason Leal disagrees with my recommended adjustment to advertising expense (Columbia Statement No. 21-R, pp. 8-10).

Q. PLEASE SUMMARIZE MR. LEAL'S RESPONSE.

A. Mr. Leal avers that the three years (2021, 2022, 2023) of historic actual expense

data presented in my direct testimony (I&E Statement No. 1, pp. 28-29) are not comparable to the FTY and FPFTY claims because of changes in the way certain costs are being budgeted and booked by cost element due to accounting changes for actual costs incurred. Further, budgeted FTY and FPFTY data includes amounts that align with other categories in the historic years, in addition to advertisement expenses, specifically for Public Awareness, whereas the actuals used in my table do not (Columbia Statement No. 21-R, p. 8). He then presented an updated table showing historic, FTY, and FPFTY expense claims, which is summarized in the abbreviated table below (Columbia Statement No. 21-R, p. 9):

	2021	**2022**	**2023**	**FTY**	**FPFTY**
As Filed Total	$571,123	$632,658	$528,368	$597,235	$610,332
Rebuttal Total	$556,237	$700,057	$542,296	$597,235	$610,332

Mr. Leal rejects my recommended adjustment to advertising expense based upon an average of inconsistent historical information. Columbia's claim remains at $610,332, noting that this amount is in line with actual spending from 2021 to 2023 (Columbia Statement No. 21-R, p. 8).

Q. WHAT IS YOUR RESPONSE TO MR. LEAL'S ASSERTION?

A. First, Mr. Leal asserts that I recommended a $247,646 adjustment to advertising expense. This is not the correct amount. I actually recommended an adjustment of $45,204 ($610,332 - $565,128) to advertising expense in my direct testimony

(I&E Statement No. 1, p. 28). As explained in my direct testimony, the increases in advertising expense claims were not supported and reliable estimates based on the HTY 2023 recoverable advertising expense because Columbia did not provide any support with a breakdown of expenses claimed in the FTY and FPFTY in response to I&E-RE-30-D(C) (I&E Exhibit No. 1, Schedule 7). However, based on updated information provided in the Company's rebuttal testimony, I am updating my recommended adjustment based on the updated information provided above, however continuing to apply a three-year average of the historic actual expense to even out highs and lows in this expense.

Q. WHAT IS YOUR UPDATED RECOMMENDATION FOR ADVERTISING EXPENSE?

A. I recommend an updated allowance of $599,530 (($556,237 + $700,057 + $542,296) ÷ 3) for advertising expense, or a reduction of $10,802 ($610,332 - $599,530) to the Company's claim as explained above.

<u>NCSC ALLOCATED COMPENSATION – PROFIT SHARING AND STOCK REWARDS EXPENSE</u>

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR NCSC ALLOCATED COMPENSATION.

A. In direct testimony, I recommended a complete disallowance of the $3,735,123 claim for NCSC allocated profit sharing and stock rewards expense (I&E

Statement No. 1, p. 31).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. Yes. Columbia witness Kimberly Cartella disagrees with my recommended disallowance of NCSC allocated compensation expense (profit sharing and stock rewards) (Columbia Statement No. 19-R, pp. 6-9).

Q. PLEASE SUMMARIZE MS. CARTELLA'S RESPONSE CONCERNING PROFIT-SHARING EXPENSE?

A. Ms. Cartella explains that as part of the total rewards package to attract, retain, and motivate employees who are qualified to perform the functions needed by the Company, profit sharing is an element of the Company's Retirement Savings Plan (401(k)), not the Omnibus Incentive Plan and supports all employees' retirement savings, not just certain high-level executives. Company contributions for profit sharing are deposited into employees' retirement accounts, which supplements employees' individual contributions to their retirement accounts. (Columbia Statement No. 19-R, pp. 6-7).

Q. WHAT IS YOUR RESPONSE TO MS. CARTELLA?

A. I accept Ms. Cartella's response as discussed in the other employee benefits expense section above and withdraw my recommendation for removal of NCSC profit-sharing expense of $230,925 from the NCSC compensation expense claim.

Q. PLEASE SUMMARIZE MS. CARTELLA'S RESPONSE CONCERNING STOCK REWARDS EXPENSE?

A. Ms. Cartella rejects my recommendation to disallow 100% of stock rewards expense. She states that these rewards are not based upon return on equity or appreciation of the parent company's stock. The Company recognizes that the long-term incentive (LTI) rewards should not be based upon financial metrics alone but should also include the achievement of goals that are beneficial to customers. LTI rewards are based on achievement of essential operational metrics that include safety, employee engagement, environmental greenhouse gas emission reductions, operational excellence and net operating earnings per share which is driven by the Company meeting its budget (Columbia Statement No. 19-R, pp. 4-5). Additionally, she states that she has been advised by counsel that the Commission has allowed recovery of incentive compensation as a part of payroll where the compensation plan includes provisions that are designed to provide benefits to customers, as the Company's plan does. She is further advised that the Commission has allowed full recovery of incentive compensation amounts even where financial performance is a trigger to payment of the rewards (Columbia Statement No. 19-R, p. 9).

Q. WHAT IS YOUR RESPONSE TO MS. CARTELLA?

A. As discussed in my direct testimony, stock rewards are limited to certain top-level executives, and therefore, it has not been made clear how stock rewards expense is

directly related to providing safe and reliable service to ratepayers (I&E Statement No. 1, p. 32). Additionally, the achievement of financial goals/metrics of the parent company and other operating companies' combined financial performance may influence the determination of stock rewards for certain top-level executives at the corporate management level. I continue to recommend removal of the entire stock rewards expense from the NCSC compensation claim as discussed in my direct testimony (I&E Statement No. 1, p. 32).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR NCSC ALLOCATED COMPENSATION – PROFIT SHARING AND STOCK REWARDS?

A. Yes, partially. I recommend an updated allowance of $230,925 or a reduction of $3,504,198 ($3,735,123 - $230,925) to NCSC allocated compensation expense after accepting profit-sharing expense of $230,925.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

I&E Statement No. 2-SR
Witness: D. C. Patel

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2024-3046519

Surrebuttal Testimony

of

D. C. Patel

Bureau of Investigation & Enforcement

Concerning:

Rate of Return

Effective Date of New Rates

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INTRODUCTION OF WITNESS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is D. C. Patel and my business address is Pennsylvania Public Utility Commission, Commonwealth Keystone Building, 400 North Street, Harrisburg, PA 17120.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission (Commission) in the Bureau of Investigation & Enforcement (I&E) as a Fixed Utility Financial Analyst.

Q. ARE YOU THE SAME D. C. PATEL WHO IS RESPONSIBLE FOR THE DIRECT TESTIMONY CONTAINED IN I&E STATEMENT NO. 2 AND THE SCHEDULES IN I&E EXHIBIT NO. 2?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of Columbia Gas of Pennsylvania, Inc. (Columbia or Company) witness Paul R. Moul regarding rate of return topics including the cost of common equity, the overall fair rate of return that will be applied to the Company's rate base, and management performance reward points (Columbia Statement No. 8-R). In

addition, I will address OCA witness Christopher C. Walters's concerns regarding my DCF analysis and use of the Company's claimed common equity ratio (OCA Statement No. 3-R).

The absence of any comments or responses to particular statements or topics addressed in Columbia's rebuttal testimony and that of other parties' witnesses concerning the return on equity does not imply my acceptance or support of the Company's or other parties' positions in this proceeding.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. No. I refer to my direct testimony (I&E Statement No. 2) and schedules contained in my exhibit (I&E Exhibit No. 2) where necessary.

Q. WHAT WAS YOUR ORIGINAL OVERALL RECOMMENDATION IN DIRECT TESTIMONY?

A. I recommended the following rate of return for the Company (I&E Statement No. 2, p. 6 and I&E Exhibit No. 2, Schedule 1):

I&E Recommendation Columbia Gas of Pennsylvania, Inc. Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	43.12%	5.07%	2.19%
Short-Term Debt	2.48%	5.25%	0.13%
Common Equity	54.40%	9.93%	5.40%
Total	**100.00%**		**7.72%**

SUMMARY OF MR. MOUL'S REBUTTAL TESTIMONY

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY TO YOUR RATE OF RETURN RELATED RECOMMENDATIONS.

A. Mr. Moul disputes my recommendations regarding an appropriate proxy group, my reliance on and application of the Discounted Cash Flow (DCF) method and exclusion of Capital Asset Pricing Model (CAPM) results in determination of an appropriate return on equity (ROE), the DCF growth rate, and disallowance of his leverage adjustment to the DCF results. Further, Mr. Moul disagrees with the appropriate risk-free rate to use and my exclusion of a size adjustment in the CAPM analysis, my disagreement with his use of the Risk Premium (RP) and Comparable Earnings (CE) methods, and lastly, my recommended disallowance of additional basis points for exemplary management performance. Finally, Mr. Moul opines that my recommended equity allowance understates the cost of equity in the current environment of high interest rates and company-specific risk factors in this proceeding (Columbia Statement No. 8-R).

UPDATED ANALYSIS

Q. DID THE COMPANY UPDATE TO ITS RATE OF RETURN CLAIM?

A. No. Mr. Moul does not provide any additional information or updated cost of equity model results and continues to support his original cost of equity recommendation and the overall rate of return (Columbia Statement No. 8-R, p. 1), which is reproduced as shown below (Columbia Exhibit No. 400, Schedule 1, p. 1):

COLUMBIA GAS OF PENNSYLVANIA, INC.
Summary of Cost of Capital

Type of Capital	Ratio	Cost Rate	Weighted Cost Rate
Long-Term Debt	43.12%	5.07%	2.19%
Short-Term Debt	2.48%	5.25%	0.13%
Common Equity	54.40%	11.75%	6.39%
Total	**100.00%**		**8.71%**

PROXY GROUP

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR PROXY GROUP.

A. Mr. Moul claims that I omitted Southwest Gas Holdings, Inc. from my proxy group. He argues that I incorrectly employed the criterion that 50% or more of a company's revenues must be generated from the regulated gas utility industry as opposed to using both income and asset percentages. He claims that margins on other (non-utility) business segments like energy trading by the companies in our

proxy groups are dissimilar to the utility business. Additionally, he presents a comparison of percentage contribution of gas utility revenues, income, and assets in the utility company's total revenues, income, and assets to justify his proxy group company composition (Columbia Statement No. 8-R, pp. 11-13).

Q. DO YOU AGREE WITH MR. MOUL'S ASSERTION THAT THE PERCENTAGE OF GAS UTILITY INCOME TO THE COMPANY'S TOTAL INCOME IS A MORE APPROPRIATE CRITERION?

A. No. I disagree with Mr. Moul's assertion that a gas utility income criterion is also an appropriate criterion because generation of revenue is the first step that drives the net income (net profit) and cash flow. A company's realization of net income depends on various factors such as management, operational, and financial efficiency in the best use of utility assets with available resources, O&M cost containment measures, capital expenditure programs, etc. Therefore, a utility's revenue composition is a more appropriate measure than net income for establishing a proxy group because this measure represents the percentage of cash flow a company receives from each business segment. While the financial community is more likely to rely on measures of income rather than measures of revenue when making credit assessments and investment decisions, the purpose of a proxy group is to compile a set of companies that have similar risks to the subject utility. If less than 50% of revenues come from the regulated natural gas

business, the company is not comparable to the subject utility as it does not provide a similar level of regulated natural gas business.

Additionally, in the most recent Columbia Water base rate proceeding, the Commission concludes,[1]

> In Columbia Gas 2021, we stated the following regarding the proxy group at issue in that proceeding: First, as I&E and the ALJ pointed out, a company's revenues represent the percentage of cash flow the company receives from each business line related to providing a good or service. Therefore, if less than fifty percent of revenues come from the regulated gas sector, the company is not comparable to the subject utility as it does not provide a similar level of regulated business.
>
> As further noted by I&E, while two companies or segments can have the same level of revenue, their net operating income may vary greatly, depending on their performance and decisions. The purpose of a proxy group is to compile a set of companies that have similar risks to the subject utility. As such, we are of the same opinion, as in our decisions in *Columbia Gas 2021* and *PECO 2021*, that if less than 50% of a utility's revenues come from the regulated business sector, the company is not comparable to the subject utility as it does not provide a similar level of regulated business.
>
> Based on the specific record developed in the instant case, we find that the percentage of revenues generated from regulated utility operations, in this instance regulated water utility operations, is the appropriate criterion to include when setting Columbia's proxy group. Therefore, we concur with I&E that Essential Utilities should be excluded from the proxy group that we will use in setting the authorized ROE and the resulting overall rate of return for Columbia in this proceeding.

[1] *Pa. PUC v. Columbia Water Company,* Docket No. R-2023-3040258, pp.75, 76, and 77 (Order Entered January 18, 2024).

Q. DO YOU AGREE WITH MR. MOUL'S ASSERTION THAT THE PERCENTAGE OF GAS UTILITY ASSETS IN THE COMPANY'S TOTAL ASSETS IS A MORE APPROPRIATE CRITERION?

A. No. Calculating the percentage of utility assets that make up the total assets of a company is not always a reliable way of determining if a business is primarily a regulated utility. Assets are accounted for at the original cost minus depreciation, which means that the value of an asset depends on its age. Therefore, it is possible for the regulated utility segment of a company to have assets that are predominately depreciated. Although a utility may have assets that are significantly depreciated, it does not always indicate the level of business a company does. A company, or its parent company, can have most of its utility assets depreciated but still do more business as a utility than as another business.

Another reason that the percentage of utility business is not always accurately represented by using the percentage of utility assets to the total assets is that there are differences between businesses in the amount of capital needed. Generally, a utility company requires a higher level of assets (asset value) to produce a comparatively small level of cash flow while another business may need only a small amount of assets to produce a large level of cash flow. Therefore, comparing the assets of a gas utility segment to the total assets of a company is not an appropriate criterion as it could be misleading.

Q. PLEASE REITERATE WHY YOU ELIMINATED SOUTHWEST GAS HOLDINGS, INC. FROM YOUR PROXY GROUP.

A. As explained in my direct testimony, Southwest Gas Holdings, Inc. was excluded for not meeting my criterion that 50% or more of revenues must be generated from regulated gas utility operations. Again, this criterion is important because revenues represent the percentage of cash flow a company receives from each business line related to providing a good or service. If less than 50% of revenues come from the regulated gas sector, the companies are not comparable to the subject utility as they do not provide a similar level of regulated business (I&E Statement No. 2, p. 10).

Q. DO YOU HAVE ANY CHANGES TO YOUR PROXY GROUP?

A. No. For the reasons discussed above, the percentage of revenue is an appropriate criterion in selection of the proxy group companies. As Southwest Gas Holdings, Inc. include an insufficient percentage of regulated gas revenues of 39% (Columbia Statement No. 8-R, p. 13), they should not be included in the proxy group and compared to Columbia.

<u>DISCOUNTED CASH FLOW</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR DCF ANALYSIS.

A. Mr. Moul agrees that results of a DCF analysis should be given weight, but he

asserts that use of multiple methods provides a superior foundation to determine the cost of equity. He compares the latest distribution system improvement charge (DSIC) rate of 10.15% determined by the Commission in the Quarterly Earnings Summary Reports at Docket No. M-2024-3048688, which is above the DCF return of 9.79% calculated using current stock prices (Columbia Statement No. 8-R, p. 15). He further disagrees with my results based on the outcomes of certain individual companies and disputes my growth rate analysis. Finally, Mr. Moul disagrees with my recommendation to reject his leverage adjustment (Columbia Statement No. 8-R, pp. 13-21).

EXCLUSIVE USE OF THE DCF

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR USE OF THE DCF METHOD.

A. Mr. Moul asserts that the use of more than one method provides a superior foundation for the cost of equity determination. He claims that the use of more than one method will capture the multiplicity of factors that motivate investors to commit their capital to a particular enterprise. He cites the Commission orders in 2012 PPL Electric, 2021 Aqua Pennsylvania, and 2023 Columbia Water base rate cases where the Commission acknowledged use of DCF and CAPM in determination of an appropriate cost of common equity (Columbia Statement No. 8-R, pp. 13-15).

Q. WERE ANY METHODS OTHER THAN THE DCF EMPLOYED IN YOUR ANALYSIS?

A. Yes. Although my recommendation was based on the results of my DCF analysis, I also employed the CAPM as a comparison. For the reasons discussed in my direct testimony, the DCF method is the most reliable and forward-looking model reflecting the economic market (I&E Statement No. 2, pp. 18-20). Although no one method can capture every factor that influences an investor, including the results of methods less reliable than the DCF does not make the end result more reliable or more accurate. In direct testimony, I cited several cases that illustrate the methodology I employed is consistent with the methodology historically used by the Commission in base rate proceedings as recently as 2017, 2018, 2020, and 2021 (I&E Statement No. 2. p. 18).

However, as indicated in my direct testimony (I&E Statement No. 2, p. 23) the Commission recently deviated from prior Commission practice when it indicated in the 2022 Aqua Pennsylvania rate case order that its method "for determining Aqua's ROE shall utilize both I&E's DCF and CAPM methodologies"[2] and that "I&E's DCF and CAPM produce a range of reasonableness for the ROE … ."[3] Similarly, recently, the Commission's 2024 Columbia Water rate case order relied on the results of I&E's DCF and CAPM

[2] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 154 (Order Entered May 16, 2022).

[3] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order Entered May 16, 2022).

analyses for determining Columbia Water's ROE.[4] In my direct testimony, I fully explain why the CAPM should not be used as a primary method and continue to express those concerns in this proceeding as to why it should only be used as a comparison to, not a check of, the DCF. Thus, I disagree with a method that provides the CAPM comparable weight to the DCF method (I&E Statement No. 2, pp. 19-26). In fact, the extreme variations in the CAPM analysis results between Mr. Moul (13.86%), Mr. Walters (9.63% - 10.53%), and mine (10.86%) only highlight the unreliability and subjectivity of the CAPM method, further invalidating its use for establishing an appropriate ROE for ratemaking.

Q. PLEASE CONTINUE.

A. In the most recent Pennsylvania-American Water Company (PAWC) case, the Commission agreed with the ALJs' recommended ROE based on I&E's results of DCF and CAPM analyses that produces an ROE of 9.45% and denied PAWC's request for an upward adjustment to its ROE for exemplary management performance. Though the Commission determined an ROE based on the average results of DCF and CAPM analyses, the Commission most importantly notes in the order,[5]

> Before concluding this section, we stress that based upon the specific record developed in this proceeding, we have determined that taking the average of the DCF and CAPM results produces a reasonable ROE. However, we do not

[4] *Pa. PUC v. Columbia Water Company,* Docket Nos. R-2023-3040258, p. 105 (Order Entered January 18, 2024).
[5] *Pa. PUC v. Pennsylvania-American Water Company*, Docket Nos. R-2023-3043189 and R-203-3043190, pp. 194-195 (Order Entered July 22, 2024).

> strictly endorse averaging the DCF and CAPM in other proceedings where it is determined that methodologies other than the DCF are necessary to determine the utility's ROE. Consistent with these determinations, we shall deny PAWC's Exception No. 1, I&E's Exception No. 1, and the OCA's Exception No. 11.

DSIC RATES

Q. SHOULD THE COMMISSION CONSIDER THE AUTHORIZED DSIC RATE ESTABLISHED IN THE QUARTERLY EARNINGS SUMMARY REPORTS AS AN APPROPRIATE MEASURE TO DETERMINE THE COST OF EQUITY IN THIS PROCEEDING?

A. No. Mr. Moul's comparison between the I&E recommended return on equity of 9.93% in this proceeding and the Commission's DSIC rate of 10.15% is misguided. My understanding is that the DSIC rate is designed to encourage its use and to incentivize accelerated pipeline replacement and infrastructure upgrades to bring aging infrastructure closer to meeting safety and reliability requirements in between base rate filings. To ever suggest the cost of equity must be at or above the DSIC rate is inappropriate and not in the public interest. Additionally, the DSIC rate establishes a benchmark above which a utility is considered "overearning" for use of the DSIC mechanism. As such, the DSIC rate should not serve as a proper measurement of a subject utility's cost of equity in a base rate proceeding since the DSIC rate is routinely higher than any return on equity approved in such base rate proceedings. In fact, 66 Pa. C.S. § 1358(b)(3) states the following,

> The distribution system improvement charge shall be reset at zero if, in any quarter, data filed with the commission in the utility's most recent annual or quarterly earnings report show that the utility will earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the distribution system improvement charge.

Finally, the DSIC mechanism serves to lower a utility's risk because it reduces the lag time in the recovery of a company's capital outlays. DSIC spending requires preapproval of eligible plant via a Long-Term Infrastructure Improvement Plan so there is little question as to the prudence of those expenditures.

Q. ARE THERE ANY POTENTIAL PROBLEMS WITH AWARDING A RETURN ON EQUITY THAT IS EQUAL TO OR HIGHER THAN THE DSIC RATE?

A. Yes. First, if a company achieves the awarded return that is above the DSIC rate, it eliminates the possibility for the utility to utilize the DSIC mechanism until its earnings fall below the DSIC rate. Further, if a company believes it will receive a return higher than the DSIC rate in a litigated base rate proceeding, it will remove the incentive to use the DSIC mechanism between rate filings and may encourage more frequent filing of base rate cases. Additionally, it may encourage litigation as opposed to settlement of cases, since companies may improperly believe this is the new norm, which will increase rate case costs to customers.

Therefore, in my opinion, the DSIC rate should generally be an incentive rate that is higher than a return on equity percentage granted in a rate proceeding.

Q. ARE THERE ANY INSTANCES YOU ARE AWARE OF WHERE THE COMMISSION GRANTED A RETURN ON EQUITY THAT WAS HIGHER THAN THE MOST RECENTLY PUBLISHED DSIC RATE?

A. Yes. In the 2021 Aqua base rate case, the Commission awarded that company a return on equity of 10.00%,[6] which was higher than the published DSIC rate for water and wastewater utilities of 9.80%[7] around that same period.

Q. WERE THERE ANY SPECIAL CIRCUMSTANCES THAT CAUSED THE COMMISSION'S GRANTED RETURN ON EQUITY FOR AQUA TO EXCEED THE DISC RATE AT THE TIME?

A. Yes. The Commission granted 25 basis points for management effectiveness,[8] which caused the return on equity of 9.75% to go up to 10.00%, thereby exceeding the effective DSIC rate at that time of 9.80% for water and wastewater. Please note, however, I will address management performance in a separate section of

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6 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order Entered May 16, 2022).

7 PA Public Utility Commission, Bureau of Technical Utility Services Report on the Quarterly Earnings of Jurisdictional Utilities for the Year Ended December 31, 2021, approved at Public Meeting on June 16, 2022, at Docket No. M-2022-3032405.

8 *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket Nos. R-2021-3027385 & R-2021-3027386, pp. 178 (Order Entered May 16, 2022).

testimony below. In my opinion, the Commission decision in the Aqua case is not indicative of "the new normal" or setting precedent for other utilities.

EVALUATING THE DCF BASED ON INDIVIDUAL RESULTS

Q. SUMMARIZE MR. MOUL'S RESPONSE REGARDING THE RESULTS OF YOUR DCF METHOD.

A. Mr. Moul explains that the principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and thereby smooth out any abnormalities. He then states that when some results are unreasonable on their face, the reliability of, or the witness' application of, that method must be questioned. He points to the DCF results of 8.76% and 8.69% of Chesapeake Utilities Corp. and One Gas Inc. respectively from my proxy group and claims that it fails to provide a sufficient spread over the yield on A-rated public utility bonds, which currently stand at 5.74% in May 2024 (Columbia Statement No. 8-R, pp. 19-20). Mr. Moul presents a table showing my proxy group companies' modified DCF mean result of 10.31% after removing low end DCF results of Chesapeake Utilities Corp. and One Gas Inc. in contrast to my DCF results of 9.93% that includes these two companies (Columbia Statement No. 8-R. pp. 20-21)

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S ATTEMPT TO DISAGGREGATE YOUR DCF RESULTS?

A. First, I disagree with Mr. Moul's modified DCF mean results of 10.31% after excluding DCF results of Chesapeake Utilities Corp. (8.76%) and One Gas Inc. (8.69%) from my proxy group. It appears that Mr. Moul presents these results with variations to my proxy group data just to prove his DCF analysis is correct and undermine my DCF analysis results with the ultimate objective to justify his DCF results of 10.74% without his leverage adjustment of 1.31%. It is important to note that each company has a different jurisdictional operating, financial, and management set up. Therefore, I believe Chesapeake Utilities Corp. and One Gas Inc.'s DCF results are not an outlier or abnormal and should not be ignored when calculating the proxy group mean results unless the projections would result in a negative DCF result for these companies. Applying Mr. Moul's logic, if I remove NiSource Inc.'s high end DCF result of 11.82% (Columbia Statement No. 8-R, p. 21), my mean DCF result would be 9.53%, which is lower than my calculated DCF result of 9.93%. Additionally, the principal purpose of assembling a proxy group of companies is to avoid relying on data for a single company that is not representative and thereby to smooth out any abnormalities. Therefore, it is inappropriate to remove only low-end DCF results in calculating mean results.

Second, Mr. Moul derives his suggested 4.57% (10.31% - 5.74%) spread over the yield of on A-rated public utility bonds. I disagree with Mr. Moul's suggested 4.57% spread as reasonable based on his recalculation of my DCF

results. In fact, my DCF result offers a 4.84% (9.93% - 5.07% = 4.84%) spread or margin over the Company's claimed long-term debt cost of 5.07% (I&E Exhibit No. 2, Schedule 1), which is higher than Mr. Moul's suggested spread of 4.57%. I certainly believe that my DCF result offers a reasonable and sufficient spread over the Company's claimed long-term debt cost.

GROWTH RATE

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR GROWTH RATES.

A. Mr. Moul argues that my mean growth rate of 5.95% is below his calculated 6.75% growth rate. He then states that the 4.65% growth rate for Northwest Natural Gas Co. and 4.67% for ONE Gas Inc. appear to be outliers because the range of growth rates for other companies is 5.29% (Spire, Inc.) to 7.60% (NiSource, Inc.) (Columbia Statement No. 8-R, p. 20).

Q. DO YOU AGREE WITH MR. MOUL'S CRITICISM ABOUT YOUR GROWTH RATE IN DCF ANALYSIS?

A. No. Mr. Moul's comments in response to my use of a low growth rate of 5.95%, as compared to his determined 6.75% growth rate, lack objective rationale and defeat the purpose of using a proxy group. Mr. Moul himself states, "The principal purpose of assembling a barometer group is to avoid relying on data for a single company that may not be representative and to thereby smooth out any

abnormalities" (Columbia Statement No. 8-R, p. 19). This acknowledgement is counterintuitive to his suggestion to characterize as outliers and exclude the low-end growth rate estimates for Northwest Natural Gas Co. and ONE Gas Inc. from my analysis. Ironically, and worth noting, Mr. Moul employs the low-end growth estimates for these two companies he is criticizing in his own proxy group and analysis and he is not concerned with the 9.50% and 10.00% growth estimates Value Line offers for NiSource Inc. and Southwest Gas Holdings, Inc. that he uses in his growth rate determination of 6.75% (Columbia Exhibit No. 400, Schedule 9). These estimates are 275 (9.50% - 6.75%) and 325 (10.00% - 6.75%) basis points higher than his average growth rate of 6.75%. Additionally, as discussed in my direct testimony, I reiterate that Mr. Moul arbitrarily chooses to use a 6.75% growth rate claiming that DCF growth rates should not be established by mathematical formulation, although the average of his sources for the growth rate is 6.29% [(5.87% + 5.69% + 7.31%) ÷ 3] (I&E Statement No. 2, pp. 49-50).

LEVERAGE ADJUSTMENT

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING HIS LEVERAGE ADJUSTMENT.

A. First, Mr. Moul states that credit rating agencies do not measure the market-required cost of equity for a company, nor are they concerned with how it is applied in the rate-setting context. Rather, the credit rating agencies are only concerned with the interests of lenders and the timely payment of principal and

interest by companies (Columbia Statement No. 8-R, p. 26). Then, Mr. Moul questions my references to prior Commission orders rejecting claimed leverage adjustments to the cost of equity and interprets a couple orders in his favor indirectly or remotely to support a leverage adjustment in determining the cost of equity (Columbia Statement No. 8-R, pp. 26-27). Finally, Mr. Moul disagrees with my claim that investors base their decisions on the book value of a company's debt and equity (Columbia Statement No. 8-R, pp. 27-28).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S REBUTTAL TESTIMONY CONCERNING CREDIT RATING AGENCIES?

A. Mr. Moul has actually supported my argument that his proposed leverage adjustment is not needed by stating that the credit rating agencies are only concerned with the timely payment of principal and interest by utilities. Mr. Moul's stated need for a leverage adjustment is based on his assertion that there is a difference in financial risk associated with book value capitalization and market value capitalization, which must be considered in determining a return on equity (Columbia Statement No. 8-R, p. 28).

Financial risk does relate to the capital structure of a company, but it is created by the financing decisions (the use of debt or equity) and the amount of leverage or debt chosen to finance a company's assets. Financial risk and the book value capital structure of a company are represented in the financial statements, which are part of what is evaluated by rating agencies. Mr. Moul

agrees with me that credit rating agencies use a company's booked debt obligations, found in the financial statements, in their analysis to assess financial risk and determine creditworthiness (Columbia Statement No. 8-R, p. 26).

Q. SUMMARIZE MR. MOUL'S RESPONSE TO YOUR REFERENCE OF PRIOR COMMISSION ORDERS.

A. Mr. Moul refers to the discussion in my direct testimony about six recent cases where the Commission has rejected a "leverage adjustment" (I&E Statement No. 2, pp. 55-56). He explains that the Commission's decision to disallow a "leverage adjustment" in the 2008 Aqua Pennsylvania proceeding does not invalidate its use. Further, he states, "Notably, the Commission did not repudiate the leverage adjustment in the Aqua case, but instead arrived at an 11.00% return on equity for Aqua by including a separate return increment for management performance" (Columbia Statement No. 8-R, p. 26). Next, Mr. Moul claims that the adjustment proposed in the 2010 City of Lancaster case was much different than what he proposes in this case. Then, regarding the 2017 UGI Electric Utilities, Inc. - Electric Division case, Mr. Moul acknowledges the Commission granted a "management performance increment," not a leverage adjustment when arriving at the allowed equity return of 9.85%. As for the 2020 Columbia Gas case, Mr. Moul concedes that the Company accepted I&E's return on equity recommendation of 9.86%, which did not include a leverage adjustment or additional points for management performance. Additionally, in the 2020 PECO

Gas case, he argues that the Commission arrived at an equity return on the higher side without a leverage adjustment, therefore no adjustment was warranted. Finally, in the 2021 Aqua case, Mr. Moul acknowledges that the Commission set the cost of equity without a leverage adjustment (Columbia Statement No. 8-R, pp. 26-27).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S COMMENTS REGARDING THE REFERENCED PRIOR COMMISSION ORDERS IN YOUR DIRECT TESTIMONY?

A. In this proceeding, Mr. Moul is recommending a 131-basis point (1.31%) "leverage adjustment" to the DCF results. To be clear, the Commission did in fact refuse to accept the leverage adjustment in the 2008 Aqua case by stating "…we reject the ALJ's recommendation to allow a 65 basis points leverage adjustment."[9] The management performance points awarded to Aqua were case-specific and in no way related to the proposed leverage adjustment. Regarding the 2010 City of Lancaster case, the Commission did not reject the leverage adjustment based on the manner in which it was calculated, but rather, the Commission stated, "…the ALJ's recommendation is in error as any adjustment to the results of the market based DCF as we have previously adopted are unnecessary and will harm ratepayers."[10] Regarding the 2017 UGI Electric case, the Commission concluded

[9] *Pa. PUC v. Aqua Pennsylvania, Inc.,* Docket No. R-00072711, pp. 38-39 (Order Entered July 31, 2008).
[10] *Pa. PUC v. City of Lancaster – Bureau of Water*, Docket No. R-2010-2179103, p. 101 (Order Entered July 14, 2011).

that, "…an artificial adjustment in this proceeding is unnecessary and contrary to the public interest. Accordingly, we decline to include a leverage adjustment in our calculation of the DCF cost of equity."[11] Regarding the 2020 Columbia Gas case, the Commission stated,

> … we have adopted the ALJ's recommendation to use I&E's DCF methodology utilizing I&E's dividend yield of 3.34% and growth rate of 6.52%. As noted above, the ALJ did not specify a recommended cost of equity for Columbia in their Recommended Decision. However, we note that I&E's methodology results in an ROE of 9.86%.[12]

The ALJ's Recommended Decision stated the following:

> The ALJ agrees with BIE's reasoning that Columbia Gas' calculated return on equity was flawed for five reasons: (1) the weights given to the results of the Company's CAPM, RP, and CE analyses; (2) certain aspects of Columbia's discussion of risk; (3) Columbia Gas' application of the DCF including the forecasted growth rate and leverage adjustment used; (4) Columbia's inclusion of a size adjustment, reliance on the 30-year Treasury Bond for the risk-free rate, and the use of a double-adjusted *beta* in the CAPM analysis; and (5) the Company's request for an additional 20 basis points for "strong management performance" is unjustified.[13]

While the Company accepted I&E's DCF return without regard to the leverage adjustment or management performance in the last base rate case, in the Recommended Decision, the ALJ clearly rejected the Company's proposed

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[11] *Pa. PUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058, pp. 93-94 (Order Entered October 25, 2018).

[12] *Pa. PUC v. Columbia Gas of Pennsylvania*, *Inc.*, Docket No. R-2020-3018835, p. 141 (Order eEntered February 19, 2021).

[13] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.*, Docket No. R-2020-3018835, Recommended Decision, pp. 184-185 (Order Entered February 19, 2021).

leverage adjustment, and the Commission agreed with the ALJ's Recommended Decision.

In the 2020 PECO Energy - Gas Division case, the Commission stated,

> … we have adopted the ALJ's recommendation to use I&E's DCF methodology and to use I&E's CAPM calculation as a check on the reasonableness of the DCF determined cost of equity. Therefore, we shall adopt the ALJ's recommended 10.24% cost of equity. In our view, this is an appropriate cost of equity for PECO given the record developed in this proceeding.[14]

In the Recommended Decision, the ALJ agreed with I&E's recommended cost of equity, which did not include a leverage adjustment.[15]

Finally, regarding the 2021 Aqua base rate case, the Commission did in fact reject the Company's proposed leverage adjustment as follows,

> We find I&E's arguments in opposition to the Company's position to be persuasive. For example, as I&E observed, credit rating agencies assess financial risk based upon a company's booked debt obligations and the ability of its cash flow to cover the interest payments on those obligations. The agencies use a company's financial statements, and not the company's market capital structure, in conducting their analysis. It is a company's financial statements that affect the market value of the stock, and, therefore, the financial statements and the book value capital structure are relied upon in an analysis such as that done by rating agencies. I&E St. 2 at 40; I&E St. 2-SR at 10. Accordingly, we find that the record in this proceeding supports rejecting the Company's requested leverage adjustment.[16]

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[14] *Pa. PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, p. 171 (Order Entered June 22, 2021).

[15] *Pa. PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929, Recommended Decision, p. 215 (Order Entered June 22, 2021).

[16] *Pa. PUC v. Aqua Pennsylvania, Inc*., Docket No. R-2021-3027385, pp. 166-167 (Order Entered June 22, 2021).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S ASSERTION THAT INVESTORS DO NOT BASE THEIR DECISIONS ON BOOK VALUE, BUT RATHER THE RETURN THEY EXPECT TO EARN ON THE DOLLARS THEY INVEST?

A. Investors purchase securities such as stocks at market value as opposed to book value. In doing so, they accept the returns and associated risks implied by market prices. However, financial statements, which are based on book values, show the entire true financial position of a company, providing the foundation for investment and financing decisions. For example, financial institutions such as banks lend money based on actual book values and not the current price of a stock. Further, almost all financial ratios used in financial analysis utilize at least one book value variable from either the income statement or the balance sheet.

Mr. Moul's assertion that investors are unconcerned with the book value debt, or "some accounting value of little relevance to them" (Columbia Statement No. 8-R, p. 28) of a utility is unsupported. Clearly an investor is fully aware and considers all the financial risks of the utility when determining a required return. In addition, the market capitalization information included in Value Line's reports and discussed by Mr. Moul is not the same as market value capital structure. Market capitalization refers to the number of shares outstanding multiplied by the current price, which is commonly used to measure the total market value of a company's stocks on a particular day in the stock market. A market value capital structure refers to the ratio of market debt to market equity, which, to my

knowledge, is not included in Value Line's reports. Therefore, Mr. Moul's contention that Value Line includes market capitalization data does not offer any support for his leverage adjustment.

Q. HAS YOUR RECOMMENDATION CHANGED FROM DIRECT TESTIMONY REGARDING MR. MOUL'S LEVERAGE ADJUSTMENT?

A. No. For the reasons discussed above, I continue to recommend that Mr. Moul's 131-basis point leverage adjustment to the DCF results be rejected.

<u>INFLATION AND CAPITAL COSTS</u>

Q. SUMMARIZE MR. MOUL'S GENERAL DISCUSSION ABOUT INFLATION AND CAPITAL COSTS.

A. Mr. Moul asserts that the Commission should recognize that accommodative policy by the Federal Open Market Committee (FOMC) has ended, and higher interest rates have occurred and will prevail in the future due to high inflation rates (Columbia Statement No. 8-R. p. 7). He states that there have been dramatic increases in inflation, prompting the FOMC to increase the Fed funds rate to combat inflation and the Fed funds rate has been increased by the FOMC eleven times since March 16, 2022, amounting to a 5.25% increase. He presents Blue Chip and Congressional Budget Office forecasts of yields on 10-year treasury notes by year for the period 2025-2029 (Columbia Statement No. 8-R, p. 8) and asserts that with this upward move in interest rates, an equity return well above

10% is warranted today (Columbia Statement No. 8-R, p. 6). Finally, he concludes that the Commission should consider the forecast of interest rates when it sets the cost of equity for Columbia (Columbia Statement No. 8-R, p. 9).

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S REBUTTAL TESTIMONY REGARDING INFLATION AND CAPITAL COSTS?

A. The historic high inflation rate and forecasts of 10-year treasury yields do not suggest any meaningful conclusion because inflation has come down significantly from the historic levels and the changes in bond yields are continuous and volatile, and always driven by capital market conditions, which are influenced by various economic and financial market conditions. In contrast, it is important to note that the Federal Reserve commitment for interest rate cuts is intact and it did not state that there will be no possibility of a rate cut in 2024-2025; it just wants to see the target inflation level closer to 2%. Per the latest news,[17] the Federal Reserve and analysts now predict interest rate cut(s) likely by end of the year 2024 and more rapidly next year, to make up to four rate cuts in 2025, up from three projected previously.

As discussed in my direct testimony, I reiterate that the Federal Reserve's commitment to interest rate reductions would have the effect of reducing potential

[17] Powell Signals Rate Cut Coming Into View but Declines to Say When (msn.com) (accessed on July 16, 2024). Powell's closer attention to cooling job market boosts hopes for Fed rate cuts (yahoo.com) (accessed on July 16, 2024).

inflation and interest rate risks for 2025 capital costs, when Columbia's rates will be in effect (I&E Statement No. 2, pp. 25-26). Additionally, it is important to note that unlike unregulated companies, public utilities may file rate cases to address unforeseen or increased expenses and/or revenue shortfalls due to changes in market conditions, and historically Columbia is filing base rate cases frequently.

Q. DOES THE DCF METHOD ADEQUATELY FACTOR IN THE IMPACT OF RECENT AND FORECASTED INFLATION AND INTEREST RATES?

A. Yes. My DCF calculation includes a spot stock price when determining the projected dividend yield and analysts who generate forecasted earnings growth rates should take current and projected inflation and interest rates into consideration as well. Therefore, the DCF analysis contains the most up-to-date projected information of any model. Thus, Mr. Moul's concerns of high inflation and interest rates (Columbia Statement No. 8-R, p. 16) are adequately covered by using the DCF as a primary method for determining an appropriate return on equity. Therefore, there is no need to adjust for inflation or increased interest rates in the market determined DCF results.

<u>CAPITAL ASSET PRICING MODEL</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR APPLICATION OF THE CAPM.

A. Mr. Moul opines that my CAPM analysis understates the cost of equity for a few

reasons, including my use of the yield on 10-year Treasury Notes for my risk-free rate, failure to use leverage adjusted betas, and rejection of his size adjustment (Columbia Statement No. 8-R, p. 30). Each of these topics are discussed in more detail below.

RISK-FREE RATE

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR USE OF THE YIELD ON THE 10-YEAR U.S. TREASURY NOTE.

A. Mr. Moul claims that by using the 10-year Treasury Note, I introduced a systematic understatement of CAPM returns. He opines that his use of the yield on a 30-year U.S. Treasury Bond is more appropriate than my use of the yield on a 10-year Treasury Note because 30-year bonds are "more a reflection of investor sentiment of their required returns." Additionally, he provides a recalculation of my risk-free rate to use in the CAPM formula (Columbia Statement No. 8-R, pp. 30-31)

Q. DO YOU AGREE WITH MR. MOUL THAT USING THE YIELD OF A 30-YEAR U.S. TREASURY BOND IS MORE APPROPRIATE DUE TO A LONGER-TERM BOND BEING LESS SUSCEPTIBLE TO FEDERAL POLICY ACTIONS?

A. No. As explained in my direct testimony (I&E Statement No. 2, pp. 59-61), I chose the 10-year Treasury Note as it balances the short-comings of the short-term

T-Bill and the 30-year Treasury Bond. Although long-term Treasury Bonds have less risk of being influenced by federal policies, they have substantial maturity risk associated with the market risk. In addition, long-term treasury bonds bear the risk of unexpected inflation. As such, my choice of a 10-year Treasury Note is more appropriate. Additionally, as mentioned in my direct testimony, the Commission has agreed with I&E and recognized the 10-year Treasury Note as the superior measure of the risk-free rate of return.[18]

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING YOUR CALCULATION OF THE RISK-FREE RATE USED IN THE CAPM FORMULA.

A. Mr. Moul opines that I have incorrectly given the same weight to the yield on the 10-year Treasury Note for the third and fourth quarter of 2024 as I do for the entire five-year period encompassing 2025 to 2029. He then recalculates the risk-free rate by averaging the 10-year Treasury yield forecasts by year from 2025 through 2030 ignoring my 3Q 2024 and 4Q 2024 yields (I&E Exhibit No. 2, Schedule 9). to increase my calculated risk-free rate from 3.88% to 4.07% (Columbia Statement No. 8-R, p. 31).

[18] *Pa. PUC v. UGI Utilities, Inc. - Electric Division,* Docket No. R-2017-2640058, p. 99 (Order Entered October 25, 2018).

Q. DO YOU AGREE WITH MR. MOUL'S ANALYSIS OF YOUR RISK-FREE RATE?

A. No. Mr. Moul's revised calculation proposes to give equal weight to each separate year from 2025 to 2030 and ignored 3Q 2024 and 4Q 2024 yields. The flaw with this approach is that the further out into the future one forecasts, the less reliable and more speculative the estimates become; therefore, to give the less reliable estimates equal weight would not be appropriate. It is more appropriate to weight the forecasted quarterly yields for 2024-2025 and the average yield for the period 2025-2029 as I have done in my direct testimony (I&E Exhibit No. 2, Schedule 9). My calculation provides a more accurate estimation of the risk-free rate for the FPFTY.

More importantly, what Mr. Moul fails to recognize, the risk-free rate he uses in his own calculation of 3.75% (Columbia Statement No. 8, p. 38, line 24 through p. 39, line 2) is notably lower than the 3.88% risk-free rate used in my CAPM analysis. Therefore, his criticisms of my risk-free rate appear meaningless and carry no weight.

LEVERAGE ADJUSTED BETAS

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE USE OF LEVERAGE ADJUSTED BETAS.

A. Mr. Moul simply claims that I failed to use leverage adjusted betas (Columbia Statement No. 8-R, p. 30). He does not offer an explanation beyond what he

argued in his direct testimony.

Q. IS THE USE OF "LEVERAGE ADJUSTED BETAS" IN A CAPM ANALYSIS APPROPRIATE?

A. No. Mr. Moul's adjustment only serves to inflate the result of his CAPM analysis which I have discussed in greater detail in my direct testimony (I&E Statement No. 2 pp. 61-62). Value Line is a well-known and trusted source that both investors and the Commission rely upon, therefore, it is not necessary to make any type of adjustment to the Value Line betas. Additionally, it is worth mentioning again that a stock with a price movement that is greater than the overall stock market will have a beta that is greater than one and would be described as having more investment risk than the market. Due to being regulated and the monopolistic nature of utilities, very rarely do they have a beta equal to or greater than one. Therefore, in this case, to apply an adjusted beta of 1.10 rather than Value Line average beta of 0.87 to the entire industry or gas proxy group as Mr. Moul has done to account for the alleged financial risk associated with the book value capital structure is completely unwarranted and irrational.

SIZE ADJUSTMENT

Q. SUMMARIZE YOUR DIRECT TESTIMONY REGARDING A SIZE ADJUSTMENT.

A. In direct testimony, I stated that Mr. Moul's 102-basis point CAPM size

adjustment is unnecessary because none of the technical literature he cited in his direct testimony supporting investment adjustments related to the size of a company is specific to the utility industry. In addition, I presented an article by Dr. Annie Wong that demonstrates that there is no need to make an adjustment for the size of a company in utility rate regulation. Further, I noted that the Commission has recently rejected the application of a size adjustment to the CAPM cost of equity calculation where it agreed that the same literature the Company cites is not specific to the utility industry (I&E Statement No. 2, pp. 63-64).

Q. SUMMARIZE MR. MOUL'S RESPONSE IN REBUTTAL TESTIMONY REGARDING A SIZE ADJUSTMENT.

A. Mr. Moul states that enormous changes have occurred in the industry since the article "Utility Stocks and the Size Effect: An Empirical Analysis" by Dr. Annie Wong was published. He also references the Fama/French study, "The Cross-Section of Expected Stock Returns," to illustrate that his size adjustment is a separate factor from beta that helps explain systematic risk and returns. Additionally, Mr. Moul opines external factors, such as loss of larger customers and unexpected changes in expenses, can affect the financial performance of a small company.

Q. DOES THE TIME THAT HAS ELAPSED SINCE AN ARTICLE WAS WRITTEN NECESSARILY INVALIDATE ITS RESULTS?

A. No. Although Mr. Moul states that enormous changes have occurred in the industry since the 1960s, he presents no evidence that these "changes" have caused the need for a size adjustment. To the contrary, Dr. Wong's study demonstrated that one does *not* need to be made in the regulated utility industry. As stated in my direct testimony, absent any credible article to refute Dr. Wong's findings, Mr. Moul's size adjustment to his CAPM results should be rejected (I&E Statement No. 2, pp. 63-64).

Q. DOES THE FAMA/FRENCH STUDY REFUTE DR. WONG'S ARTICLE?

A. No. As stated in my direct testimony, Dr. Wong's article presents evidence that although a size effect may exist for industrial stocks, it does not exist for utility stocks. As the Fama/French study is not specific to utility stocks, it does not demonstrate that a size effect exists in the utility industry. In addition, the size effect that exists for industrial stocks varies to such an extent that it is difficult to predict. The difficulty in predicting the effect of size is demonstrated in the variance from year to year of the measurement of difference between the annual returns on the large and small-capitalization stocks of the NYSE/AMEX/NASDAQ in the Ibbotson *Stocks, Bonds, Bills & Inflation: 2015 Yearbook*. As stated on page 100 of the SBBI Yearbook,

> While the largest stocks actually declined in 2001, the smallest stocks rose more than 30%. A more extreme case occurred in the depression-recovery year of 1933, when the difference between the first and10th decile returns was far more substantial. The divergence in the performance of small- and large- cap stocks is evident. In 30 of the 89 years since 1926, the difference between the total returns of the largest stocks (decile 1) and the smallest stocks (decile 10) has been greater than 25 percentage points.

Page 109 states,

> In four of the last 10 years, large-capitalization stocks (deciles 1-2 of NYSE/AMEX/NASDAQ) have outperformed small-capitalization stocks (deciles 9-10). This has led some market observers to speculate that there is no size premium. But statistical evidence suggests that periods of underperformance should be expected.

Page 112 states,

> Because investors cannot predict when small-cap returns will be higher than large-cap returns, it has been argued that they do not expect higher rates of return for small stocks.

Aswath Damodaran notes in his study "Equity Risk Premiums (ERP): Determinants, Estimation, and Implications" - The 2022 Edition on page 50 states:

> In the four decades since 1980, the small cap premium has been non-existent, raising questions about whether it still persists or whether it was an artifact of the twentieth century.

Page 51 states,

> Finally, a series of studies have argued that market capitalization, by itself, is not the reason for excess returns but that it is a proxy for other ignored risks such as illiquidity and poor information. The argument that there is, in fact, no small cap premium and that we have observed over time is just an artifact of history should be given credence.

Page 53-54 states,

> Even if you believe that small cap companies are more exposed to market risk than large cap ones, this is a sloppy and lazy way of dealing with that risk, since risk ultimately has to come from something fundamental (and size is not a fundamental factor).

Q. PLEASE CONTINUE.

A. In my opinion, it is not appropriate to link the small size effect of non-regulated companies with the regulated utility industry because regulated utilities, small or large, have a market monopoly in the certificated service jurisdiction and are permitted to seek recovery of the full cost of service and a fair and reasonable rate of return on rate base. The regulatory ratemaking mechanism enables utilities to reduce risk as opposed to unregulated companies that face sales revenue and net income pressures due to a highly competitive market structure.

Q. ARE MR. MOUL'S CONCERNS REGARDING THE IMPACT OF LOSING LARGE CUSTOMERS OR UNEXPECTED INCREASES IN EXPENSES VALID?

A. No. Regulated utility companies have the option to file base rate cases to address declining revenues and to recover the increasing costs of doing business in addition to emergency rate relief provisions for large unforeseen impacts. In contrast, non-utility businesses that may be significantly impacted by events of this nature due to small operating size do not have these opportunities. Further, while a smaller utility may pay higher prices for services and materials just due to

volume buying power, the actual costs are part of the revenue requirement presented by that company, so to increase the return to account for the potential size disadvantage would only further unfairly burden ratepayers who are already likely paying higher utility bills to recover the higher operating costs.

Q. DO YOU HAVE AN ADDITONAL RESPONSE TO MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE SIZE ADJUSTMENT?

A. Yes. As discussed in my direct testimony, I reiterate that the Commission has rejected the application of a size adjustment to the cost of equity calculation in base rate case proceedings[19] (I&E Statement No. 2, p. 64).

Q. WHAT IS YOUR RECOMMENDATION REGARDING MR. MOUL'S SIZE ADJUSTMENT?

A. I continue to recommend that his use of the 1.02% size adjustment be disallowed in the CAPM analysis/results.

Q. MR. MOUL HAS RECALCULATED YOUR CAPM RESULT. DO YOU AGREE WITH HIS RECALCULATION?

A. No. Mr. Moul's recalculation of my CAPM result is incorrect for a couple of reasons. As discussed in my direct testimony and above, he used an inaccurate

[19] *Pa. PUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058 (Order Entered October 25, 2018). *See generally* Disposition of Capital Asset Pricing Model (CAPM), p. 100.

risk-free rate, the overall market return, and an unnecessary size adjustment (Columbia Statement No. 8-R, p. 32). Because of these factors, the recalculation of my CAPM results as Mr. Moul illustrates is unreliable and unnecessary.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING YOUR CAPM ANALYSIS?

A. Yes. My recommended cost of equity is primarily based upon my DCF analysis for the reasons explained above and in my direct testimony. I reiterate that I present a CAPM analysis to the Commission for comparison, not for recommendation purposes as the inputs are highly subjective, and other than beta, not company or industry specific.

RISK PREMIUM

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE RISK PREMIUM (RP) METHOD.

A. Mr. Moul opines that the RP method should be given consideration because it is straight-forward, understandable, and uses a company's own borrowing rate. He claims it provides a direct and complete reflection of a utility's risk and return and reflects prospective interest rates in the model, and therefore, the RP method should be given weight in determining the equity cost rate in this case (Columbia Statement No. 8-R, p. 35).

Q. DO YOU AGREE WITH MR. MOUL THAT THE RP METHOD PROVIDES A DIRECT AND COMPLETE REFLECTION OF A UTILITY'S RISK AND RETURN?

A. No. The RP method produces an indirect measure when compared to the DCF method.

Q. PLEASE COMMENT ON THE INDIRECT MEASURE OF THE RP METHOD VERSUS THE MORE DIRECT MEASURE OF THE DCF METHOD.

A. Mr. Moul claims my statement, that the Risk Premium method does not measure the current cost of equity as directly as the DCF, is without foundation. However, in my direct testimony, I have clearly illustrated how the two measures are different (I&E Statement No. 2, pp. 20-21 and 37). The main reason is that the RP method determines the rate of return on common equity indirectly by observing the cost of debt (interest rate) and adding to it an equity risk premium. The DCF measures equity more directly through the stock information, whereas the RP method measures equity indirectly using debt information.

<u>COMPARABLE EARNINGS</u>

Q. SUMMARIZE MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE COMPARABLE EARNINGS (CE) METHOD.

A. Mr. Moul claims that using the CE method satisfies the comparability standard

established in the *Hope Natural Gas* case. Additionally, he states, "the financial community has expressed the view that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively in the capital markets" (Columbia Statement No. 8-R, p. 37).

Q. DO YOU BELIEVE THAT THE COMPANIES USED BY MR. MOUL IN HIS CE METHOD ANALYSIS ARE SIMILARLY SITUATED AND COMPARABLE TO COLUMBIA?

A. No. As explained in my direct testimony (I&E Statement No. 2, pp. 37-38) the companies in Mr. Moul's analysis are not regulated utilities and similarly situated, and therefore, are too disparate to be used in a CE analysis. For example, the criteria Mr. Moul uses to choose the companies in his proxy group for CE analysis are unregulated industries like Chemicals, Retail Stores, Financial Services, Telecom, Food, IT Services, Industrials, Machinery, Trucking, Diversified Business, Banking, Petroleum, Aerospace/Defense, Railroad, etc. (Columbia Exhibit No. 400, Schedule 14, pp. 1-2). All the companies of his proxy group operate in industries very different from a utility company and operate under different degrees of regulation. Also, a large majority, if not all the companies Mr. Moul uses in his analysis are not monopolies, which utilities largely are. This means that they have significantly more competition and would require a higher return for the added risk. Further, the CE method should be excluded because it is

entirely subjective as to which companies are comparable and it is debatable whether historical accounting returns are representative of the future.

MANAGEMENT PERFORMANCE POINTS

Q. SUMMARIZE THE COMPANY'S REBUTTAL TESTIMONY REGARDING MANAGEMENT PERFORMANCE POINTS.

A. Mr. Moul continues to advocate for 25 additional basis points to the cost of equity as he asserts that Columbia has performed in an exemplary manner. As in his direct testimony, he points to Mark Kempic's direct and rebuttal testimony for justification and to support his claim (Columbia Statement No. 8-R, p. 38).

However, Mr. Kempic did not respond to my direct testimony or provide any additional information in support of recognition of exemplary management performance or any rationale or basis for the company's claim of 25 additional basis points to the cost of equity.

Q. WHAT IS YOUR RESPONSE TO MR. MOUL'S REBUTTAL TESTIMONY REGARDING THE CONSIDERATION OF ADDITIONAL BASIS POINTS FOR MANAGEMENT PERFORMANCE?

A. I have already addressed this topic in my direct testimony (I&E Statement No. 2, pp. 67-70) in response to Mr. Kempic's direct testimony (Columbia Statement No. 1, pp. 30-56). I maintain that Columbia, or any utility company, should not reap additional rewards for programs funded by ratepayers or for meeting their

obligations under 66 Pa C.S.A. §1501. Also, I am aware that under 66 Pa C.S.A. §523 the Commission shall consider a utility's exemplary management performance, however, it is not mandatory that the Commission should grant additional basis points in the cost of equity.

Further, the issuance of equity points to recognize exemplary management performance must always be done on a case-by-case basis. Again, as discussed in my direct testimony, the situation in the 2021 Aqua Pennsylvania case was very specific to that company rescuing troubled water and wastewater systems and preventing health and safety concerns regarding drinking water. This scenario does not apply to Columbia. Notably, in the UGI Electric case, which was decided in a pre-pandemic climate when ratepayers were not faced with the current level of inflation, the Commission awarded UGI Electric a nominal five additional basis points for management effectiveness.

Finally, I must emphasize my primary argument, that for any company, true strong management performance is earning a higher return through its efficient use of resources and cost cutting measures. The greater net income resulting from cost savings and true efficiency in management and operations is available to be passed on to shareholders.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS CONCERNING THE COMPANY'S CLAIM REGARDING MANAGEMENT PEFORMANCE?

A. Yes. I am aware of the rising costs of capital due to the after-effects of the

pandemic and inflation; however, I believe it is important not to over burden ratepayers.

Additionally, and perhaps most importantly, I must reiterate that most of the programs or upgrades related to customer service and safety as discussed by Mr. Kempic in his direct testimony are ultimately *funded by ratepayers* and any savings resulting from cost cutting measures would likely be offset by the addition of basis points for management performance as ratepayers would have to fund those additional costs as well. Hence, this defeats the purpose of efforts to reduce costs to benefit ratepayers.

Q. HAS YOUR RECOMMENDATION REGARDING THE COMPANY'S REQUEST FOR ADDITIONAL BASIS POINTS FOR MANAGEMENT PERFORMANCE CHANGED?

A. No. I continue to recommend that any additional basis points for management performance be rejected.

<u>OVERALL RATE OF RETURN</u>

Q. HAS YOUR OVERALL RATE OF RETURN RECOMMENDATION CHANGED FROM YOUR DIRECT TESTIMONY?

A. No. My recommended cost of equity and overall rate of return remain unchanged from my direct testimony.

Q. WHAT IS YOUR OVERALL RATE OF RETURN RECOMMENDATION?

A. I continue to recommend the following rate of return for Columbia:

I & E Recommendation Columbia Gas of Pennsylvania, Inc. Summary of Cost of Capital			
Type of Capital	**Ratio**	**Cost Rate**	**Weighted Cost Rate**
Long-Term Debt	43.12%	5.07%	2.19%
Short-Term Debt	2.48%	5.25%	0.13%
Common Equity	54.40%	9.93%	5.40%
Total	**100.00%**		**7.72%**

As discussed in my direct testimony, I reiterate that my recommended return on equity of 9.93% is higher than the average return on equity of 9.78% of all gas utility rate cases decided/approved by state regulatory authorities in the first quarter of 2024 (I&E Statement No. 2, p. 71).

EFFECTIVE DATE OF NEW RATES

Q. SUMMARIZE YOUR RECOMMENDATION IN DIRECT TESTIMONY FOR THE EFFECTIVE DATE OF NEW RATES.

A. In direct testimony, I recommended that Columbia should agree to make new rates effective January 1, 2025 (the first day of the FPFTY) instead of the proposed date, December 18, 2024, to avoid any unreasonable and unjustified impact on ratepayers (I&E Statement No. 1, p. 76). As discussed in direct testimony, my recommendation is more appropriate, fair, and logical in the interest of customers because the ratemaking calculation (projection for revenues, expenses, rate base,

taxes, etc.) for new rates includes the 12-month FPFTY beginning January 1, 2025 through December 31, 2025, and it does not encompass the period December 18, 2024 through December 31, 2025 (I&E Statement No. 1, pp. 74-76).

Q. DID ANY WITNESS RESPOND TO YOUR RECOMMENDATION?

A. No. None of the Columbia witnesses or any other parties to this proceeding respond or disagree with my recommendation to make the new rates effective January 1, 2025, the first day of the FPFTY rather than Columbia's proposed new rates effective date of December 18, 2024.

Q. WHAT IS YOUR COMMENT RELATED TO COLUMBIA'S LACK OF RESPONSE TO YOUR RECOMMENDATION?

A. I believe Columbia has no valid reason or support to invalidate my recommendation to make the new rates effective on January 1, 2025, the first day of the FPFTY, which is appropriate and consistent with FPFTY ratemaking. To the best of my knowledge, I am unaware of any other utilities that claimed and made new rates effective prior to the beginning of the FPFTY in a base rate case.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION FOR THE EFFECTIVE DATE OF NEW RATES?

A. No. I continue to recommend that the Commission direct Columbia to make the new rates effective on January 1, 2025 (the first day of the FPFTY) instead of on

December 18, 2024, to avoid any unreasonable and unjustified impact on ratepayers and prevent Columbia from unsupported over recovery of revenues in new rates for the period December 18, 2024 through December 31, 2024 (a 16-day period).

SUMMARY OF OCA WITNESS WALTERS' REBUTTAL TESTIMONY

Q. SUMMARIZE OCA WITNESS MR. WALTERS' RESPONSE IN REBUTTAL TESTIMONY.

A. Mr. Walters takes issue with my recommended 9.93% ROE and growth rate used in my DCF analysis. Additionally, he disagrees with my acceptance and use of the Company's FPFTY capital structure (with a long-term debt ratio of 43.12%, short term debt ratio of 2.48%, and common equity ratio of 54.40%) (OCA Statement No. 3-R, pp. 3-9).

Q. WHAT IS MR. WALTERS' GENERAL CRITICISM REGARDING YOUR RECOMMENDED ROE OF 9.93% AND USE OF THE COMPANY'S CLAIMED COMMON EQUITY RATIO OF 54.40%?

A. Mr. Walters characterizes my ROE analysis and use of the Company's claimed common equity ratio as erroneous and concludes that my recommended ROE and capital structure are excessive (OCA Statement No. 3-R, p. 2).

Q. DO YOU AGREE WITH MR. WALTERS' CRITICISM?

A. No. I disagree with Mr. Walters's unsupported characterization of my ROE analysis and use of the Company's claimed common equity ratio as erroneous.

Q. SUMMARIZE MR. WALTERS' CRITICISMS REGARDING YOUR DCF ANALYSIS.

A. First, Mr. Walters states that my use of analysts' projected average growth rate of 5.95% for gas utilities in the DCF analysis cannot exceed the growth rate of the U.S. economy in which it provides services in perpetuity. He believes that the nominal long-term GDP growth rate of 4.14% is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run (OCA Statement No. 3-R, pp. 5-6). Second, he opines that the multi-stage DCF model is used more frequently than the single-stage or constant growth DCF model I used and concludes that the low-end of his recommended ROE range of 9.10% is close to the collective midpoint DCF results of 9.07% [(I&E DCF 9.93% + OCA DCF 8.20%) ÷ 2] (OCA Statement No. 3-R, p. 7).

Q. HOW DO YOU RESPOND TO MR. WALKERS' CRITICISMS OF YOUR DCF ANALYSIS?

A. First, it should be noted, in the context of recommending an appropriate return on equity and overall rate of return, I&E's role is to perform an unbiased analysis using current and reputable sources. In determining an appropriate growth rate for

my constant growth DCF analysis, I relied upon the forecasted earnings estimates from Yahoo! Finance, Zacks, and Value Line (I&E Exhibit No. 2, Schedule 6). These sources are trusted and used industry wide, including by most Company, advocate, and Commission witnesses who submit rate of return testimony. Mr. Walters, Mr. Moul, and I all utilize these independent analysts' sources for calculating an average growth rate for use in our respective DCF analyses.

The growth estimates I use from the sources listed above are five-year growth forecasts which are not short-term. I believe the five-year growth estimates are reasonable as they cover the time period of the FPFTY and rate case filing frequency of many utilities. I believe it is inappropriate and speculative to compare and set an upper limit for a utility's growth rate with the U.S. economy nominal long-term GDP growth forecast of 4.14% for next five and ten years. Mr. Walters himself used a growth rate of 4.92% for gas utilities in his constant growth DCF analysis, which is higher than his suggested upper limit based on the GDP growth forecast of 4.14% for gas utilities growth rate and calculated a mean DCF result of 9.29% for his gas utilities proxy group (OCA Exhibit CCW-7).

Second, the Commission has repeatedly confirmed I&E's constant growth DCF methodology for determining a fair return on common equity in several base rate proceedings (I&E Statement No. 2, p. 18). Specifically, in the 2020 Columbia Gas rate case, 2020 PECO Energy Company - Gas Division, and the 2023 Columbia Water rate case the Commission agreed with the ALJ's recommendation

to use I&E's cost of equity methodology, which included using five-year growth estimates in the DCF analysis.[20]

Q. SUMMARIZE MR. WALTERS' CONCERNS REGARDING YOUR RECOMMENDATION TO USE THE COMPANY'S CLAIMED CAPITAL STRUCTURE.

A. Mr. Walters disagrees with my recommended use of the Company's claimed capital structure with a common equity ratio of 54.40% largely because it conflicts with my acknowledgement that a 50% common equity and 50% long-term debt capital structure is theoretically optimal. He argues that my adoption of the Company's claimed actual capital structure with an equity ratio of 54.40% is higher than the average equity ratio of my proxy group companies and is at the high-end of the range of my proxy group (OCA Statement No. 3-R, pp. 8-9).

Q. WHAT IS YOUR RESPONSE TO MR. WALTERS' REBUTTAL TESTIMONY REGARDING YOUR RECOMMENDED CAPITAL STRUCTURE?

A. Generally, with few exceptions such as municipalities and smaller investor-owned utilities with largely contributed capital, the actual and FPFTY claimed capital

[20] *Pa. PUC v. Columbia Gas of Pennsylvania, Inc.,* Docket No. R-2020-3018835, p. 141 (Order Entered February 19, 2021); Pa. PUC v. PECO Energy Company – Gas Division; Docket No. R-2020-3018929 (Order Entered June 22, 2021); *Pa. PUC v. Columbia Water Company,* Docket No. R-2023-3040258, p. 105 (Order Entered January 18, 2024).

structure of a company and/or the parent company should be reviewed and applied in the cost of equity analysis to truly reflect the utility's financing structure (capitalization ratio) that will be used to finance the utility's rate base. Based on this fundamental procedure and comparing the Company's actual capital structure with the proxy group's capital structure range, the Company's claimed capital structure is reasonable in this case. It is difficult to assess the reasonableness of a company's capitalization ratio because there are pros and cons of higher debt or higher equity in the capital structure ratio. For example, a higher debt ratio may result in higher financial risk and borrowing costs, which negatively impacts the ratepayers. Conversely, an excessively high equity ratio results in ratepayers having to fund an unnecessarily high return.

As stated in my direct testimony, although it is not always feasible, I believe a capital structure of 50% common equity and 50% long-term debt is ideal and optimal when trying to balance the financial risks of a company as well as controlling costs to ratepayers (I&E Statement No. 2, pp. 12-14). However, applying a 50/50 capital structure or closer to this to every utility in every case as Mr. Walters seems to suggest is short-sighted. I believe motivation to make the best financing decisions possible while considering financial risks and affordability to ratepayers would be reduced if a utility believes the Commission will automatically adopt a 50/50 capital structure. For example, it would be financially beneficial for a utility to have an actual debt ratio greater than 50% and an equity ratio lower than 50% only to have it artificially brought to 50/50 during

a rate case. In this example, the utility would unnecessarily be collecting the more expensive calculated cost of equity on part of its long-term debt portion, which would not be beneficial to ratepayers. Further, the greater long-term debt percentage could possibly lead to a credit rating downgrade and higher debt costs. Using the company specific information that is known, measurable, and reasonable, whenever possible, more accurately results in a fair overall rate of return. It is important to note that Columbia's FPFTY capital structure ratios are known and measurable for foreseeable changes and consistent with the historic average capital structure ratios based on permanent capital (Columbia Exhibit No. 400, Schedule 2, p. 1). I will note, however, that there are a few limitations and exceptions as previously mentioned, which is precisely the reason we review the capital structure information of a proxy group.

Further, my recognition that a 50/50 capital structure is theoretically optimal is intended to illustrate that Mr. Moul's various other adjustments to his calculated cost of equity are unnecessary. Since the Company is benefiting from a more equity heavy capital structure, I believe any further consideration regarding financial risks is unwarranted.

Finally, other than in the 2023 Columbia Water rate case, I&E has historically been very consistent in adopting a company's claimed/actual capital structure in rate proceedings, especially when it falls within the range of capital structures of the proxy group derived from information provided by S&P Global Market Intelligence - Data Management Solutions. Notably, in this single

instance, where I&E strayed from this methodology and in fact recommended a 50/50 capital structure, the Commission rejected the positions of both I&E and OCA, stating:[21]

> On consideration of the record evidence, we are persuaded by Columbia's argument that an actual capital structure should be utilized in setting an overall rate of return in this proceeding….At the outset, we reinforce that an actual capital structure represents the Company's decision, in which it has full discretion, on how to capitalize its rate base. This actual capitalization forms the basis upon which Columbia attracts capital.

For comparison, in that proceeding, Columbia Water's actual claimed equity ratio that led to I&E's 50/50 recommendation was 63.34%, much higher than Columbia's claim of 54.40% in this proceeding.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

[21] *Pa. PUC v. Columbia Water Company,* Docket No. R-2023-3040258, p. 83 (Order Entered January 18, 2024).

I&E Statement No. 3-SR
Witness: Esyan A. Sakaya

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2024-3046519

Surrebuttal Testimony

of

Esyan A. Sakaya

Bureau of Investigation and Enforcement

Concerning:

Fully Projected Future Test Year Reporting Requirements
Hydrogen Blend Pilot Program
Weather Normalization Adjustment
Revenue Normalization Adjustment
Customer Charge
Cost of Service Study
Scale Back of Rates

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INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Esyan A. Sakaya. My business address is Pennsylvania Public Utility Commission, 400 North Street, Harrisburg, PA 17120.

Q. ARE YOU THE SAME ESYAN A. SAKAYA THAT SUBMITTED I&E STATEMENT NO. 3 ON JUNE 18, 2024?

A. Yes.

Q. DID YOU DISCOVER ANY ERRORS IN YOUR DIRECT TESTIMONY?

A. Yes. I inadvertently used the wrong customer charge data in determining the reasonableness of the Company's proposed rates. I have included my corrected proposal in the Customer Charge section of this surrebuttal testimony.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony is to address the rebuttal testimony submitted by witnesses on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company"): Kevin L. Johnson (Columbia Statement No. 6-R), Julie E. Covert (Columbia Statement No. 11-R), and Jason Leal (Columbia Statement No. 21-R). I will also address the rebuttal testimony submitted on behalf of the Pennsylvania Office of Consumer Advocate ("OCA") by witness Jerome D. Mierzwa (OCA Statement No. 5-R), the rebuttal testimony submitted

on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA") by witness Mark D. Ewen (OSBA Statement No. 1-R), and the rebuttal testimony submitted on behalf of the Pennsylvania State University ("PSU") by James L. Crist, P. E. (PSU Statement No. 1-R). My surrebuttal testimony specifically addresses the following issues:

- Fully Projected Future Test Year ("FPFTY") Reporting Requirements;
- Hydrogen Blend Recovery;
- Weather Normalization Adjustment;
- Revenue Normalization Adjustment;
- Cost of Service Allocation;
- Customer Cost Analysis;
- Customer Charge; and
- Scale Back of Rates.

Q. DOES YOUR SURREBUTTAL TESTIMONY INCLUDE AN EXHIBIT?

A. No.

FPFTY REPORTING REQUIREMENTS

Q. SUMMARIZE YOUR RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT COLUMBIA PROJECTS TO BE IN SERVICE DURING THE FTY ENDING NOVEMBER 30, 2024 AND THE FPFTY ENDING DECEMBER 31, 2025.

A. I recommended that the Company be required to provide the Commission's Bureau of Investigation and Enforcement and the Office of Consumer Advocate with an update to Columbia Exhibit No. 108, Schedule 1 no later than April 1, 2025, under this docket number, which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending November 30, 2024. I had also recommended that the Company be required to provide an additional update for actuals through December 31, 2025, no later than April 1, 2026 (I&E Statement No. 3, pp. 3-4).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Yes. Company witness Covert accepts my recommendation (Columbia Statement No. 11-R, p. 7).

HYDROGEN BLENDING RECOVERY

Q. SUMMARIZE YOUR RECOMMENDATION REGARDING COLUMBIA'S PROPOSAL TO RECOVER $54,000 IN EXPENSES RELATED TO THE PURCHASE OF HYDROGEN IN YOUR DIRECT TESTIMONY.

A. I recommended that the recovery of the $54,000 related to the purchase of Hydrogen for blending with natural gas be denied because Hydrogen is not currently being blended into the Columbia gas distribution system (I&E Statement No. 3, p. 6).

Q. DOES THE COMPANY AGREE WITH YOUR RECOMMENDATION REGARDING RECOVERY OF EXPENSES RELATED TO THE PURCHASE OF HYDROGEN?

A. No. Columbia witness Leal disagrees with my recommendation (Columbia Statement No. 21-R, pp. 10-12).

Q. WHY DOES THE COMPANY DISAGREE WITH YOUR RECOMMENDATION TO DENY RECOVERY OF EXPENSES RELATED TO THE PURCHASE OF HYDROGEN?

A. Mr. Leal cites two prior Commission allowances for the recovery of expenditures related to Research and Development ("R&D") costs as a reason to disagree with my assessment of Columbia's Hydrogen Blending expense recovery. In a 1990 National Fuel Gas Distribution Corp. ("NFG") base rate case, the Commission adopted the OCA proposal that NFG's Research Demonstration & Development

costs be established for ratemaking purposes (*Pa. P.U.C. v National Fuel Gas Distribution Corp., 73 Pa. P.U.C 552 (1990)* Docket No. R-901670). Lastly, in a 1994 NFG base rate case, the Commission again adopted an OCA's proposal that NFG's R&D costs be recovered in a base rate case. These decisions were made even though a percentage of NFG's original claim was denied (*PA PUC v NFGD Corp.,* Docket No. R-00942991, (Order Entered December 6, 1994).

Q. DOES REFERENCE TO THE ABOVE COMMISSION ORDERS INVALIDATE YOUR RECOMMENDATION?

A. No. In the abovementioned 1990 and 1994 NFG cases, the recovery of research and development related expenses were adopted by the Commission at a reduced rate based on an OCA recommendation. Furthermore, while Columbia contends that research on hydrogen blending is being performed sporadically across the U.S., the Department of Energy ("DOE") launched a broad and extensive hydrogen blending R&D program, HyBlend, in 2021. The DOE is researching limitations of existing gas pipelines and connected applications using major national laboratories to look at all aspects of the future of hydrogen blending in U.S. natural gas infrastructure, so while Columbia insists its program is more robust and complementary to others (Columbia Statement No. 9, pp. 14-15), it would appear redundant and limited with respect to the DOE HyBlend program (https://www.energy.gov/eere/fuelcells/hyblend-opportunities-hydrogen-blending-natural-gas-pipelines). Between the existence of this national level research

program and as stated in my direct testimony, since hydrogen is not currently being used by any customer class in Columbia's natural gas system, the Company should not be able to recover the expense related to the hydrogen blending skid (I&E Statement No. 3, p. 6).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. I continue to recommend that the Company's $54,000 operating and maintenance expense claim for the purchase of Hydrogen be rejected as is not considered used and useful in Columbia's distribution system and is duplicative of research being undertaken at a national level.

<u>WEATHER NORMALIZATION ADJUSTMENT</u>

Q. WHAT DID YOU RECOMMEND REGARDING THE WEATHER NORMALIZATION ADJUSTMENT?

A. I recommended that the proposal to remove the 3% deadband be denied (I&E Statement No. 3, p. 8).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION REGARDING THE WEATHER NORMALIZATION ADJUSTMENT ("WNA")?

A. Yes.

Q. WHAT IS THE COMPANY'S RESPONSE TO YOUR RECOMMENDATION REGARDING THE WNA?

A. The Company is withdrawing its request to remove the 3% deadband as it is currently controlled by a prior settlement (Columbia Statement No. 6-R, p. 2).

Q. WHAT PRIOR SETTLEMENT IMPACTED COLUMBIA'S DECISION?

A. The Company mentions an agreement in its settlement for the 2021 base rate case. In that proceeding, Columbia agreed that a final determination of the viability of its WNA pilot would not be concluded until Columbia files a base rate case after May 31, 2026 (Columbia Statement No. 6-R, p. 32).

Q. DO YOU AGREE WITH THE LANGUAGE IN THE PRIOR SETTLEMENT REGARDING THE WNA, AND COLUMBIA'S WITHDRAWAL OF ITS CLAIM IN THIS PROCEEDING?

A. Yes. Based on the Company's rebuttal testimony, Columbia agreed to wait until filing a rate base case after May 31, 2026, to determine if any changes to the current WNA mechanism can or should be proposed (Columbia Statement No. 6-R, pp. 32-34).

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. Yes. While I presently believe that the 3% deadband should be a permanent requirement, I withdraw any recommendation related to the WNA at this time

based on the existing settlement provisions.

REVENUE NORMALIZATION ADJUSTMENT

Q. SUMMARIZE YOUR RECOMMENDATION RELATED TO THE COMPANY'S PROPOSED REVENUE NORMALIZATION ADJUSTMENT.

A. In my direct testimony, I disagreed with the Company's proposal to implement a revenue normalization adjustment ("RNA") and recommended that the RNA proposal be denied for three reasons (I&E Statement No. 3, p. 11). First, the Commission determined the RNA was unnecessary in the Company's 2020 base rate proceeding. Second, the policy statement cited by the Company did not allow Columbia to abandon the necessity to charge just and reasonable rates. Third, the use of the FPFTY already provides for the estimated lower usage levels.

Q. HAS THE COMPANY RESPONDED TO YOUR RECOMMENDATION

A. Yes. The Company disagrees with my recommendation regarding the RNA (Columbia Statement No. 6, pp. 16-18).

Q. SUMMARIZE THE COMPANY'S RESPONSE TO YOUR RECOMMENDATION.

A. First, Columbia admits that the Company did not provide a full argument in support of an RNA when it was last proposed in the 2020 base rate case but claims that sufficient information is provided to support the RNA requested in this

proceeding. Second, as it relates to the policy statement regarding just and reasonable rates, Columbia states that I assumed that the Company was abandoning the Commission's Policy Statement on Alternative Ratemaking adopted at Docket R-2015-2518883 by charging unjust and unreasonable rates because the proposed RNA complements Columbia's rate design. Third, the Company states that while the use of the FPFTY already provides for projected lower usage levels, the proposed RNA would compensate any projected usage levels because it will be based upon actual usage (Columbia St. No. 6-R, pp. 16-18).

Q. DO YOU AGREE WITH THE COMPANY'S PERSPECTIVE REGARDING YOUR THREE REASONS IN SUPPORT OF DISALLOWING THE RNA?

A. No.

Q. WHAT SUPPORT DID THE COMPANY PROVIDE FOR CLAIMING THE NECESSITY OF ITS RNA PROPOSAL?

A. Company witness Johnson, in Columbia Statement No. 6-R, p. 17, states that due to customer conservation, the volumetric base rates recover less base rate revenue than required to recover the Company's cost of service. Mr. Johnson asserts the proposed RNA addresses shortfalls related to actual and normal usage and allows

Columbia an opportunity to recover its costs, which are substantially fixed and do not vary in relation to usage.

Q. DO YOU AGREE WITH THE COMPANY CLAIM REGARDING THE NECESSITY OF AN RNA?

A. No. While customer conservation will impact usage, Columbia failed to mention the impact of a purchased gas costs case to its proposed RNA. Because purchased gas costs fluctuate, Columbia ratepayers have no protection when purchased gas prices are at a discount and will still have to pay a higher gas bill with the potential addition of an RNA. In addition to this, Columbia files frequent base rate cases, staying out no more than two years. Because of this, there is no need for the RNA as the Company's rates will continue to be adjusted every year or two as has been the Company's pattern of rate case filings.

Q. WHAT SUPPORT DOES WITNESS JOHNSON PROVIDE FOR THE RNA BEING AN ALTERNATIVE RATEMAKING MECHANISM THAT BENEFITS CUSTOMERS?

A. Company witness Johnson states that the RNA would be in compliance with the Commission's Policy Statement on Alternative Ratemaking as adopted by the Commission at Docket No. M-2015-2518883 (Columbia Statement No. 6-R, pp. 17-18). Columbia asserts that the RNA mechanism does not replace the billings of the base rates established in this case, but the RNA does complement the

residential rate design in this case to better ensure the revenue requirement assigned to the residential class is not over or under recovered due strictly to rate design.

Q. DO YOU AGREE WITH THE COMPANY ASSERTION THAT THE RNA WOULD PRODUCE JUST AND REASONABLE RATES?

A. No. The RNA would increase the bills of the Company's largest customer class (residential customers) who tend to consume more gas than non-residential customers. Since the RNA is based on usage, the Company would be able to collect excess revenues during those months where the WNA overlaps with the RNA.

Q. WHAT SUPPORT DOES WITNESS JOHNSON PROVIDE FOR THE RNA BEING ABLE TO COMPENSATE OVER AN FPFTY USAGE PROJECTION?

A. Company witness Johnson states that Columbia's fixed costs necessitate the need for an RNA because of variances between forecasted and actual usage (Columbia Statement No. 6-R, p. 17). Because projections of usage levels are factored into billing determinates of the FPFTY, conservation, weather within the 3% WNA tolerance level, and other variances all contribute to usage fluctuations and necessitate the use of an RNA mechanism to allow Columbia the opportunity to recover costs (Columbia Statement No. 6-R, p. 17).

Q. DO YOU AGREE WITH THE COMPANY CLAIM OF THE RNA BEING ABLE TO COMPENSATE FOR AN FPFTY PROJECTION VARIANCE?

A. No. The RNA would supplement any FPFTY projections by creating a situation where customers would end up paying higher gas bills that could generate more revenue than what was forecasted by the Company especially during the months where the WNA overlaps with the RNA.

Q. DO YOU HAVE ANY CHANGES YOUR RECOMMENDATION?

A. No. I continue to recommend that the RNA be denied.

Q. WHY DO YOU RECOMMEND REJECTION OF THE RNA PROPOSAL?

A. The WNA is currently in effect during the months November through May and will continue until a final Order is entered in the Company's first rate case filed after May 31, 2026. The proposed RNA would be in effect during the months October through March known as the Peak Period, and April through September known as the Off-Peak Period. Based on these two mechanisms, one dependent on weather, and the other on usage, I continue to recommend rejection of the RNA mechanism. Until a final Order for the WNA is entered in the proceeding for the Company's first rate case filed after May 31, 2026, I believe the implementation of an RNA in conjunction with the WNA would not be understandable to customers or would cause outrage, and could allow Columbia to charge customers unfairly for usage during the Peak Period months where the WNA and RNA overlap. In

summary, the alleged purpose of a revenue normalization adjustment is to remove the inherent risk of not recovering the full amount of revenue allowed by the Commission due to changes in usage. Between the frequent base rate cases filed by the Company, staying out no more than two years, using an FPFTY to estimate usage and revenue, filing annual PGC cases, establishing surcharges related to a DSIC, and using a WNA, the Company has demonstrated no need for additional revenue stabilization measures.

COST OF SERVICE

Q. DID THE COMPANY PROVIDE AN ALLOCATED COST OF SERVICE STUDY IN THIS PROCEEDING?

A. Yes. The Company performed and provided three allocated cost of service ("ACOS") studies in its filing sponsored by Columbia witness Johnson as described in Columbia Statement No. 6-R, pp. 2-16. The first is a customer demand ACOS study (Columbia Exhibit No. 111, Schedule 1), the second is a peak and average ACOS study (Columbia Exhibit No. 111, Schedule 2), and the third ACOS study is an average of the customer-demand studies and the peak and average studies (Columbia Exhibit No. 111, Schedule 3).

Q. DO YOU AGREE WITH THE COMPANY THAT MULTIPLE COST OF SERVICE STUDIES ARE NECESSARY WHEN ALLOCATING COSTS?

A. No. The Commission has not made such a distinction regarding allocations based

on multiple cost of service studies that I am aware of. Requiring multiple cost of service studies could be overly burdensome to other utilities. Whether a utility presents a single or multiple cost of service studies in a base rate case should be decided based on the utility's decision, prior Commission Orders, or the specific requirements of each base rate case. If multiple cost of service studies are presented, it is then up to the Commission to decide whether to adopt all, one, or none of the studies presented on a case by case basis. In this proceeding, I continue to recommend that the Commission find that the Peak and Average is reasonable as it has in prior Commission Orders.

Q. WHICH OF THE THREE ACOS STUDIES SPONSORED BY WITNESS JOHNSON DID THE COMPANY UTILIZE TO ALLOCATE THE PROPOSED REVENUE INCREASES?

A. Consistent with the Commission's Order in Columbia's 2020 base rate proceeding, discussed above, the Company utilized the second ACOS study sponsored by Mr. Johnson, which is the peak and average study, presented in Columbia Exhibit No. 111, Schedule No. 2 to allocate the proposed revenue increases (Columbia Statement No. 6-R, p. 7).

Q. DID THE COMPANY AGREE WITH THE COMMISSION'S PREFERENCE REGARDING THE USE OF THE PEAK AND AVERAGE COSS FOR REVENUE ALLOCATION AND CUSTOMER CHARGE SETTING?

A. No. Columbia opines the use of the three studies was more appropriate despite the Commission's preference for the Peak and Average COSS. As it pertains to the revenue allocation, the Company asserts that basing the revenue allocation in this case entirely on the Peak & Average Study would not produce a reasonable result, particularly with respect to allocation of mains cost to the LDS/LGSS class (Columbia Statement No. 6-R, pp. 8-9).

Q. OTHER THAN THE COMPANY, DID ANY OTHER PARTY ALSO DISAGREE WITH YOUR RECOMMENDATION THAT ONLY THE PEAK AND AVERAGE ACOS SHOULD BE USED IN THIS PROCEEDING?

A. Yes. PSU witness Crist also opposed my use of the peak and average ACOS study only in allocating costs in this proceeding stating that there are valid reasons for other ACOS methodologies that have a sound technical and economic basis to them (PSU Statement No. 1-R, p. 11).

Q. PLEASE RESPOND TO THE COMPANY AND PSU'S OPPOSITION TO THE USE OF THE PEAK AND AVERAGE ACOS STUDY IN COST ALLOCATION.

A. In general, any system must be designed to handle peak usage and year-long average usage. In addition, I continue to believe that although mains serve customers, the type of main investment is properly determined by the throughput.

Q. DOES MR. CRIST POINT OUT WHY THE CUSTOMER DEMAND COST ALLOCATION METHOD IS PREFERRED?

A. Yes. Mr. Christ points out that the Customer-Demand cost of service study (Columbia Ex. 111, Schedule No. 1) is the only type of COSS based on cost causation and must be relied upon as being more accurate in allocating the final revenue increases among the different customer classes (PSU Statement No. 1-R, pp. 18-19).

Q. DID THE OCA RESPOND TO YOUR ACOS STUDY RECOMMENDATION?

A. Yes. OCA agreed that the Peak and Average cost allocation method should be accepted in this proceeding (OCA Statement No. 5-R, p. 7); however, the OCA disagreed with the Company's revenue allocation, which I accepted, as failing to provide adequate movement towards cost-based rates.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION REGARDING THE COMPANY'S ACOS STUDY?

A. Not entirely. I continue to recommend that the Commission use the peak and average ACOS study provided by the Company in Columbia Exhibit No. 111, Schedule 2 as the preferred method to allocate revenue increases among the different customer classes, but I do not oppose revenue allocations that facilitate movement to cost-based rates between the classes.

CUSTOMER COST ANALYSIS

Q. WHAT DID YOU RECOMMEND REGARDING THE COMPANY'S CUSTOMER COST ANALYSES?

A. I recommended the Company's customer cost analysis that includes the cost of mains should not be considered (I&E Statement No. 3, p. 20).

Q. DID THE COMPANY RESPOND TO YOUR RECOMMENDATION?

A. Yes. Mr. Johnson stated in Columbia Statement No. 6-R, pp. 3-4 that the Company continues to utilize the peak and average study as a primary study to serve as a guide to allocate the proposed revenue increases and customer costs in this proceeding.

Q. DO YOU HAVE ANY CHANGES TO YOUR RECOMMENDATION?

A. No. As stated in my direct, I continue to recommend the Company's customer

cost analysis that includes the cost of mains should not be considered (I&E St. No. 3, p. 20).

CUSTOMER CHARGES

Q. WHAT CUSTOMER CHARGES DID YOU RECOMMEND FOR THE RS, RDS, AND RC2 CLASSES?

A. On page 22 of I&E Statement No. 3, I only recommended customer charges for the RS, RDS, and RC2 classes be adjusted to be consistent with the customer cost analysis that reflected a 22.1% increase above present rates. Then on page 23 of I&E Statement No. 3, I then agreed with Columbia's 22.1% rate increase across the remaining rate classes.

Rate Schedule (Therms, annually)	Customer Cost Analysis	Company Proposed Rate	Change	I&E Proposed Rate	Percent Increase
RS, RDS, RC2					
All Usage	$25.47	$26.00	$5.14	$20.46	22.1%

Q. DO YOU CONTINUE TO RECOMMEND A 22.1% INCREASE ACROSS THE BOARD FOR ALL RATE CLASSES?

A. No, I do not. I only recommend a 22.1% increase for rate classes RS, RDS, RCS, LGSS, and LDS.

Q. WHY ARE YOU PROPOSING A CHANGE FROM YOUR INITIAL RECOMMENDATION REGARDING AN ACROSS-THE-BOARD INCREASE?

A. I realized I made an error by using the wrong customer cost analysis in determining rates, and I realized that I had to use the Company's Peak and Average COSS customer cost analysis, excluding mains, as shown in Columbia Exhibit 111, Schedule 2, p. 25 as a guide in determining customer charges.

Q. DO YOU HAVE ANY CORRECTIONS TO THE CUSTOMER CHARGE TABLE SHOWN IN YOUR DIRECT TESTIMONY?

A. Yes. I am making several adjustments to the table shown in I&E Statement No. 3, p. 21 that shows my recommended customer charges. Specifically, I am adjusting the Change and I&E Proposed Rate columns for all classes except the LDS class. It should also be noted that the change in the RS, RDS, and RCC classes was listed incorrectly as positive $5.14 when it should be negative $5.54, shown on the table below. For RS, RDS, and RCC classes I am proposing to decrease the customer charge for these classes by $5.54 from the Company' s proposed $26.00 to $20.46. For SGSS1, SCD1, and SGDS1 classes I am proposing to decrease the customer charge for these classes by $4.87 from the Company' s proposed $36.55 to $31.68. For the SGSS2, SCD2, and SGDS2 classes I am proposing to decrease the customer charge for these classes by $10.10 from the Company' s proposed $69.63 to $59.53 For the SDS class, I am proposing to decrease the customer charge by

$25.40 from the Company' s proposed $326.09 to $300.68, and finally for the LGSS class I recommend using the same customer charge being proposed by Columbia of $1479.13. My updated customer charge recommendations are shown in the table below:

2024 I&E Corrected Customer Charge Table					
Rate Schedule (Therms, annually)	Customer Cost Analysis	Company Proposed Rate	Change	I&E Proposed Rate	Percentage Increase over Present Rates
RS, RDS, RCC					
All Usage	$28.71	$26.00	($5.54)	$20.46	22.1%
SGSS1, SCD1, SGDS1					
≤6,440	$31.68	$36.55	($4.87)	$31.68	5.8%
SGSS2, SCD2, SGDS2					
to	$59.53	$69.63	($10.10)	$59.53	4.4%
SDS					
>64,400 < 110,000	$300.68	$326.09	($25.40)	$300.68	12.5%
LGSS					
110,000 to ≤ 540 000	$1711.06	$1479.13	$0	$1479.13	22.1%

Q. WHY ARE YOU MAKING THESE CHANGES TO YOUR CUSTOMER CHARGE TABLE?

A. First, I am correcting the rate structure to be reflective of gradualism and not create rate shock. Second, I am updating the monthly customer charge to be as close as possible to the Company's Peak & Average based Customer Cost

Analysis, excluding mains. With the exception of the RS, RDS, RCC, and LGSS rate classes, I developed a customer charge that matches the Company's customer cost analysis.

Q. WHY IS THE CUSTOMER CHARGE FOR RATE CLASSES RS, RDS, RCC SHOWN IN YOUR CUSTOMER CHARGE TABLE LOWER THAN WHAT IS SHOWN ON COLUMBIA'S CUSTOMER COST ANALYSIS?

A. Columbia proposed a customer charge of $26.00 for rate classes RS, RDS, and RCC despite reflecting a customer cost analysis of $28.71. Because Columbia proposed a customer charge increase to $26.00 which is 55.2% higher than the present customer charge of $16.75, I reduced the rate being proposed to $20.46 which percentagewise reduced the increase from the 55.2% to 22.1% for rate classes RSW, RDS, and RCC. Columbia's present and proposed rates for RS, RDS, and RCC can be seen on Columbia Ex. 111, Sch. 2, p. 25 and Columbia Ex. 111, Schedule 6, pp. 1-3.

Q. WHY IS THE CUSTOMER CHARGE FOR RATE CLASS LGSS SHOWN IN YOUR CUSTOMER CHARGE TABLE LOWER THAN WHAT IS SHOWN ON COLUMBIA'S CUSTOMER COST ANALYSIS?

A. Columbia proposed a customer charge of $1,479.13 for rate class LGSS despite reflecting a customer cost analysis of $1,711.06, which can be seen above on my corrected chart and in Columbia Exhibit 111, Schedule 2, p. 25 and Columbia

Exhibit 111, Schedule 6, pp. 13-15. I concur with Columbia's proposal for this customer class as it comports with my concerns regarding rate shock and gradualism.

Q. DID ANY PARTIES RESPOND TO YOUR INITIAL CUSTOMER CHARGE RECOMMENDATION?

A. Yes. First, Columbia witness Bell disagrees with my recommendation based on her support of the Company's customer charge analysis as discussed above (Columbia Statement No. 6-R, p. 11). Second, OCA witness Mierzwa disagrees with my customer charge recommendations because he claims the 22.1% increase violates the principle of gradualism and the Company's customer charge is already the highest in the Commonwealth (OCA Statement No. 4-R, pp. 2-3).

Q. DO YOU AGREE WITH MR. MIERZWA THAT AN INCREASE IN CUSTOMER CHARGE IS SIGNIFICANT?

A. Yes. However, I believe my recommendation does not violate the principle of gradualism because I recommended in I&E Statement No. 3, p. 23, the customer charges should be included in any scale back of rates.

Q. DO YOU BELIEVE THE COMPARISON OF CUSTOMER CHARGES OF THE OTHER PENNSYLVANIA NATURAL GAS DISTRIBUTION COMPANIES SHOULD BE A DETERMINING FACTOR IN COLUMBIA'S CUSTOMER CHARGES?

A. No. Each Pennsylvania natural gas distribution company has its own specific costs and allocation of these costs produce different results. Therefore, the rates of each company should be determined based on the facts and data specific to that company. The customer charges I recommend are based on the customer cost analysis using the data specific to this case.

Q. DO YOU RECOMMEND THE CUSTOMER CHARGES BASED ON THE CUSTOMER COST ANALYSIS PROVIDED IN THE PEAK AND AVERAGE ACOS STUDY?

A. Yes. For the reasons explained above, I support the customer charges in my corrected customer charge table that were based on Columbia's peak and average based ACOS study.

<u>SCALE BACK OF RATES</u>

Q. WHAT SCALE BACK METHODOLOGY DID YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommended that all customer charges and usage rates that have been proposed

an increase are scaled back proportionately based on the ACOSS that is ultimately approved by the Commission (I&E Statement No. 3, p. 23).

Q. DID THE COMPANY OPPOSE YOUR PROPOSED SCALE BACK METHODOLOGY?

A. No. Mr. Johnson states that the Company will utilize the approved ACOS study to scale back proportionally all revenue requirements for revenue and rate design purposes (Columbia Statement No. 6-R, p. 11).

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3046519
	:	
Columbia Gas of Pennsylvania, Inc.	:	
Base Rates	:	

WITNESS VERIFICATION
THE BUREAU OF INVESTIGATION AND ENFORCEMENT

I, Christine Wilson, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents preliminarily identified as:

- I&E Statement No. 1 (PROPRIETARY/Non-Proprietary),
- I&E Exhibit No. 1 (PROPRIETARY/Non-Proprietary),
- I&E Statement No. 1-R, and
- I&E Statement No. 1-SR (PROPRIETARY/Non-Proprietary).

were prepared by me or ***under my direct supervision and control***. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an Evidentiary Hearing in this matter. This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

/s/ Christine Wilson
Christine Wilson
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: July 30, 2024

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3046519
	:	
Columbia Gas of Pennsylvania, Inc.	:	
Base Rates	:	

WITNESS VERIFICATION
THE BUREAU OF INVESTIGATION AND ENFORCEMENT

I, D. C. Patel, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents preliminarily identified as:

- I&E Statement No. 2,
- I&E Exhibit No. 2, and
- I&E Statement No. 2-SR

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an Evidentiary Hearing in this matter. This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

/s/ *DCPatel*
D. C. Patel
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: July 30, 2024

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3046519
	:	
Columbia Gas of Pennsylvania, Inc.	:	
Base Rates	:	

WITNESS VERIFICATION
THE BUREAU OF INVESTIGATION AND ENFORCEMENT

I, Esyan A. Sakaya, on behalf of the Bureau of Investigation and Enforcement, hereby verify that the documents preliminarily identified as:

- I&E Statement No. 3; and
- I&E Statement No. 3-SR.

were prepared by me or under my direct supervision and control. Furthermore, the facts contained therein are true and correct to the best of my knowledge, information and belief and I expect to be able to prove the same at an Evidentiary Hearing in this matter. This Verification is made subject to the penalties of 18 Pa. C.S. § 4904 relating to unsworn falsification to authorities.

/s/ Esyan A. Sakaya
Esyan Sakaya
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement

Dated: July 30, 2024

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket Nos.: R-2024-3046519
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

DIRECT TESTIMONY

OF

DAVID E. DISMUKES, PH.D.

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 1

Date Served: June 14, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

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

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG").

Q. PLEASE DESCRIBE ACG AND ITS AREAS OF EXPERTISE.

A. ACG is a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a professor emeritus at Louisiana State University ("LSU"). Prior to my retirement in January 2023, I served as a full professor, executive director, and director of policy analysis at the LSU Center for Energy Studies and as a full professor in the Department of Environmental Sciences and the director of the Coastal Marine Institute in the LSU College of the Coast and Environment. I also served as a senior fellow at the Institute of Public Utilities at Michigan State University, where I taught energy regulatory staff and other utility stakeholders about principles, trends, and issues in the electric and natural gas industries. I am also a Distinguished Fellow and Senior Economist with the Institute for Energy Research in Washington, D.C.

Q. HAVE YOU PREPARED AN APPENDIX OUTLINING YOUR PROFESSIONAL QUALIFICATIONS?

A. Yes. My academic vitae is attached as Appendix A and includes a list of all my publications, presentations, pre-filed expert witness testimony in other jurisdictions, expert reports, expert legislative testimony, and affidavits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the Pennsylvania Office of the Consumer Advocate ("OCA") to address certain regulatory and policy issues related to the general rate case filed by Columbia Gas of Pennsylvania ("Columbia" or "the Company"). I specifically have been asked to address the Company's proposed revenue decoupling mechanism, called the Revenue Normalization Adjustment ("RNA"), and the Company's Weather Normalization Adjustment ("WNA") proposals and to place each of those proposals within the context of general regulatory and public policy principles. My recommendations about the RNA and WNA are to be read as a complementary and in conjunction with the OCA's other witnesses who provide additional bases for why these rate designs should be rejected.

II. SUMMARY OF RECOMMENDATIONS

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

A. I recommend the Commission reject the Company's RNA proposal. The RNA ultimately is a solution in search of a problem since the Company has provided no record evidence showing that this mechanism is needed. Further, the Company has provided no compelling evidence that there is any financial need for the RNA. Most revenue

decoupling proposals are tied to either new or enhanced energy efficiency efforts. The Company's RNA should be rejected, for among other reasons, since it does not include any meaningful expanded energy efficiency commitments if approved. The failure to directly tie expanded energy efficiency savings opportunities to revenue decoupling adoption shifts the entire performance risk of the RNA away from the Company and onto ratepayers. Lastly, the RNA includes no ratepayer protections, exposing customers to unneeded and potentially unnecessary rate changes for retail rates that are already higher than regional peers. Overall, the proposed RNA will provide real benefits to Columbia's parent, NiSource, and its shareholders by de-risking its revenue recovery while providing no corresponding benefits for ratepayers.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE COMPANY'S PROPOSAL TO REMOVE THE WNA DEADBAND?

A. I recommend the following:

- Consistent with the recommendation of OCA witness Jerome Mierzwa, the OCA's position is that the WNA should be discontinued in its entirety given the significant and pervasive rate harm to consumers. Columbia, through its proposal to lift the three percent deadband has effectively abandoned its pilot program that was approved in the last rate case, and the OCA believes that it is appropriate based on the record of this case to discontinue that pilot early and end the WNA in its entirety. In fact, to date, ratepayers have reimbursed the Company and its shareholders as much as $59.1 million for no documentable and meaningful benefits. The Company also has not shown the offsetting benefits it has received from having a WNA in place as opposed to not having the WNA. Thus, the OCA's position in this proceeding is that the Commission should discontinue the pilot WNA.
- If the Commission is not inclined to end the WNA in this proceeding despite the evidence, it should reject the Company's proposal to remove the three percent deadband. The clear intent of the settlement agreement in Docket No. R-2012-2321748 allowing the pilot WNA is that it would run for a three-year trial period and then be evaluated for continuation in a later (post-three year) base rate case proceeding. The request to remove the three percent deadband at the current time, prior to the end of the pilot period, is nothing more than a unilateral

request and "end-run" by the Company to change the terms and conditions of the agreement and, as proposed above the WNA should either be rejected or, at a minimum, the Company's efforts to remove the deadband should be rejected as such. The Company has not offered nor shown any ratepayer benefits that arise from the WNA or from the removal of the deadband and the Company's proposal to remove the three percent deadband serves no intent but to unjustly compensate itself and its shareholders at other parties' expense and should be rejected.

- The Company has not proven the need for the removal of the proposed deadband. It has not offered any evidence that it is suffering any financial harm due to the current conditions of the settlement agreement establishing the pilot WNA.
- The Company's WNA pilot and/or its request to remove the three percent deadband should be rejected since it has offered no ratepayer protections like a rate cap, earnings test, reduction in its allowed ROE, nor other comparable ratepayer protection nor benefit.

III. CASE OVERVIEW AND WITNESS INTRODUCTION

Q. CAN YOU DESCRIBE THE CONTEXT OF THIS RATE FILING IN RELATION TO THE COMPANY'S PRIOR GENERAL RATE INCREASE FILINGS?

A. Columbia has filed for general rate increases in 2009,[1] 2010.[2] 2012,[3] 2014,[4] 2016,[5] 2019,[6] 2020,[7] 2021,[8] and 2022,[9] each of which resulted in a grant of a rate increase with an effective date somewhere near nine months of the filing date in each case.

[1] R-2009-2149262

[2] R-2010-2215623

[3] R-2012-2321748

[4] R-2014-2406274

[5] R-2016-2529660

[6] R-2019-3010039

[7] R-2020-3018835

[8] R-2021-3024296

[9] R-2022-3031211

Q. PLEASE PROVIDE YOUR GENERAL UNDERSTANDING OF COLUMBIA GAS' PROPOSED GENERAL RATE INCREASE.

A. On March 15, 2024, Columbia Gas filed a general rate increase pursuant to Section 1308(d) of the Public Utility Code, 66 Pa. C.S. § 1308(d).[10] The end of the suspension period is on or around December 15, 2024, when new rates will take effect.[11] In its filing, the Company proposes to increase rates to produce additional overall revenues of $124.1 million per year, a 21.7 percent increase over current distribution revenues, by utilizing a fully projected future test year ("FPFTY") for ratemaking purposes.[12] The Company's proposed rate increase would apply to its approximately 445,000 residential, commercial, and industrial customers located in 450 municipalities across portions of 26 counties in western, northwestern, southern, and central Pennsylvania. If Columbia's proposal is approved: (1) the residential fixed customer charge, a charge paid no matter how much or little a consumer uses, would increase from $16.75 to $26.00, a 55 percent increase[13]; and (2) the total bill for a residential customer purchasing 70 therms per month would increase from $118.16 to $136.92, a 15.9 percent increase.[14] Columbia Gas seeks approval to guarantee that it will meet its revenue target between rate cases by way of combination of the modified WNA (with removal of existing three percent deadband) and the new RNA.[15] Columbia Gas proposes a return on equity

[10] Company petition.

[11] Docket No. R-2024-3046519, Commission Order dated April 4, 2024.

[12] Company petition

[13] *See,* Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 21:20-21.

[14] Company petition

[15] *See,* Direct Testimony of Mark Kempic, Company Statement No. 1 at 8:16-19.

of 11.75 percent, inclusive of a 25-basis point adder in recognition of superior management performance, in conjunction with an equity-rich capital structure of 54.4 percent equity and 45.6 percent debt, without consideration of the decreased risk the Company would face if its WNA and RNA proposals are approved.[16] The Company also seeks approval of a new and novel Municipal Levelization Charge ("MLC") that will be recovered from ratepayers residing in certain municipalities and designed to reflect the impact of municipal costs incurred by the Company in performing its public service obligations.[17] The Company states that the MLC will further increase bills issued to residents of the City of Pittsburgh and Perryopolis and decrease bills issued to residences of Roscoe Borough and New Sewickley.[18]

Q. PLEASE SUMMARIZE THE TESTIMONY OF OCA'S OTHER EXPERTS IN THIS PROCEEDING.

A. OCA's witness touch on most all aspects of the Company's rate case.

- Mr. Greg Meyer, OCA Statement 2, supports the OCA's traditional revenue requirements recommendations. Mr. Meyer also discusses the reasons why PAWC cannot meet its burden of proving the reasonableness of its FPFTY projections to support its request for an annual revenue increase of $124.1 million. Mr. Meyer recommends that Columbia's annual revenue requirement should be reduced by $15.0 million due in part to his recommended adjustments to rate base and expenses and due, in major part, to Mr. Meyer's incorporation of the analysis and recommendations of OCA rate of return expert witness Christopher Walters and OCA depreciation expert witness Brian C. Andrews.
- Mr. Christopher Walters, OCA Statement 3, addresses the appropriate capital structure for ratemaking, the return on equity, and the impact of the Company's claims for alternative ratemaking as well as its request for an additional 25 basis points for management performance. Mr. Walters recommends a market-based

[16] *See,* Direct Testimony of Paul Moul, Company Statement No. 8 at 1:18-2:8.

[17] *See,* Direct Testimony of Mark Kempic, Company Statement No. 1 at 9:11-13.

[18] *See,* Direct Testimony of Nicole Palony, Company Statement No. 9 at 18:5-14.

return on equity of 9.45%, which is the midpoint of his reasonable range of 9.10% to 9.80% based on the analytical methods he used. He also proposes a common equity ratio of 50.0%, which strikes a reasonable balance with industry norms and the book value equity ratios of the proxy group companies used to assess the Company's cost of equity. Mr. Walter's adjustments reduce the revenue requirement impact by $72.4 million per year. Exhibit GRM-1, p. 13. However, if the Commission accepts the Company's alternative ratemaking proposal of the RNA on top of maintaining the WNA, Mr. Walters recommends a return on equity of 9.275%, which is the midpoint of the lower half of his recommended range (*i.e.*, 9.10% to 9.45%).

- Mr. Brian C. Andrews, OCA Statement 4, is the OCA's expert witness on depreciation. He testifies that that Columbia has greatly overstated its proposed depreciation rates and recommends adjusting the proposed depreciation rates and test year depreciation expense downward by $43 million. The reduction is the result of using the Average Life Group ("ALG") (also known as the Broad Group) procedure rather than the Equal Life Group ("ELG") procedure, which the Company has proposed to use.

- Mr. Jerome Mierzwa, OCA Statement 5, is the OCA's expert witness on cost-of-service studies, revenue allocation, rate structure, rate design, and alternative ratemaking. Mr. Mierzwa provides adjustments to the Company's cost of service, recommendations regarding proposed rate designs, including the MLC, and recommendations regarding PAWC's alternative ratemaking claims, including the WNA and RNA.

- Mr. Roger C. Colton, OCA Statement 6, addresses the impact of the Company's existing and proposed rates on low-income customers. He recommends changes in the Company's procedures and processes. Mr. Colton also demonstrates that the customer charge, WNA, and RNA proposals will disproportionately harm low-income customers. He also addresses the company's performance in key areas that impact customers.

- Mr. Nicholas DeMarco, OCA Statement 7, provides an analysis and recommendations regarding customer-service issues.

Q. PLEASE EXPLAIN HOW YOUR TESTIMONY RELATES TO THE TESTIMONY OF THE WITNESSES DESCRIBED ABOVE.

A. My testimony should be considered complementary to the testimony of the OCA's other expert witnesses who testify about the overall affordability of Columbia's existing and proposed rates, its customer charge proposal, and its alternative ratemaking proposes of the modified WNA and the new RNA, including the testimonies of Roger C.

Colton (affordability and low-income customers), Jerome D. Mierzwa (rate design and alternative ratemaking), and Christopher C. Walters (rate of return).

IV. REGULATORY LAG

A. Company Proposal

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

A. The Company generally expresses concern regarding the impact of regulatory lag and revenue stability on its ability to recover costs in a timely fashion.[19] The Company submits generally that approval of the Company's requests are necessary for Columbia to provide safe and reliable natural gas service while providing the Company with a reasonable opportunity to recover its costs and earn a fair rate of return and demonstrate to the investment community that the Commission continues to support the need for intensified focus on pipeline safety matters as well as the need for reasonable and predictable earnings.[20]

The Company argues that the goal of the WNA is to improve customer bill and revenue stability, but that such goals are not fully realized unless the 3 percent deadband is removed and hence its proposal to remove the deadband will better achieve revenue stabilization.[21] Regarding the RNA, the Company argues that the proposed RNA is designed to "break the link" between residential distribution revenues received by the Company and gas consumption by residential customers and will promote revenue

[19] *See*, Direct Testimony of Mark Kempic, Company Statement No. 1 at 9, 14; *see also*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 28-29, 35-36, 38-39, 43-44.

[20] *See*, Direct Testimony of Mark Kempic, Company Statement No. 1 at 5: 7-13.

[21] *See*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 28-29, 35.

stabilization because it relies on distribution revenue per customer, not usage per customer.[22] Regarding increasing the residential customer charge from $16.75 to $26.00, the Company argues that the increase is necessary because historical recover of fixed costs through the volumetric rate portion inevitably results in the over or under recovery of those costs because the revenues generated by volumetric use of gas can be greatly sensitive to customer usage fluctuations that vary due to conservation efforts or other changing consumption characteristics.[23]

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ADDRESS THESE PERCEIVED REGULATORY LAG CONCERNS?

A. Yes. The Company has put forward a series of proposed regulatory mechanisms and changes to existing regulatory mechanisms designed to reduce regulatory lag. These regulatory lag proposals include an RNA and a redesign of the WNA. More specifically, the Company proposes (1) to modify the existing WNA by removing the 3% deadband to fully realize revenue stability for the Company; (2) to implement a reconcilable RNA that is designed to mitigate the over and under recovery of the residential cost of service based on a Benchmark Distribution Revenue per Bill (BDRB) to achieve revenue stability for the Company; and (3) that the proposed WNA and RNA will work together because the WNA applies to each individual customer's consumption and usage patterns based on the impact of weather (requiring in the Company's opinion no reconciliation adjustment) while the RNA would recover distribution revenues that

[22] *Id*. at 36.

[23] *Id*. at 23-24.

deviate from test year benchmark distribution revenues, exclusive of distribution revenues adjusted through the WNA.[24] Additionally, the Company proposes a very large monthly residential customer charge of $26.00 to shift cost recovery through the fixed portion of rate design.[25]

B. Overview of Regulatory Lag

Q. PLEASE DEFINE REGULATORY LAG.

A. Regulatory lag can be defined in a number of different ways. One definition holds that regulatory lag is the time period between when a utility's rates go into effect, after the course of an evidentiary hearing process and its next rate case.[26] Another definition holds that regulatory lag can be represented as the period between when a utility investment is undertaken and the time it enters into rates.[27] Yet another definition holds that regulatory lag is the time period in which a utility's achieved rate of return differs from that allowed by regulators.[28] At the heart of all these definitions is one theme: the frequency and timing of rate cases can impact, positively or negatively, utility earnings.

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[24] *See*, Direct Testimony of Mark Kempic, Company Statement No. 1 at 9, 14; *see also*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 28-29, 35-36, 38-39, 43-44.

[25] *See*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 23-24.

[26] 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.

[27] 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.

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

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

A. Typically, utilities control the duration between rate cases. In most states, utilities have the statutory ability to request rate increases if they believe that their rates are not affording them the opportunity to earn a fair return on and of their investments and prudently incurred costs. While state utility commissions and other stakeholders can, in theory, request a utility be "brought in" for a rate case, my experience is, and research indicates, that this event rarely happens. For instance, research on the topic of regulatory lag conducted in the early 1980s by Ronald Braeutigam and James Quirk, surveyed state utility rate cases during the period 1948 to 1978 and found that over 350 of the 363 surveyed rate cases (96 percent) were brought by a regulated utility, with the smaller number attributable to regulators or consumer groups. While this is an older, dated study, the results are likely to ring true even over the past two decades.

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

A. Yes. When the timing of a rate case is left in the hands of the utility, it has the ability to effectively shift the risk of regulation and regulatory lag away from itself and onto ratepayers. The option to request higher rates by utilities, in effect, creates a price floor that buttresses a utility's value.[29] This price floor allows shareholders to retain benefits created by regulatory lag (*i.e.*, earning an actual rate of return that is higher than the authorized rate of return or over-earning), as well as the option to defend against

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

challenges to those benefits through the timing of a rate case. Paul Joskow, writing as early as 1973, concluded in a frequently referenced regulatory article, that utility commissions tend to defend against rate increases, but are less aggressive in pursuing rate decreases when rates are stable or decreasing in real terms.[30] This outcome has often been thought to have occurred in the post-war period until about the late 1960s, and arguably throughout the 1990s.

C. Role of Regulatory Lag and Efficiencies

Q. IS REGULATORY LAG UNFAIR OR CONFISCATORY TO UTILITIES?

A. No. The premise that regulatory lag is somehow unfair is simply antithetical to most of the research in utility regulation over the past 50 years. Regulatory lag has long been recognized as a key component of the overall regulatory compact given the discipline it can impose on utility operational and investment decisions. Regulation acts as a substitute for the disciplines of competition.[31] Regulatory lag prevents utility regulation from devolving into a "cost-plus" approach that simply passes through costs on a dollar-for-dollar basis to ratepayers and can lead to cost and investment inefficiencies. The cost-plus regulatory approach also shifts a considerable amount of performance-related risk away from utilities and onto ratepayers and leads to inefficient outcomes, which was recognized as early as the 1960s and has come to be known as the "Averch-Johnson" or "A-J" effect.

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

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

Q. HOW ARE THE CONCLUSIONS REGARDING REGULATORY LAG RELATED TO WHAT IS COMMONLY REFERRED TO AS THE "A-J EFFECT?"

A. In the early 1960s, a seminal article was published that dramatically influenced the theory and practice of utility regulation and economic thinking regarding the optimal regulation of natural monopolies. This article, authored by Professors Harvey Averch and Leland Johnson, and published in the *American Economic Review* in 1962, posited that rate of return regulation creates an incentive for regulated utilities to overcapitalize, resulting in an inefficient utilization of resources and higher-than-optimal rates.[32] This finding; however, was premised upon a model with a number of assumptions, one of which presumed there was no regulatory lag and that rates were set on a period-to-period basis: in other words, rates were set on a "cost-plus" regulatory approach.

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.[33] 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 process[34] and (2) the positive efficiency incentives created by regulatory

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[32] H. Averch and L. Johnson. (1962) "Behavior of the Firm under Regulatory Constraint," *American Economic Review*. 52:1052-1069.

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

[34] 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*,

lag.[35] 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.[36]

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.[37] 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.[38] One of his additional findings at the time, however, was that these incentives might also discourage regulated firms from investing in research and development.

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.

[35] 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.

[36] 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.

[37] 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.

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

Q. HOW DOES THIS RESEARCH RELATE TO THE COMPANY'S PROPOSAL?

A. Essentially, this research demonstrates that the Company's premise – that regulatory lag is inherently bad – is fundamentally flawed. In fact, regulatory lag can be a *positive* attribute of traditional cost of service regulation because it induces efficiencies.

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

A. No. Interestingly, this notion is a myth that arises in the practice of public utility regulation but is debunked by several academic articles. Elizabeth Bailey, who also served as an economic researcher at Bell Laboratories, addressed this issue originally raised by Klevorick during this active period of regulatory scholarship in the 1960s and 1970s. Bailey found that regulatory lag helped to facilitate, not reduce, the incentives for cost-reducing innovations.[39] Bailey's work built upon earlier work that she did with Roger Coleman in 1971 that further supported the conclusions of Baumol and Klevorick, that regulatory lag induces profit-maximizing firms to adopt minimum-cost production alternatives.[40]

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

A. Yes, and these are important to recognize since the perceived concern of regulatory lag in the presence of increased capital investments required to meet increased safety, reliability, and security demands is a key element backing the

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

[40]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.

Company's proposal.[41] However, it should be recognized that the key benefits of regulatory lag are the weakening of the natural incentive for a utility to over-capitalize and the strengthening of the natural incentive for a utility to minimize production costs in order to increase shareholder profits. Several of the Company's proposed cost recovery riders, and other regulatory lag mitigation proposals, that will be discussed in the following section of my testimony and other OCA witnesses, diverge considerably from the principles of traditional regulation, and could lead to over-capitalization biases identified by Averch and Johnson over 60 years ago and not induce cost-reducing innovations as identified by Bailey.

Q. PLEASE EXPLAIN THE TERM "REGULATORY COMPACT."

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

Q. DOES THE REGULATORY COMPACT IMPLY ANYTHING ABOUT SAFETY AND RELIABILITY?

A. Certainly, safety and reliability are cornerstones of this long-recognized regulatory relationship.

[41] *See,* Direct Testimony of Mark Kempic, Company Statement No. 1 at 5: 7-13; *see also* Direct Testimony of G. Skinner, Company Statement No. 16 at 3-7.

Q. DO THE COMPANY'S PERCEIVED INFLATION CHALLENGES REPRESENT A SOLID RATIONALE FOR ITS PROPOSED WEAKENING OF REGULATORY LAG?

A. No. The Company cites the impact of inflation as a "driver" of the need for Columbia to seek this rate increase.[42] The Company also notes that its future expenses are based on inflation-adjusted numbers.[43] Further, the Company, in discussion its proposed cost of capital, claims that its cost of equity analysis reflects the impact of "high levels of inflation," not seen over the past forty years.[44] However, today's energy markets, while witnessing their fair share of challenges, are a far cry from those experienced during the energy crises of the early to mid-1970s and the early 1980s. Consider that during those time periods, utilities: were grappling with inflation that was measured in double, not single, digits; saw decreases in the growth rates of total use and use per customer that were double the rates seen today; and were grappling with a capital construction program for nuclear power and coal that makes many of today's infrastructure investments pale in comparison (at least in real, inflation-adjusted dollars).

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

A. Yes, there have been a few studies that have examined regulatory lag during the inflationary period of the 1970s. The conclusions are mixed. Seth Norton, for instance,

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[42] *See*, Direct Testimony of Mark Kempic, Company Statement No. 1 at 18.

[43] *See*, Direct Testimony of Nicholas Bly, Company Statement No. 15 at 5; *see also*, Direct Testimony of Birttany Komenda, Company Statement No. 4, at 37.

[44] *See*, Direct Testimony of Paul Moul, Company Statement No. 8 at 4.

conducted empirical research examining 45 utilities over a period from 1945 to 1974. The period spans both the high growth, high productivity, low-cost periods for the industry prior to 1970 and the inflationary low growth periods throughout the 1970s. According to Norton, there were no significant financial impediments or opportunities created by regulatory lag in any of these periods.[45]

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

A. Yes. The Company's proposals to reduce regulatory lag are asymmetrical and unfairly tilt the risk scale in its favor. If adopted, these proposals would shift regulatory, investment, and performance risk away from the Company and entirely onto ratepayers.

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

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

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

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

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. DOES THE COMPANY ALREADY HAVE MECHANISMS IN PLACE THAT REDUCE REGULATORY LAG?

A. Yes. The Company uses a fully projected future test year ("FPFTY"), as permitted by statute, which is defined as the 12-month period beginning with the first month that the new rates will be placed in effect after the application of the full suspension period under Section 1308(d). 66 Pa. C.S. § 315(e). The rates that go into effect are based on the utility plant that is projected to be reasonably certain in service at the end of the FPFTY, along with reasonably certain projected expenses at the end of the FPFTY. All the revenue requirement components are determined using the end date of the FPFTY. In its Implementation Order, the Commission recognized the importance of this change, stating, "[u]nder this approach, the risks associated with regulatory lag will be substantially reduced because the new rates will be consistent with the test year used to establish

those rates for at least the first year.at using the FPFTY."[46] Thus, the ability to use the FPFTY is a mechanism in currently in place that reduces regulatory lag.

Q. HOW SHOULD THE COMMISSION EVALUATE THE COMPANY'S REGULATORY LAG PROPOSALS IN THIS PROCEEDING?

A. These proposals, collectively, change the fundamental nature and "trade-off" between ratepayers and Columbia. The proposals fundamentally shift incentives for efficiency which could lead to even higher prices than what Columbia's ratepayers are already facing. Further, these proposals, collectively, shift several risks away from the Company and onto ratepayers. These risks include, but are likely not limited to performance risk, regulatory risks, and financial risks. Nowhere has the Company provided any record evidence that shows it really needs these mechanisms, much less providing any evidence that ratepayers will receive any net benefits from these shifts in risk. As a result, they need to be rejected, as I and other OCA witnesses will discuss in further detail in our respective testimonies.

V. REVENUE DECOUPLING AND THE PROPOSED RNA

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RNA.

A. The proposed RNA is a revenue decoupling mechanism, that would allow the Company to recover any revenue difference between its test year revenue per customer and actuals. This mechanism would defer the difference as adjusted for actual customer

[46] *Implementation of Act 11 of 2012,* Docket No. M-2012-2293611, Order at 5 (Aug. 2, 2012) (*Act 11 of 2012 Implementation Order*). *See* Costello, Ken, *Future Test Year: Evidence from State Utility Commissions*, National Regulatory Review Institute, NRRI Report 13-10 (October 2013) at 8, n. 24, https://pubs.naruc.org/pub/FA86C105-05F5-9766-BC78-29829AC50361, last viewed January 3, 2024.

growth on a monthly basis until they are assessed and recovered from ratepayers.[47] Unlike the WNA, which limits lost revenue recovery to weather-related changes in sales, the Company's proposed decoupling mechanism will allow the Company to periodically adjust its distribution service rates to recover any lost revenues that may arise regardless of the reason including any unaccounted for weather losses, losses due to end use energy efficiency, changes in the economy or energy commodity prices and other end-use ratepayer efficiency outcomes drive by their own actions or changing federal appliance standards. The mechanism would apply to only customers that are not part of the Company's Customer Assistance Program ("CAP").[48] The RNA, if approved, will apply to non-CAP customers in Rate RSS (residential sales service) and Rate RDS (residential distribution service, or choice customers).[49]

Q. PLEASE EXPLAIN HOW THE RNA WOULD BE CALCULATED.

A. The proposed RNA is calculated on an RPC basis, which is a common form of revenue decoupling for the natural gas utilities. Under an RPC based approach, actual RPC for the applicable rate schedules is periodically compared against baseline RPC amounts determined by a base rate case.[50] This form of revenue decoupling will insulate a utility and its shareholders from variation in customer natural gas usage while allowing for utility revenues to increase for increases in customer counts. Revenue decoupling proposals, like the proposed RNA, are often adopted to "break" the purported link

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[47] *See,* Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 40: 12-17.

[48] *Id.* at 36: 4-6.

[49] *Id.* at 40: 15-17.

[50] *Id.* at 40: 12-14.

between earnings and volumes making the utility financially indifferent in making additional sales, supposedly reducing the utility's incentive to discourage end-user energy efficiency.

Q. DOES THE COMPANY'S METHODS DIFFER FROM OTHER COMMON REVENUE DECOUPLING APPROACHES?

A. The Company's proposed method will recover revenue difference from ratepayers every six months, or from two different periods in a year.[51] The first period is referred to as the "peak period" and includes the peak usage months of October through March.[52] The second period is referred to as the off-peak period and includes the months of April through September.[53] Further, revenue surpluses/deficiencies from peak period are credited/recovered during the following peak period where as revenue surpluses/deficiencies during the off-peak period are recovered during that subsequent period.[54]

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

A. Yes. The advent of revenue decoupling mechanisms began in earnest in the late 1980s and was boosted by inclusion as a regulatory review requirement in the Energy Policy Act of 1992.[55] During this period, revenue decoupling initiatives were driven

[51] *Id.* at 40: 20-22.

[52] *Id.* at 40: 20-22.

[53] *Id.* at 40: 20-22; 41: 1-6.

[54] *Id.* at 41: 9-17.

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

primarily by the electric utility industry, as well as many of the same energy efficiency and environmental advocates promoting the mechanism today. Most revenue decoupling mechanisms adopted during this period were eliminated during the electric restructuring process that began in the early 1990s and accelerated through the better part of the decade.

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

A. Yes. Trackers of all types eliminate the positive incentives typically afforded through regulatory lag. It is a basic economic fact that rational utility management has little incentive to enhance efficiencies (operational and capital) if it has no effect on the utility's profits.[56] This is precisely the situation that can arise when a utility is guaranteed revenues and can pass higher costs through to ratepayers with minimal consequences on sales and profits. Such an approach is completely at odds with traditional regulatory principles and ratemaking practices.

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

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

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

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.[57]

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

A. Yes. Utilities also often claim that revenue decoupling eliminates an inherent utility "throughput incentive" to increase sales. Here, the Company argues that the RNA will eliminate disincentives for the promotion of consumer efficiency programs because reduced throughput will not lead to revenue and earnings erosion due to under-recovery because the link between the level of throughput or sales and base revenue recoveries is broken with the implementation of the RNA.[58]

[57] *Id.*

[58] *See*, Direct Testimony of K.L. Johnson, Company Statement No. 6 at 37-38.

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 to increase 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.[59]

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

A. Yes. Direct Exhibit DED-1 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 utilities[60] 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 utilities[61] have similar mechanisms (28 percent of total gas utilities). This data reveals that: (a) despite a history of revenue decoupling that exceeds 30 years, the number of electric and gas utilities with revenue decoupling riders is still in the minority; and (b) the mere fact that a revenue decoupling mechanism has been approved

[59] *See,* "Utility Rate Decoupling," Alliance to Save Energy, October 24, 2013.

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

[61] *Id*.

in a particular jurisdiction does not mean that it is appropriate for all electric and gas utilities in that jurisdiction.

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

A. Yes. As shown by Exhibit DED-2, a substantial portion of historic decoupling mechanisms were approved in the late 2000s and very early 2010s. This period was characterized by highly volatile and often elevated wholesale natural gas prices in which the future outlook for natural gas supply was uncertain. In fact, at one time, the U.S. anticipated being a net importer of natural gas supplies and several large-scale facilities along the Gulf Coast and Atlantic seaboard were announced to support these large imports. Energy policies during this time period were strongly oriented towards encouraging greater levels of fuel switching and energy efficiency. Revenue decoupling was seen as a tool to not only facilitate this transition, but to financially insulate natural gas utilities from the effects of volatile natural gas markets. This circumstance simply no longer exists: almost every year, the U.S. reports record levels of natural gas production, relatively low natural gas prices, and low relatively low natural gas price volatility.

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

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

("CMP") decoupling mechanism during its trial period,[62] and ultimately opted to terminate the decoupling mechanism at a later date, following a period of extremely poor outcomes for ratepayers.[63]

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

A. Yes. The Montana Public Service Commission ("MPSC") authorized the fixed cost recovery mechanism ("FCRM") for NorthWestern Energy on a four-year pilot basis in 2019.[64] In 2020, the COVID-19 pandemic caused massive economic disruptions and disruptions in working conditions as more workers began to work from home. The MPSC twice approved requests to delay implementation of the pilot due to the pandemic; as such, the pilot was never implemented[65] before the MPSC ultimately discontinued it.[66]

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[62] Leslie Hudson and Stephanie Seguino, *Assessing Maine's ERAM experiment*, 3 MAINE POLICY REV. at 82 (1994).

[63] *Id*. at 83.

[64] 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.

[65] 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.

[66] *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.[67]

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.[68]

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

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

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.[69] 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 <u>minimum</u> 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

[69] Costello, Ken (September 2009), "How Should Regulators View Cost Trackers?" National Regulatory Research Institute at 8.

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

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

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

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

A. No. Exhibit DED-3 presents historic return on equity ("ROE") for the Company dating back to 2010. Page 1 of this exhibit calculates the Company's achieved ROE relative to its allowed ROE. While there are instances where the Company has had challenges earning at its allowed ROE, the table shows this is clearly a cost-related issue, not one attributable to revenue attrition. If anything, the challenge for the Company has been, and continues to be, its cost-efficiencies. Thus, the RNA is simply a solution in 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 DED-4 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 DED-4 (page 1) shows that residential UPC has fallen from 86 MCF per customer in 2011 to 80.9 MCF per customer in 2022. This is an average decline of 0.5

percent per year. However, total residential sales volumes have increased from 24.8 million MCF in 2011 to 29.1 million MCF in 2022. Thus, as I noted earlier, the problem with the Company earning its allowed ROE has little to do with revenues, and more to do with costs. The RNA is simply a solution in search of a problem.

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

A. Exhibit DED-4 (page 2) shows that declines in gas usage do not necessarily translate into declining revenues. Over the past several years, the Company has seen growth in its residential RPC and growth from new customers added to its system. These combined elements led to strong non-fuel revenue growth per customer ranging from $220 per customer in 2011 to $815 per customer in 2022. Exhibit DED-4 (page 4) shows similar trends in commercial RPC.

B. Proposed RNA provides no customer benefits.

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

A. The Company states that the proposed RNA eliminates an inherent utility incentive to increase sales by "breaking the link" between earnings and volumetric sales.[70] The Company furthermore argues that a benefit of the proposed RNA is that the proposed mechanism is reciprocal and balanced in nature, protecting customer bills when revenue

[70] *See,* Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 36: 14-15.

recoveries are higher than normal, and assessing surcharges only when RPC is lower than normal.[71]

Q. IS THE COMPANY'S ARGUMENT CONCERNING BREAKING THE LINK BETWEEN EARNINGS AND VOLUMETRIC SALES UNIQUE?

A. No. Many energy efficiency advocates, as well as certain (but not all) utilities, often argue that current regulatory pricing practices discourage utility-sponsored energy efficiency programs.[72] These advocates argue that energy efficiency reduces sales thereby reducing a utility's ability to recover its fixed costs. Revenue decoupling removes the relationship between sales and revenues, and in doing so, theoretically removes the claimed disincentive utilities have for promoting end-user energy efficiency.[73]

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

A. No. The Company's proposed RNA is not tied to any expanded efforts in demand-side management or energy efficiency. The Company has also noted that it has not conducted any recent studies or analyses on how the proposed RNA is different and/or similar to the mechanisms approved in other jurisdictions.[74]

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[71] *Id.* at 37: 1-3.

[72] NRDC's Fourth Annual Energy Report: *Accelerating Into a Clean Energy Future,* (2016).

[73] *Id.*

[74] OCA DR 12-006.

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

A. No. The Company has not conducted any study or analysis of its past financial performance as if the proposed RNA had been implemented.[75]

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

A. The Company issued its first annual report following the close of the program's first year in March of this year.[76] Within its report, the Company listed savings of 7,461 Dth for the Online Energy Audit and Kit ("OAK") Program and 6,861 Dth for the Residential Prescriptive ("RP") Program.[77] The total annual savings of 14,322 Dth fell short of 2023 projections reaching only 83 percent of the 17,184 Dth projected.[78] Using the Total Resource Cost ("TRC") Test, the Company calculated a benefits-to-cost ratio of 3.34 with $1.8 million in present value of net benefits to customers.[79] As of the end of 2023, the Company's progress is 17 percent towards its three year goal of 1.3 million Dth saved.

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

A. The Company plans to spend $4 million over the course of three years on the administration and delivery of its two existing programs. As of 2024, the Company has

[75] OCA DR 12-007.

[76] Columbia EE Report, 2023.

[77] *Id.*

[78] *Id.*

[79] *Id.*

spent $619 thousand, or 15 percent, of its three-year budgeted amount. The total portfolio spend was 53 percent of the budgeted 2023 amount.

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

A. No.

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

A. No. A variety of factors can influence sales between rate cases and lead to situations where retail sales and revenues will differ from those observed in a utility's test year. Consider that test year retail sales and revenues in a rate case are usually based upon a "typical" year, and as such, are based upon typical factors such as the unexplained weather trends, the economy, and prices, among other things. In any given year, the actual performance of the economy may differ from the test year. The differences in sales created by the economy, commodity prices, and other factors usually account for greater changes in revenue than those resulting from utility-sponsored energy efficiency programs.

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

A. Yes. The RNA will allow monthly differences between actual and allowed RPC to be trued up for each of the applicable rate classes on an annual basis. The proposed

RNA, if approved, will not be adjusted to account for revenue variations that are created by such factors as changes in energy prices, the economy, or other factors.

Q. YOU STATED ABOVE THAT THE COMPANY DOES NOT PROPOSE TO EXPAND ITS ENERGY EFFICIENCY OFFERINGS. WHY IS IT IMPORTANT?

A. This omission is important for three reasons. First, the entire premise for the RNA, to the extent it is even allowed, should be to remove a disincentive to aggressively pursue energy efficiency activities. While the Company currently has various EE&C programs, the Company also appears to have adequate incentives in promoting these programs since they were initiated without revenue decoupling. Further, and more importantly, the Company has not proposed any new incremental offerings to accompany the RNA proposal. Approving the RNA alone, without any new or incremental energy efficiency program commitments, effectively "decouples" the problem from the solution. Second, this omission shifts the entire regulatory and performance-related risk associated with the Company's future energy efficiency activities entirely onto ratepayers since there is nothing to assure that the RNA, in fact, will lead to enhanced energy efficiency efforts. Third, the proposal itself suggests the Company's EE&C activity is not adequate, yet the Company does not quantify or provide any other record evidence to show how it could be doing more than it is already doing with regards to its EE&C service offerings.[80]

[80] OCA DR 12-020.

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

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

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

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

> The regulatory construct for decoupling in Washington has centered on the utility's performance relative to conservation. Our approval of decoupling in our two pilot programs was founded on the premise that lost margins affected the utility's appetite for offering additional conservation programs. Thus, both pilots required the companies to account for lost margin due to conservation, and to discriminate between the various causes of lost margin. In that more limited context, we conclude that the recovery of lost margin attributable to Avista's programmatic and non-programmatic conservation endeavors is sufficient to encourage Avista's [Demand Side Management] DSM efforts. We seek to avoid guaranteed

> recovery of lost margin that would occur should lost margin from other causes be included in the mechanism. [81]

The WUTC reiterated this principle again in its 2010 investigation into utility conservation incentives stating that "revenue recovery by the company under the mechanism will be conditioned upon a utility's level of achievement with respect to its conservation target."[82]

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

A. No. Utilities and other revenue decoupling advocates often note that rate changes are "symmetrical" under revenue decoupling and that while rates can increase, there is often an equal opportunity for rate decrease that would not otherwise arise but for the presence of a revenue decoupling mechanism. Such a position is simply false.

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

A. Yes. Exhibit DED-5 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

[81] 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 Filling; 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.

[82] 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.

Graceful Systems and hereafter will be referred to as the "Lesh Report."[83] 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.

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

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

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.[84] 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.[85] The study also found that, contrary to popular belief and advocacy, those states with revenue decoupling did not have meaningful changes in output due to efficiency.[86] Indicating that price increases result in pure increases of revenue to the adopting utility and its shareholders.[87] 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.[88]

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[84] 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.

[85] *Id.*

[86] *Id.*

[87] *Id.*

[88] *Id.*

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

A. Yes. Exhibit DED-6 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 any peer utility in the grouping of comparable mid-Atlantic natural gas utilities. Columbia ranks dead last as the most expensive utility for 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.

C. RNA shifts risks from Company shareholders to ratepayers

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

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

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

A. Yes. In denying a proposed revenue normalization adjustment by Washington Gas Light, the D.C. Public Service Commission ("DC PSC") noted its historic policy of

reflecting decreases in utility risk through corresponding reductions in allowed ROE.[89] Indeed, in earlier proceedings before it, the DC PSC noted that, because decoupling mechanisms provide benefits such as "reduced risk" for the utility, "it is imperative that on the other side of the ledger that the customers receive an offsetting benefit."[90] Such offsetting benefits could include "imposing [a] reduction in the utility's ROE, imposition of certain reporting requirements, establishment of specified energy efficiency performance requirements and benchmarking requirements, as well as the creation of reliability standards with attendant penalties for failure to meet said standards."[91] Accordingly, the DC PSC approved a 50 basis point reduction in ROE when approving a bill stabilization adjustment "as part of the approval of the BSA to balance the ledger by providing a benefit to consumers in exchange for the benefit to the Company and shareholders of reaping lowered business risk."[92]

Additionally, in the application of Aquarion Water Company of Connecticut ("Aquarion"), the Public Utilities Regulatory Authority ("Authority") of Connecticut addressed Aquarion's revenue adjustment mechanism, which reconciles in rates the difference between actual revenues and allowed revenues.[93] The Authority found that

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

[90] *Formal Case No. 1053*, Order No. 15556 ¶ 26, rel. Sept. 28, 2009.

[91] *Id.*

[92] *Id.* ¶ 29.

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

there "must be a reduction in risk from the revenue adjustment mechanism"[94] and deducted 10 basis points from the company's allowed ROE accordingly.[95]

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

A. Yes, as referenced earlier, one of the more widely recognized failures of revenue decoupling occurred in Maine during the early 1990's. The program, known as "ERAM" ("Electric Revenue Adjustment Mechanism"), was put into place for a three-year trial period to encourage CMP to promote energy efficiency.[96] The adoption of the ERAM coincided with a recession that resulted in lower sales levels and substantial revenue deferrals. CMP was entitled to recover these deferrals under the provisions of the ERAM mechanism, which by the end of 1992 had already reached a staggering $52 million, an amount equal to more than six percent of CMP's annual revenues, causing the Maine Public Utilities Commission to take the dramatic step of opening hearings to consider the suspension of the ERAM during its trial period.[97] The ERAM was ultimately terminated on November 30, 1993.[98] In later assessing the reasons for the ERAM's failure, observers noted:

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[94] *Id*.

[95] *Id*. at 115.

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

[97] 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.

[98] *Id*. at 83.

- The large accruals resulted primarily from the economic recession and were exacerbated by the inaccurate revenue forecast of the preceding rate case, the withdrawal of the 1991 rate case filing, warm weather, and the test year choice.[99]
- By being shielded from the recession, CMP may not have had the same incentives to operate efficiently in the way that other companies were at that time.[100]
- The ERAM failed in providing CMP with a sufficient incentive to pursue demand side management and other conservation measures.[101]

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

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

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[99] *Id*. at 84.

[100] *Id*. at 85.

[101] *Id*.

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.[102]

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

> Normalized EBITDA within the Utilities segment was $80 million for the quarter, slightly below Q2 2019. As I previously mentioned, growth at our regulated utilities was driven by our 2019 settled rate cases, ARP spending and strong operational execution, which was partially overshadowed by COVID-19 related impacts, including lower margins in our retail business.
>
> As a reminder, approximately 70 percent of our regulated utilities earnings are protected through decoupling and fixed billing charges. In all the jurisdictions where we operate have (*sic*) approved the creation of regulatory assets to allow for the recovery of incremental costs related to COVID-19. We are tracking these costs and our lost revenue due to the pandemic and we will continue to work with our regulators on

[102] 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).

the definition and treatment of recoverable impacts within those regulatory assets.[103]

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

A. Yes. NiSource, Columbia's parent, has provided periodic updates to its shareholders over the past several years regarding its state-level efforts at minimizing financial risk through the use of periodic cost and revenue recovery mechanisms, or trackers. Examples of these are provided in Exhibit DED-7 and come from investor-relations presentations provided to investors in 2024, 2022, 2020, and 2018. Each survey presentation provides slides discussing NiSource's attempts at securing risk-reducing regulatory mechanisms across all their electric and natural gas utilities in Ohio, Indiana, Virginia, Kentucky, Maryland, and Pennsylvania. This survey is not limited to revenue decoupling but includes a variety of other tracker mechanisms, particularly investment cost/pipeline replacement trackers. Notably, Columbia Gas of PA does not utilize the Distribution System Improvement Charge (DSIC), even though it has been authorized under the Public Utility Code since 2012 along with approval of a Long-Term Infrastructure Improvement Plan or LTIIP.

[103] AltaGas Ltd., *Second Quarter 2020 Financial Results Conference Call*, at 11 (July 30, 2020) (emphasis added), https://www.altagas.ca/sites/default/files/2020-08/ALA%20Transcript%20July%2030%202020%20FINAL.pdf.

D. RNA does not include any ratepayer protections.

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

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

Q. DOES THE COMPANY'S PROPOSED RNA INCLUDE ANY RATEPAYER PROTECTIONS?

A. No. The Company makes a simple request for an RNA, and the clear benefits its offers its shareholders, but offers no ratepayer protections nor other benefits in return for this generous risk-shifting regulatory mechanism. The use of ratepayer protections is common amount utilities and state regulators. These mechanisms are designed to put boundaries and conditions on revenue decoupling to assure that ratepayers do not suffer any unnecessary negative impacts from the introduction of revenue decoupling.

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

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

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

A. These protections limit the revenue recovery that any utility can receive from its decoupling mechanism. Generally, these limitations consist of hard percentage revenue or rate caps, such that annual recoveries cannot exceed a fixed percent of total revenues or base revenues. In some instances, these dollars can be deferred and recovered in other, later time periods; in other instances, the utility simply forgoes any recovery. The Company has provided no recommended revenue nor rate cap as part of its RNA proposal which is a serious limitation that exposes ratepayers to potentially large monthly/annual revenue recovery balances.

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

A. Earnings tests assure that a utility with revenue decoupling do not receive excess earnings. These tests, often based off annual or quarterly earnings compliance filings, examine whether a utility is above or below its authorized ROE. Utilities that are earning at (within deadband), or above their authorized ROE, are not allowed to recover revenues from its decoupling mechanism when an earnings test/limitation is in place. An earnings test assures that revenue decoupling is truly used to assist utilities to earn their authorized ROE, and no more, thereby protecting ratepayers from "over-supporting" a utility's earnings. Columbia has provided nor offered no comparable ratepayer protection provision as part of its RNA, despite the fact that these are relatively common for utilities with revenue decoupling across the country.

Q. HOW DO NEW INCREMENTAL ENERGY EFFICIENCY TARGETS OR GOALS SERVE AS A RATEPAYER PROTECTION?

A. I noted earlier that the Company's RNA does not include any commitment to new incremental energy efficiency savings. Such commitments are common components of any revenue decoupling approval. A very large number of utilities (both electric and gas) have made energy efficiency commitments as part of their revenue decoupling approvals. The Company, however, is making no such commitment despite the fact that the intent of this proposal is to remove its throughout incentive which presumably discourages active utility engagement in end use energy efficiency.

Q. HOW ARE PILOTS USED TO "TEST-DRIVE" A DECOUPLING MECHANISM?

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

Q. DISCUSS HOW COMPLIANCE REVIEWS ARE INCLUDED.

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

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

A. No. Often utilities argue that revenue decoupling helps protect against regulatory lag, much like the Company has argued in this proceeding.[104] Given that utilities are made "whole" from revenue decoupling, the theory is they will be less likely to need to file

[104] *See,* Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 36: 21-22; 37: 1-3.

for a rate case to account for purportedly sales-driven deterioration in earnings. Few rate cases, in turn, purport to lower overall regulatory costs. However, the Company has not proposed any stay-out provisions, reflecting the need for fewer rate cases, as part of its RNA. Again, showing how the benefits of the RNA are one-sided, accrue to shareholders exclusively with no corresponding benefits for ratepayers.

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

A. No. Exhibit DED-9 shows that a number of states, as well as the Federal Energy Regulatory Commission ("FERC"), have made adjustments to the allowed rate of return in recognition of the fact that revenue neutrality programs change the risk profiles of regulated utilities. Some of these adjustments have actually been proposed by utilities, and in a number of cases, these adjustments have been adopted. Adjustments range from 10 to 50 basis points on a utility's allowed ROE. The proposed RNA would inherently reduce the Company's financial risk, shifting these risks onto ratepayers. Other jurisdictions that have recognized this risk-shifting have reduced allowed ROEs by as much as 50 basis points, yet no such offer has been made in the current proceeding.

VI. WEATHER NORMALIZATION PROPOSAL

Q PLEASE DISCUSS THE COMPANY'S WNA.

A. The Company originally proposed its WNA in Docket No. R-2012-2321748.[105] The Company's WNA is a form of weather-only-related revenue decoupling that is assessed upon residential ratepayers for their usage during the October to May period of each

[105] Docket No. R-2012-2321748, Direct Testimony of Strauss 25:6.

year.[106] The months of June through September were excluded from the WNA because, according to the Company, historical data showed that no significant weather variation occurs during those months.[107] Any weather related differences in usage are recovered from ratepayers (or credited) as a volumetric surcharge (or credit) on a monthly basis. This difference is applied to only the non-gas related (or base) charges.[108] The Company's original proposal did not include any deadband or other ratepayer protection mechanism such as a rate cap or earnings test. The Company claimed that "simplicity is a key rate design consideration for Columbia."[109] They believed that the WNA would be easier to understand and explain to customers without the use of the dead band.[110]

Q. IS THE WNA A PILOT?

A. Yes. The Company's WNA has been approved on a pilot basis since 2012 as a result of rate case settlements without any defined methods for evaluating the success of the WNA over time.

In the 2012 base rate proceeding, the WNA was approved on a pilot basis, with the following additional elements agreed to in a Joint Settlement:

> a. The Company shall implement a 5% deadband as part of its WNA mechanism. There will be no adjustment to account for weather except to account for changes greater than 105% of normal weather or changes less than 95% of normal weather. Any adjustment would adjust only to the deadband threshold.

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[106] *Id.* 26:1-3.

[107] *Id.* 26:17-19.

[108] *Id.* 26:9-14.

[109] *Id.* 32:14.

[110] *Id.* 32:12-13.

> b. The WNA shall operate as a pilot for a minimum period of three years commencing October 2013, and shall continue until a final order in the first rate case that is filed after May 31, 2016. The Joint Petitioners will review the WNA and determine the ongoing status thereof in Columbia's base rate case that is filed after May 31, 2016. For informational purposes, the Company shall maintain and provide to the OCA, I&E and OSBA by October 1 of each year commencing October 1, 2014 all reports and records supporting the operation of its WNA for the preceding year, including the Company's monthly computation of the WNA and all data underlying the Company's monthly WNA computation.[111]

In the 2018 base rate proceeding, at R-2018-2647577, the Partial Settlement provided that the proposed WNA "will continue as a pilot and will include a 3% deadband" to take effect on January 31, 2019, and that the "proposal to exclude the month of October from the operation of the revised WNA is . . . accepted." A 3 percent deadband in that Partial Settlement meant that a billing adjustment will only occur if the variation of actual heating degree days is lower than 97 percent or higher than 103 percent of the normal heating degree days for an individual billing cycle.[112]

In the 2021 proceeding, the WNA was approved on a pilot basis, based on the following agreement of the settling parties:

> Columbia's proposal to continue its Pilot Weather Normalization Adjustment ("WNA") mechanism until a final order is entered in the Company's first rate case filed after May 31, 2026 is approved. For informational purposes, the Company shall continue to maintain and provide to the OCA, I&E and OSBA by October 1 of each year all reports and records supporting the operation of its WNA for the preceding year, including the Company's monthly computation of

[111] *See Pa. Pub. Util. Comm'n v. Columbia Gas of Pa., Inc*., Docket No. R-2012-2321748 (Recommended Decision Issued April 24, 2013) and (Order entered May 23, 2013).

[112] *See Pa. Pub. Util. Comm'n v. Columbia Gas of Pa., Inc*., Docket No. R-2018-2647577 (Order entered December 6, 2018).

> the WNA and all data underlying the Company's monthly WNA computation.113
>
> Hence, the parties agreed to continue the WNA with the 3 percent deadband until a final order is entered in the Company's first rate case filed after May 31, 2026 is approved.

Q. WAS THAT THE EXTENT OF THE AGREEMENT IN THE 2021 SETTLEMENT?

A. No. The Parties also agreed in paragraph 57 of the Joint Petition for Settlement:

> This Settlement is being presented only in the context of these proceedings in an effort to resolve the proceedings in a manner that is fair and reasonable. The Settlement is the product of compromise between and among the Joint Petitioners. This Settlement is presented without prejudice to any position that any of the Joint Petitioners may have advanced and without prejudice to the position any of the Joint Petitioners may advance in the future on the merits of the issues in future proceedings except to the extent necessary to effectuate the terms and conditions of this Settlement.114

Q. WHAT IS THE EFFECT OF COLUMBIA'S PROPOSAL IN THIS PROCEEDING TO MODIFY THE WNA PILOT AGREED TO AND APPROVED IN THE 2021 CASE BY REMOVING THE 3 PERCENT DEADBAND IN THIS CASE?

A. Counsel informs me that since Columbia is proposing to modify the provisions of the WNA approved in Docket No. R-2021-3024296, whether the WNA should continue in effect requires evaluation in this proceeding. The Company has not provided this evaluation in the current proceeding.

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113 *See Pa. Pub. Util. Comm'n v. Columbia Gas of Pa., Inc.*, Docket R-2021-3024296 (Order entered December 16, 2021) at 15.

114 2021 Joint Petition for Settlement, ¶ 57.

Q. WHAT RATEPAYER BENEFITS DID THE COMPANY CLAIM ARISE FROM THE WNA?

A. The Company in this proceeding stated that the goal of the WNA was to improve customer bill stability, however it did not provide any examples of the pilot improving customer bill stability since its implementation.[115] Further, as I noted earlier, the Company did not offer any ratepayer protections such as a rate/revenue cap, a recovery deadband, nor an earnings test.

Q. HAVE YOU REVIEWED THESE ANNUAL REPORTS?

A. Yes. Exhibit DED-10 includes a summary of the over/under collections from these reports for each season. The summary of these reports shows that WNA has, on a net basis, required ratepayers to reimburse the Company revenues up to as much as $59.1 million over the period of 2013 through 2024.[116]

Q. PLEASE DISCUSS HOW THE COMPANY PROPOSES TO CHANGE THE WNA?

A. The Company is proposing to eliminate the three percent deadband currently in effect for the WNA.[117] The Company claims that the deadband distorts the true effects of weather and doesn't allow the goal of customer bill and revenue stability to be fully realized.[118]

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[115] *See,* Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 35:12-13.

[116] Please note that positive values represent surcharges, and negative values represent credits.

[117] *See,* Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 35:6-7.

[118] *Id.* at 35:12-14.

Q. DID THE COMPANY PROVIDE ANY STUDIES OR ANALYSES TO SUPPORT THESE CLAIMS?

A. No. The Company did not provide any evidence in support of its proposal to remove the deadband.

Q. DID THE COMPANY IDENTIFY HOW THE MERITS OF THE WNA WOULD BE EVALUATED?

A. No. The Company did not identify how it would evaluate the success of the WNA in the future. Furthermore, it has provided no support for how the removal of the deadband would be evaluated in the future. Further, as noted earlier, if offers no quid pro quo from ratepayers, in the form of a lower ROE, nor other protection mechanism (such as a rate cap or earnings test).

Q. WHAT ARE YOUR WNA RECOMMENDATIONS?

A. I recommend the following:

- Consistent with the recommendation of OCA witness Jerome Mierzwa, the OCA's position is that the WNA should be discontinued in its entirety given the significant and pervasive rate harm to consumers. Columbia, through its proposal to lift the three percent deadband has effectively abandoned its pilot program that was approved in the last rate case, and the OCA believes that it is appropriate based on the record of this case to discontinue that pilot early and end the WNA in its entirety. In fact, to date, ratepayers have reimbursed the Company and its shareholders as much as $59.1 million for no documentable and meaningful benefits. The Company also has not shown the offsetting benefits it has received from having a WNA in place as opposed to not having the WNA. Thus, the OCA's position in this proceeding is that the Commission should discontinue the pilot WNA.
- If the Commission is not inclined to end the WNA in this proceeding despite the evidence, it should reject the Company's proposal to remove the three percent deadband. The clear intent of the settlement agreement in Docket No. R-2012-2321748 allowing the pilot WNA is that it would run for a three-year trial period and then be evaluated for continuation in a later (post-three year) base rate case proceeding. The request to remove the three percent deadband at the current time, prior to the end of the pilot period, is nothing more than a unilateral

request and "end-run" by the Company to change the terms and conditions of the agreement and, as proposed above the WNA should either be rejected or, at a minimum, the Company's efforts to remove the deadband should be rejected as such. The Company has not offered nor shown any ratepayer benefits that arise from the WNA or from the removal of the deadband and the Company's proposal to remove the three percent deadband serves no intent but to unjustly compensate itself and its shareholders at other parties' expense and should be rejected.

- The Company has not proven the need for the removal of the proposed deadband. It has not offered any evidence that it is suffering any financial harm due to the current conditions of the settlement agreement establishing the pilot WNA.
- The Company's WNA pilot and/or its request to remove the three percent deadband should be rejected since it has offered no ratepayer protections like a rate cap, earnings test, reduction in its allowed ROE, nor other comparable ratepayer protection nor benefit.

VII. CONCLUSION AND RECOMMENDATIONS

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

A. I recommend the Commission reject the Company's RNA proposal. The RNA ultimately is a solution in search of a problem since the Company has provided no record evidence showing that this mechanism is needed. Further, the Company has provided no compelling evidence that there is any financial need for the RNA. Most revenue decoupling proposals are tied to either new or enhanced energy efficiency efforts. The Company's RNA should be rejected, for among other reasons, since it does not include any meaningful expanded energy efficiency commitments if approved. The failure to directly tie expanded energy efficiency savings opportunities to revenue decoupling adoption shifts the entire performance risk of the RNA away from the Company and onto ratepayers. Lastly, the RNA includes no ratepayer protections, exposing customers to unneeded and potentially unnecessary rate changes for retail rates that are already

higher than regional peers. Overall, the proposed RNA will provide real benefits to NiSource and its shareholders by de-risking its revenue recovery while providing no corresponding benefits for ratepayers.

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

A. For the reasons articulated above, I recommend the Commission end the WNA pilot as the Company has not shown any symmetrical benefit from the program over the years that it has been in existence. If the Commission is inclined to allow the pilot to continue, it should reject the Company's proposal to remove the WNA deadband

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2023-Current	Professor Emeritus
2014-2023	Executive Director (Retired in 2023)
2007-2023	Director, Division of Policy Analysis
2006-2023	Professor
2003-2014	Associate Executive Director
2001-2006	Associate Professor
1999-2001	Research Fellow and Adjunct Assistant Professor
1995-2000	Assistant Professor

College of the Coast and the Environment (Department of Environmental Studies)

2014-2023	Professor (Joint Appointment with CES)
2010-2023	Director, Coastal Marine Institute
2010-2014	Adjunct Professor

E.J. Ourso College of Business Administration (Department of Economics)

2006-2023	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Michigan State University, East Lansing, Michigan

Institute of Public Utilities

2018-Current Senior Fellow

Florida State University, Tallahassee, Florida

College of Social Sciences, Department of Economics

1995 Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current Consulting Economist/Principal
1995-1999 Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

1999-2001 Senior Economist

Florida Public Service Commission, Tallahassee, Florida

Division of Communications, Policy Analysis Section

1995 Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993 Planning & Research Economist
1992-1993 Economist

Project for an Energy Efficient Florida/FlaSEIA, Tallahassee, Florida

1994 Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992 Research Associate
1989-1991 Senior Research Analyst
1988-1989 Research Analyst

GOVERNMENT & ADVISORY APPOINTMENTS

2023 – Current	Distinguished Fellow & Senior Economist Institute For Energy Research Washington, D.C.
2017 -- Current	Member, National Petroleum Council. U.S. Department of Energy.
2020-2023	Co-Chairperson, Energy Advisory Committee, World Trade Center New Orleans, Louisiana.
2007-2023	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.

2007-2023	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

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3. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy. Pp. 60.

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International Association for Energy Economics: The Only Constant is Change August: 444-452.

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5. "Challenges and Opportunities for Distributed Energy Resources in the Natural Gas Industry." (2002). In *Natural Gas and Electric Industries Analysis 2001-2002*. Edited by Robert Willett. With Martin J. Collette, Ritchie D. Priddy, and Jeffrey M. Burke. Houston, TX: Financial Communications Company, 114-131.

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7. "Electric Power Generation." (2000). In the *Macmillan Encyclopedia of Energy*. Edited by John Zumerchik. New York: Macmillan Reference.

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2. "Opportunities for Carbon Capture, Utilization and Storage in Louisiana." (2020). *LOGA Industry Report*. Summer: 18-21.
3. "The Challenges of the Regulatory Review of Diversification Mergers." (2016). With Michael W. Deupree. *Electricity Journal*. 29 (2016): 9-14.
4. "Unconventional Natural Gas and the U.S. Manufacturing Renaissance" (2013). *BIC Magazine*. Vol. 30: No. 2, p. 76 (March).
5. "Louisiana's Tuscaloosa Marine Shale Development: Emerging Resource and Economic Potentials" (2012). *Spectrum*. January-April: 18-20.
6. "The Impact of Legacy Lawsuits on Louisiana's Conventional Drilling Activity" (2012). *LOGA Industry Report*. Spring 2012: 27-34.
7. "Value of Production Losses Tallied for 2004-2005 Storms." (2008). With Mark J. Kaiser and Yunke Yu. *Oil and Gas Journal*. Vol. 106.27: 32-26 (July 21) (part 3 of 3).
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31. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: Completed.

32. *Principal Investigator*. "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Completed.

33. *Principal Investigator*. "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Completed.

34. *Principal Investigator*. "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Completed.

35. *Principal Investigator*. "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, Completed.

36. *Principal Investigator*. "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

37. *Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, Completed.

38. *Principal Investigator*. "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: Completed.

39. *Principal Investigator*. "Ultra-Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

40. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

41. *Principal Investigator*. " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

42. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

43. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

44. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

45. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

46. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and

Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

47. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

48. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

49. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

50. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

51. *Co-Principal Investigator*. "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "The changing nature of Gulf of Mexico energy infrastructure." (2017). Session 3B: New Directions in Social Science Research. 27th Gulf of Mexico Region Information Technology Meetings. U.S. Department of the Interior, Bureau of Ocean Energy Management, Environmental Studies Program. New Orleans, LA. August 24.

2. "Capacity utilization, efficiency trends, and economic risks for modern CHP installations." (2017). U.S. Department of Energy, 2017 Industrial Energy Technology Conference, New Orleans, LA June 21.

3. "Vulnerability assessment of the central Gulf of Mexico coast using a multi-dimensional approach." (2016). With Siddhartha Narra. Eighth International Conference on Environmental Science and Technology. June 6-10, Houston, TX.

4. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). With Gregory Upton. Southern Economic Association Meeting 2015. New Orleans, Louisiana. November 23.

5. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks" (2015). With Gregory Upton. 38th IAEE International Conference, Antalya, Turkey. May 26.

6. "Modifying Renewables Policies to Sustain Positive Economic and Environmental Change" (2015). IEEE Annual Green Technologies ("Greentech") Conference. April 17.

7. "The Gulf Coast Industrial Investment Renaissance and New CHP Development

Opportunities." (2014). Industrial Energy and Technology Conference, New Orleans, Louisiana. May 20.

8. "Estimating Critical Energy Infrastructure Value at Risk from Coastal Erosion" (2014). With Siddhartha Narra. American's Estuaries: 7th Annual Summit on Coastal and Estuarine Habitat Restoration. Washington, D.C., November 3-6.

9. "Economies of Scale, Learning Curves, and Offshore Wind Development Costs" (2012). With Gregory Upton. Southern Economic Association Annual Conference, New Orleans, LA November 17.

10. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7.

11. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

12. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3.

13. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7.

14. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19.

15. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16.

16. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

17. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). U.S. Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

18. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

19. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

20. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

21. “Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned.” (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

22. “An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana.” (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

23. “Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases.” (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

24. “GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand.” (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

25. “Are There Any In-State Uses for Alaska Natural Gas?” (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: “Energy Markets in Turmoil: Making Sense of It All.” Vancouver, British Columbia, Canada. October 7.

26. “The Economic Impact of State Oil and Gas Leases on Louisiana.” (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

27. “Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana.” (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

28. “New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico.” (2002). With Vicki Zatarain. 2002 National IMPLAN Users’ Conference. New Orleans, Louisiana, September 4-6.

29. “Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring.” (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

30. “Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach.” (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

31. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

32. “Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation.” (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

33. “Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry.” (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

34. “Modeling Regional Power Markets and Market Power.” (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

35. “Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana” (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

36. “Empirical Issues in Electric Power Transmission and Distribution Cost Modeling.” (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

37. “Modeling Electric Power Markets in a Restructured Environment.” (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

38. “Benchmarking Electric Utility Distribution Performance.” (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

39. “Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry.” (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

40. “Benchmarking Electric Utility Transmission Performance.” (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

41. “A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry.” (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

42. “New Paradigms for Power Engineering Education.” (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

43. “Cogeneration and Electric Power Industry Restructuring.” (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

44. “The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978.” (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

45. “Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS.” (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

46. “Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS.” (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

47. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

48. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

49. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

50. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

51. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

52. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. Panelist. "Fuel Security, Resource Adequacy & Value of Transmission." (2019). 6th Annual Electricity Dialogue at Northwestern University: Energy and Capacity: Transitions? Northwestern University Center of Law, Regulation, and Economic Growth.

2. "Air Emissions Regulation and Policy: The Recently Proposed Cross State Air Pollution Rule and the Implications for Louisiana Power Generation." Lecture before School of the Coast & Environment. November 5, 2011.

3. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

4. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

5. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

6. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

7. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

8. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

9. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New

Orleans, Louisiana.

10. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

11. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "The role and outlook for CCS in Louisiana energy manufacturing development." (2024). GINP-CCS International Network. February 20, 2024.

2. "Louisiana energy manufacturing development outlook and the energy transition." (2024). Greater Baton Rouge Industry Alliance. February 1, 2024.

3. "Gulf Coast Energy Outlook 2024." (2023). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2023.

4. "Louisiana clean, green industry: reconciling industrial decarbonization, capital formation, and growth." (2023). Louisiana State Bar Association, Public Utility Section. December 1, 2023.

5. "Expert witness training: considerations for preparation and effective execution during public utility regulatory hearings and proceedings." (2023). On the Behalf of the National Association of State Utility Consumer Advocates, Accounting and Finance Subcommittee. September 21, 2023.

6. "Gulf cost energy outlook: traditional resources and the energy transition." (2023). AAPL/Gulf Coast Land Institute Meetings. April 26, 2023.

7. "Ratepayer considerations in the promotion of clean energy." (2023). Public Utility Law Section Roundtable Discussion. April 21, 2023.

8. "Gulf coast energy outlook: traditional resources and the energy transition." (2023). Louisiana Engineering Society. April 19, 2023.

9. "Carbon capture & storage: three thoughts and considerations." (2023). Gulf Coast Power Association. 9th Annual MISO/SPP Conference. March 9, 2023.

10. "Natural gas markets: prices; trends; and ratepayer impacts." (2023). Maryland Energy Advocates Virtual Monthly Meeting. February 17, 2023.

11. "Hydrogen overview and its role in Louisiana decarbonization." (2022). Louisiana Public Service Commission Monthly Business & Executive Meeting. November 17, 2022.

12. "High winter natural gas prices and ratepayer impacts." (2022). National Association of State Utility Consumer Advocates ("NASUCA") Annual Conference. November 14, 2022.

13. "Facing the future together: the Louisiana energy transition, industrial decarbonization, and capital formation trends." (2022). Louisiana Chemical Association: Annual Meeting 2022. October 27, 2022.

14. “Louisiana and the energy transition: reconciling industrial decarbonization, capital formation, and growth.” (2022). Louisiana Air and Waste Management 2022 Annual Meeting. October 26, 2022.

15. “The Louisiana energy transition, industrial decarbonization, and industrial capital formation trends.” (2022). Postlethwaite & Netterville: 2022 Governmental Update. August 4, 2022.

16. “Identifying and mapping regulatory requirements for CCUS projects.” (2022). SECARB Offshore GOM Gulf Regulator Workshop. New Orleans LA. May 16, 2022.

17. “Louisiana industrial decarbonization opportunities.” (2022). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Meeting. May 11, 2022. Baton Rouge, LA.

18. “Natural Gas outlook, 2022: supply, demand, and geopolitical considerations.” (2022). National Association of State Utility Consumer Advocates (“NASUCA”) Monthly Natural Gas Committee Webinar. March 30, 2022.

19. “Louisiana industrial decarbonization opportunities.” (2022). LSU Law School, Journal of Energy Law and Resources Symposium on Energy Transitions. February 4, 2022. Baton Rouge, LA.

20. Panelist. Grid Resiliency in the Era of Extreme Weather. Gulf Coast Power Association 8th Annual MISO/SPP Regional Meeting. February 9, 2022. New Orleans, LA.

21. Panelist. Natural Gas Industry Update. (2022). National Association of State Utility Consumer Advocates Annual Meeting. (virtual). November 8, 2021.

22. “Overview of Louisiana’s greenhouse gas emissions and trends.” (2021). Louisiana Energy Users Group (“LEUG”) Meeting. November 11, 2021.

23. “State of energy in Louisiana: a preview of the 2021 Gulf Coast Energy Outlook.” (2021). Financial Planning Association of Baton Rouge. November 10, 2021.

24. “Replacing natural gas and industrial decarbonization: utility and ratemaking issues.” (2021). Virtual Joint Annual Meeting: Virginia Committee for Fair Utility Rates, Old Dominion Committee for Fair Utility Rates, and Virginia Industrial Gas Users Group Workshop. September 8, 2021.

25. “Louisiana 2021 GHG Inventory: Update and summary of preliminary findings.” (2021). Presentation before the Climate Initiative Task Force. July 29, 2021.

26. “Opportunities for the development of a hydrogen economy in Louisiana.” (2021). Louisiana Energy Climate Solutions Workshop. June 15, 2021.

27. “Natural gas: Building gas system resilience. Overview of the 2021 polar vortex and its implications for gas resiliency.” (2021). National Association of State Utility Consumer Advocates (“NASUCA”). Virtual mid-year meeting. June 14, 2021.

28. “Status and briefing on the Louisiana greenhouse gas inventory and emissions analysis.” (2021). Scientific Advisory Group (“SAG”) Meeting, Governor’s Climate Initiative Task Force. March 29, 2021.

29. “Louisiana carbon capture: sinks; sources; and the role of transportation in industrial applications.” (2021). LSU Journal of Energy Law & Resources Symposium on Carbon Capture and Solutions. February 5, 2021.

30. “Natural gas outlook, 2021: production, demand, pandemic and policy.” (2021). National Association of State Utility Consumer Advocates (“NASUCA”) Monthly Natural Gas Committee Webinar. January 20, 2021.

31. “Consumer Perspectives on the Rate Design of the Future.” (2020). National Association of State Utility Consumer Advocates (“NASUCA”). Annual Conference, November 10.

32. “Evaluation of Louisiana’s Depleted Gas Reservoirs for Geological Carbon Sequestration.” (2020). Louisiana Mid-Continent Oil and Gas Association (“LMOGA”) Carbon Capture and Underground Storage (“CCUS”) Committee Meeting. August 25.

33. “The 2020 Gulf Coast Energy Outlook: COVID-19 update.” (2020). Baton Rouge Area Chamber of Commerce Business Webinar. COVID-19 and Global Supply Impacts on the Capital Region and Louisiana Economies. Baton Rouge, LA. June 3.

34. “Ratepayer benefits of reforming PURPA”. (2020). Harvard Electricity Policy Group Webinar. PURPA: A time to reform or reduce its role? March 26.

35. “Pipeline industry: economic trends and outlook”. (2020). Joint Industry Association Annual Meeting. Louisiana Mid-Continent Oil and Gas Association (“LMOGA”) and the Louisiana Oil and Gas Association (“LOGA”). Lake Charles, LA March 5.

36. “The outlook for natural gas: storm clouds ahead?” (2020). National Association of State Utility Consumer Advocates (“NASUCA”). Natural Gas Committee Webinar, February 26.

37. “The 2020 Gulf Coast Energy Outlook”. (2020). University of Louisiana Lafayette, Southern Unconventional Resources Center for Excellence. Lafayette, LA February 16.

38. “Opportunities for carbon capture, utilization, and storage in the Louisiana chemical corridor”. (2020). Air and Waste Management Association, Louisiana Section Luncheon. Gonzales, LA January 16.

39. Panelist. (2020). Baton Route Advocate, 2020 Economic Outlook Summit. Baton Rouge Advocate. January 8.

40. “2020 Louisiana business climate outlook: the view from the energy sector.” (2019). American Council of Engineering Companies Fall Conference. November 21, 2019. Baton Rouge, LA

41. “The urgency of PURPA reform in protecting ratepayers.” (2019). Americans for Tax Reform, Fall 2019 Coalition Leaders Summit, November 14, 2019. New Orleans, LA.

42. “Louisiana’s coast and the energy industry.” (2019). 2019 API Delta Chapter Joint Society Luncheon Meeting. November 12, 2019, New Orleans, LA.

43. “Reforming PURPA: implications for ratepayers.” (2019). Thomas Jefferson Institute for Public Policy, Annual Energy Summit, State Policy Network Annual Meeting. Colorado Springs, CO, October 28.

44. “Natural gas outlook: supply, demand and prices.” (2019). National Association of State Utility Consumer Advocates, Natural Gas Committee Monthly Meeting. July 30, 2019.

45. “The economic impacts and outlook for LNG development on the Gulf Coast.” (2019). 73rd Annual Meeting of the Southern Legislative Conference of the Council of State Governments. New Orleans, LA, July 14. (prepared presentation, hurricane cancellation)

46. “Natural gas outlook: supply, demand, and prices.” (2019). NASUCA Mid-Year Meeting. Portland, OR, June 20.

47. “Overview of Louisiana LNG issues and trends.” (2019). Berlin: LNG, Energy Security, and Diversity Reporting Tour, LSU Center for Energy Studies. Baton Rouge, LA, May 9.

48. “Overview of Louisiana energy issues and outlook.” (2019). Australian Media Visit, Greater New Orleans, Inc./Baton Rouge Area Foundation. Baton Rouge, LA, April 29.

49. “Gulf Coast Energy Outlook 2019: Regional trends and outlook.” (2019). Women’s Energy Network. Baton Rouge, LA, April 23.

50. “MISO Grid Vision 2033.” (2019). 2019 Spring Regulator and Policymaker Forum. New Orleans, LA, April 15-16.

51. “Ratepayer benefits of reforming PURPA.” (2019). LSU Center for Energy Studies Industry Advisory Council Meeting. March 27.

52. “Incentives, risk, and the changing nature of regulation.” (2019). NASUCA Water Committee monthly meeting/webinar. March 13.

53. “Gulf Coast Energy Outlook 2019: Production, trade and infrastructure trends.” (2019). 66th Annual Mineral Board Institute Meetings. Baton Rouge, LA, March 14.

54. “A golden age: energy outlook 2019.” (2019). Engineering News Record Webinar. February 13.

55. Panelist. (2019). Baton Route Advocate, 2019 Economic Outlook Summit. Baton Rouge Advocate. January 8.

56. “MISO Grid Vision 2033.” (2018). 2018 Winter Regulatory and Policymaker Forum. New Orleans, LA, December 11.

57. “Gulf Coast Energy Outlook 2019.” (2018). LSU Center for Energy Studies, Baton Rouge, LA, Fall 2018.

58. “How LNG is transforming Louisiana’s energy economy.” (2018). Louisiana State Bar Association, Public Utility Section. Baton Rouge, LA, November 30.

59. “Overview of Louisiana LNG issues and trends.” (2018). Kean Miller Law Firm: Energy and Environmental Practice Group. Baton Rouge, LA, November 28.

60. “Infrastructure and capacity: challenges for development.” (2018). Society of Utility and Regulatory Financial Analysts (SURFA) Annual Meeting, New Orleans, LA, April 20.

61. “Louisiana industrial cogeneration trends.” (2018). Annual Louisiana Solid Waste Association Conference, Lafayette, LA, March 16.

62. “Gulf Coast industrial development: overview of trends and issues.” (2018). Gulf Coast Power Association Meetings, New Orleans, LA, February 8.

63. “Energy outlook – reflection on market trends and Louisiana implications.” (2017). IberiaBank Corporation Bank Board of Directors Meeting, New Orleans, LA. November 15.

64. “Integrated carbon capture and storage in the Louisiana chemical corridor.” (2017). Industry Associates Advisory Council Meeting, Baton Rouge, LA. November 7.

65. “The outlook for natural gas and energy development on the Gulf Coast.” (2017). Louisiana Chemical Association, Annual Meeting, New Orleans, LA. October 26.

66. “Critical energy infrastructure: the big picture on resiliency research.” (2017). National Academies of Science, Engineering, and Medicine. New Orleans, LA. September 18.

67. “The changing nature of Gulf of Mexico energy infrastructure.” (2017). 27th Gulf of Mexico Region Information Technology Meetings, New Orleans, LA, August 24.

68. “Capacity utilization, efficiency trends, and economic risks for modern CHP installations.” (2017). Industrial Energy Technology Conference, New Orleans, LA. June 21.

69. “Crude oil and natural gas outlook: Where are we and where are we going?” (2017). CCREDC Economic Trends Panel. Corpus Christi, TX, June 15.

70. “Navigating through the energy landscape.” (2017). Baton Rouge Rotary Luncheon. Baton Rouge, LA, May 24.

71. “The 2017-2018 Louisiana energy outlook.” (2017). Junior Achievement of Greater New Orleans, JA BizTown Speaker Series. New Orleans, LA, May 12.

72. “The Gulf Coast energy economy: trends and outlook.” (2017). Society for Municipal Analysts. New Orleans, LA, April 21.

73. “Gulf coast energy outlook.” (2017). E.J. Ourso College of Business, Dean’s Advisory Council, Energy Committee Meeting. Baton Rouge, LA, March 31.

74. “Recent trends in energy: overview and impact for the banking community.” (2017). Oil and Gas Industry Update, Louisiana Bankers Association. Baton Rouge, LA, March 24.

75. “How supply, demand and prices have influenced unconventional development.” (2016). Energy Annual Meeting, CLEER-University Advisory Board Lecture. New Orleans, LA, September 17.

76. “The Basics of Natural Gas Production, Transportation, and Markets.” (2016). Center for Energy Studies. Baton Rouge, LA, August 1.

77. “Gulf Coast industrial development: trends and outlook.” (2016). Investor Relations Group Meeting, Edison Electric Institute. New Orleans, LA, June 23.

78. “The future of policy and regulation: Unlocking the Treasures of Utility Regulation.” (2016). Annual Meeting, National Conference of Regulatory Attorneys. Tampa, FL, June 20.

79. “Utility mergers: where’s the beef?”. (2016). National Association of State Utility Consumer Advocates Mid-Year Meetings. New Orleans, LA, June 6.

80. “Overview of the Clean Power Plan and its application to Louisiana.” (2016). Shell Oil Company Internal Meeting. April 12.

81. “Energy and economic development on the Gulf Coast: trends and emerging challenges.” (2016). Gas Processors Association Meeting. New Orleans, LA, April 11.

82. “Unconventional Oil and Gas Drilling Trends and Issues.” (2016). French Delegation Visit, LSU Center for Energy Studies. March 16.

83. “Gulf Coast Industrial Growth: Passing clouds or storms on the horizon?” (2016). Gulf Coast Power Association Meetings. New Orleans, LA, February 18.

84. "The Transition to Crisis: What do the recent changes in energy markets mean for Louisiana?" (2016). Louisiana Independent Study Group. February 2.

85. "Regulatory and Ratepayer Issues in the Analysis of Utility Natural Gas Reserves Purchases" (2016). National Association of State Utility Consumer Advocates Gas Consumer Monthly Meeting. January 25.

86. "Emerging Issues in Fuel Procurement: Opportunities & Challenges in Natural Gas Reserves Investment." (2015). National Association of State Utility Consumer Advocates Annual Meeting. Austin, Texas. November 9.

87. "Trends and Issues in Net Metering and Solar Generation." (2015). Louisiana Rural Electric Cooperative Meeting. November 5.

88. "Electric Power: Industry Overview, Organization, and Federal/State Distinctions." (2015). EUCI. October 16.

89. "Natural Gas 101: The Basics of Natural Gas Production, Transportation, and Markets." (2015). Council of State Governments Special Meeting on Gas Markets. New Orleans, LA. October 14.

90. "Update and General Business Matters." (2015). CES Industry Associates Meeting. Baton Rouge, Louisiana. Fall 2015.

91. "The Impact of Infrastructure Cost Recovery Mechanisms on Pipeline Replacements and Leaks." (2015). 38th IAEE 2015 International Conference. Antalya, Turkey. May 26.

92. "Industry on the Move – What's Next?" (2015). Event Sponsored by Regional Bank and 1012 Industry Report. May 5.

93. "The State of the Energy Industry and Other Emerging Issues." (2015). Lex Mundi Energy & Natural Resources Practice Group Global Meeting. May 5.

94. "Energy, Louisiana, and LSU." (2015). LSU Science Café. Baton Rouge, Louisiana. April 28.

95. "Energy Market Changes and Impacts for Louisiana." (2015). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 22.

96. "Incentives, Risk and the Changing Nature of Utility Regulation." (2015). NARUC Staff Subcommittee on Accounting and Finance Meetings, New Orleans, Louisiana. April 22.

97. "Modifying Renewables Policies to Sustain Positive and Economic Change." (2015). IEEE Annual Green Technologies ("Greentech Conference"). April 17.

98. "Louisiana's Changing Energy Environment." (2015). John P. Laborde Energy Law Center Advisory Board Spring Meeting, Baton Rouge, Louisiana. March 27.

99. "The Latest and the Long on Energy: Outlooks and Implications for Louisiana." (2015). Iberia Bank Advisory Board Meeting, Baton Rouge, Louisiana. February 23.

100. "A Survey of Recent Energy Market Changes and their Potential Implications for Louisiana." (2015). Vistage Group, New Orleans, Louisiana. February 4.

101. "Energy Prices and the Outlook for the Tuscaloosa Marine Shale." (2015). Baton Rouge Rotary Club, Baton Rouge, Louisiana. January 28.

102. "Trends in Energy & Energy-Related Economic Development." (2014). Miller and

Thompson Presentation, Baton Rouge, Louisiana. December 30.

103. "Overview EPA's Proposed Rule Under Section 111(d) of the Clean Air Act: Impacts for Louisiana." (2014). Louisiana State Bar: Utility Section CLE Annual Meeting, Baton Rouge, Louisiana. November 7.

104. "Overview EPA's Proposed Clean Power Plan and Impacts for Louisiana." (2014). Clean Cities Coalition Meeting, Baton Rouge, Louisiana. November 5.

105. "Impacts on Louisiana from EPA's Proposed Clean Power Plan." (2014). Air & Waste Management Annual Environmental Conference (Louisiana Chapter), Baton Rouge, Louisiana. October 29, 2014.

106. "A Look at America's Growing Demand for Natural Gas." (2014). Louisiana Chemical Association Annual Meeting, New Orleans, Louisiana. October 23.

107. "Trends in Energy & Energy-Related Economic Development." (2014). 2014 Government Finance Officer Association Meetings, Baton Rouge, Louisiana. October 9.

108. "The Conventional Wisdom Associated with Unconventional Resource Development." (2014). National Association for Business Economics Annual Conference, Chicago, Illinois. September 28.

109. Unconventional Oil & Natural Gas: Overview of Resources, Economics & Policy Issues. (2014). Society of Environmental Journalists Annual Meeting. New Orleans, Louisiana. September 4.

110. "Natural Gas Leveraged Economic Development in the South." (2014). Southern Governors Association Meeting, Little Rock, Arkansas. August 16.

111. "The Past, Present and Future of CHP Development in Louisiana." (2014). Louisiana Public Service Commission CHP Workshop, Baton Rouge, Louisiana. June 25.

112. "Regional Natural Gas Demand Growth: Industrial and Power Generation Trends." (2014). Kinetica Partners Shippers Meeting, New Orleans, Louisiana. April 30.

113. "The Technical and Economic Potential for CHP in Louisiana and the Impact of the Industrial Investment Renaissance on New CHP Capacity Development." (2014). Electric Power 2014, New Orleans, Louisiana. April 1.

114. "Industry Investments and the Economic Development of Unconventional Development." (2014). Tuscaloosa Marine Shale Conference & Expo, Natchez, Mississippi. March 31.

115. Discussion Panelist. Energy Outlook 2035: The Global Energy Industry and Its Impact on Louisiana, (2014). Grow Louisiana Coalition, Baton Rouge, Louisiana. March 18.

116. "Natural Gas and the Polar Vortex: Has Recent Weather Led to a Structural Change in Natural Gas Markets?" (2014). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. February 19.

117. "Some Unconventional Thoughts on Regional Unconventional Gas and Power Generation Requirements." (2014). Gulf Coast Power Association Special Briefing, New Orleans, Louisiana. February 6.

118. "Leveraging Energy for Industrial Development." (2013). 2013 Governor's Energy Summit, Jackson, Mississippi. December 5.

119. "Natural Gas Line Extension Policies: Ratepayer Issues and Considerations." (2013).

National Association of State Utility Consumer Advocates Annual Meeting, Orlando, Florida. November 19.

120. "Replacement, Reliability & Resiliency: Infrastructure & Ratemaking Issues in the Power & Natural Gas Distribution Industries." (2013). Louisiana State Bar, Public Utility Section Meetings. November 15.

121. "Natural Gas Markets: Leveraging the Production Revolution into an Industrial Renaissance." (2013). International Technical Conference, Houston, TX. October 11.

122. "Natural Gas, Coal & Power Generation Issues and Trends." (2013). Southeast Labor and Management Public Affairs Committee Conference, Chattanooga, Tennessee. September 27.

123. "Recent Trends in Pipeline Replacement Trackers." (2013). National Association of State Utility Consumer Advocates Monthly Gas Committee Meeting. September 19.

124. Discussion Panelist (2013). Think About Energy Summit, America's Natural Gas Alliance, Columbus Ohio. September 16-17.

125. "Future Test Years: Issues to Consider." (2013). National Regulatory Research Institute, Teleseminar on Future Test Years. August 28.

126. "Industrial Development Outlook for Louisiana." (2013). Louisiana Water Synergy Project Meetings, Jones Walker Law Firm, Baton Rouge, Louisiana. July 30.

127. "Natural Gas & Electric Power Coordination Issues and Challenges." (2013). Utilities State Government Organization Conference, Pointe Clear, Alabama. July 9.

128. "Natural Gas Market Issues & Trends." (2013). Western Conference of Public Service Commissioners, Santa Fe, New Mexico. June 3.

129. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Louisiana Chemical Association/Louisiana Chemical Industry Alliance Annual Legislative Conference, Baton Rouge, Louisiana. May 8.

130. "Infrastructure Cost Recovery Mechanism: Overview of Issues." (2013). Energy Bar Association Annual Meeting, Washington, D.C. May 1.

131. "GOM Offshore Oil and Gas." (2013). Energy Executive Roundtable, New Orleans, Louisiana. March 27.

132. "Louisiana Unconventional Natural Gas and Industrial Redevelopment." (2013). Risk Management Association Luncheon, March 21.

133. "Natural Gas Market Update and Emerging Issues." (2013). NASUCA Gas Committee Conference Call/Webinar, March 12.

134. "Unconventional Resources and Louisiana's Manufacturing Development Renaissance." (2013). Baton Rouge Press Club, De La Ronde Hall, Baton Rouge, LA, January 28.

135. "New Industrial Operations Leveraged by Unconventional Natural Gas." (2013) American Petroleum Institute-Louisiana Chapter. Lafayette, LA, Petroleum Club, January 14.

136. "What's Going on with Energy? How Unconventional Oil and Gas Development is Impacting Renewables, Efficiency, Power Markets, and All that Other Stuff." (2012). Atlanta Economics Club Monthly Meeting. Atlanta, GA. December 11.

137. “Trends, Issues, and Market Changes for Crude Oil and Natural Gas.” (2012). East Iberville Community Advisory Panel Meeting. St. Gabriel, LA. September 26.

138. “Game Changers in Crude and Natural Gas Markets.” (2012). Chevron Community Advisory Panel Meeting. Belle Chase, LA, September 17.

139. “The Outlook for Renewables in a Changing Power and Natural Gas Market.” (2012). Louisiana Biofuels and Bioprocessing Summit. Baton Rouge, LA. September 11.

140. “The Changing Dynamics of Crude and Natural Gas Markets.” (2012). Chalmette Refining Community Advisory Panel Meeting. Chalmette, LA, September 11.

141. “The Really Big Game Changer: Crude Oil Production from Shale Resources and the Tuscaloosa Marine Shale.” (2012). Baton Rouge Chamber of Commerce Board Meeting. Baton Rouge, LA, June 27.

142. “The Impact of Changing Natural Gas Prices on Renewables and Energy Efficiency.” (2012). NASUCA Gas Committee Conference Call/Webinar. 12 June 2012.

143. “Issues in Gas-Renewables Coordination: How Changes in Natural Gas Markets Potentially Impact Renewable Development” (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

144. “Issues in Natural Gas End-Uses: Are We Really Focusing on the Real Opportunities?” (2012). Energy Bar Association, Louisiana Chapter, Annual Meeting, New Orleans, LA. April 12, 2012.

145. “The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana.” (2012). Louisiana Oil and Gas Association Annual Meeting, Lake Charles, LA. February 27, 2012.

146. “The Impact of Legacy Lawsuits on Conventional Oil and Gas Drilling in Louisiana.” (2012) Louisiana Oil and Gas Association Annual Meeting. Lake Charles, Louisiana. February 27, 2012.

147. “Louisiana’s Unconventional Plays: Economic Opportunities, Policy Challenges. Louisiana Mid-Continent Oil and Gas Association 2012 Annual Meeting. (2012) New Orleans, Louisiana. January 26, 2012.

148. “EPA’s Recently Proposed Cross State Air Pollution Rule (“CSAPR”) and Its Impacts on Louisiana.” (2011). Bossier Chamber of Commerce. November 18, 2011.

149. “Facilitating the Growth of America’s Natural Gas Advantage.” (2011). BASF U.S. Shale Gas Workshop Management Meeting. Florham Park, New Jersey. November 1, 2011.

150. “CSAPR and EPA Regulations Impacting Louisiana Power Generation.” (2011). Air and Waste Management Association (Louisiana Section) Fall Conference. Environmental Focus 2011: a Multi-Media Forum. Baton Rouge, LA. October 25, 2011.

151. “Natural Gas Trends and Impact on Industrial Development.” (2011). Central Gulf Coast Industrial Alliance Conference. Arthur R. Outlaw Convention Center. Mobile, AL. September 22, 2011.

152. “Energy Market Changes and Policy Challenges.” (2011). Southeast Manpower Tripartite Alliance (“SEMTA”) Summer Conference. Nashville, TN September 2, 2011.

153. “EPA Regulations, Rates & Costs: Implications for U.S. Ratepayers.” (2011). Workshop:

"A Smarter Approach to Improving Our Environment." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 5, 2011.

154. Panelist/Moderator. Workshop: "Why Wait? Start Energy Independence Today." 38th Annual American Legislative Exchange Council ("ALEC") Meetings. New Orleans, LA. August 4, 2011.

155. "Facilitating the Growth of America's Natural Gas Advantage." Texas Chemical Council, Board of Directors Summer Meeting. San Antonio, TX. July 28, 2011.

156. "Creating Ratepayer Benefits by Reconciling Recent Gas Supply Opportunities with Past Policy Initiatives." National Association of State Utility Consumer Advocates ("NASUCA"), Monthly Gas Committee Meeting. July 12, 2011.

157. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

158. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

159. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

160. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

161. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

162. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

163. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

164. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

165. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

166. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

167. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

168. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater

Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

169. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

170. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

171. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

172. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

173. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

174. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

175. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

176. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

177. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

178. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

179. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

180. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

181. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

182. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

183. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

184. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

185. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

186. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

187. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economics (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

188. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

189. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

190. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

191. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

192. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

193. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

194. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

195. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

196. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

197. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

198. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

199. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy

Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

200. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

201. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

202. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

203. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

204. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

205. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

206. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

207. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

208. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

209. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

210. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

211. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

212. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

213. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

214. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

215. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

216. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

217. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

218. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

219. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

220. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

221. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

222. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

223. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

224. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

225. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

226. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

227. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

228. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

229. “The Outlook for Energy.” Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

230. “The Outlook for Energy.” Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

231. “Background and Overview of LNG Development.” Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

232. “Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry.” Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

233. “The Economic Opportunities for a Limited Industrial Retail Choice Plan.” Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

234. “Energy Issues for Industrial Customers of Gas and Power.” Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

235. “Energy Issues for Industrial Customers of Gas and Power.” Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

236. “Energy Issues for Industrial Customers of Gas and Power.” American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

237. “Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry.” Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

238. “Energy Issues for Industrial Customers of Gas and Power.” Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

239. “LNG In Louisiana.” Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

240. “Louisiana Energy Issues.” Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

241. “The Gulf South: Economic Opportunities Related to LNG.” Presentation before the Energy Council’s 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

242. “Natural Gas and LNG Issues for Louisiana.” Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

243. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

244. The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

245. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

246. “Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy.” Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

247. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

248. “Natural Gas Outlook: Trends and Issues for Louisiana.” Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

249. “Natural Gas Outlook” Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

250. “Competitive Bidding in the Electric Power Industry.” Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

251. “Regional Transmission Organization in the South: The Demise of SeTrans” Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

252. “Affordable Energy: The Key Component to a Strong Economy.” Presentation before the National Association of Regulatory Utility Commissioners (“NARUC”), November 18, 2003, Atlanta, Georgia.

253. “Natural Gas Outlook.” Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

254. “Issues and Opportunities with Distributed Energy Resources.” Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

255. “What’s Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook” Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

256. “An Introduction to Distributed Energy Resources.” Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

257. “Merchant Energy Development Issues in Louisiana.” Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

258. “Merchant Power Plants and Deregulation: Issues and Impacts.” Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 18, 2002.

259. “Merchant Power and Deregulation: Issues and Impacts.” Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

260. “Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana.” Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

261. “Economic Impacts of Merchant Power Plant Development in Mississippi.” Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

262. “Economic Opportunities for Merchant Power Development in the South.” Presentation before the Southern Governor’s Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

263. “The Changing Nature of the Electric Power Business in Louisiana.” Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

264. “Power Business in Louisiana: Background and Issues.” Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

265. “The Changing Nature of the Electric Power Business in Louisiana: Background and Issues.” Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

266. “The Changing Nature of the Electric Power Business in Louisiana: Background and Issues.” Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

267. “The Economic Impacts of Merchant Power Plant Development In Mississippi.” Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

268. “Energy Conservation and Electric Restructuring.” With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

269. “Pricing and Regulatory Issues Associated with Distributed Energy.” Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: “Is the Window Closing for Distributed Energy?” Houston, Texas, October 13, 2000.

270. “Electric Reliability and Merchant Power Development Issues.” Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

271. “A Introduction to Distributed Energy Resources.” Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

272. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

273. “Electricity 101: Definitions, Precedents, and Issues.” Energy Council’s 2000 Federal Energy and Environmental Matters Conference. Loews L’Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

274. “LSU/CES Distributed Energy Resources Initiatives.” Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

275. “Distributed Energy Resources Initiatives.” Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

276. “Merchant Power Opportunities in Louisiana.” Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

277. Roundtable Discussant. “Environmental Regulation in a Restructured Market” The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

278. “The Political Economy of Electric Restructuring In the South” Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

279. “The Dynamics of Electric Restructuring in Louisiana.” Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

280. “The Implications of Electric Restructuring on Independent Oil and Gas Operations.” Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

281. “What’s Happened to Electricity Restructuring in Louisiana?” Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

282. “A Short Course on Electric Restructuring.” Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

283. “The Implications of Electric Restructuring on Independent Oil and Gas Operations.” Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

284. “How Will Utility Deregulation Affect Tourism.” Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

285. “Reflections and Predictions on Electric Utility Restructuring in Louisiana.” With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

286. “Electric Utility Restructuring in Louisiana.” Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

287. “Electric Utility Restructuring.” Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

288. “Electric Utility Restructuring: Issues and Trends for Louisiana.” Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

289. “The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues.” Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

290. “Electric Restructuring: Louisiana Issues and Outlook for 1997.” Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

291. “Restructuring the Electric Utility Industry.” Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

292. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

293. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

294. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

295. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

296. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

297. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

298. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

299. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

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

1. Expert Testimony. Docket No. 20240025-EI. (2024). Before the Florida Public Service Commission. *In Re: Petition for rate increase by Duke Energy Florida, LLC.* On Behalf of The Citizens of the State of Florida. Issues: load forecasting, multi-year rate increase, energy affordability.

2. Expert Testimony. Docket No. 20240026. (2024). Before the Florida Public Service Commission. *In Re: Petition for rate increase by Tampa Electric Company.* On Behalf of The Citizens of the State of Florida. Issues: load forecasting, affordability.

3. Expert Testimony. Docket No. 2024-34-E. (2024). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Dominion Energy South Carolina, incorporated for authority to adjust and increase its retail electric rate schedules tariffs, and terms and conditions.* On Behalf of South Carolina Department of Consumer Affairs. Issues: GRID investment, cost of service, revenue allocation, rate design.

4. Expert Testimony. Cause No. 46011. (2024). Before the State of Indiana, Indiana Utility Regulatory Commission. *Petition of Ohio Valley Gas, Inc. for (1) authority to increase its rates and charges for gas utility service, (2) approval of new schedules of rates and charges, (3) approval of decoupling through a new sales reconciliation component rider, and (4) approval of necessary and appropriate accounting relief and other requests.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: decoupling, sales reconciliation component rider.

5. Expert Testimony. Docket No. 2024-UA-42. (2024). Before the Mississippi Public Service Commission. *Joint Application of Centerpoint Energy Resources Corp. and Delta Utilities MS, LLC for all necessary authorizations and approvals for Delta Utilities MS, LLC to acquire the assets of Centerpoint Energy Resources Corp. and for approval of a certificate*

of public convenience and necessity for Delta Utilities MS, LLC, and for related relief. On Behalf of Delta Utilities MS, LLC. Issues: economic benefits, ratemaking, other benefits.

6. Expert Testimony. Docket No. S-37187. (2024). Before the Louisiana Public Service Commission. *Delta Utilities No. LA, LLC, Delta Utilities S. LA., and Centerpoint Energy Resources Corp. Ex. Parte. In RE : Application for authority to operate as a local distribution company and incur indebtedness and joint application for approval for transfer and acquisition of local distribution company assets and related relief.* On Behalf of Delta Utilities No. LA, LLC. Issues: economic benefits, ratemaking, other benefits.

7. Expert Testimony. D.P.U. 23-150. (2024). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid Pursuant to G.L. c. 164 § 94 and 220 C.M.R. 5.00 for Approval of an Increase in Base Distribution Ratesand Approval of a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Issues: capital tracker, Y-factor, IDRF, PBR, alternative regulation, benchmarking analysis.

8. Expert Testimony. Cause No. 45990. (2024). Before the Indiana Utility Regulatory Commission. *Verified Petition of Southern Indiana Gas and Electric Company D/B/A Centerpoint Energy Indiana South ("CEI South) for (1) Authority to modify its rates and charges for electric utility service through a phase in of rates (2) approval of new schedules of rates and charges and new and revised riders, including but not limited to a new tax adjustment rider and a new green power rider (3) approval of a critical peak pricing ("CPP") pilot program, (4) approval of revised depreciation rates applicable to electric and common plant in service, (5) approval of necessary and appropriate accounting relief, including authority to capitalize as rate base all cloud computing costs and defer to a regulatory asset amounts not already included in base rates that are incurred for third-party cloud computing arrangements, and (6) approval of an alternative regulatory plant granting CEI South a waiver from 170 IAC 4-1-16(f) to allow for remote disconnection for non-payment.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: proposed rate increases, cost of service study, minimum system study, revenue distribution, rate design, TOU-CPP pilot.

9. Expert Testimony. Cause No. 45967. (2024). Before the Indiana Utility Regulatory Commission. *Petition of Northern Indiana Public Service Company LLC Pursuant to Ind. Code §§ 8-1-2-42, 8-1-2-42.7 and 8-1-2-61 for (1) authority to modify its retail rates and charges for gas utility service through a phase in of rates; (2) approval of new schedules of rates and charges, general rule sand regulations, and riders (both existing and new): (3) approval of a new sales reconciliation adjustment mechanism; (4) approval of revised gas deprecation rates applicable to its gas plant in service; (5) approval of necessary and appropriate accounting relief, including but not limited to approval of certain deferral mechanisms for pensions, other post-retirement benefits and line locate expenses; and (6) to the extent necessary, approval of any of the relief requested herein pursuant to Ind. Code Ch. 8-1-2-5.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: sales reconciliation adjustment.

10. Expert Testimony. F.C. No. 1176. (2024). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Implement a Multiyear Rate Plan for Electric Distribution Service in the District of Columbia.* On Behalf of the Office of the People's Counsel for the District of

Columbia. Issues: affordability, revenue distribution, rate design, multi-year rate planning, bill stabilization adjustment.

11. Expert Testimony. Case No. 23-0460-E-42T (2023). Before the Public Service Commission of West Virginia Charleston. *In the Matter of Monongahela Power Company and the Potomac Edison Company rule 42T tariff filing to increase rates and charges.* On Behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia. Issues: cost of service, zero intercept study, revenue allocation, rate design, net energy metering rider.

12. Expert Testimony. Docket No. DPU 23-81. (2023). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Gas Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Gas Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Direct and Surrebuttal. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

13. Expert Testimony. Docket No. DPU 23-80. (2023). Before the Commonwealth of Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil (Electric Division), pursuant to G.L. c. 164, § 94 and 220 CMR 5.00, for Approval of a General Increase in Base Distribution Rates for Electric Service and a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General, Office of Ratepayer Advocacy. Direct and Surrebuttal. Issues: alternative regulation performance-based ratemaking, cost of service, revenue distribution, rate design.

14. Expert Testimony. Case No. 23-03803-W-42T and 23-0384-S-42T (2023). Before the Public Service Commission of West Virginia Charleston. In the Matter of West Virginia-America Water Company rule 42T application to increase rates and charges. On Behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia. Issues: revenue distribution, rate design, affordability, service quality.

15. Expert Testimony. Cause No. 45933 (2023). Before the Indiana Utility Regulatory Commission. *Petition of Indiana Michigan Power Company an Indiana Corporation, for authority to increase rates and charges for electric utility service through a phase in rate adjustment; and for approval of related relief including: (1) revised depreciation rates, including cost of removal less salvage, and updated depreciation expense; (2) accounting relief, including deferrals and amortization; (3) inclusion of capital investment; (4) rate adjustment mechanism proposals, including new grant projects rider and modified tax rider; (5) a voluntary residential customer powerpay program; (6) waiver or declination of jurisdiction with respect to certain rules to facilitate implementation of the powerpay program; (7) cost recovery for cook plant subsequent license renewal evaluation project; and (8) new schedules of rates, rules and regulations.* On Behalf of Indiana Office of Utility Consumer Counselor. Issues: cost of service, rate design, revenue distribution, service fees.

16. Expert Report. (2023). *Alternative regulation deficiencies and potential ratepayer harms*. On Behalf of the Office of the Consumer Advocate of Iowa. October 3, 2023.

17. Expert Testimony. Docket No. 2023.06.057. (2023). Before the Public Service

Commission of the State of Montana. *In the Matter of Energy West Montana's Application for Approval of Gas Cost Hedging Plan for West Yellowstone.* On Behalf of the Montana Consumer Counsel. Issues: gas hedging program.

18. Legislative Testimony. (2023). Ratepayer harms from alternative regulation in Oklahoma. Appearing on the Behalf of the Petroleum Alliance of Oklahoma. October 23, 2023.

19. Expert Testimony. Cause No. 45911. (2023). Before the State of Indiana Utility Regulatory Commission. *Petition of Indianapolis Power & Light Company D/B/A AES Indiana ("AES Indiana") for authority to increase rates and charges for electric utility service, and for approval of related relief, including (1) revised depreciation rates, (2) accounting relief, including deferrals and amortizations, (3) inclusion of capital investments, (4) rate adjustment mechanism proposals, including new economic development rider, (5) remote disconnect/reconnect process and (6) new schedules of rates, rules and regulations for service*. On Behalf of Indiana Office of Utility Consumer Counselor. Direct and Cross-Answering. Issues: allocated cost of service, revenue distribution, rate design, trackers.

20. Expert Testimony. Docket No. 23-06007. (2023). Before the Public Utilities Commission of Nevada. *In the Matter of the Application by Nevada Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers.* On Behalf of the Nevada Bureau of Consumer Protection. Issues: marginal cost of service study, embedded cost of service study, revenue distribution, rate design.

21. Expert Testimony. Docket No. UE-230172. (2023). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission, Complainant v. Pacificorp dba Pacific Power & Light Company, Respondent.* On Behalf of the Washington State Office of the Attorney General Public Counsel Unit. Issues: rate design, revenue distribution, cost of service.

22. Expert Testimony. Case No. U-21389. (2023). 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 for other Relief*. On Behalf of the Michigan Department of the Attorney General. Issues: capital expenditure adjustments, overview of proposal.

23. Expert Report. Case No. 22-1094-WW-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio, Inc. For the Period July 1, 2022 through June 30, 2023.* Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

24. Expert Report. Case No. 22-1096-ST-AIR. (2023). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc*. *For the period July 1, 2022 through June 30, 2023*. Prepared for the Public Utilities Commission of Ohio. Issues: cost of service, billing determinants, revenue distribution, rate design.

25. Expert Report. *Analysis of the effectiveness and ratepayer impacts regarding the Natural Gas Rate Stabilization Act of 2005. (S.C. Code Ann. Section 58-5-410).* On Behalf of the South Carolina Department of Consumer Affairs. July 27, 2023.

26. Expert Testimony. Docket No. 2023-70-G. (2023). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc's application for adjustments in its natural gas rate schedules and tariffs.* On Behalf of the South Carolina

Department of Consumer Affairs. Issues: revenue credit, revenue distribution, rate design. Direct and Surrebuttal.

27. Expert Testimony. Docket No. E-01345A-22-0144. (2023). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for a hearing to determine the fair value of the utility property of the company for ratemaking purposes, to fix a just and reasonable rate of return thereon, and to approve rate schedules designed to develop such return. On Behalf of the Utilities Division Arizona Corporation Commission.* Issues: cost of service, revenue distribution, rate design. Direct and Surrebuttal.

28. Expert Testimony. Docket No. 23-0068 (consol.) 23-0069. (2023). Before the Illinois Commerce Commission. *North Shore Gas Company, The Peoples Gas Light and Coke Company Proposed general increase in rates and revisions to service classifications, riders and terms and conditions of service.* On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

29. Expert Testimony. Docket No. 23-067. (2023). Before the Illinois Commerce Commission. *Ameren Illinois Company Proposed general increase in gas delivery service rates.* On Behalf of the Illinois Attorney General. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

30. Expert Testimony. Docket No. 23-066. (2023). Before the Illinois Commerce Commission. *Northern Illinois Gas Company d/b/a Nicor Gas Company Proposed general increase in gas rates.* On Behalf of the People of the State of Illinois. Issues: integrity management, infrastructure metrics, natural gas policy, state gas policy.

31. Expert Testimony. Docket No. U-22-081. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study Designated as TA334-4 Filed by Enstar Natural Gas Company, A Division of SEMCO Energy, Inc.* On Behalf of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, revenue distribution.

32. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: cost of service, rate design, seasonal rates, revenue allocation, customer charge.

33. Expert Testimony. Docket No. 2022.11.099. (2023). Before the Department of Public Service Regulation. *In the Matter of Montana-Dakota Utilities Co. for Authority to Establish Increased Rates for Electric Service.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Answering. Issues: rate increase, cost of service study, marginal cost of service, revenue allocation, rate design.

34. Expert Testimony. Docket No. U-22-078. (2023). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement Study and Tariff Filing Designated as TA510-1 Filed by Alaska Electric Light & Power Company.* On Behalf of the Office of the Attorney General, Regulatory Affairs & Public Advocacy Section. Issues: rate design, cost of service, revenue allocation, seasonal rates.

35. Expert Testimony. Docket No. U-21193. (2023). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for Approval of its*

Integrated Resource Plan pursuant to MCL 460.6t, and for other relief. On Behalf of the Michigan Department of the Attorney General. Issues: Resource planning, coal retirements, asset amortization, financial compensation mechanism.

36. Expert Testimony. Docket No. RP22-1033. (2023). Before the Federal Energy Regulatory Commission. *Northern Natural Gas Company.* On Behalf of the Northern Municipal Distributors Group and the Midwest Region Gas Task Force Association. Issues: tariff provisions, rate analysis, discount adjustment.

37. Expert Testimony. Docket No. 22-061-U. (2023). Before the Arkansas Public Service Commission. *In the Matter of an Investigation into Potential Cost Shifting Associated with Net Metering.* On Behalf of the Office of Tim Griffin, Attorney General of Arkansas. Issues: policy, net metering background.

38. Expert Testimony. Docket No. 22F-0263EG. (2023). Before the Public Utility Commission of the State of Colorado. *Olson's Greenhouses of Colorado, LLC. Complainant, v. Public Service Company of Colorado Respondent*. On Behalf of Olson's Greenhouses of Colorado, LLC. Issues: reliability, system upgrades, weather normalization.

39. Expert Testimony. Docket No. 2022.07.078. (2022). Before the Public Service Commission of the State of Montana. *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.* On Behalf of the Montana Consumer Counsel. Direct and Cross-Intervenor. Issues: riders, fixed cost recovery mechanism, power cost adjustment, cost of service, revenue distribution.

40. Expert Testimony. Docket No 2022-254-E. (2022). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Duke Energy Progress, LLC for Authority to Adjust and Increase its Electric Rates and Charges.* On Behalf of South Carolina Department of Consumer Affairs. Direct and Surrebuttal. Issues: Cost of service, revenue allocation, rate design.

41. Expert Testimony Docket No. 22-06014. (2022). *Before the Public Utilities Commission of Nevada. In the Matter of the Application by Sierra Pacific Power Company D/B/A NV Energy, filed pursuant to NRS 704.110(3) and NRS 704.110(4), addressing its annual revenue requirement for general rates charged to all classes of electric customers*. On Behalf of the Nevada Bureau of Consumer Protection. Issues: rate design, cost of services, marginal cost of service, revenue distribution.

42. Expert Testimony Docket No. 2022.06.067. (2022). *Before the Public Service Commission of the State of Montana. In RE NorthWestern Energy's Application for an Advanced Metering Opt-Out Tariff.* On Behalf of the Montana Consumer Counsel. Direct and Rebuttal. Issues: meter issues, opt-out fees, tariffs options.

43. Expert Testimony Docket No. 16-036-FR. (2022). *Before the Arkansas Public Service Commission. In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, INC., Pursuant to APSC Docket NO. 15-015-U. On Behalf of the Arkansas Attorney General Leslie Rutledge.* Issues: Rate design, netting adjustment, performance standards, projected year adjustments.

44. Expert Testimony Formal Case No. 1169. (2022). *Before the Public Service Commission of the District of Columbia. In the Matter of the application of Washington Gas Light*

Company for authority to increase existing rates and charges for gas service. On Behalf of the People's Counsel for the District of Columbia. Direct and Rebuttal. Issues: Revenue allocation, weather normalization, rate design.

45. Expert Testimony Case No. U-21224. (2022). *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 for other relief*. On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, revenue distribution, policy overview.

46. Expert Report. Case No. 695287. (2022). Before the Nineteenth Judicial District Court, The Parish of East Baton Rouge, State of Louisiana. *Washington-St. Tammany Electric Cooperative, Inc. and Claiborne Electric Cooperative, Inc., Plaintiff v. Louisiana Generating, L.L.C., Defendant.* On Behalf of Louisiana Generating, L.L.C. Issues: environmental regulations, re-fueling, regulatory rules, collateral benefits.

47. Expert Report. Case No. 0:20-cv-60981-AMC. (2022). *Café, Gelato & Panini LLC, d/b/a Café Gelato Panini, on behalf of itself and all others similarly situated, Plaintiff v. Simon Property Group, Inc., Simon Property Group, L.P., M. S. Management Associates, Inc. And The Town Center at Boca Raton Trust, Defendant.* On Behalf of Simon Property Group, Inc.

48. Expert Testimony Case No. U-20836. (2022). *Before the Michigan Public Service Commission. In the Matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, revenue distribution, peer comparison.

49. Expert Testimony. D.P.U. 22-22. (2022*). Before the Department of Public Utilities of the Commonwealth of Massachusetts. Petition of NSTAR Electric Company d/b/a Eversource Energy for Approval of a Performance-Based Ratemaking Plan and Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, §94 and 220 C.M.R. §5.00.* On Behalf of Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate design, TFP analysis, rate increases, benchmark analysis, revenue distribution. Direct and Surrebuttal.

50. Expert Testimony. Docket No. 21-097-U. (2022). In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs. On Behalf of the Office of Arkansas Attorney General. Issues: cost of service, rate design, reliability, billing determinant adjustment.

51. Expert Testimony. Docket No. 2021-361-G. (2022). Before the Public Service Commission of South Carolina. *In the Matter of: Dominion Energy South Carolina, Inc.'s Request for Approval of New Natural Gas Energy Efficiency Programs*. On Behalf of South Carolina Department of Consumer Affairs. Issues: DSM Rider, energy efficiency, shared savings. Direct and Surrebuttal.

52. Expert Report. Case No. 21-596-ST-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio Wastewater, Inc. For the Period January 1, 2021 through December 31, 2021*. Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

53. Expert Report. Case No. 21-595-WW-AIR. (2022). *Audit of the Application to Increase Rates of Aqua Ohio, Inc*. *For the Period January 1, 2021 through December 31, 2021.* Prepared for Public Utilities Commission of Ohio. Issues: rate design, cost of service, revenue distribution.

54. Expert Testimony. Docket No. 2021.09.112. (2022). *Before the Public Service Commission of the State of Montana. In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes.* On Behalf of the Montana Consumer Counsel. Issues: wholesale energy hedging, market exposure, overview of PCCAM filing, demand side management costs.

55. Expert Affidavit. Docket No. 2:21-cv-1074. (2021). In the United States District Court for the Western District of Louisiana. *The State of Louisiana by and through its Attorney General, Jeff Landry et al. Plantiffs, v. Joseph R. Biden, Jr., in his official capacity as President of the United States; et al., Defendants.* On Behalf of the Attorney General of Louisiana. Issues: social cost of carbon, carbon tax, environmental policy.

56. Expert Testimony. Case No. U21090. (2021). *Before the Michigan Public Service Commission. In the matter of the application of Consumers Energy Company for approval of its Integrated Resource Plan pursuant to MCL 460.6t, certain accounting approvals, and for other relief*. On Behalf of the Michigan Department of the Attorney General. Issues: IRP, coal plant retirements, acquisition premiums, financial compensation mechanism.

57. Expert Testimony. Docket No 16-036-FR. (2021). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: netting adjustments, rate increases, projected year adjustments, reliability.

58. Expert Report. Docket JCCP No. 4861. (2021). Before the Superior Court of the State of California County of Los Angeles, Central Civil West. *Coordination Proceeding Special Title [Rule 3.550] Southern California Gas Leak Cases.* On Behalf of Toll Brothers. Issues: gas leak, public service obligation, integrity management.

59. Expert Testimony. Docket No. U-35927. (2021). Before the Louisiana Public Service Commission. *In Re: Application of 1803 Electric Cooperative, Inc. for Approval of Power Purchase Agreements and for Cost Recovery.* Direct and Cross-Answering. On Behalf of Cleco Cajun LLC. Issues: tolling agreements, generation acquisition, risk factors.

60. Expert Testimony. Docket No. 21-060-U. (2021). Before the Arkansas Public Service Commission. *In the Matter of Joint Application of Centerpoint Energy Resources Corp. and Summit Utilities Arkansas, Inc. For all Necessary Authorizations and Approvals for Summit Utilities Arkansas, Inc. To Acquire the Arkansas Assets of Centerpoint Energy Resources Corp. and for Approval of a Certificate of Public Convenience and necessity for Summit Utilities Arkansas, Inc.* Direct and Surrebuttal. On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: asset acquisition, ratepayer benefits, acquisition synergies, Rider FRP.

61. Expert Affidavit. Civil Action No. 2:21-cv-00778 (2021). Before the United States District Court for the Western District of Louisiana. *The State of Louisiana v. Joseph R. Biden, Jr.* Issues: leasing and drilling moratorium, state revenue, coastal restoration, economic activity.

62. Expert Testimony. Docket No. 21-044-U (2021). Before the Arkansas Public Service Commission. *In the Matter of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas' Request to Extend Rider FRP.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: ratepayer benefits, service quality, cost of service, FRP extension.

63. Expert Testimony. Docket No. 17-010-FR (2021). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: rate increase, investment and expense trends, revenue deficiency, leak performance.

64. Expert Testimony. Case No. U-20963 (2021). 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 for other relief.* On Behalf of the Michigan Department of the Attorney General. Issues: cost of service, peak allocation, revenue distribution.

65. Expert Testimony. U-20-072, U-20-073, U-20-074. (2021). Before the Regulatory Commission of Alaska. *In the Matter of the Revenue Requirement study and Tariff Filing designated as TA886-2 filed by Alaska Power Company, In the Matter of the Revenue Requirement study and Tariff filing designated as TA6-521 filed by Goat Lake Hydro, Inc., In the Matter of the Revenue Requirement study and Tariff filing designated as TA4-573 filed by BBL Hydro, Inc.* On Behalf of the Alaska Office of Attorney General. Issues: rate groups, cost of service.

66. Expert Testimony. Docket No. P20-001. (2021). Before the Louisiana Pilotage Fee Commission. *In Re: Request for Increase in Approved Pilot Complement; Increased Funding for necessary Additional Manpower; Upward Adjustment of Estimated Average Annual Pilot Compensation; and Related Relief Pursuant to LA R.S. 34:112.* On Behalf of the Louisiana Chemical Association (LCA) and Louisiana Mid-Continent Oil & Gas Association (LMOGA). Issues: unreasonable requests, fee structure, economic impact, over earnings.

67. Expert Testimony. D.P.U. 20-120. (2021). Before the Commonwealth of Massachusetts Before the Department of Public Utilities. *Petition of Boston Gas Company d/b/a National Grid Pursuant to G.L. c. 164, 94 and 220 C.M.R. 5.00 for Approval of an Increase in Base Distribution Rates and Approval of a Performance-Based Ratemaking Plan.* On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy. Issues: rate increase, accelerated depreciation, benchmarking analysis, performance incentive mechanism.

68. Expert Testimony. RPU-2020-0001. (2020). Before the Iowa Utilities Board. *In Re: Iowa-American Water Company.* On Behalf of the Office of Consumer Advocate. Issues: rate increase, test trackers, RSM accounting ratemaking construct.

69. Expert Testimony. BPU Docket Nos. QO19010040 and GO20090622. (2020). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Energy Efficiency Programs and the Associated Cost Recovery Mechanisms Pursuant to the Clean Energy Act, N.J.S.A. 48:3-87.8 et seq. and 48:3-98.1 et seq.* On behalf of the Division of Rate Counsel. Issues: CBA requirements, capacity benefits, volatility benefits.

70. Expert Testimony. Docket No. 2020-125-E. (2020). Before the Public Service Commission of South Carolina. *In the Matter of: Application of Dominion Energy South Carolina, Incorporated for Adjustments of Rates and Charges (See Commission Order No. 2020-313).* On Behalf of the South Carolina department of Consumer Affairs. Issues: cost of service, revenue allocation, rate design.

71. Answering Testimony. Before the United States of America Federal Energy Regulatory Commission. Docket No. RP20-614-000 and RP20-618-000. (2020). *Transcontinental Gas Pile Line Company, LLC.* On Behalf of the North Carolina Utilities Commission. Issues: Tariff revisions, assessment of Transco claims.

72. Expert Testimony. Docket No. 16-036-FR. (2020). *Before the Arkansas Public Service Commission. In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U. Direct and Surrebuttal*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increases, investment and expenses trends, load forecast, historic year netting adjustment, reliability issues.

73. Expert Testimony. Docket No. 2019.12.101. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Application for Approval of Capacity Resource Acquisition.* On the Behalf of the Montana Consumer Counsel. Issues: sale of capital asset, evaluation benefits, ratepayer cost exposure, reserve fund.

74. Expert Testimony. Formal Case No. 1162. (2020). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges for Gas Service*. On Behalf of the Office of the People's Counsel. Issues: rate increase, revenue adjustment, weather normalization, rate design, revenue distribution.

75. Expert Testimony. Docket No. E-01345A-19-0236. (2020). Before the Arizona Corporation Commission. *In the Matter of the Application of Arizona Public Service Company for Ratemaking Purposes to Fix a Just and Reasonable Rate of Return Thereon, to Approve Rate Schedules Designed to Develop such Return*. Direct and Surrebuttal. On Behalf of the Utilities Division of the Arizona Corporation Commission. Issues: Cost of Service, Revenue Distribution, Rate Design.

76. Expert Testimony. Docket No. 17-010-FR. (2020). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate increase, leak replacement and reduction, netting adjustment, revenue deficiency, accounting policy changes.

77. Expert Testimony. Case No. U-20697. (2020). 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 for other relief*. On Behalf of the Michigan Department of Attorney General. Issues: cost of service, revenue distribution, rate design.

78. Expert Testimony. Docket No. 2019.09.058. (2020). Before the Public Service Commission of the State of Montana. *In the Matter of NorthWestern Energy's Annual PCCAM Filing and Application for Approval of Tariff Changes*. On the Behalf of the Montana Consumer Counsel. Issues: purchase power expenses, cost sharing, PCAAM

power cost.

79. Expert Testimony. Formal Case No. 1156. (2020). Before the Public Service Commission of the District of Columbia. *In the matter of Potomac Electric Power Company for authority to implement a multiyear rate plan for electric distribution service in the district of Columbia.* Direct, Rebuttal, Surrebuttal, Supplemental, and Second Supplemental. On Behalf of the Office of the People's Counsel. Issues: revenue distribution, rate design, customer charge, performance metric policies, performance metric incentives.

80. Expert Testimony. Case No. U-20561. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority*. On Behalf of the Michigan Department of Attorney General. Issues: Cost of service, allocation of production plant, allocation of sub-transmission plant, revenue distribution.

81. Expert Testimony. Cause No. 45253. (2019). Before the Indiana Utility Regulatory Commission. *Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code 8-1-2-42.7 and 8-1-2-61, for (1) Authority to Modify its Rates and Charges for Electric Utility Service through a Step-In of New Rates and Charges using a Forecasted Test Period; (2) Approval of New Schedules of Rates and Charges, General Rules and Regulations, and Riders; (3) Approval of a Federal Mandate Certificate Under Ind. Code 8-1-8.4-1; (4) Approval of Revised Electric Depreciation Rates Applicable to its Electric Plant in Service; (5) Approval of Necessary and Appropriate Accounting Deferral Relief; and (6) Approval of a Revenue Decoupling Mechanism for Certain Customers Classes*. On Behalf of the Indiana Office of Utility Consumer Counsel. Issues: Decoupling, revenue decoupling mechanism and design, commission policy, benchmarking analysis.

82. Expert Testimony. Docket 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues*:* Solar investment, risk assessment, proposed rider.

83. Expert Testimony. Docket No. 16-036-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

84. Expert Testimony. Docket No. 19-019-U. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Petition of Entergy Arkansas, LLC for Approval of a Build-Own-Transfer Arrangement for a Renewable Resource and for all other Related Approvals*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: Solar project approval, ratepayer risk, cost allocation.

85. Expert Testimony. Docket No. 17-010-FR. (2019). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Centerpoint Energy Resources Corp. D/B/A Centerpoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: retail rates, leak analysis, revenue deficiency, investments.

86. Expert Testimony. Case No. U-20471. (2019). Before the Michigan Public Service Commission. *In the matter of the Application of DTE Electric Company for approval of its*

Integrated Resource Plan pursuant to MCL 460.6t, and for other relief. On Behalf of the Michigan Department of Attorney General. Issues: load forecasting, least-cost system planning.

87. Expert Report. Docket No. 18-004422. (2019). Before the State of Florida Division of Administrative Hearings. *Peoples Gas System vs. South Sumter Gas Company, LLC and the City of Leesburg.* On Behalf of the City of Leesburg. Issues: retail rates, customer growth, sales trends and forecasts, policy, cost of service, socio-economic trends and forecasts.

88. Expert Testimony. Docket Nos. GO18101112 and EO18101113. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of its Clean Energy Future-Energy Efficiency ("CEF-EE") Program on a Regulated Basis.* On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, decoupling mechanisms.

89. Expert Testimony. Docket Nos. EO18060629 and GO18060630. (2019). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric and Gas Company for Approval of the Second Energy Strong Program (Energy Strong II)*. On behalf of the Division of Rate Counsel. Issues: economic impact, cost benefit analysis, infrastructure replacement, cost recovery tracker mechanisms.

90. Expert Report. Docket No. 2011-AD-2. (2019). On Behalf of the Mississippi Public Service Commission. *Order Establishing Docket to Investigate the Development and Implementation of Net Metering Programs and Standards.* On Behalf of the Mississippi Public Utilities Staff. Issues: Net-metering, distributed generation.

91. Expert Testimony. Docket No. D2018.2.12. (2018). Before the Public Service Commission of the State of Montana. *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.* On Behalf of the Montana Consumer Counsel. Issues: Net-metering, cost of service, revenue distribution, rate design.

92. Expert Testimony. Docket No. 19-SEPE-054-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Sunflower Electric Power Corporation and Mid-Kansas Electric Company, Inc. for an Order Approving the Merger of Mid-Kansas Electric Company, Inc. into Sunflower Electric Power Corporation*. On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger impacts, rates, tariffs.

93. Expert Testimony. Docket No. 18-046-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Oklahoma Gas and Electric Company Pursuant to APSC Docket No. 16-052-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: formula rate plan, plant investment and expenses benchmarking analysis, reliability.

94. Expert Testimony. Docket No. 16-036-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: rate design, reliability, and formula rate plan.

95. Expert Testimony. Docket No. 2017-AD-0112. (2018). Before the Mississippi Public

Service Commission. *In Re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project.* On Behalf of the Mississippi Public Utilities Staff. Issues: cost of service and rate design.

96. Expert Affidavit. Docket No. 87011-E. (2018). Before the 16th Judicial District Court Parish of St. Martin State of Louisiana. *Bayou Bridge Pipeline, LLC versus 38.00 Acres, More or Less, Located in St. Martin Parish; Barry Scott Carline, et al.* Issues: economic impacts.

97. Expert Testimony. Docket No. QO18080843. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Nautilus Offshore Wind, LLC for the Approval of the State Waters Wind Project and Authorizing Offshore Wind Renewable Energy Certificates.* On behalf of the Division of Rate Counsel. Issues: regulatory policy and cost-benefit analyses.

98. Expert Testimony. Docket No. ER18010029 and GR18010030. (2018). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Public Service Electric and Gas Company for Approval of an Increase in Electric and Gas Rates and for Changes in the Tariffs for Electric and Gas Service, B.P.U.N.J. No. 16 Electric and B.P.U.N.J No. 16 Gas, and for Changes in Depreciation Rates, Pursuant to N.J.S.A. 48:2-18, N.J.S.A. 48:2-21 and N.J.S.A. 48:2-21.1, and for Other Appropriate Relief.* On behalf of the Division of Rate Counsel. Issues: rate proposal, revenue decoupling, regulatory policy, cost benchmarking.

99. Expert Testimony. Docket No. T-34695. (2018). Before the Louisiana Public Service Commission. *In re: Application for a rate increase on service originating at Grand isle and termination at St. James for Crude Petroleum as currently outlined in LPSC Tariff No. 75.2*. On Behalf of Energy XXI GOM, LLC. Issues: cost of service, rate design, and alternative regulation.

100. Expert Testimony. Docket No. 17-071-U. (2018). Before the Arkansas Public Service Commission*. In the Matter of the Application of Black Hills Energy Arkansas, Inc. for Approval of a General Change in Rates and Tariffs*. On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, billing determinates.

101. Expert Testimony. Docket No. 17-010-FR. (2018). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

102. Expert Testimony. Case No. PU-17-398. (2018). Before the North Dakota Public Service Commission. *In the Matter of the Application of Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in North Dakota*. On Behalf of the North Dakota Service Commission Advocacy Staff. Issues: cost of service, marginal cost of service, and rate design.

103. Expert Testimony. Docket No. 20170179-GU. (2018). Before the Florida Public Service Commission. *In re: Petition for rate increase and approval of depreciation study by Florida City Gas.* On Behalf of the Citizens of the State of Florida. Issues: policy issues concerning long-term gas capacity procurement.

104. Expert Testimony. Docket No. 18-KCPE-095-MER. (2018). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy*

Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Merger of Westar, Inc. and Great Plains Energy Incorporated. On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

105. Expert Testimony. Docket No. GR17070776. (2018). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of the Next Phase of the Gas System Modernization Program and Associated Cost Recovery Mechanism ("GSMP II"). On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

106. Expert Affidavit. Case No. 18-489. (2018). Before the Civil District Court for the Parish of Orleans, State of Louisiana. *Bayou Bridge Pipeline, LLC versus The White Castle Lumber and Shingle Company Limited and Jeanerette Lumber & Shingle CO. L.L.C.* Issues: economic impact of crude oil pipeline development.

107. Expert Testimony. Docket No. 16-036-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: cost of service, rate design, alternative regulation, formula rate plan.

108. Expert Testimony. Docket No. 2017-AD-0112. (2017). Before the Mississippi Public Service Commission. *In re: Encouraging Stipulation of Matters in Connection with the Kemper County IGCC Project*. On Behalf of the Mississippi Public Utilities Staff. Issues: financial analysis, rates and cost trends, economic impacts of proposal.

109. Expert Testimony. Case No. 2017-00179. (2017). Before the Public Service Commission, Commonwealth of Kentucky. *Electronic Application of Kentucky power Company For (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; (4) An Order Approving Accounting Practices to Establish a Regulatory Asset or Liability Related to the Big Sandy 1 Operation Rider; and (5) An Order Granting All Other Required Approvals and Relief.* On Behalf of the Office of the Kentucky Attorney General. Issues: rate design, revenue allocation, economic development.

110. Expert Testimony. Docket No. 17-010-FR. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filing of CenterPoint Energy Resources Corp. D/B/A CenterPoint Energy Arkansas Gas Pursuant to APSC Docket No. 15-098-U.* On Behalf of the Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

111. Expert Testimony. Formal Case No. 1142. (2017). Before the Public Service Commission of the District of Columbia. *In the Matter of the Merger of AltaGas Ltd. and WGL Holdings, Inc.* On Behalf of the Office of the People's Counsel. Issues: merger/acquisition policy, financial risk, ring-fencing, and reliability.

112. Expert Testimony. D.P.U. 17-05. (2017). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00*. On Behalf of the Massachusetts Office of the Attorney General Office of Ratepayer Advocacy.

Issues: performance-based ratemaking, multi-factor productivity estimation.

113. Deposition and Testimony. (2017) Before the Nebraska Section 70, Article 13 Arbitration Panel. *Northeast Nebraska Public Power District, City of South Sioux City Nebraska; City of Wayne, Nebraska; City of Valentine, Nebraska; City of Beatrice, Nebraska; City of Scribner, Nebraska; Village of Walthill, Nebraska, vs. Nebraska Public Power District.* On the Behalf of Baird Holm LLP for the Plaintiffs. Issues: rate discounts; cost of service; utility regulation, economic harm.

114. Expert Testimony. Docket No. 16-052-U. (2017). Before the Arkansas Public Service Commission. *In the Matter of the Application of the Oklahoma Gas and Electric Company for Approval of a General Change in Rates, Charges and Tariffs.* On the Behalf of the Office of Arkansas Attorney General Leslie Rutledge. Issues: cost of service, rate design, alternative regulation, formula rate plan.

115. Expert Testimony. Docket No. 16-KCPE-593-ACQ. (2016). Before the Kansas Corporation Commission. *In the Matter of the Joint Application of Great Plains Energy Incorporated, Kansas City Power & Light Company, and Westar Energy, Inc. for Approval of the Acquisition of Westar, Inc. by Great Plains Energy Incorporated.* On the Behalf of the Kansas Electric Power Cooperative, Inc. Issues: merger/acquisition policy, financial risk, and ring-fencing.

116. Expert Testimony. Formal Case No. 1139. (2016). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.* On the Behalf of the Office of the People's Counsel for the District of Columbia. Issues: cost of service, rate design, alternative regulation.

117. Expert Affidavit. Docket No. CP15-558-000 (2016). Before the United States of America Federal Energy Regulatory Commission. *PennEast Pipeline Company, LLC*. Affidavit and Reply Affidavit. On the Behalf of the New Jersey Division of Rate Counsel. Issues: pipeline capacity, peak day requirements.

118. Expert Testimony. Docket No. RPU-2016-0002. (2016). Before the Iowa Utilities Board. *In re: Iowa American Water Company application for revision of rates.* On behalf of the Office of Consumer Advocate. Issue: revenue stabilization mechanism, revenue decoupling.

119. Expert Testimony. Docket No. 15-015-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Formula Rate Plan Filings of Entergy Arkansas, Inc., Pursuant to APSC Docket No. 15-015-U*. On behalf of the Office of the Arkansas Attorney General Leslie Rutledge. Issue: formula rate plan evaluation.

120. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: load forecasting.

121. Expert Testimony. Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI. (2016). Before the Florida Public Service Commission. *In re: Petition for rate increase by Florida Power & Light Company (consolidated).* On behalf of the Citizens of the State of Florida. Issue: off-system sales incentives.

122. Expert Testimony. Project No. 5-103. (2016). United States of America Federal Energy Regulatory Commission. *Confederated Salish and Kootenai Tribes Energy Keepers, Incorporated*. On behalf of the Flathead, Mission, and Jocko Valley Irrigation Districts and the Flathead Joint Board of Control of the Flathead, Mission, and Jocko Valley Irrigation Districts.

123. Expert Testimony. Docket No. 15-098-U. (2016). Before the Arkansas Public Service Commission. *In the Matter of the Application of CenterPoint Energy Resources Corp. d/b/a CenterPoint Energy Arkansas Gas for a General Change or Modification in its Rates, Charges and Tariffs.* On behalf of the Office of the Arkansas Attorney General. Issues: formula rate plan, cost of service and rate design.

124. Expert Testimony. BPU Docket No. GM15101196. (2016). *In the Matter of the Merger of Southern Company and AGL Resources, Inc*. On behalf of the New Jersey Division of Rate Counsel. Issues: merger standards of review, customer dividend contributions, synergy savings and costs to achieve, ratemaking treatment of merger-related costs.

125. Expert Testimony. Docket No. 15-078-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Joint Application of SourceGas Inc., SourceGas LLC, SourceGas Holdings LLC and Black Hills Utility Holdings, Inc. for all Necessary Authorizations and Approvals for Black Hills Utility Holdings, Inc. to Acquire SourceGas Holdings LLC.* On behalf of the Office of the Arkansas Attorney General. Issues: public policy and regulatory policy associated with the acquisition.

126. Expert Testimony. Docket No. 15-031-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of SourceGas Arkansas Inc. for an Order Approving the Acquisition of Certain Storage Facilities and the Recovery of Investments and Expenses Associated Therewith.* On behalf of the Office of the Arkansas Attorney General. Issues: cost-benefit analysis, transmission cost analysis, and a due diligence analysis.

127. Expert Testimony. Docket No. 15-015-U. (2015). Before the Arkansas Public Service Commission. *In the Matter of the Application of Entergy Arkansas, Inc. for Approval of Changes in Rates for Retail Electric Service.* On behalf of the Office of the Arkansas Attorney General. Issues: economic development riders and production plant cost allocation.

128. Expert Testimony. Docket No. 7970. (2015). Before the Vermont Public Service Board. *Petition of Vermont Gas Systems, Inc., for a certificate of public good pursuant to 30 V.S.A.§ 248, authorizing the construction of the "Addison Natural Gas Project" consisting of approximately 43 miles of new natural gas transmission pipeline in Chittenden and Addison Counties, approximately 5 miles of new distribution mainlines in Addison County, together with three new gate stations in Williston, New Haven, and Middlebury, Vermont*. On behalf of AARP-Vermont. Issues: net economic benefits of proposed natural gas transmission project.

129. Expert Testimony. File No. ER-2014-0370 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of Kansas City Power & Light Company for Authority Implement A General Rate Increase for Electric Service*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, class cost of service, and policy and ratemaking considerations in connection with electric vehicle charging stations.

130. Expert Testimony. File No. ER-2014-0351 (2015). Before the Public Service Commission of the State of Missouri. *In the Matter of The Empire District Electric Company for Authority To File Tariffs Increasing Rates for Electric Service Provided to Customers In the Company's Missouri Service Area*. On behalf of the Missouri Office of the People's Counsel. Issues: customer charges, rate design, revenue distribution, and class cost of service.

131. Expert Testimony. D.P.U. 14-130 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of the Company's 2015 Gas System Enhancement Program Plan, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015.* On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

132. Expert Testimony. D.P.U. 14-131 (2015). Before the Massachusetts Department of Public Utilities. *Petition of The Berkshire Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

133. Expert Testimony. D.P.U. 14-132 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for approval by the Department of Public Utilities of the Companies' Gas System Enhancement Program for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

134. Expert Testimony. D.P.U. 14-133 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Liberty Utilities for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

135. Expert Testimony. D.P.U. 14-134 (2015). Before the Massachusetts Department of Public Utilities. *Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

136. Expert Testimony. D.P.U. 14-135 (2015). Before the Massachusetts Department of Public Utilities. *Petition of NSTAR Gas Company for approval by the Department of Public Utilities of the Company's Gas System Enhancement Program Plan for 2015, pursuant to G.L. c. 164, § 145, and for rates to be effective May 1, 2015*. On behalf of the Attorney General's Office. Issues: ratepayer protections, cost allocations, rate design, performance metrics.

137. Expert Report. Docket No. X-33192 (2015). Before the Louisiana Public Service Commission. *Examination of the Comprehensive Costs and Benefits of Net Metering in Louisiana.* On behalf of the Louisiana Public Service Commission. Issues: cost-benefit, cost of service, rate impact.

138. Expert Testimony. F.C. 1119 (2014). Before the District of Columbia Public Service

Commission. *In the Matter of the Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and new Special Purpose Entity, LLC*. On behalf of the Office of the People's Counsel. Issues: economic impact analysis, reliability, consumer investment fund, regulatory oversight, impacts to competitive electricity markets.

139. Expert Report. Civil Action 1:08-cv-0046 (2014). Before the U.S. District Court for the Southern District of Ohio. *Anthony Williams, et al., v. Duke Energy International, Inc., et al.* On behalf of Markovits, Stock & DeMarco, Attorneys & Counselors at Law. Issues: public utility regulation, electric power markets, economic harm.

140. Expert Testimony. D.P.U. 14-64 (2014). Before the Massachusetts Department of Public Utilities. *NSTAR Gas Company/HOPCO Gas Services Agreement. On behalf of the Office of the Public Advocate*. Issues: certain ratemaking features associated with the proposed Gas Service Agreement.

141. Expert Testimony. Docket Nos. 14-0224 and 14-0225 (2014). Before the Illinois Commerce Commission. *In the Matter of the Peoples Gas Light and Coke Company and North Shore Gas Company Proposed General Increase in Rates for Gas Service (consolidated)*. On behalf of the People of the State of Illinois. Issues: test year expenses, cost benchmarking analysis, pipeline replacement, and leak rate comparisons.

142. Expert Testimony. Docket 8191 (2014). Before the Vermont Public Service Board. *In Re: Petition of Green Mountain Power Corporation for Approval of a Successor Alternative Regulation Plan.* On the behalf of AARP-Vermont. Issues: Alternative Regulation.

143. Expert Testimony. Docket No. 2013-00168 (2014). Before the Maine Public Utilities Commission. *In the Matter of the Request for Approval of an Alternative Rate Plan (ARP 2014) Pertaining to Central Maine Power Company*. On behalf of the Office of the Public Advocate. Issues: class cost of service study, marginal cost of service study, revenue distribution and rate design.

144. Expert Testimony. D.P.U. 13-90 (2013). Before the Massachusetts Department of Public Utilities. *Petition of Fitchburg Gas and Electric Light Company (Electric Division) d/b/a Unitil to the Department of Public Utilities for approval of the rates and charges and increase in base distribution rates for electric service.* On behalf of the Office of the Ratepayer Advocate. Issues: capital cost adjustment mechanism and performance-based regulation.

145. Expert Testimony. BPU Docket Nos. EO13020155 and GO13020156. (2013). Before the State of New Jersey Board of Public Utilities. *I/M/O The Petition of Public Service Electric & Gas Company for the Approval of the Energy Strong Program.* On behalf of the Division of Rate Counsel. Issues: economic impact, infrastructure replacement program rider, pipeline replacement, leak rate comparisons and cost benefit analysis.

146. Expert Testimony. D.P.U. 13-75 (2013). Before the Massachusetts Department of Public Utilities. *Investigation by the Department of Public Utilities on its Own Motion as to the Propriety of the Rates and Charges by Bay State Gas Company d/b/a Columbia Gas of Massachusetts set forth in Tariffs M.D.P.U. Nos. 140 through 173, and Approval of an Increase in Base Distribution Rates for Gas Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., filed with the Department on April 16, 2013, to be effective May 1, 2013*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement, and leak

rate comparisons; environmental benefits analysis; O&M offset; and cost benchmarking analysis.

147. Expert Testimony. Docket No. 13-115 (2013). Before the Delaware Public Service Commission. *In the Matter of the Application of Delmarva Power & Light Company FOR an Increase in Electric Base Rates and Miscellaneous Tariff Changes* (Filed March 22, 2013). On the Behalf of Division of the Public Advocate. Issues: pro forma infrastructure proposal, class cost of service study, revenue distribution, and rate design.

148. Expert Testimony. Formal Case No. 1103 (2013). Before the Public Service Commission of the District of Columbia. *In the Matter of the Application of the Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. On the Behalf of the Office of the People's Counsel of the District of Columbia. Issues: Pro forma adjustment for reliability investments.

149. Expert Testimony. Case No. 9326 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments to its Electric and Gas Base Rates*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Electric Reliability Investment ("ERI") initiatives, pro forma gas infrastructure proposal, tracker mechanisms, class cost of service study, revenue distribution, and rate design

150. Rulemaking Testimony. (2013). Before the Louisiana Tax Commission. Examination of Louisiana Assessors' Association Well Diameter Analysis, economic development policies regarding midstream assets and industrial development.

151. Expert Testimony. Case No. 9317 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Delmarva Power & Light Company for Adjustments to its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

152. Expert Testimony. Case No. 9311 (2013). Before the Public Service Commission of Maryland. *In the Matter of the Application of Potomac Electric Power Company for an Increase in its Retail Rates for the Distribution of Electric Energy*. Direct, and Surrebuttal. On the Behalf of the Maryland Office of the People's Counsel. Issues: Grid Resiliency Charge, tracker mechanisms, pipeline replacement, class cost of service study, revenue distribution, and rate design.

153. Expert Testimony. Docket No. 12AL-1268G (2013). Before the Public Utilities Commission of the State of Colorado. *In the Matter of the Tariff Sheets Filed by Public Service Company of Colorado with Advice No. 830 – Gas. Answer*. On the Behalf of the Colorado Office of Consumer Counsel. Issues: Pipeline System Integrity Adjustment, tracker mechanisms, pipeline replacement and leak rate comparisons.

154. Expert Testimony. BPU Docket No. EO12080721 (2013). Before the New Jersey Board of Public Utilities. *In the Matter of the Public Service Electric & Gas Company for Approval of an Extension of Solar Generation Program*. On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal, Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design and net economic benefits.

155. Expert Testimony. BPU Docket No. EO12080726 (2013). Before the New Jersey Board

of Public Utilities. *In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Loan III Program.* On the Behalf of the New Jersey Division of Rate Counsel. Direct, Rebuttal and Surrebuttal. Issues: solar energy market design, solar energy market conditions, solar energy program design.

156. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. December 17, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

157. Expert Testimony. D.P.U. 12-25. (2012). Before the Massachusetts Department of Public Utilities. *In the Matter of Bay State Gas Company d/b/a/ Columbia Gas Company of Massachusetts Request for Increase in Rates*. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Target infrastructure replacement program rider, pipeline replacement and leak rate comparisons.

158. Expert Testimony. Docket Nos. UE-120436, et.al. (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms, attrition adjustments.

159. Expert Testimony. Case No. 9286. (2012) Before the Public Service Commission of Maryland. *In Re: Potomac Electric Power Company ("Pepco") General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

160. Expert Testimony. Case No 9285. (2012) Before the Public Service Commission of Maryland. *In Re: the Delmarva Power and Light Company General Rate Case*. On the Behalf of the Maryland Office of the People's Counsel. Issues: Capital tracker mechanisms/reliability investment mechanisms, reliability issues, regulatory lag, class cost of service, revenue distribution, rate design.

161. Expert Testimony. Docket Nos. UE-110876 and UG-110877 (consolidated). (2012). Before the Washington Utilities and Transportation Commission. *Washington Utilities and Transportation Commission v. Avista Corporation D/B/A Avista Utilities*. On the Behalf of the Washington Attorney General, Office of the Public Counsel. Issues: Revenue Decoupling, lost revenues, tracker mechanisms.

162. Expert Testimony. BPU Docket No. EO11050314V. (2012). Before the New Jersey Board of Public Utilities. *In the Matter of the Petition of Fishermen's Atlantic City Windfarm, LLC for the Approval of the State Waters Project and Authorizing Offshore Wind Renewable Energy Certificates*. On the Behalf of the New Jersey Division of Rate Counsel. February 3, 2012. Issues: approval of offshore wind project and ratepayer financial support for the proposed project.

163. Expert Testimony. Docket No. NG 0067. (2012). Before the Public Service Commission of Nebraska. *In the Matter of the Application of SourceGas Distribution, LLC Approval of a General Rate Increase*. On the Behalf of the Public Advocate. January 31, 2012. Issues: Revenue Decoupling, Customer Adjustments, Weather Normalization

Adjustments, Class Cost of Service Study, Rate Design.

164. Expert Testimony. Docket No. G-04204A-11-0158. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of UNS Gas, Inc. for the Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of Its Arizona Properties*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

165. Expert Testimony. Formal Case Number 1087. (2011). Before the Public Service Commission of the District of Columbia. On the Behalf of the Office of the People's Counsel of the District of Columbia. *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*. Issues: Regulatory lag, ratemaking principles, reliability-related capital expenditure tracker proposals.

166. Expert Affidavit. Case No. 11-1364. (2011). *The State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission v. United States Environmental Protection Agency and Lisa P. Jackson.* Before the United States Court of Appeals for the District of Columbia Circuit. On the behalf of the State of Louisiana, the Louisiana Department of Environmental Quality, and the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

167. Expert Affidavit. Docket No. EPA-HQ-OAR-2009-0491. (2011). Before the U.S. Environmental Protection Agency. *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*. On the Behalf of the Louisiana Public Service Commission. Issues: Impacts of environmental costs on electric utilities, compliance requirements, investment cost of mitigation equipment, multi-area dispatch modeling and plant retirements.

168. Expert Testimony. Case No. 9296. (2011). Before the Maryland Public Service Commission. *On the Behalf of the Maryland Office of People's Counsel. In the Matter of the Application of Washington Gas Light Company for Authority to Increase Existing Rates and Charges and Revise its Terms and Conditions for Gas Service*. Issues: Infrastructure Cost Recovery Rider; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

169. Expert Testimony. Docket No. G-01551A-10-0458. (2011). Before the Arizona Corporation Commission. On the Behalf of the Arizona Corporation Commission Staff. *In the Matter of the Application of Southwest Gas Corporation for the Establishment of Just and Reasonable Rates and Charges Designed to Realize A Reasonable Rate of Return on the Fair Value of its Properties throughout Arizona*. Issues: Revenue Decoupling; Class Cost of Service Modeling; Revenue Distribution; Rate Design.

170. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. *In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company*. Issues: Revenue Decoupling and Rate Design. (Direct and Rebuttal)

171. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer

Advocacy. *Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Capital Cost Rider, Revenue Decoupling.

172. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. *Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism*. Issues: Pipeline Replacement Rider, Revenue Decoupling.

173. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

174. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

175. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

176. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

177. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

178. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

179. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

180. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

181. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

182. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

183. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

184. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

185. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

186. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380-A, ex parte, (2009). Before the Louisiana Public Service Commission. In re: Environmental Adjustment Clause and Environmental Certification for Electric Power Generation Resources. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets cost recovery treatment; other generation planning issues.

187. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

188. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues:

revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

189. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

190. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

191. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

192. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

193. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

194. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

195. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

196. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the

Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

197. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

198. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

199. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

200. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

201. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

202. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

203. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

204. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

205. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

206. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

207. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff

Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

208. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

209. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

210. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

211. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

212. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

213. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

214. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

215. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of

Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

216. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

217. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

218. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

219. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

220. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

221. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

222. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

223. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

224. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

225. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

226. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161;

480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

227. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

228. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

229. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

230. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

231. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

232. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

233. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

234. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

235. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

236. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

237. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

238. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

239. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

240. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

241. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

242. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

243. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

244. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

245. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

246. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

247. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-

Effective Conservation Potentials for Florida.

248. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

249. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Contributor, 2014-2018, *Wall Street Journal*, *Journal Reports*, Energy

Editorial Board Member, 2015-2017, *Utilities Policy*

Referee, 2014-Current, *Utilities Policy*

Referee, 2010-Current, *Economics of Energy & Environmental Policy*

Referee, 1995-Current*, Energy Journal*

Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*

Referee, 2005, *Energy Policy*

Referee, 2004, *Southern Economic Journal*

Referee, 2002, *Resource & Energy Economics*

Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists ("IAEE"), United States Association of Energy Economics ("USAEE"), the National Association for Business Economics ("NABE"), and the Energy Bar Association (National and Louisiana Chapter; current Board member of LA chapter).

HONORS AND AWARDS

Baton Rouge Business Report, Selected as one of the "Capital Region 500" (2023).

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current).

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Energy and the Environment (Survey Course)

Principles of Microeconomic Theory

Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept. of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on “Society and the Coast.”

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

“The Gulf Coast Energy Situation: Outlook for Production and Consumption.” Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

“The Impact of Hurricane Katrina on Louisiana’s Energy Infrastructure and National Energy Markets.” Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

“Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation.” Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

“Regulatory and Ratemaking Issues with Cost and Revenue Trackers.” Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

“Demand Modeling and Forecasting for Regulators.” Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

“Demand Modeling and Forecasting for Regulators.” Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

“Regulatory and Cost Recovery Approaches for Smart Grid Applications.” Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

"Regulatory and Ratemaking Issues Associated with Cost and Expense Adjustment Mechanisms." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 28, 2011.

"Utility Incentives, Decoupling, and Renewable Energy Programs." Michigan State University, Institute of Public Utilities, Advanced Regulatory Studies Program. Lansing, Michigan. September 29, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 6-8, 2012.

"Traditional and Incentive Ratemaking Workshop." New Mexico Public Utilities Commission Staff. Santa Fe, NM October 18, 2012.

"Traditional and Incentive Ratemaking Workshop." New Jersey Board of Public Utilities Staff. Newark, NJ. March 1, 2013.

"Natural Gas Issues and Recent Market Trends." Michigan State University Institute of Public Utilities, GridSchool Regulatory Studies Program, East Lansing, Mich., March 29, 2017.

"Gas Supply Planning and Procurement: Regulatory Overview and issues." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Natural Gas Supply Issues and Challenges." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 17, 2017.

"Incentives, Risk and Changes in the Nature of Regulation." Michigan State University Institute of Public Utilities, Basic Regulatory Studies Program, East Lansing, Mich., Aug 18, 2017.

"Traditional and Alternative Forms of Regulation: Background and Overview." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Utility and policy motivations for risk and change." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

"Traditional and Alternative Forms of Regulation: Incentives and Formula Based Methods." Michigan State University Institute of Public Utilities, Advanced Regulatory Studies Program, East Lansing, Mich., October 2, 2017.

THESIS/DISSERTATIONS COMMITTEES

Active:
1 Thesis Committee Memberships (Environmental Studies)
2 Ph.D. Dissertation Committee (Economics)
Completed:
8 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences,

Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Committee Member, Energy Education Curriculum Committee. E.J. Ourso College of Business. LSU (2016-Current).

Chairman, LSU Energy Initiative/LSU Energy Council (2014-Current).

Co-Director & Steering Committee Member, LSU Coastal Marine Institute (2009-2014).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-2014); Full Member (2014-current).

LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Board Member (2018). Energy Bar Association, Louisiana Chapter.

Program Committee Member (2017). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2016). Gulf Coast Power Association Conference. New Orleans.

Program Committee Member (2015). Gulf Coast Power Association Workshop/Special Briefing.

"Gulf Coast Disaster Readiness: A Past, Present and Future Look at Power and Industry Readiness in MISO South."

Advisor (2008). National Association of Regulatory Utility Commissioners. Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

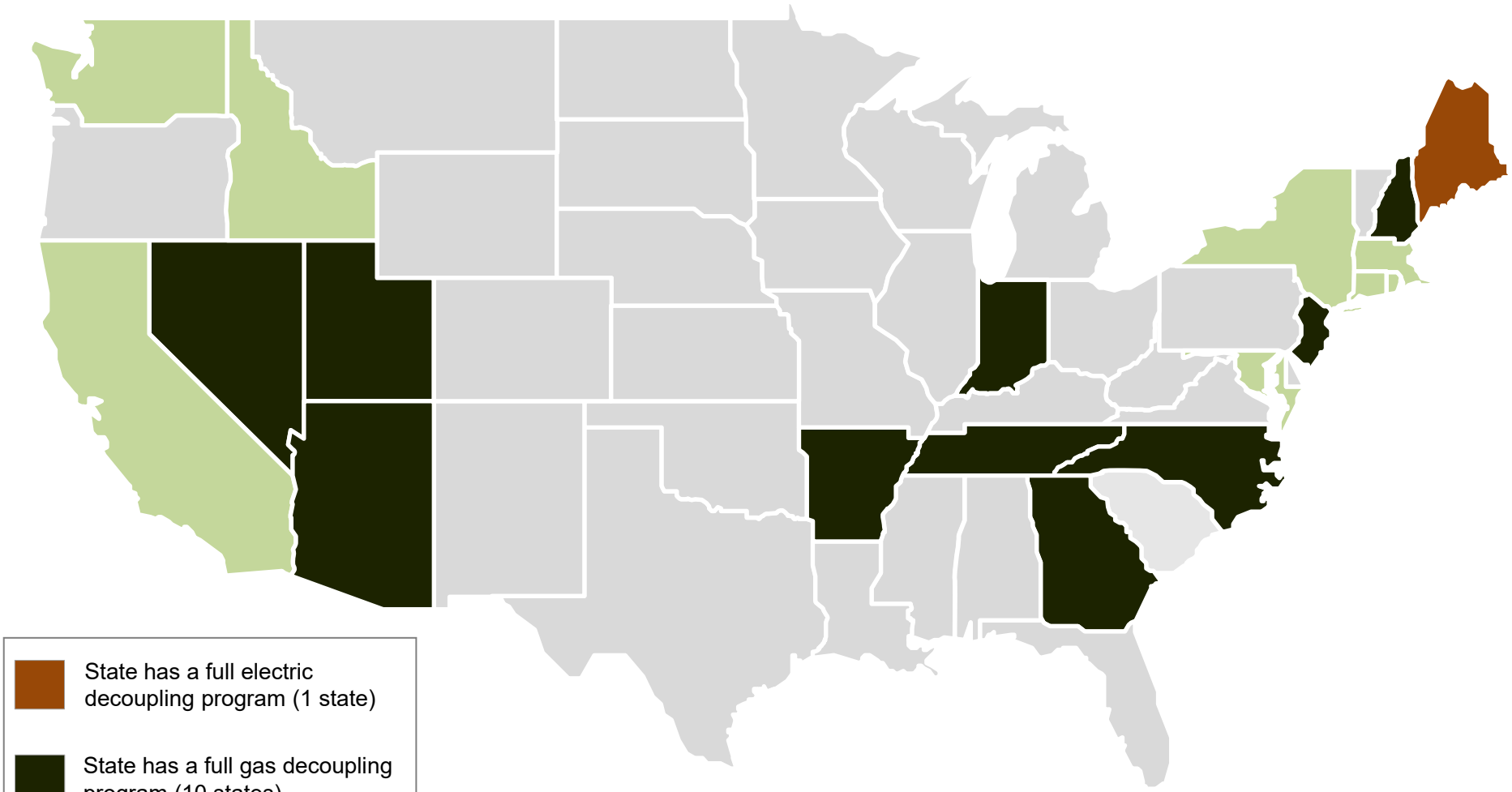
Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Table of Exhibits

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Map of States with Decoupling Programs

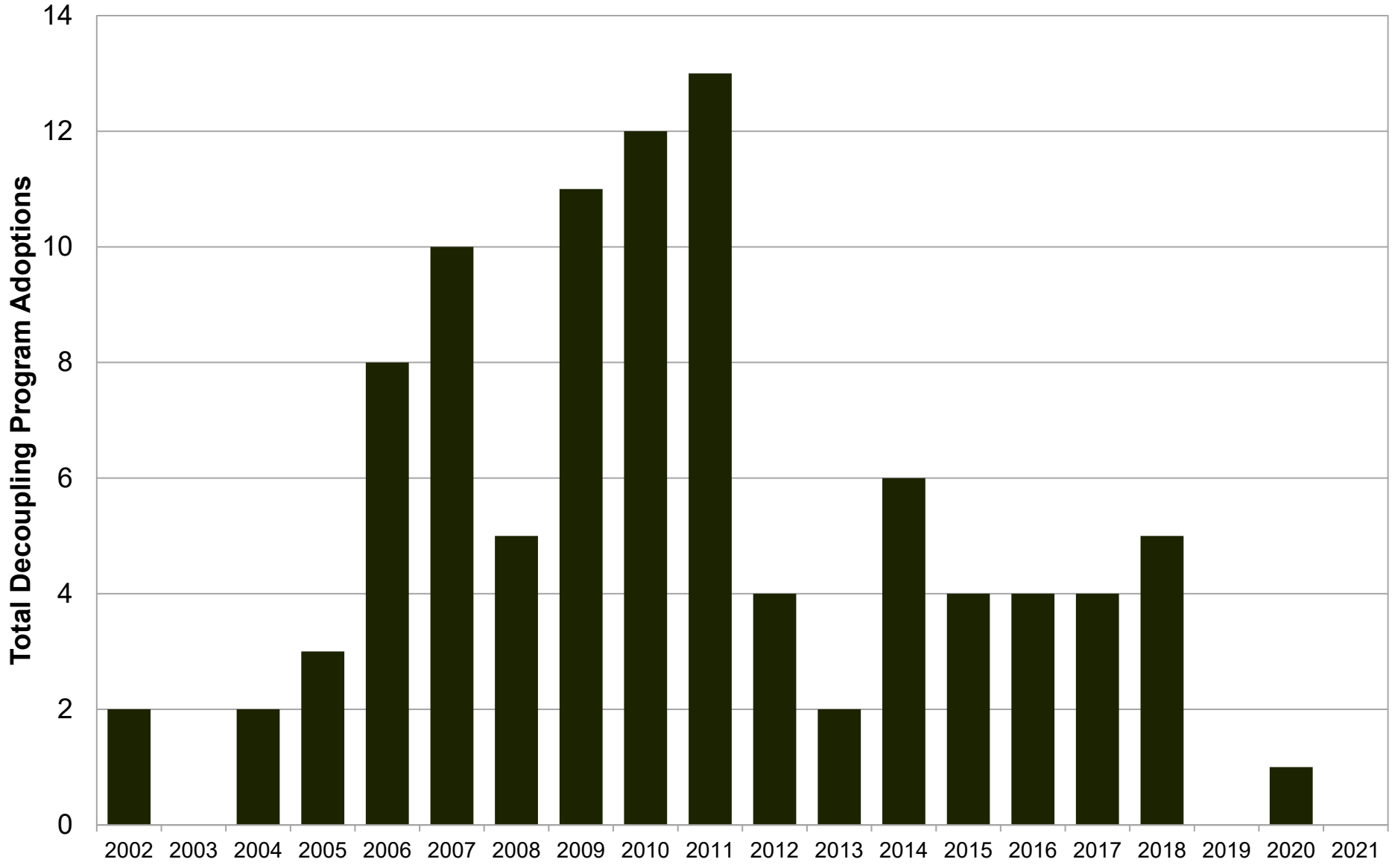
Witness: Dismukes
Docket No. R-2024-3046519
Exhibit DED-1



Source: S&P Global.

Decoupling Program Adoption by Year

Witness: Dismukes
Docket No. R-2024-3046519
Exhibit DED-2



Source: Commission Orders.

Columbia Gas of Pennsylvania Historic ROE (2010-2023)

	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 Avaliable 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%**

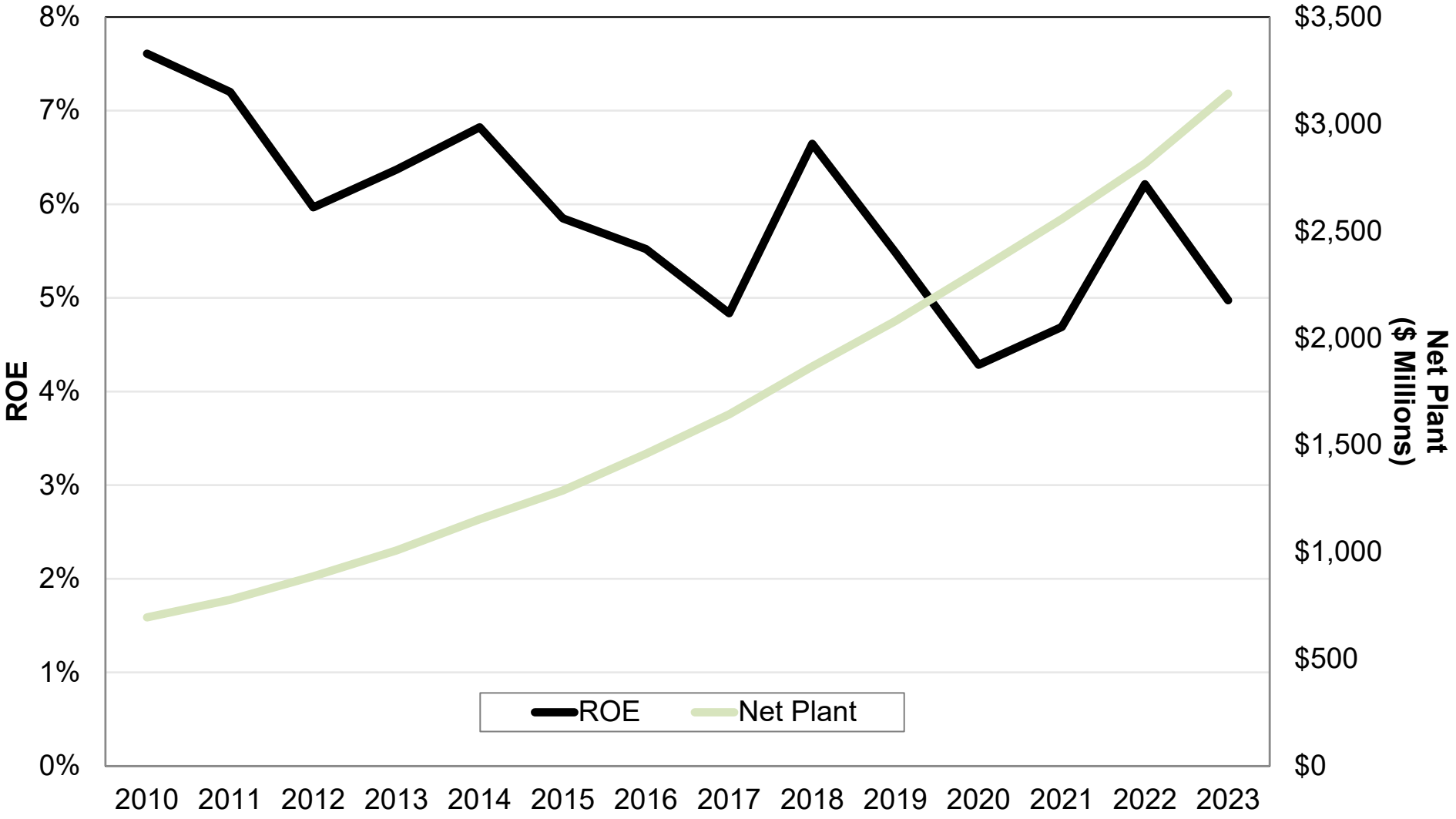
Source: Gas Annual Reports

Columbia Gas of Pennsylvania Historic ROE (2010-2023)

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

Source: Gas Annual Reports

Columbia Gas of Pennsylvania Historic ROE (2010-2023)



Source: Gas Annual Reports

Consumption Loss and New Customer Growth – Residential

	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%

Source: EIA 176

Consumption Loss and New Customer Growth – Residential Non-Fuel Revenue

	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	232,691,713	331,837	701	4,488,248	11,974,083	5.4%	2.1%
2019	264,317,796	337,268	784	27,369,795	4,256,289	1.6%	11.8%
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%

Source: EIA 176

Consumption Loss and New Customer Growth – Commercial

	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%

Source: EIA 176

Consumption Loss and New Customer Growth – Commercial Non-Fuel Revenue

	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	40,087,665	26,078	1,537	9,048,722	(3,687,795)	-8.4%	26.1%
2019	44,120,644	24,782	1,780	6,340,313	(2,307,334)	-5.0%	15.8%
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%

Source: EIA 176

Lesh Summary

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%**

Source: Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review (2009)

Peer Comparison of Average Total Revenues

State	Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
		($/Mcf)												
PA	**Columbia Gas of Pennsylvania**	**$12.65**	**$12.12**	**$11.38**	**$11.79**	**$12.63**	**$13.46**	**$12.57**	**$14.21**	**$13.05**	**$13.98**	**$13.91**	**$15.98**	**$19.40**
MD	Baltimore Gas & Electric	$11.67	$11.74	$12.21	$11.92	$11.61	$12.17	$12.19	$14.01	$12.78	$13.26	$14.66	$16.25	$17.99
NJ	New Jersey Natural Gas	$12.76	$13.48	$11.44	$12.90	$11.66	$10.42	$9.40	$10.96	$11.00	$11.35	$12.37	$12.66	$15.52
NJ	Elizabethtown	$12.14	$11.92	$11.56	$11.38	$10.78	$8.12	$8.16	$8.49	$8.89	$9.38	$10.49	$10.26	$12.30
NJ	Public Service Electric & Gas	$12.67	$11.21	$10.51	$9.86	$8.39	$6.81	$7.47	$8.09	$7.70	$8.48	$8.21	$8.62	$10.53
NJ	South Jersey Gas Company	$13.95	$11.95	$13.61	$12.92	$12.88	$13.98	$11.27	$12.70	$14.02	$14.44	$14.83	$15.45	$18.29
NY	Central Hudson Gas & Electric	$16.89	$17.72	$16.39	$15.35	$17.01	$14.67	$14.51	$16.28	$17.23	$17.07	$17.90	$19.57	$22.87
NY	Consolidated Edison NY	$19.98	$18.49	$17.78	$17.96	$16.78	$13.95	$13.97	$15.46	$16.76	$17.44	$18.65	$20.80	$24.82
NY	Liberty Utilities - St. Lawrence	$11.94	$12.84	$13.22	$12.73	$12.29	$12.45	$10.96	$11.64	$11.51	$10.74	$10.57	$11.07	$13.31
NY	National Fuel Gas Dist - NY	$10.85	$10.89	$10.34	$9.62	$10.11	$7.84	$6.83	$8.07	$8.16	$7.88	$7.74	$8.55	$10.88
NY	New York State Elec & Gas	$12.44	$12.70	$12.35	$11.07	$10.84	$9.74	$9.49	$10.43	$10.27	$10.15	$9.57	$10.70	$12.96
NY	Niagara Mohawk	$11.81	$12.14	$11.26	$10.50	$9.66	$8.41	$8.18	$8.98	$9.00	$8.77	$7.89	$9.94	$12.20
NY	Orange & Rockland Utilities Inc	$15.64	$15.33	$14.52	$13.82	$13.41	$10.35	$11.03	$14.27	$14.63	$13.71	$12.76	$14.52	$16.99
NY	Rochester Gas and Elec	$11.89	$11.63	$11.34	$10.38	$9.95	$8.67	$8.26	$9.08	$9.51	$8.77	$8.17	$9.46	$11.48
NY	The Brooklyn Union Gas Co	$13.66	$13.10	$11.84	$11.61	$11.87	$10.94	$11.11	$12.99	$13.40	$14.15	$14.40	$14.74	$17.57
OH	Columbia Gas of Ohio	$9.58	$10.13	$7.68	$9.00	$10.60	$9.31	$9.31	$10.60	$9.98	$10.15	$10.22	$12.74	$15.09
OH	Duke Energy Ohio	$12.05	$12.00	$12.09	$11.49	$12.41	$12.86	$12.76	$13.18	$12.11	$11.11	$10.75	$13.45	$16.28
OH	East Ohio Gas Co	$10.47	$9.56	$7.80	$7.71	$8.23	$6.59	$6.02	$7.13	$6.85	$7.22	$6.58	$8.90	$11.50
OH	Northeast Ohio Natural Gas	$9.93	$9.56	$8.62	$9.32	$10.05	$6.77	$6.27	$6.82	$7.18	$8.45	$7.93	$9.42	$11.88
OH	Suburban Natural Gas Co	$11.71	$11.85	$11.65	$12.68	$11.98	$10.17	$10.63	$11.96	$10.89	$9.83	$9.07	$11.24	$12.86
PA	Peco Energy Co	$12.26	$11.58	$11.44	$11.13	$11.33	$10.25	$8.82	$9.24	$9.89	$11.16	$10.18	$10.04	$13.17
PA	Peoples Gas Co	$12.13	$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	$11.94	$12.15	$11.04	$10.97	$11.17	$9.93	$8.55	$10.17	$9.94	$10.41	$9.64	$10.52	$13.38
PA	Philadelphia Gas Works	$15.15	$14.81	$15.44	$14.69	$14.27	$13.69	$13.95	$14.90	$14.35	$15.03	$15.27	$15.29	$18.32
PA	UGI Utilities	$13.79	$12.72	$11.37	$10.78	$10.54	$10.01	$9.37	$11.16	$10.98	$10.65	$11.40	$11.38	$14.38
WV	Mountaineer Gas Co	$12.09	$11.26	$10.53	$9.79	$10.23	$11.01	$10.06	$10.01	$10.21	$10.21	$10.58	$10.95	$12.49
	Peer Group Average	**$12.78**	**$12.54**	**$11.92**	**$11.65**	**$11.67**	**$10.43**	**$10.02**	**$11.21**	**$11.21**	**$11.31**	**$11.25**	**$12.35**	**$14.89**

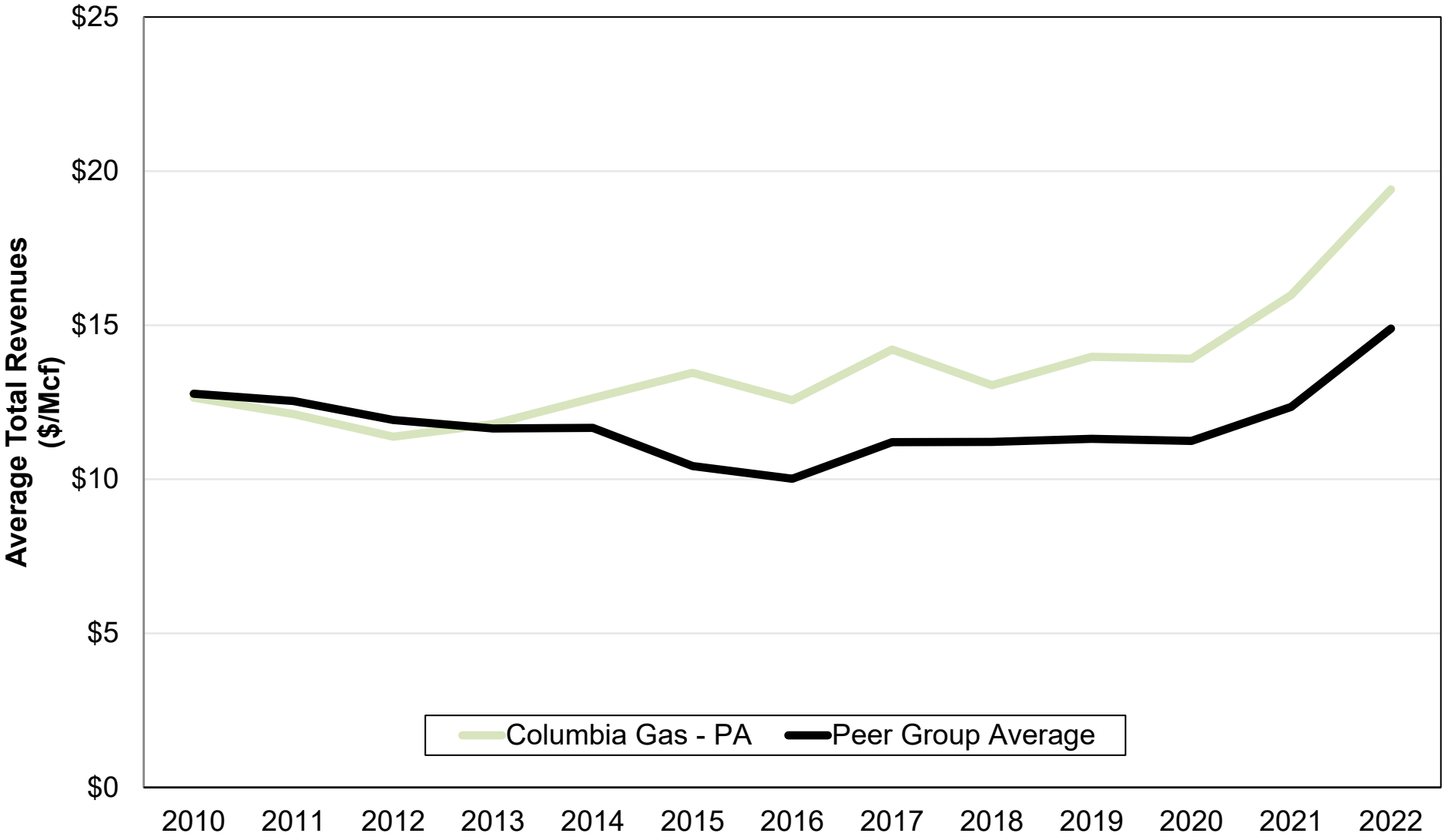
Source: EIA 176

Peer Comparison of Average Total Revenues

State	Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
			(Ranking)											
PA	**Columbia Gas of Pennsylvania**	**17**	**14**	**11**	**17**	**20**	**22**	**22**	**22**	**19**	**21**	**20**	**23**	**24**
MD	Baltimore Gas & Electric	5	9	19	18	14	19	21	21	18	19	22	24	21
NJ	New Jersey Natural Gas	19	22	12	21	15	15	12	13	15	17	18	16	17
NJ	Elizabethtown	14	11	14	13	10	5	5	5	5	7	12	8	7
NJ	Public Service Electric & Gas	18	5	5	6	2	3	4	4	3	4	6	2	1
NJ	South Jersey Gas Company	22	12	22	22	21	25	19	17	22	23	23	22	22
NY	Central Hudson Gas & Electric	25	25	25	25	26	26	26	26	26	25	25	25	25
NY	Consolidated Edison NY	26	26	26	26	25	24	25	25	25	26	26	26	26
NY	Liberty Utilities - St. Lawrence	9	20	21	20	18	20	16	15	16	14	13	12	12
NY	National Fuel Gas Dist - NY	4	4	4	4	6	4	3	3	4	2	2	1	2
NY	New York State Elec & Gas	16	18	20	11	11	9	13	11	12	9	8	10	10
NY	Niagara Mohawk	7	15	8	8	3	6	6	6	6	5	3	6	6
NY	Orange & Rockland Utilities Inc	24	24	23	23	22	14	17	23	24	20	19	19	19
NY	Rochester Gas and Elec	8	8	9	7	4	7	7	7	7	6	5	5	3
NY	The Brooklyn Union Gas Co	20	21	16	15	16	16	18	18	21	22	21	20	20
OH	Columbia Gas of Ohio	1	3	1	2	9	8	10	12	10	10	11	17	15
OH	Duke Energy Ohio	11	13	17	14	19	21	23	19	17	15	15	18	18
OH	East Ohio Gas Co	3	1	2	1	1	1	1	2	1	1	1	3	4
OH	Northeast Ohio Natural Gas	2	2	3	3	5	2	2	1	2	3	4	4	5
OH	Suburban Natural Gas Co	6	10	15	19	17	12	15	16	13	8	7	13	9
PA	Peco Energy Co	15	7	13	12	13	13	9	8	8	16	10	7	11
PA	Peoples Gas Co	13	17	18	16	23	18	20	20	20	18	16	15	16
PA	Peoples Natural Gas Co	10	16	7	10	12	10	8	10	9	12	9	9	13
PA	Philadelphia Gas Works	23	23	24	24	24	23	24	24	23	24	24	21	23
PA	UGI Utilities	21	19	10	9	8	11	11	14	14	13	17	14	14
WV	Mountaineer Gas Co	12	6	6	5	7	17	14	9	11	11	14	11	8

Source: EIA 176

Peer Comparison of Average Total Revenues



Source: EIA 176



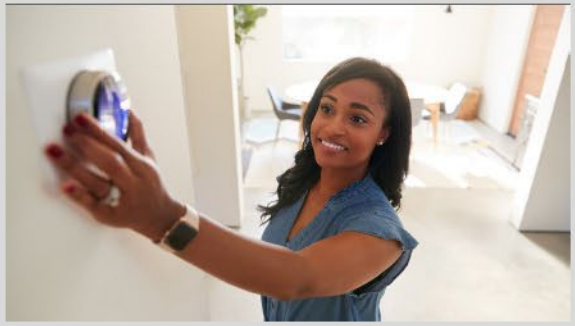


NiSource®

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

SUPPLEMENTAL SLIDES
YEAR END 2023 RESULTS

February 21, 2024





NiSource Investor Relations Presentations

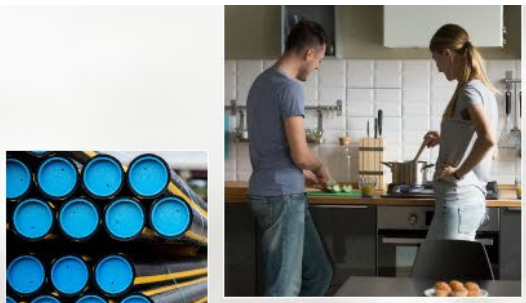
SUPERIOR REGULATORY AND STAKEHOLDER FOUNDATION

		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				

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 FY 2024	$46 $69	Jan 2023 Jan 2024
Columbia Gas of Kentucky	Safety Modification and Replacement Program (SMRP)	FY 2023 FY 2024	$42 $40	Jan 2023 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 TDSIC 7: Mar 2023 – Aug 2023	$150 $207	Sep 2023 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 TDSIC 3: Jan 2023 – Aug 2023	$144 $145	Feb 2023 Sep 2024






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

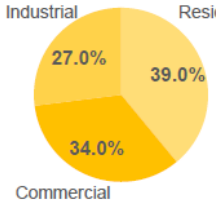
- 490K Customers
- ~3,100 Employees(1)
- 0.7% Annual Customer Growth(2)
- 13,000 Miles of Distribution/Transmission
- 3,000 MW of Generation Capacity



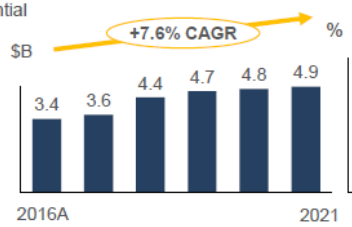
Unique Insights/Opportunities

100%	Lowest	MISO	~$3B	$170-$230M
Of coal generation to be retired by 2026-2028	Number of complaints(3) in the state over the past 5 years	Geographic proximity provides future transmission opportunity	In generation investments 2022-2027	In annual investment opportunity outside of generation

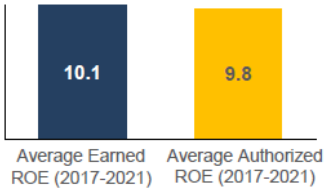
Net Revenue Mix(4)



Rate Base(4)



Return on Equity(1)



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

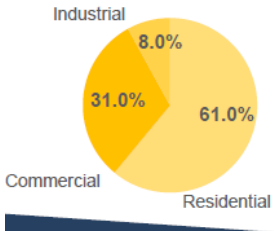
- 1.5M Customers
- ~2,300 Employees
- 0.5% Annual Customer Growth(1)
- 20,514 Miles of Pipeline



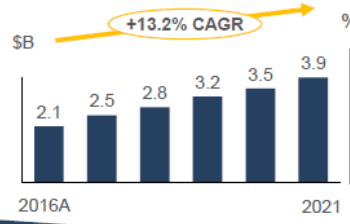
Unique Insights/Opportunities

$20-$100B	100%	#2	1,200	$550M
Investment by Intel Corporation in Central Ohio	Of capital investment tracked and recovery beginning within 12 months	In customer satisfaction based on 2021 JD Power Survey	Communities served throughout the state of Ohio	In annual investment opportunity

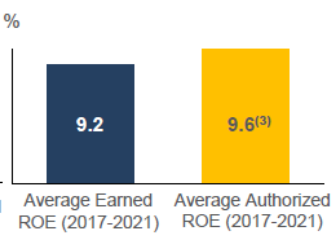
Net Revenue Mix(2)



Rate Base



Return on Equity



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

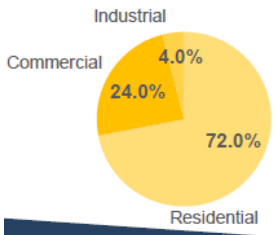
- 443K Customers
- ~800 Employees
- 0.6% Annual Customer Growth(1)
- 7,756 Miles of Pipeline



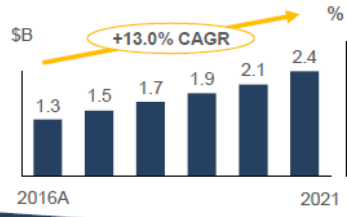
Unique Insights/Opportunities

1.1K Miles	100%	#2	9	$375M
Of remaining priority pipe	Of capital recovered with zero lag	In customer satisfaction based on 2021 JD Power Survey	Of the last 10 base rate proceedings have been settled	In annual investment opportunity

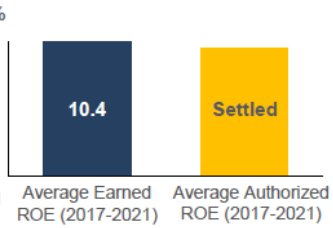
Net Revenue Mix(2)



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

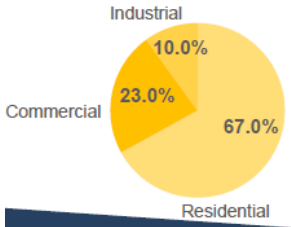
- 853K Customers
- ~3,100 Employees(1)
- 0.8% Annual Customer Growth(2)
- 18,437 Miles of Pipeline



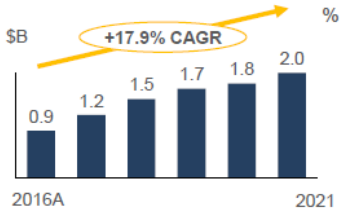
Unique Insights/Opportunities

$130.29	Lowest	100%	Largest	$150-$250M
Average residential bill over the last 5 years – the lowest in the state	Number of complaints(3) in the state over the past 5 years	Of distribution rate cases settled since 1987	LDC in the state of Indiana	In annual investment opportunity

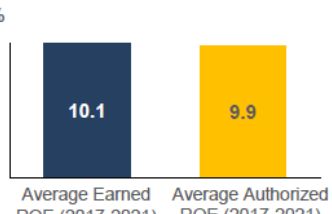
Net Revenue Mix(4)



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

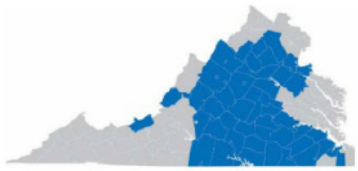
Key Riders/Constructs	Weighted Avg. Regulatory Lag
Transmission, Distribution, and Storage System Improvement Charge(TDSIC)	12 Months(6) (80% of Investment)
Federally Mandated Cost Adjustment (FMCA)	11 Months(6)
Bad Debt	Base Rates / Fuel Costs
Energy Efficiency	Forecasted with a True-Up to Actual
Fuel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



2nd Nationally in overall CSAT(4) through 3Q2022 (among 85 brands)

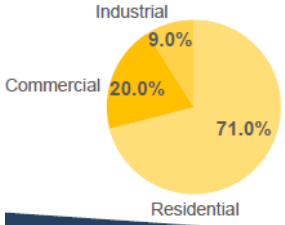
Top Decile Nationally in damage prevention

Awarded For energy efficiency and community service by Virginia DOE

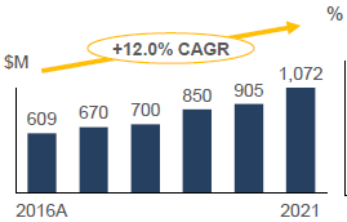
1st Amongst major VA LDC's in customer growth rate(2)

$45-$70M In annual investment opportunity

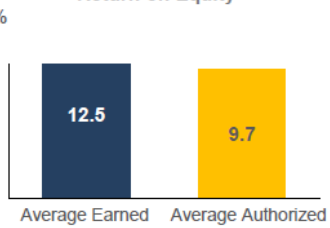
Net Revenue Mix(3)



Rate Base



Return on Equity(5)



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

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

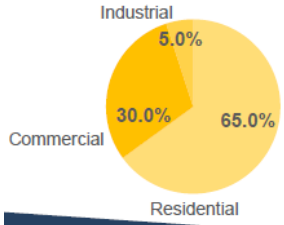
$50M
In annual investment opportunity

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

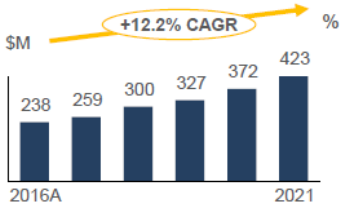
Recognized
For Leadership in Emerging Energy/Transition Environment(3)

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)

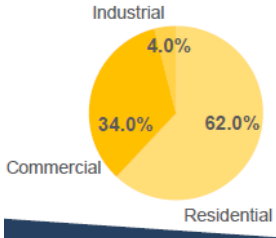
102
Miles of cast Iron/Bare Steel pipeline replaced since 2008

0
PHMSA/DOT reportable incidents in 2021

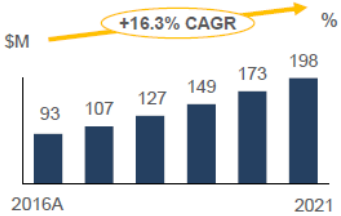
Revenue
Normalization enables full recovery of distribution revenue (residential)

$25-$35M
In annual investment opportunity

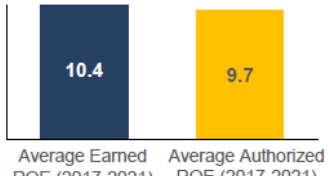
Net Revenue Mix(3)



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

NiSource









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

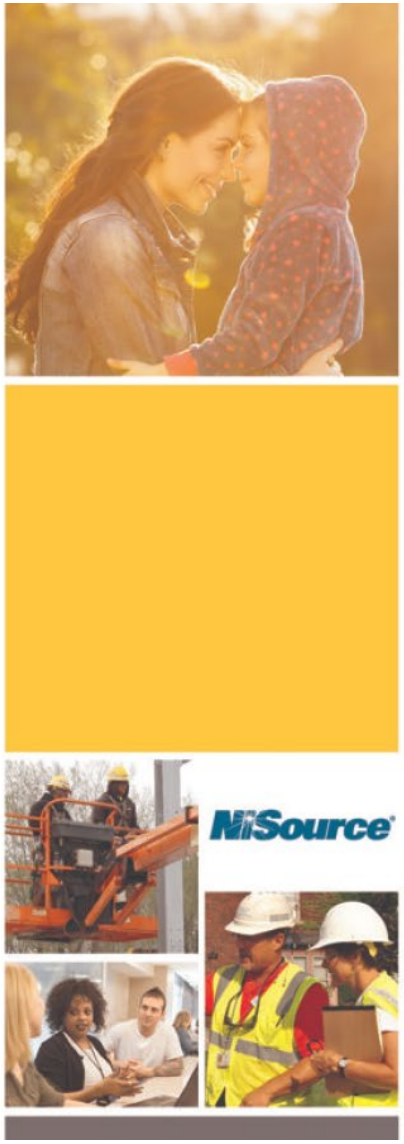
Company	Mechanism	Incremental Investments		Recovery	
		Period	Amount ($ Millions)	Filing Date	Effective Date
Columbia Gas of Ohio	Infrastructure Replacement Program (IRP)	FY 2018	$199.6	Feb 2019	May 2019
		FY 2019	$234.4	Feb 2020	May 2020
Columbia Gas of Ohio	Capital Expenditure Program (CEP)	FY 2018	$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:

Highlight	Key Components	Status
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:

Highlight	Key Components	Status
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

* 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 and Gas Decoupling Programs

Company	Utility Type - Gas/ Electric	Decouping - 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	
Switerland 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

Electric and Gas Decoupling Programs

Company	Utility Type - Gas/ Electric	Decouping - 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

Electric and Gas Decoupling Programs

Company	Utility Type - Gas/ Electric	Decouping - 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
Corning 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

WNA Annual Report Summary

Heating Season	Revenue Impact
2013-2014	$ (9,356,200.00)
2014-2015	(10,981,225.00)
2015-2016	11,522,044.00
2016-2017	13,904,913.97
2017-2018	(6,052,269.62)
2018-2019	(3,734,377.25)
2019-2020	4,979,367.40
2020-2021	5,327,157.73
2021-2022	2,530,224.11
2022-2023	17,441,275.00
2023-2024	33,544,435.80
Total	**$ 59,125,346.14**

Source: DR OCA 17-003 & Company WNA Annual Reports

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, David E. Dismukes, 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 14, 2024

Signature: 

David E. Dismukes

Address: 5800 One Perkins Place Dr., Suite 5-F
Baton Rouge, LA 70808

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Direct Testimony & Exhibit of

Greg R. Meyer

OCA Statement 2

On behalf of

Pennsylvania Office of Consumer Advocate

PUBLIC VERSION

June 14, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11633

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Direct Testimony of Greg R. Meyer

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QUALIFICATIONS OF GREG R. MEYER ..... APPENDIX A

EXHIBIT NO. 1

INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Senior Principal of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of Pennsylvania Office of Consumer Advocate ("OCA").

CASE OVERVIEW

Q PLEASE PROVIDE A CASE OVERVIEW AS IT PERTAINS TO COLUMBIA GAS' REQUESTED REVENUE REQUIREMENT.

A On March 15, 2024, Columbia Gas filed a request to increase its base utility rates by approximately $124.1 million, a 21.7% increase over current distribution revenues, by utilizing a Fully Projected Future Test Year ("FPFTY") for ratemaking purposes. In addition to the requested revenue increase, Columbia Gas also requested approval of a

Revenue Normalization Adjustment mechanism and a request to remove the dead band associated with the currently effective Weather Normalization Adjustment. In addition, Columbia Gas requested approval of a Municipal Levelization Charge.

If the full revenue request is granted by the Commission, Columbia Gas has estimated that a residential customer who purchases 70 therms of gas a month would experience an increase in its bill from $118.16 to $136.92 per month or a 15.88% increase. A small commercial customer purchasing 150 therms a month would see its bill increase from $196.43 to $226.24 or a 15.18% increase. A small industrial customer purchasing 1,215 therms a month would see a bill increase from $1,281.25 to $1,452.98 or a 13.40% increase.

In analyzing the revenue increase requested by Columbia Gas, we have performed the following procedures:

- Read the direct testimony of Columbia Gas' witnesses;
- Issued discovery requests;
- Reviewed the responses to discovery requests of the OCA and other parties;
- Reviewed the workpapers of Columbia Gas' witnesses; and
- Developed positions regarding certain aspects of Columbia Gas' rate request.

Based on BAI's review of the revenue requirement requested by Columbia Gas, we believe the revenue increase requested by Columbia Gas — $124.1 million — is significantly overstated. Based on the results of our audit, we believe Columbia Gas should reduce its current revenue requirement by approximately $15.0 million. That is, Columbia's customers should receive a decrease of $15.0 million to current rates.

Q PLEASE IDENTIFY THE OCA WITNESSES WHO FILED REVENUE REQUIREMENT DIRECT TESTIMONY AND THE ISSUES THEY ADDRESSED.

A OCA filed the direct revenue requirement testimony of three witnesses, who are listed below with a brief description of their rate case areas.

- Greg Meyer, OCA Statement 2 - Revenue Requirement, including the following issues:
  - Plant In-Service;
  - Sales Revenues;
  - Uncollectible Expense;
  - Labor Expense;
  - Incentive Compensation;
  - Rate Case Expense;
  - Injuries and Damages;
  - Corporate Insurance Expense;
  - Materials and Supplies; and
  - Taxes and Interest Synchronization.

- Christopher Walters, OCA Statement 3 - Return on Equity (ROE) and Capital Structure; and

- Brian Andrews, OCA Statement 4 - Depreciation expense resulting from a detailed depreciation study.

To the extent I do not address a specific issue that should not be construed as acceptance of that issue. I reserve the right to adopt other parties' positions.

Q HAVE YOU PREPARED A SUMMARY OF THE ADJUSTMENTS THE OCA IS PROPOSING TO COLUMBIA GAS' REVENUE REQUIREMENT.

A Yes. Table GRM-1 summarizes the adjustments the OCA is proposing to Columbia Gas' revenue requirement.

TABLE GRM-1

Revenue Requirement Adjustments

Line	Issue	Witness	Total (1)
1	Company Proposed Revenue Deficiency[1]		$ 124.1
	PA OCA Adjustments:		
	Cost of Capital Adjustment:		
2	Return on Equity	Walters	$ 60.1
3	Capital Structure	Walters	$ 12.3
4	Total Cost of Capital Adjustment		$ 72.4
5	Depreciation	Andrews	$ 43.9
6	North Franklin Incident	DeMarco	$ 0.0
7	Plant-in-Service	Meyer	$ 4.4
8	Sales Revenues	Meyer	$ 12.2
9	Uncollectibles Expense	Meyer	$ 1.4
10	Labor	Meyer	$ 1.9
11	Incentive Compensation	Meyer	$ 1.8
12	Rate Case Expense	Meyer	$ 0.4
13	Injuries and Damages	Meyer	$ 0.0
14	Corporate Insurance Expense	Meyer	$ 0.5
15	Materials and Supplies	Meyer	$ 0.1
16	Total PA OCA Adjustments		$ 139.1
17	OCA Proposed Revenue Deficiency		$ (15.0)

Source and Note:

1. Exhibit 102, Schedule 3, Page 5.

2. These adjustments are calculated on a pre-tax rate of return basis and, therefore, any effects of interest synchronization are not included. Please see Exhibit No. 1 of Greg Meyer's Direct Testimony for a detailed revenue requirement calculation.

PLANT IN-SERVICE

Q PLEASE EXPLAIN YOUR PLANT IN-SERVICE ADJUSTMENT.

A I am proposing to adjust Columbia Gas' projected plant-in-service additions for the shortfall of investment that has not been achieved through the first quarter of 2024. I am proposing to adjust Columbia Gas' forecasted plant additions by approximately $41 million. I will demonstrate how this adjustment is conservative.

Q WHAT IS THE HISTORICAL TREND FOR COLUMBIA GAS MEETING ITS BUDGETED LEVEL OF PLANT ADDITIONS?

A For the last five years, Columbia Gas has over-budgeted plant additions in four of the last five years. I have prepared Table GRM-2 that shows the historic levels of plant investments compared with the budgeted levels.

TABLE GRM-2

Net Plant - Budget to Actual

Year	Budget (1)	Actual (2)	Difference (3)	% Difference (4)
2018	$345,370,173	$296,131,730	$(49,238,443)	-14.26%
2019	Not Available Due to No Rate Case Filed for 2019			
2020	$377,820,871	$369,198,667	$ (8,622,204)	-2.28%
2021	$756,880,833	$722,396,955	$(34,483,878)	-4.56%
2022	$379,065,389	$378,901,421	$ (163,968)	-0.04%
2023	$423,128,624	$423,793,886	$ 665,262	0.16%

Sources:
1. Years of 2018 to 2021 are from Docket No. R-2022-3031211 Data Response to OCA Set 5 Question 2.
2. Years of 2022 to 2023 are from Data Response to OCA Set 9, Question 10.
3. Years of 2024 and 2025 are from Exhibit No. 108, Schedule No. 1.

As can be seen from the Table GRM-2, Columbia Gas has budgeted more for its capital program compared to actual plant additions (less plant retirements) for four of the last five years. In 2023, Columbia Gas actually invested more in plant additions than it had budgeted for that year.

Q HAVE YOU PERFORMED ANY UPDATED ANALYSIS OF ACTUAL PLANT ADDITIONS COMPARED TO BUDGETED ADDITIONS?

A Yes. I have compared actual plant additions to the budgeted levels of plant additions for the first three months of 2024 (January-March). I have prepared Table GRM-3 to show the results of my analysis.

TABLE GRM-3

2024 Budget to Actual Net Plant

	Actual[1]			Budget[2]			Variance	
Month	Additions	Retirements	Net Plant	Additions	Retirements	Net Plant	Net Plant	%
January	$12,453,590	$ 3,908,129	$ 8,545,461	$28,067,054	$ 1,967,378	$26,099,676	$(17,554,215)	-67%
February	$10,956,610	$ 1,286,883	$ 9,669,727	$27,572,429	$ 1,790,831	$25,781,598	$(16,111,871)	-62%
March	$18,910,340	$ 3,552,012	$15,358,328	$33,012,433	$ 9,866,800	$23,145,633	$ (7,787,305)	-34%
Total	$42,320,539	$ 8,747,024	$33,573,516	$88,651,916	$13,625,009	$75,026,907	$(41,453,391)	-55%

Sources and Notes:
1. Data Response to OCA-9-014 Attachment A.
2. Exhibit No. 108 Schedule No. 1.

Table GRM-3 shows that for the first three months of 2024, Columbia Gas has over-budgeted plant additions by approximately $41 million or a negative 55% variance from budgeted levels. This is the highest variance when compared to the annual variances I show in Table GRM-2.

Q DO YOU BELIEVE THE RESULTS FROM YOUR ANALYSIS IN 2024 SHOULD BE REFLECTED IN COLUMBIA GAS' REVENUE REQUIREMENT?

A Yes. I am proposing to reduce the FPFTY budgeted capital additions by $41 million to account for the current over-budgeted plant additions that have occurred in the first three months of 2024. This adjustment would reduce Columbia Gas' revenue requirement by approximately $4.4 million.

Q HOW WOULD YOU RESPOND TO THE ARGUMENT THAT COLUMBIA GAS CAN CATCH UP IN ITS CAPITAL PROGRAM TO MEET OR EXCEED THE BUDGETED CAPITAL INVESTMENTS INCLUDED IN THE FPFTY?

A The history of budget to actual net plant additions would indicate that Columbia Gas will not catch up or exceed its projected net plant in service projections. I continue to believe based on current data and historic net plant additions that Columbia Gas will not meet its budgeted plant additions for the FPFTY.

Q EARLIER YOU MENTIONED THAT YOU BELIEVE YOUR NET PLANT ADJUSTMENT COULD BE INTERPRETED AS CONSERVATIVE. PLEASE COMMENT.

A I continue to believe my net plant adjustment is conservative. I have reflected the actual to budget deviation that occurred for the first three months of 2024. I could have interpolated those results over the entire forecast period and developed a much larger adjustment. Instead, I am proposing that the FPFTY be adjusted for the over-budgeted

net plant additions that have already occurred. One must recognize that there still remains 21 months of capital spending before the end of the FPFTY. There is a good possibility that further net plant investments will not match the Columbia Gas budgeted plant additions, especially since history suggests that Columbia Gas will not meet its budgeted net plant additions.

LABOR EXPENSE

Q WHAT LEVEL OF LABOR (WAGE) EXPENSE IS COLUMBIA GAS REQUESTING FOR THE FPFTY?

A Columbia Gas is requesting $38.2 million in wage expenses for the FPFTY.

Q ARE YOU SUPPORTIVE OF THAT LEVEL OF WAGE EXPENSES?

A No. I believe Columbia Gas has overstated labor expenses for the FPFTY period. I am recommending an adjustment to reduce Columbia Gas' requested level of payroll expense by approximately $1.95 million, as explained further below.

Q PLEASE DESCRIBE THE DIFFERENT EMPLOYEE GROUPS THAT ARE INCLUDED IN THE TOTAL COLUMBIA GAS PAYROLL.

A Columbia Gas employs several employees from different union groups (USW 13836, USW 1852, USW 7139, USW 475 and USW 479). In addition to those union employees, Columbia Gas has employees that are classified into the following groups:

- Non-Union Manual;
- Clerical; and

- Exempt.

As of November 30, 2023, total payroll cost for all these employee groups totaled approximately $66.7 million. I would note this level of labor cost and includes labor costs that will ultimately be capitalized. I will discuss the capitalization of payroll later in the testimony.

Q WERE YOU PROVIDED INFORMATION THAT BROKE DOWN THE TOTAL PAYROLL AT NOVEMBER 30, 2023 BY EMPLOYEE GROUP?

A Yes. Columbia Gas prepared a workpaper that showed the breakdown of this total payroll expense by labor group at November 30, 2023.

Q WHAT PAYROLL INCREASES WERE GRANTED TO THE DIFFERENT LABOR GROUPS FROM NOVEMBER 2023 TILL THE FPFTY?

A I have listed the payroll increases by labor group in [redacted].

TABLE GRM-4

Q PLEASE DESCRIBE HOW YOU ANNUALIZED PAYROLL WITH THE ABOVE INFORMATION.

A I applied the projected payroll increases for the different periods of time and the months applicable to the FPFTY. For example, if a payroll increase for a labor group occurred halfway in the FPFTY period, I applied the labor expense increase to half the months in the FPFTY. In this way, I captured the correct increase in payroll expenses subject to the FPFTY period. I performed this calculation for each labor group listed above.

After I calculated the payroll increases for each labor group that would be in effect during the FPFTY, I applied the capitalization factor used by Columbia Gas

(51.48%) to determine annualized payroll expense to be included in the cost of service. I compared this total to the total proposed by Columbia Gas which resulted in a reduction Columbia Gas' proposed payroll expense of $1.95 million.

Q WHAT EFFECT DOES YOUR ADJUSTMENT HAVE ON COLUMBIA GAS' PROPOSED REVENUE REQUIREMENT?

A My adjustment would reduce Columbia Gas' proposed revenue requirement by $1.95 million.

INCENTIVE COMPENSATION

Q HAVE YOU READ THE DIRECT TESTIMONY OF BRITTANY KOMENDA AS IT RELATES TO INCENTIVE COMPENSATION?

A Yes, I have.

Q PLEASE DESCRIBE THE COMPANY'S INCENTIVE COMPENSATION PLANS.

A The Company offers two overarching types of incentive compensation: Cash Based Awards Programs or Short-Term Incentive Plans ("STIP") and a 2020 Omnibus Incentive Plan. The pool of funding provided in the STIP is determined by corporate performance measures that include Earnings per Share ("EPS") metrics weighted at 70% and Operational Excellence, Occupational Health and Safety, and Customer Satisfaction metrics weighted at varying degrees within the STIPs.[1] We have submitted

[1]Question No. GAS-RR-027.

discovery on the 2020 Omnibus Incentive Plan and if it contains the achievement of financial goals, we reserve the right to update our adjustment.

Q DID THE COMPANY PROPOSE ANY ADJUSTMENTS RELATED TO INCENTIVE COMPENSATION?

A Yes, Columbia Gas has adjusted their normalized Historical Test Year ("HTY") for budgeting purposes. The total cost of Columbia Gas' incentive compensation plans is $4,267,188.[2] Columbia Gas is requesting recovery of the expense portion of these costs after adjusting for their budgets. Columbia Gas' proposed level of incentive compensation expense is $2,562,000 for the FPFTY.

Q DO YOU AGREE WITH THIS PROPOSED LEVEL OF INCENTIVE COMPENSATION?

A No. I am proposing to eliminate the portion of incentive compensation costs that are related to financial goals from Columbia Gas' revenue requirement. These amounts of compensation are tied heavily to factors that benefit shareholders and the Company has failed to demonstrate that there is a direct benefit to Columbia Gas' ratepayers for this portion of the incentive compensation plans.

[2]Exhibit No. 4, Schedule No. 2, Page 4 of 31.

Q DO YOU BELIEVE ACHIEVING A CERTAIN LEVEL OF EPS IS DIRECTLY BENEFICIAL TO CUSTOMERS?

A Generally, I would disagree with this statement. I am aware of certain situations that would increase EPS but not be beneficial to customers. For example, if an employee left the utility, the utility could wait a certain period of time to fill the vacancy in order to increase its EPS. Furthermore, I would argue that incentive plans could be changed to include metrics that would not be tied to financial targets but could be shown to benefit customers directly. It is these metrics that should be used to recognize incentive compensation awards.

Q ARE YOU PROPOSING THAT THESE INCENTIVE DISALLOWANCES RESULT IN A DECREASE OF INCENTIVE PAYMENTS TO COLUMBIA GAS' EMPLOYEES?

A No. I am proposing to disallow the recovery of these costs through rates, but not to decrease the amount paid to employees through these incentive programs. I contend that the incentive payments not included in rates should be funded by Columbia Gas' shareholders.

Q PLEASE EXPLAIN YOUR ADJUSTMENT TO INCENTIVE COMPENSATION EXPENSE.

A I am proposing to eliminate the portion of incentive compensation costs that are related to financial goals because the programs have a financial performance measure that is directly tied to the EPS that, in principle, is the amount of earnings available to

shareholders. This performance measure predominantly benefits shareholders. For this reason, I propose to remove $1.8 million from Columbia Gas' proposed revenue requirement. Table GRM-5, below, shows how I calculated the $1.8 million.

TABLE GRM-5

Incentive Compensation Adjustment

Line	Description	Amount (1)
1	Incentive Compensation Paid in 2023 [1]	$ 4,267,188
2	O&M Percentage[1]	51.48%
3	FTY Budget Adjustment (Total Cost)[2]	$ 907,673
4	FPFTY Budget Adjustment (Total Cost)[2]	$ (198,135)
5	Total Incentive Compensation Costs in 2025 (Line 1 + Line 3 + Line 4)	$ 4,976,726
6	Financial Portion of Short-Term	70.00%
7	OCA Proposed Incentive Compensation Costs (Line 5 x Line 6)	$ 1,493,018
8	OCA Proposed Incentive Compensation Expense (Line 7 x Line 2)	$ 768,606
9	Company Proposed Incentive Compensation Expense[3]	$ 2,562,000
10	Adjustment to Revenue Requirement (Line 8 - Line 9)	$(1,793,394)

Sources:
1. Exhibit 4 Schedule No. 2 Page 4
2. Budgets from Exhibit 104 Schedule No. 1 Pages 3 and 4 divided by Line 2.
3. Exhibit 104 Schedule No. 1 Page 2.

RATE CASE EXPENSE

Q HAVE YOU READ THE DIRECT TESTIMONY OF BRITTANY KOMENDA AS IT RELATES TO COLUMBIA GAS' RATE CASE EXPENSE ADJUSTMENT?

A Yes, I have.

Q WHAT LEVEL OF RATE CASE EXPENSE IS THE COMPANY REQUESTING IN THIS RATE CASE?

A Columbia Gas is requesting recovery of $1.1 million in rate case expense. Columbia Gas is proposing to amortize rate case expenses over one year.

Q ARE YOU IN AGREEMENT WITH THE LEVEL OF RATE CASE EXPENSE AND THE AMORTIZATION PERIOD?

A I take no issue with the length of the amortization period due to the frequent filing of Columbia Gas' prior rate cases. I do take issue with the level of rate case expense. The level is too high when compared to their previous rate case expense levels. Table GRM-6, below, shows the amounts requested and expensed for rate case expense in the last three Columbia Gas cases. As can be seen from Table GRM-6, Columbia Gas historically requests approximately 40% over their actual level of rate case expense.

TABLE GRM-6

Historical Rate Case Expense Levels

Line	Case	Amount Expensed (1)	Amount Requested (2)	% Over Requested (3)
1	R-2020-3018835	$782,522	$1,060,000	26%
2	R-2021-3024296	$525,497	$1,060,000	50%
3	R-2022-3031211	$710,297	$1,254,200	43%
4	Average	$672,772	$1,124,733	40%

Source:
Company Data Response to Question No. Staff RE-004-D

Q WHAT LEVEL OF RATE CASE EXPENSE DO YOU RECOMMEND FOR THIS RATE CASE?

A I recommend the rate case expense be reduced by the approximately 40% that is historically over requested. Reducing rate case expense by approximately 40% would bring the level of rate case expense to $0.6 million

Q WHAT IS THE IMPACT ON REVENUE REQUIREMENT FROM YOUR PROPOSED LEVEL OF RATE CASE EXPENSE?

A Columbia Gas' revenue requirement would be reduced by $0.4 million.

MATERIALS AND SUPPLIES

Q IS COLUMBIA GAS REQUESTING INCLUSION OF MATERIALS AND SUPPLIES IN RATE BASE IN THIS RATE CASE?

A Yes. In its FPFTY, Columbia Gas is requesting recovery of $1,094,320 for materials and supplies.

Q DO YOU SUPPORT THE INCLUSION OF MATERIALS AND SUPPLIES IN RATE BASE WHEN DETERMINING A UTILITY RATE CASE REVENUE REQUIREMENT?

A Generally, I do. However, in this rate case, I am proposing a total disallowance of materials and supplies in rate base.

Q WHAT IS YOUR RATIONALE FOR DISALLOWING MATERIALS AND SUPPLIES FROM RATE BASE IN THIS RATE CASE?

A Columbia Gas has chosen not to propose a working capital allowance for this rate case. In many instances this would have been recognized as a benefit for ratepayers. However, I have discovered that Columbia Gas sells it accounts receivables to a third party.[3] By doing so, Columbia Gas has significantly improved its cash receipts from the average date of service.

Q WHAT EFFECT WOULD SELLING THE ACCOUNTS RECEIVABLES HAVE ON A WORKING CAPITAL REQUIREMENT?

A It is my belief that selling Columbia Gas' accounts receivables would result in a negative cash working capital requirement. Therefore, by forgoing a cash working capital study, Columbia Gas' rate base is overstated. I propose to offset the lack of a cash working capital study by not recognizing any materials and supplies balance in rate base.

Q PLEASE EXPLAIN YOUR RATIONALE ON WHY SELLING COLUMBIA GAS' ACCOUNTS RECEIVABLES WOULD RESULT IN A NEGATIVE CASH WORKING CAPITAL TOTAL.

A By selling Columbia Gas' accounts receivables, the company will have use of the revenues much sooner than if it had to wait for customers to pay their bills. For example, if Columbia Gas sold its receivables five days after bill rendition, I would expect that Columbia Gas would have an extra 15 days of use of those revenues versus waiting for

[3]Docket No. G-2011-2268697 as referenced to in Company Response to OCA Set 9, Question 9.

the customers to pay their bills.[4] Having use of the revenues approximately 15 days early means the Company will have use of those funds before many of its expenses are due to be paid. A cash working capital study measures the time it takes the utility to pay its cash expenses before it recovers funds from ratepayers. If the revenues billed to customers are sold, then Columbia Gas has use of those funds much sooner and that will result in a negative cash working capital total. For ratemaking purposes, a negative cash working capital study would reduce Columbia Gas' rate base. Reducing the Columbia Gas' rate base would reduce their revenue requirement.

Q PLEASE SUMMARIZE YOUR POSITION.

A Columbia Gas has not filed a cash working capital study. Based on my experience, the results of such a study would show that customers on average pay for the cash expenses to operate Columbia Gas before the Company has to pay its day to day cash expenses. By not performing a cash working capital study, Columbia Gas is essentially requesting a rate base total that is overstated. To recognize the overstatement of rate base due to Columbia Gas not being willing to perform a cash working capital study, I recommend that the Commission not recognize any materials and supplies in rate base.

Q WHY DID YOU CHOOSE TO ELIMINATE MATERIALS AND SUPPLIES.

A Materials and supplies are another form of working capital similar to cash working capital. I believe a properly conducted cash working capital study recognizing the sale

[4]Assume an average collection lag of 20-21 days, less the 5 days until the receivables are sold results in a 15 day use of funds period.

of accounts receivables would produce a result that would negate the positive working capital balance associated with materials and supplies.

Q WHAT IS THE REVENUE REQUIREMENT IMPACT FROM YOUR RECOMMENDATION?

A My recommendation will lower Columbia Gas' revenue requirement by $99,085.

CORPORATE INSURANCE EXPENSE

Q PLEASE DESCRIBE THE COMPANY'S INSURANCE EXPENSE.

A Columbia Gas' insurance expense amounts included in their revenue requirement are detailed in the data response to I & E Data Request RE-021. In it, Columbia Gas lists the types of insurance which include: property, primary liability, excess liability, directors and officers liability, fiduciary liability, crime, special crime, cyber, professional liability, travel accident, primary workers' compensation, and medical stop loss premiums. The total corporate insurance expense that Columbia Gas has included in their revenue requirement is $5.0 million.[5]

Q DO YOU HAVE ANY CONCERNS WITH COLUMBIA GAS' INSURANCE EXPENSE THAT IT PROPOSES TO INCLUDE IN ITS REVENUE REQUIREMENT?

A Yes. Columbia Gas includes Directors and Officers Liability insurance as part of its insurance expense and proposes to recover the full amount of these costs from

[5]Company Exhibit No. 104, Schedule No. 1, Page 2.

customers.[6] The level of Directors and Officers Liability insurance that Columbia Gas is including in their future test year expense is $594,530.[7]

Q WHAT IS DIRECTORS AND OFFICERS LIABILITY INSURANCE?

A Directors and officers liability insurance is insurance that protects the directors and officers and the Company from liability for claims for legal actions.

Q ARE YOU PROPOSING TO DISALLOW DIRECTORS AND OFFICERS LIABILITY INSURANCE FROM COLUMBIA GAS' REVENUE REQUIREMENT?

A Yes. I am proposing to reduce Columbia Gas' revenue requirement by $594,530.

Q WHAT IS YOUR RATIONALE FOR PROPOSING THIS ADJUSTMENT?

A The insurance protects directors and officers and the Company if a party sues the directors and officers or the Company. These costs typically help to prevent losses from legal actions brought against the Company and/or its directors and officers. These legal actions can include shareholder class action, failure to manage, act or disclose, stock value decreases, and regulatory claims.

Clearly, from the above description of the insurance coverages, Columbia Gas' shareholders, not its ratepayers, are the beneficiaries from this type of insurance and should bear the burden of the insurance premiums. Customers should not have to pay

[6]Company Response to Data Request OCA 16-006.
[7]Company Response to Data Request OCA 16-004.

for insuring the actions of management that go against the principles of safe and reliable service. Shareholders should be responsible for insuring the actions of management as these actions directly relate to the financial health of the Company.

To be clear, I am not proposing that Columbia Gas not have Directors and Officers Liability Insurance. I am proposing to assign those costs to the shareholders who are the beneficiaries of that insurance coverage.

Q PLEASE DESCRIBE YOUR ADJUSTMENT.

A As stated above, the level of Directors and Officers Liability insurance included in Columbia Gas' revenue requirement is $594,530.[8] I recommend shareholders be responsible for the entire costs and these expenses be removed from Columbia Gas' revenue requirement. Removing these costs reduces the future test year revenue requirement by $594,530.

SALES REVENUES

Q HAVE YOU REVIEWED THE LEVEL OF RESIDENTIAL REVENUES COLUMBIA GAS IS PROPOSING TO INCLUDE IN THIS RATE CASE?

A Yes, I have reviewed the level of residential revenues proposed by Columbia Gas in this rate case.

[8]Company Response to Data Request OCA 16-004.

Q HOW DO REVENUES FACTOR INTO THE RATEMAKING FORMULA?

A A utility's revenue requirement is calculated by adding the utility's expenses (depreciation, taxes, O&M costs and administrative general costs) to the rate of return allowed on rate base. The utility's normalized current revenues are then subtracted from the revenue requirement to determine the required revenue increase or revenue deficiency. Therefore, all else being equal, the failure to properly calculate revenues will lead to the authorized revenue deficiency being wrong. If revenues are understated, as I contend is occurring in this case, then the authorized revenue deficiency will be overstated.

Q HOW ARE REVENUES GENERALLY CALCULATED?

A Revenues are generally calculated by determining a normalized level of usage per customer (in Dths) for each rate class. This normalized usage is then multiplied by the normalized number of customers or bills to arrive at total usage. Total usage is then multiplied by the appropriate tariff rates for each rate class to arrive at a normalized level of revenues per class.

Q DO YOU AGREE WITH THE LEVEL OF RESIDENTIAL REVENUES PROPOSED BY COLUMBIA GAS?

A No. The level of residential revenues proposed by Columbia Gas are understated.

Q WHAT IS THE BASIS FOR YOUR POSITION?

A Columbia Gas is proposing a level of residential usage per customer of 82.19 Dth.[9] I will show that this level of residential usage per customer, and thus the level of usage and residential revenues, are understated when looking at historical usage per customer levels.

Q PLEASE PROVIDE THE HISTORIC LEVEL OF RESIDENTIAL USAGE PER CUSTOMER.

A I have prepared Table GRM-7 which shows the historical level of residential usage per customer.

TABLE GRM-7

Historical Usage per Customer

Year	Usage per Customer
2018	94.45
2019	86.34
2020	78.57
2021	82.50
2022	83.33
5 Year Average	85.04

Source:
1. Company Response to Question No. GAS-RR-011.

[9]Exhibit No. 103, Page 8, Residential Volumes Divided by Residential Bills Divided by 12; (27,607,392.2 + 2,701,478.4 + 3,782,137.3) / ((4,148,557 + 296,625 + 532,015) / 12).

As can be seen from Table GRM-7, Columbia Gas is proposing a level of residential usage per customer that has been exceeded four out of the last five years with COVID being the exception year.

Q WHAT LEVEL OF RESIDENTIAL USAGE PER CUSTOMER DO YOU RECOMMEND TO ANNUALIZE RESIDENTIAL REVENUES?

A I propose to average the usage per customer for the five years 2018-2022. This produces an average usage per customer bill of 85.04 Dth. This level of usage per customer is modest considering it includes the abnormally low year of COVID.

Q WHAT LEVEL OF CUSTOMER BILLS DO YOU PROPOSE FOR ANNUALIZING RESIDENTIAL REVENUES?

A I have accepted Columbia Gas' estimated level of customers for the FPFTY of 414,766.[10]

Q WHAT LEVEL OF USAGE RESULTS FOR THE RESIDENTIAL CLASS?

A Applying the usage per customer bill of 85.04 Dth to the total number of customers, as proposed by Columbia Gas, results in a total residential usage level of 35,270,907 Dth.

[10]Company Exhibit No. 103, Page 8.

Q WHAT IS THE REVENUE REQUIREMENT IMPACT FROM YOUR PROPOSED RESIDENTIAL REVENUE ANNUALIZATION?

A I have calculated that the annualization of FPFTY revenues using my proposed usage per customer of 85.04 Dth would increase FPFTY revenues by approximately $4.5 million. Therefore, Columbia Gas' revenue deficiency should be reduced by $4.5 million.

UNCOLLECTIBLES EXPENSE

Q HAVE YOU READ THE DIRECT TESTIMONY OF BRITTANY KOMENDA AS IT RELATES TO UNCOLLECTIBLES EXPENSE?

A Yes, I have.

Q DO YOU AGREE WITH THE PROPOSED LEVEL OF UNCOLLECTIBLES EXPENSE BY COLUMBIA GAS?

A No. Columbia Gas proposes a level of uncollectibles expense of approximately $9.7 million in the FPFTY.

Q WHAT LEVEL OF UNCOLLECTIBLES EXPENSE DO YOU RECOMMEND?

A I recommend a level of uncollectibles equal to the three year average of uncollectibles for the last three years. Table GRM-8, below, shows the last five years of uncollectibles.

TABLE GRM-8

Uncollectibles Expense (Net Writes Offs)

Year	Net Write Offs[1]
2019	$ 5,920,064
2020	$ 2,882,792
2021	$ 9,432,257
2022	$ 6,703,255
2023	$ 8,776,515
3 Year Average	$ 8,304,009
4 Year Average	$ 6,948,705
5 Year Average	$ 6,742,977

Source:
1. Exhibit No. 1, Schedule 9, Page 1 and Data Response to OCA Set 9 Question 1 Charge Offs Minus Recoveries.

As can be seen from Table GRM-8, Columbia Gas' proposed level of uncollectibles expense is higher than every year dating back to 2019. My proposed level of uncollectibles expense of $8.3 million is conservative as it includes an abnormally high year of uncollectibles due to the effects of COVID.

Q WHAT IS THE IMPACT ON REVENUE REQUIREMENT OF YOUR PROPOSED LEVEL OF UNCOLLECTIBLES EXPENSE?

A My adjustment reduces Columbia Gas' proposed revenue requirement by $1.4 million.

INJURIES AND DAMAGES

Q DOES COLUMBIA GAS PROPOSE TO INCLUDE AN INFLATION ADJUSTMENT FOR ITS INJURIES AND DAMAGES EXPENSE?

A Yes. Columbia Gas has proposed to adjust its normalized HTY injuries and damages expense by an inflation factor of 1.99% for the Future Test Year ("FTY") and 2.17% for the FPFTY.

Q ARE YOU GENERALLY SUPPORTIVE OF INFLATION ADJUSTMENTS?

A No. Inflation adjustments do not represent known and measurable changes to the utility's revenue requirement. I am opposed to Columbia Gas' inflation adjustment because it will overstate expenses for the FTY and FPFTY.

Q WHAT HAS BEEN THE HISTORICAL LEVEL OF INJURIES AND DAMAGES EXPENSE?

A I have prepared Table GRM-9 that shows the historic levels of injuries and damages expense.

TABLE GRM-9

Historic Level of Injuries & Damages

Year	Injuries & Damages
12/22 - 11/23	$ 367,013
12/21 - 11/22	$ 322,404
12/20 - 11/21	$ 206,698
12/19 - 11/20	$ 441,144
12/18 - 11/19	$ 397,834

Source:
Exhibit No. 4, Schedule No. 2, Page 11.

As can be seen from Table GRM-9, the level of actual expenses for injuries and damages has fluctuated for the years of 2019-2023. These has been no discernable trend of these expenses increasing. In fact, the level of expenses has decreased in 2021. Therefore, the application of an inflation factor is unjustified. I propose to include the 12 months ending November 2023 level of expense of $367,013 with no adjustments for inflation or the time value of money.

Q WHAT IS THE IMPACT OF YOUR PROPOSED ADJUSTMENT ON COLUMBIA GAS' PROPOSED REVENUE REQUIREMENT?

A I have proposed to eliminate the inflation for injuries and damages that is included in Columbia Gas' proposed revenue requirement. Removing this inflation reduces Columbia Gas' revenue requirement by $31,061.

TAXES AND INTEREST SYNCHRONIZATION

Q. HAVE YOU ADJUSTED THE TAX EXPENSE ASSOCIATED WITH YOUR RECOMMENDATIONS?

A. Yes, in determining the net income impact of each adjustment I calculated the associated tax impact. I have presented the effects on income tax on Exhibit No. 1, page 8.

Q. WHAT TAX RATE DID YOU USE?

A. I used the Company's proposed effective tax rate of 27.48%. This was calculated using adjusted operating income presented on the Company's Exhibit 102, Schedule 3, page 5.[11]

Q. HAVE YOU ALSO MADE AN INTEREST SYNCHRONIZATION ADJUSTMENT IN YOUR REVENUE REQUIREMENT PRESENTATION?

A. Yes. Since there were adjustments that changed both the weighted cost of debt and rate base, an interest synchronization adjustment was necessary. This adjustment is also presented on my Exhibit No. 1, page 8. Interest synchronization is necessary to match the tax deduction for interest expense with the level of interest expense collected from customers contained within Mr.Walters' capital structure and weighted cost of debt proposals.

[11]This tax rate is calculated as 1-0.72524687 = 27.48%.

OTHER

Q DO YOU HAVE ANY OTHER ADJUSTMENTS REGARDING COLUMBIA'S REVENUE REQUIREMENT?

A Yes. I will incorporate the recommendations of OCA witness Nicolas A. DeMarco relating to safety incidents and any final impact to the revenue requirement in my surrebuttal testimony. At this time, he is recommending a disallowance of $25,000 deductible expense relating to Columbia's involvement in the North Franklin Incident at Docket No. M-2022-3012079, and he is reserving his right to make further recommendations in surrebuttal based on further discovery in this proceeding.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

APPENDIX A

QUALIFICATIONS OF GREG R. MEYER

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Senior Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from the University of Missouri in 1979 with a Bachelor of Science Degree in Business Administration, with a major in Accounting. Subsequent to graduation I was employed by the Missouri Public Service Commission. I was employed with the Commission from July 1, 1979 until May 31, 2008.

I began my employment at the Missouri Public Service Commission as a Junior Auditor. During my employment at the Commission, I was promoted to higher auditing classifications. My final position at the Commission was an Auditor V, which I held for approximately ten years.

As an Auditor V, I conducted audits and examinations of the accounts, books, records and reports of jurisdictional utilities. I also aided in the planning of audits and

investigations, including staffing decisions, and in the development of staff positions in which the Auditing Department was assigned. I served as Lead Auditor and/or Case Supervisor as assigned. I assisted in the technical training of other auditors, which included the preparation of auditors' workpapers, oral and written testimony.

During my career at the Missouri Public Service Commission, I presented testimony in numerous electric, gas, telephone and water and sewer rate cases. In addition, I was involved in cases regarding service territory transfers. In the context of those cases listed above, I presented testimony on all conventional ratemaking principles related to a utility's revenue requirement. During the last three years of my employment with the Commission, I was involved in developing transmission policy for the Southwest Power Pool as a member of the Cost Allocation Working Group.

In June of 2008, I joined the firm of Brubaker & Associates, Inc. as a Consultant. Since joining the firm, I have presented testimony and/or testified in the state jurisdictions of Arkansas, Florida, Idaho, Illinois, Indiana, Iowa, Kentucky, Maryland, Missouri, Montana, New Mexico, Ohio, Utah, Washington, Wisconsin and Wyoming. I have also appeared and presented testimony in Alberta and Nova Scotia, Canada. In addition, I have filed testimony at the Federal Energy Regulatory Commission ("FERC"). These cases involved addressing conventional ratemaking principles focusing on the utility's revenue requirement. The firm Brubaker & Associates, Inc. provides consulting services in the field of energy procurement and public utility regulation to many clients including industrial and institutional customers, some utilities and, on occasion, state regulatory agencies.

More specifically, we provide analysis of energy procurement options based on consideration of prices and reliability as related to the needs of the client; prepare rate, feasibility, economic, and cost of service studies relating to energy and utility services; prepare depreciation and feasibility studies relating to utility service; assist in contract negotiations for utility services, and provide technical support to legislative activities.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

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Columbia Gas of Pennsylvania, Inc.

FPFTY Proposed Revenue Requirement

Line	Description	Reference	Amount (1)
1	Proforma Rate Base at Present Rates	Exhibit No. 1 Page 2	$ 3,446,539,856
2	Return on Rate Base[1]	Exhibit No. 1 Page 12	7.26%
3	Total Requirement[2]	Line 1 x Line 2	$ 250,372,422
4	Net Operating Income at Present Rates	Exhibit No. 1 Page 4	$ 261,287,506
5	Net Required Operating Income	Line 3 - Line 4	$ (10,915,083)
6	Revenue Conversion Factor	Company Exhibit 102, Schedule 3, Page 5	1.37884083
7	Gross Revenue Requirement	Line 5 x Line 6	$ (15,050,163)

Note:

1. See OCA Direct Testimony of Chris Walters for OCA Proposed Capital Structure and Return on Equity Adjustment Details.

2. The difference between Columbia Proposd and OCA Proposed Total Requirement (Line 3 above) is explained by Chris Walter's Cost of Capital Adjustments as seen on Exhibit No. 1 Page 3.

3. A reference that indicates "No Specific Adjustment Proposed" does not mean acceptance of Columbia's proposed amounts.

Columbia Gas of Pennsylvania

Rate Base Adjustments

Line	Description	Reference	Company Proposed FPFTY[1]	OCA Adjustment	OCA Proposed FPFTY
			(1)	(2)	(3) = (1) + (2)
1	Property Plant and Equipment	Exhibit No. 1 Page 3	$ 3,949,617,853	$ (41,453,391)	$ 3,908,164,462
2	Working Capital[2]	Direct Testimony of Greg Meyer	$ 41,193,199	$ (1,094,320)	$ 40,098,879
3	Deferred Income Taxes	No Specific Adjustment Proposed	$ (497,227,686)	$ -	$ (497,227,686)
4	Customer Deposits	No Specific Adjustment Proposed	$ (4,496,884)	$ -	$ (4,496,884)
5	Customer Advances for Construction	No Specific Adjustment Proposed	$ 1,085	$ -	$ 1,085
6	Total Rate Base		$ 3,489,087,567	$ (42,547,711)	$ 3,446,539,856

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Source:

1. Company Exhibit 108 Page 3.

2. Working Capital Adjustment includes adjustment to Materials and Supplies Expense

3. A reference that indicates "No Specific Adjustment Proposed" does not mean acceptance of Columbia's proposed amounts.

Columbia Gas of Pennsylvania

2024 Budget to Actual Net Plant

	Actual[1]			Budget[2]			Variance	
Month	**Additions**	**Retirements**	**Net Plant**	**Additions**	**Retirements**	**Net Plant**	**Net Plant**	**%**
January	$ 12,453,590	$ 3,908,129	$ 8,545,461	$ 28,067,054	$ 1,967,378	$ 26,099,676	$ (17,554,215)	-67%
February	$ 10,956,610	$ 1,286,883	$ 9,669,727	$ 27,572,429	$ 1,790,831	$ 25,781,598	$ (16,111,871)	-62%
March	$ 18,910,340	$ 3,552,012	$ 15,358,328	$ 33,012,433	$ 9,866,800	$ 23,145,633	$ (7,787,305)	-34%
Total	$ 42,320,539	$ 8,747,024	$ 33,573,516	$ 88,651,916	$ 13,625,009	$ 75,026,907	$ (41,453,391)	-55%

Sources and Notes:

1. Data Response to OCA-9-014 Attachment A.
2. Exhibit No. 108 Schedule No. 1.

Columbia Gas of Pennsylvania

Statement of Income at Present Rates

Line	Description	Reference	Company Proposed FPFTY at Present Rates[1]	Adjustments Proposed by OCA	OCA Proposed FPFTY at Present Rates
			(1)	(2)	(3) = (1) + (2)
1	Total Operating Revenues	Exhibit No. 1 Page 5	$ 786,107,079	$ 12,217,836	$ 798,324,915
2	Total Operating Revenue Deductions[2]	Exhibit No. 1 Pages 6 and 7	$ 539,524,899	$ (50,673,970)	$ 488,850,929
3	Operating Income Before Income Taxes	Line 1 - Line 2	$ 246,582,180	$ 62,891,806	$ 309,473,986
4	Income Taxes	Exhibit No. 1 Page 8	$ 32,834,907	$ 15,472,784	$ 48,307,691
5	Investment Tax Credit	Company Exhibit 107 Page 7a	$ (121,211)	$ -	$ (121,211)
6	Operating Income	Line 3 - Line 4 - Line 5	$ 213,868,484	$ 47,419,022	$ 261,287,506

Sources and Notes:

1. Company Exhibit 102, Schedule 3, Page 3.

2. Includes depreciation expense adjustment as detailed in OCA Direct Testimony of Brian Andrews.

3. A reference that indicates "No Specific Adjustment Proposed" does not mean acceptance of Columbia's proposed amounts.

Columbia Gas of Pennsylvania

Residential Sales Revenue Adjustment

Line	Description	Amount
		(1)
1	2017 Usage per Customer[1]	79.69
2	2018 Usage per Customer[1]	94.45
3	2019 Usage per Customer[1]	86.34
4	2020 Usage per Customer[1]	78.57
5	2021 Usage per Customer[1]	82.50
6	2022 Usage per Customer[1]	83.33
7	5 Year Average Usage per Customer	85.04
8	5 Year Average Usage per Customer without 2020	85.26
9	Number of Customers[2]	414,766
10	CPA Proposed Usage per Customer[3]	82.19
11	PA OCA Proposed Usage per Customer	85.04
12	PA OCA Adjustment to Usage per Customer	2.85
13	PA OCA Adjustment to Usage	1,181,255
14	PA OCA Adjustment to Reveue Requirement[4]	$ 12,217,836

Sources:
1. Company Response to Question No. GAS-RR-011.
2. Company Exhibit No. 103, Page 8.
3. Exhibit No. 103, Page 8, residential volumes ÷ (residential rills ÷ 12).
4. Line 13 multipled by restidential rates on Exhibit No. 3, Schedule No. 1, Page 1.

Columbia Gas of Pennsylvania

Operation and Maintenance Expense Adjustments

Line	Description	Reference	Company Proposed FPFTY[1]	OCA Adjustment	OCA Proposed FPFTY
			(1)	(2)	(3) = (1) + (2)
1	Labor	Direct Testimony of Greg Meyer	$ 38,227,431	$ (1,948,702)	$ 36,278,729
2	Incentive Compensation	Exhibit No. 1 Page 9	$ 2,562,000	$ (1,793,394)	$ 768,606
3	Pension	No Specific Adjustment Proposed	$ -	$ -	$ -
4	Pension Deferral Amortization	No Specific Adjustment Proposed	$ 844,977	$ -	$ 844,977
5	OPEB	No Specific Adjustment Proposed	$ -	$ -	$ -
6	Other Employee Benefits	No Specific Adjustment Proposed	$ 8,527,000	$ -	$ 8,527,000
7	Outside Services	No Specific Adjustment Proposed	$ 19,865,592	$ -	$ 19,865,592
8	Building Leases	No Specific Adjustment Proposed	$ 938,262	$ -	$ 938,262
9	Other Rent and Leases	No Specific Adjustment Proposed	$ 546,000	$ -	$ 546,000
10	Corporate Insurance	Direct Testimony of Greg Meyer	$ 4,961,000	$ (594,530)	$ 4,366,470
11	Injuries and Damages	Direct Testimony of Greg Meyer	$ 398,074	$ (31,061)	$ 367,013
12	Employee Expenses	No Specific Adjustment Proposed	$ 1,563,000	$ -	$ 1,563,000
13	Company Memberships	No Specific Adjustment Proposed	$ 585,692	$ -	$ 585,692
14	Utilities and Fuel Used in Company Operations	No Specific Adjustment Proposed	$ 1,426,083	$ -	$ 1,426,083
15	Advertising	No Specific Adjustment Proposed	$ 610,332	$ -	$ 610,332
16	Fleet & Other Clearing	No Specific Adjustment Proposed	$ 8,847,000	$ -	$ 8,847,000
17	Materials & Supplies	No Specific Adjustment Proposed	$ 6,135,015	$ -	$ 6,135,015
18	Other O&M	No Specific Adjustment Proposed	$ (1,114,000)	$ -	$ (1,114,000)
19	PUC, OCA, OSBA Fees	No Specific Adjustment Proposed	$ 2,550,000	$ -	$ 2,550,000
20	NCSC	No Specific Adjustment Proposed	$ 71,249,563	$ -	$ 71,249,563
21	Operation and Maintenance Expense from Budget		$ 168,723,021	$ (4,367,687)	$ 164,355,334
22	Rate Case Expense	Exhibit No. 1 Page 10	$ 1,008,000	$ (403,200)	$ 604,800
23	Uncollectible Accounts	Exhibit No. 1 Page 11	$ 9,713,182	$ (1,409,173)	$ 8,304,009
24	COVID-19 Amortization	No Specific Adjustment Proposed	$ 708,091	$ -	$ 708,091
25	Total Rider USP	No Specific Adjustment Proposed	$ 37,168,342	$ -	$ 37,168,342
26	Interest on Customer Deposits	No Specific Adjustment Proposed	$ 302,637	$ -	$ 302,637
27	Other Adjustments	No Specific Adjustment Proposed	$ 54,000	$ -	$ 54,000
28	Total Operation and Maintenance Expense		$ 217,677,273	$ (6,180,060)	$ 211,497,213

Source and Note:

1. Company Exhibit 104, Schedule 1, Page 2.

2. A Reference that indicates "No Specific Adjustment Proposed" does not mean acceptance of Columbia's proposed amounts.

Columbia Gas of Pennsylvania

Depreciation Expense Adjustments

Line	Description	Reference	OCA Adjustment (1)
1	Depreciation Expense Adjustment of Brian Andrews	Direct Testimony of Brian Andrews	$ (43,884,544)
2	Depreciation Expense Adjustment from Rate Base Adjustments	Plant Rate Base Adjustment x OCA Proposed Depreciation Rate for Mains (1.47%)	$ (609,365)
3	Total Other Operating Revenue Deduction Adjustments		$ (44,493,909)

Columbia Gas of Pennsylvania

Interest and Taxes Effect

Tax Rate	27.48%

Line	Adjustment	Revenue Amount (1)	Expense Amount (2)	Difference in Interest Expense[1] (3)	Tax Amount (4)	Operating Income Amount (5)
1	Sales Revenues	$ 12,217,836	$ -		$ 3,356,889	$ 8,860,947
2	Depreciation	$ -	$ (44,493,909)		$ 12,224,841	$ 32,269,068
3	Uncollectibles Expense	$ -	$ (1,409,173)		$ 387,175	$ 1,021,998
4	Labor	$ -	$ (1,948,702)		$ 535,412	$ 1,413,290
5	Incentive Compensation	$ -	$ (1,793,394)		$ 492,741	$ 1,300,654
6	Rate Case Expense	$ -	$ (403,200)		$ 110,780	$ 292,420
7	Injuries and Damages	$ -	$ (31,061)		$ 8,534	$ 22,527
8	Directors and Officers Insurance	$ -	$ (594,530)		$ 163,349	$ 431,181
9	Interest Sync			$ 6,576,582	$ (1,806,937)	
10	Total				$ 15,472,784	

Note:

1. Calculated by taking the OCA proposed rate base multipled by the OCA proposed weighted cost of debt and subtracting the Company proposed interest expense.

Columbia Gas of Pennsylvania

Incentive Compensation Adjustment

Line	Description	Amount (1)
1	Incentive Compensation Paid in 2023 [1]	$ 4,267,188
2	O&M Percentage	51.48%
3	FTY Budget Adjustment (Total Cost)[2]	$ 907,673
4	FPFTY Budget Adjustment (Total Cost)[2]	$ (198,135)
5	Total Incentive Compensation Costs in 2025 (Line 1 + Line 3 + Line 4)	$ 4,976,726
6	Financial Portion of Short-Term	70.00%
7	OCA Proposed Incentive Compensation Costs (Line 5 x Line 6)	$ 1,493,018
8	OCA Proposed Incentive Compensation Expense (Line 7 x Line 2)	$ 768,606
9	Company Proposed Incentive Compensation Expense[2]	$ 2,562,000
10	Adjustment to Revenue Requirement (Line 8 - Line 9)	$ (1,793,394)

Sources:
1. Exhibit 4 Schedule No. 2 Page 4
2. Budgets from Exhibit 104 Schedule No. 1 Pages 3 and 4 divided by Line 2.
3. Company Response to I&E Data Request RE-039-D.

Columbia Gas of Pennsylvania

Rate Case Expense Adjustment

Line	Description	Amount (1)
1	Columbia Proposed Rate Case Expense[1]	$ 1,008,000
2	Average % Over Requested[2]	40.00%
3	OCA Proposed Adjustment to Rate Case Expense	$ (403,200)

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Sources:

1. Company Exhibit 104, Schedule 1, Page 2.

2. Table GRM-6 of OCA Direct Testimony of Greg Meyer.

Columbia Gas of Pennsylvania

Uncollectible Expense Adjustment

Line	Description	Amount (1)
1	FPFTY Uncollectible Accounts Expense Bundled[1]	$ 8,506,675
2	FPFTY Uncollectible Accounts Expense Unbundled[1]	$ 1,206,507
3	Total FPFTY Uncollectible Accounts	$ 9,713,182
4	3 Year Average Net Write Offs[2]	$ 8,304,009
5	OPC Adjustment to FPFTY Uncollectible Accounts Expense	$ (1,409,173)

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Sources:

1. Exhibit 104, Schedule No. 2, Page 15

2. Average of Three Years of Exhibit No. 1, Schedule 9, Page 1 and Data Response to OCA Set 9 Question 1 Charge Offs Minus Recoveries.

Columbia Gas of Pennsylvania

Pre-Tax Rate of Return

Line	Capital Type	Ratio	Cost Rate	Weighted Cost Rate	Tax Factor[1]	Pre-Tax Rate of Return
1	Long-Term Debt	47.52%	5.07%	2.41%	1	2.41%
2	Short-Term Debt	2.48%	5.25%	0.13%	1	0.13%
3	Common Equity	50.00%	9.45%	4.73%	1.37884083	6.52%
4	Total	100.00%		7.26%		9.05%

Source:

1. Company Exhibit 102, Schedule 3, Page 5.

Columbia Gas of Pennsylvania, Inc.

Cost of Capital & Revenue Requirement Impact at 52% Common Equity

Company Proposed Cost of Capital (Exhibit No. 400, Schedule 5)

	Capital Amount	Capital Ratio	Component Costs	Wtd. Average Costs	Tax Conversion Factor	Pre-Tax Wtd Avg. Cost of Capital
Short-Term Debt	87,624,509	2.48%	5.250%	0.130%		0.130%
Long-Term Debt	1,526,000,000	43.13%	5.070%	2.190%		2.190%
Common Equity	1,924,792,528	54.40%	11.750%	6.390%	1.37884083	8.811%
Total Capital	$3,538,417,037	100.00%		8.710%		11.131%

Company Proposed Weighting, Christopher C. Walters' ROE

	Capital Amount	Capital Ratio	Component Costs	Wtd. Average Costs	Tax Conversion Factor	Pre-Tax Wtd Avg. Cost of Capital
Short-Term Debt	87,624,509	2.48%	5.250%	0.130%		0.130%
Long-Term Debt	1,526,000,000	43.13%	5.070%	2.190%		2.190%
Common Equity	1,924,792,528	54.40%	9.450%	5.140%	1.37884083	7.087%
Total Capital	$3,538,417,037	100.00%		7.460%		9.407%

Christopher C. Walters' Proposed Cost of Capital

	Capital Amount	Capital Ratio	Component Costs	Wtd. Average Costs	Tax Conversion Factor	Pre-Tax Wtd Avg. Cost of Capital
Short-Term Debt	87,624,509	2.48%	5.250%	0.1300%		0.130%
Long-Term Debt	1,681,584,010	47.52%	5.070%	2.4094%		2.409%
Common Equity	1,769,208,519	50.00%	9.450%	4.7250%	1.37884083	6.515%
Total Capital	$3,538,417,037	100.00%		7.264%		9.054%

Company Proposed Rate Base	Exhibit No. 102, Schedule 3	$3,489,087,567
Incremental Change to Cost of Capital Using Mr. Walters' ROE and Company weighting		-1.724%
Impact of Change to Cost of Capital - Change to ROE Only		($60,136,205)
Incremental Change to Cost of Capital Using Mr. Walters' recommended ROE and weighting of 52% common equity		-0.353%
Impact of Change to Cost of Capital - Changing Cap Structure and ROE		($12,308,157)
Total Impact of Changes with 52% common equity - Al		($72,444,361)

Note: Pre-Tax Wtd. Average Cost of Capital calculated using Columbia Gas' Gross Revenue Conversion Factor of 1.37884083. See Exhibit No. 102, Schedule 3, Page 5, line 6.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Greg Meyer, hereby state that the facts above set forth in my Direct Testimony, OCA 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 14, 2024

Signature: 

Greg Meyer

Address: Brubaker Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Direct Testimony and Exhibits of

Christopher C. Walters

OCA Statement 3

On behalf of

Pennsylvania Office of Consumer Advocate

June 14, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11633

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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Direct Testimony of Christopher C. Walters

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Direct Testimony of Christopher C. Walters

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. WHAT IS YOUR OCCUPATION?

A. I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. This information is included in Appendix A to my testimony.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of Pennsylvania Office of Consumer Advocate ("OCA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony in this proceeding is to present my findings and recommendations to the Commission as to the proper rate of return to allow Columbia Gas of Pennsylvania, Inc. (i.e., "Columbia Gas" or "the Company") in the current proceeding.

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In Section III of my testimony, I review and analyze the regulated utility industry's access to capital, credit rating trends, and outlooks, as well as the overall trend in the authorized ROE for utilities throughout the country. I conclude that the trend in authorized ROEs for utilities has declined over the last several years and has remained below 10.0% in more recent history. I also review the impact that the Federal Reserve's (the "Fed") monetary policy actions have had on the cost of capital.

In Section IV of my testimony, I outline how a fair ROE should be established, provide an overview of the market's perception of the Company's investment risk, comment on the Company's proposed capital structure, and present the analyses I relied on to estimate an appropriate ROE for Columbia Gas. Based on the results of several

cost of equity estimation methods performed on publicly traded utility companies, I estimate the current fair market ROE for the Company to fall within the range of 9.10% to 9.80%. Based on my assessment of the Company's overall risk profile and the results of the analytical methods, I recommend Columbia Gas be awarded an ROE of 9.45%, which is the mid-point of my estimated range.

In Section V of my testimony, I respond to Company witness Mr. Paul Moul's estimate of the current market cost of equity for Columbia Gas. Mr. Moul recommends the Company be authorized an ROE of 11.75%. I demonstrate that his ROE recommendations are excessive and should be rejected.

Based on all of the foregoing, I request this Commission adopt the following recommendations:

1. Reject Columbia Gas's proposed ROE of 11.75% and instead adopt my recommended ROE of 9.45%, which is based on my assessment of the current and expected capital market environment, the Company's overall risk profile, and the results of several analytical methods which I have used, to determine a fair and reasonable ROE to be authorized for Columbia Gas.

2. I recommend the Commission reject Columbia Gas's proposed equity ratio of 54.4% and instead authorize Columbia Gas an equity ratio of 50.0%.

3. My recommended ROE and capital structure along with the Company's proposed embedded cost of debt produce an overall ratemaking ROR of 7.264%.

4. My recommendations, taken together, would reduce Columbia Gas's retail natural gas delivery service revenue requirements by approximately $72.4 million.

5. If the Commission accepts Columbia's capital structure, then I recommend that it reduce the awarded ROE to 9.275%, which is the midpoint of the lower half of my recommended range.

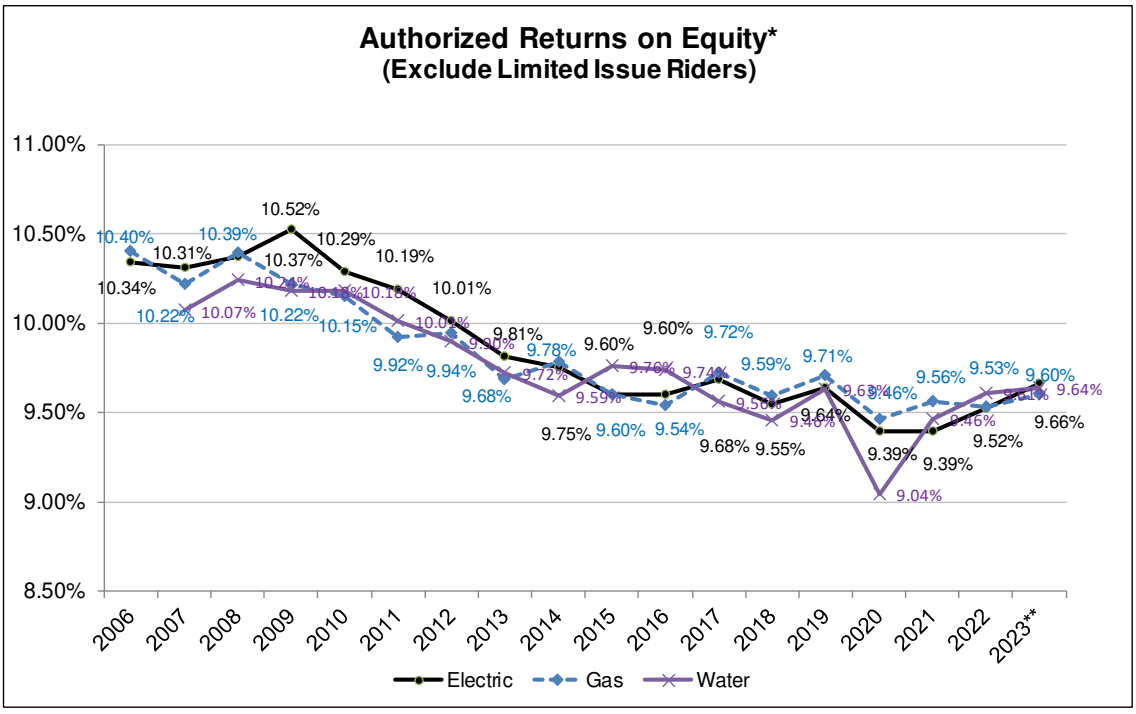
III. ACCESS TO CAPITAL AND ECONOMIC ENVIRONMENT

III.A. Regulated Utility Industry Authorized ROEs, Access to Capital, and Credit Strength

Q. PLEASE DESCRIBE THE OBSERVABLE EVIDENCE ON TRENDS IN AUTHORIZED ROEs FOR REGULATED UTILITIES.

A. Authorized ROEs for regulated utilities have generally declined over the last 10 years, as illustrated in Figure CCW-1, and have been below 10.0% for about the last nine years.

FIGURE CCW-1



Source and Notes:
* Electric Returns exclude Limited Issue Riders.
** *S&P Global Market Intelligence*, RRA Regulatory Focus, Major Rate Case Decisions -- January - December 2023, Februrary 6, 2024 at page 4.

Q. PLEASE DESCRIBE THE DISTRIBUTION OF AUTHORIZED ROEs FOR UTILITIES FOR THE LAST FEW YEARS.

A. The distribution of data refers to the way data is spread out or distributed across different values or ranges of values. The distribution of authorized ROEs for regulated natural gas distribution and water utility companies, as determined by state public utility regulatory bodies since 2016 is summarized in Table CCW-1.

TABLE CCW-1

Distribution of Authorized ROEs

		Natural Gas[1]				Water			
Line	Year	Average	Median	Share of Decisions ≤ 9.5%	Share of Decisions ≤ 9.7%	Average	Median	Share of Decisions ≤ 9.5%	Share of Decisions ≤ 9.7%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	2016	9.52%	9.50%	52%	74%	9.74%	9.75%	12.50%	12.50%
2	2017	9.71%	9.60%	43%	74%	9.56%	9.63%	44.44%	44.44%
3	2018	9.73%	9.80%	53%	72%	9.46%	9.20%	53.33%	53.33%
4	2019	9.70%	10.23%	23%	57%	9.63%	9.73%	16.67%	16.67%
5	2020	9.42%	9.40%	68%	87%	9.04%	9.15%	83.33%	83.33%
6	2021	9.53%	9.52%	50%	74%	9.46%	9.60%	20.00%	20.00%
7	2022	9.50%	9.40%	53%	80%	9.61%	9.75%	37.50%	62.50%
8	2023	9.60%	9.38%	27%	43%	9.64%	9.57%	40.00%	60.00%
9	2024	10.03%	9.70%	29%	43%	-	-	-	-

Source and Notes:
[1] S&P Global Market Intelligence, data through 4/26/24.
- Excludes limited issue rider cases.

The distribution shows that the majority of authorized ROEs since 2016 have generally been below 9.7%, with many of those being below 9.5%.

Q. HOW HAS THE AUTHORIZED COMMON EQUITY RATIO FLUCTUATED OVER THE SAME TIME PERIOD FOR UTILITIES?

A. In general, the utility industry's common equity ratios have not deviated too much from the range of 50.0% to 52.0%. As shown in Table CCW-2 below, I have provided the

authorized common equity ratios for utilities around the country, excluding the reported common equity ratios for Arkansas, Florida, Indiana, and Michigan. For my overall market analysis, I have excluded the reported authorized common equity ratios for these states because these jurisdictions include sources of capital outside of investor-supplied capital such as accumulated deferred income taxes. As such, the reported common equity ratios in these states would result in a downward bias in the reported permanent common equity ratios authorized for ratemaking purposes within my trend analysis.

TABLE CCW-2

Trends in State Authorized Common Equity Ratios
(Industry)

		Electric[1]		Natural Gas[1]		Water[1]	
Line	Year	Average	Median	Average	Median	Average	Median
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	2013	50.12%	51.03%	51.16%	50.43%	48.34%	45.79%
2	2014	50.28%	50.00%	51.90%	51.99%	49.69%	50.27%
3	2015	50.24%	50.48%	49.79%	50.33%	51.52%	51.36%
4	2016	49.70%	49.99%	51.85%	51.35%	50.65%	50.77%
5	2017	50.02%	49.85%	51.13%	51.76%	48.43%	46.09%
6	2018	50.60%	50.23%	52.58%	53.08%	52.41%	53.22%
7	2019	51.55%	51.37%	52.72%	52.22%	50.75%	50.35%
8	2020	50.94%	51.17%	52.34%	52.00%	49.75%	48.55%
9	2021	51.01%	52.00%	51.63%	52.00%	51.96%	52.73%
10	2022	51.57%	51.92%	51.84%	52.00%	51.53%	51.15%
11	2023	51.59%	52.27%	52.45%	52.00%	52.53%	53.40%
12	2024	50.18%	51.20%	52.40%	51.21%	-	-
13	Min	49.70%	49.85%	49.79%	50.33%	48.34%	45.79%
14	Max	51.59%	52.27%	52.72%	53.08%	52.53%	53.40%
15	Average	50.65%	50.96%	51.82%	51.70%	50.69%	50.33%
16	Median	50.44%	51.10%	51.88%	51.99%	50.75%	50.77%

Source and Notes:
[1] S&P Global Market Intelligence; data through April 26, 2024.
- Excludes Arkansas, Florida, Indiana and Michigan because they include non-investor capital.

Q. HAVE REGULATED UTILITY COMPANIES BEEN ABLE TO MAINTAIN RELATIVELY STRONG INVESTMENT-GRADE CREDIT RATINGS DURING PERIODS OF DECLINING AUTHORIZED ROEs?

A. Yes. As shown below in Table CCW-3, the credit ratings of the industry have improved since 2009. In 2009, approximately 75% of natural gas utilities were rated BBB+ or higher. Currently, 85% of the industry has a rating of BBB+ or higher.

TABLE CCW-3

S&P Ratings by Category
Natural Gas Utility Subsidiaries
(Year End)

Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
A or higher	50%	50%	50%	50%	38%	33%	33%	44%	56%	33%	38%	38%	13%	15%	17%	19%
A-	0%	0%	0%	0%	38%	33%	33%	22%	11%	11%	38%	38%	38%	38%	38%	35%
BBB+	25%	25%	38%	38%	13%	22%	33%	33%	33%	44%	13%	13%	25%	30%	29%	34%
BBB	13%	13%	0%	0%	0%	0%	0%	0%	0%	11%	13%	13%	25%	18%	16%	12%
BBB-	13%	13%	13%	13%	13%	11%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Below BBB-	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: S&P CAPITAL IQ and Market Intelligence, data retrieved 5/7/24.
Note: Subsidiary ratings used.

Q. HAVE UTILITIES BEEN ABLE TO ACCESS EXTERNAL CAPITAL TO SUPPORT CAPITAL EXPENDITURE PROGRAMS?

A. Yes. In Regulatory Research Associates' ("RRA") April 2, 2024 Utility Capital Expenditures report, *RRA Financial Focus*, a division of S&P Global Market Intelligence, made several relevant comments about utility investments generally:

- Multiple drivers are expected to elevate utility capital expenditures over the next several years. Pent-up demand to replace aging equipment continues to propel considerable utility investments in infrastructure, while artificial intelligence increases the power demands of datacenters daily.

- Projected 2024 capital expenditure for the 45 energy utilities included in the RRA representative sample of publicly traded, US-based utilities is $184 billion — an upswell of nearly 11% from the group's $166 billion of actual spending in 2023. The increase is largely driven by

federal legislation enacted in 2021 and 2022 supporting infrastructure investment.

* * *

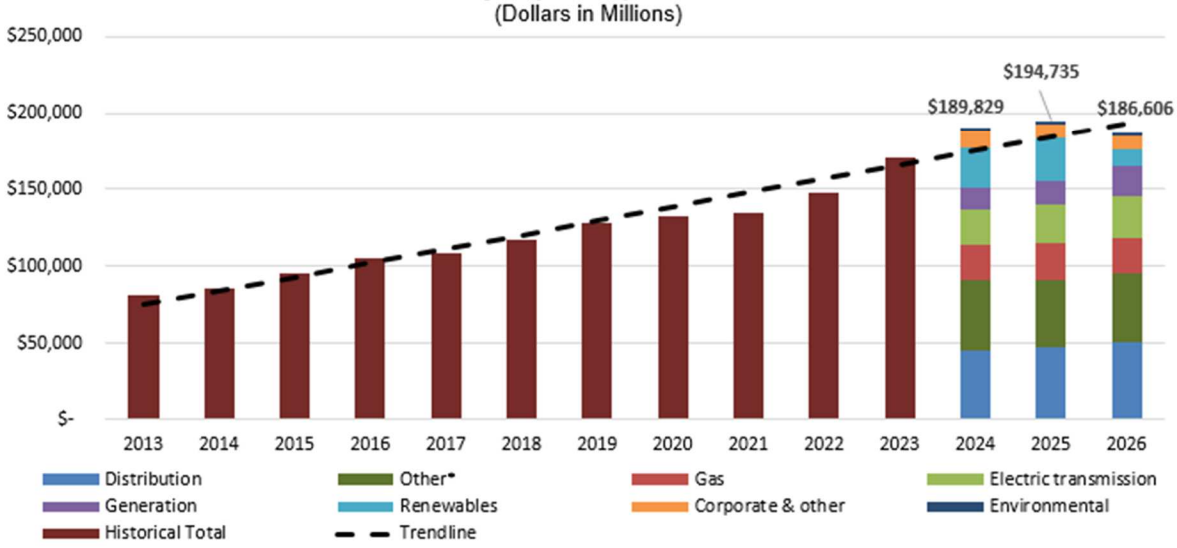
- Aggregated energy utility capex estimates for both 2024 and 2025 indicate successively higher spending levels, reaching $184 billion and $191 billion, respectively. Spending expectations for 2024 and beyond are likely to increase as the companies' plans for future projects continue to solidify around the new federal legislation supporting infrastructure investment.

- Utilities have multiple opportunities to finance and support energy investments through mechanisms available within the Inflation Reduction Act and the Infrastructure Investment and Jobs Act of 2021. These pieces of legislation provide billions of dollars for power infrastructure investments, financial incentives for nuclear power plants and funding for battery storage technology, among other provisions.[1]

As shown in Figure CCW-2 below, capital expenditures for the regulated electric and natural gas delivery utilities have increased considerably over the period 2023 into 2024, and the forecasted capital expenditures remain elevated through the end of 2025.

[1] *S&P Global Market Intelligence, RRA Financial Focus*: "Utility capex primed for profusion in 2024 and beyond," April 2, 2024.

FIGURE CCW-2



*Other category consists of utilities that do not report capital expenditures by category: Avangrid, Hawaiian Electric, PG&E and Portland General Electric.
Source: *S&P Global Market Intelligence, RRA Financial Focus*, Utility Capital Expenditures Update, March 27, 2024, Tables 1 and 3.

As demonstrated in Figure CCW-2 above, and in the comments made by *RRA S&P Global Market Intelligence*, capital investments for the utility industry continue to stay at elevated levels, and these capital expenditures are expected to fuel utilities' profit growth into the foreseeable future. This is clear evidence that the capital investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that allows for funding these elevated capital investments. While capital markets embrace these profit-driven capital investments, regulatory commissions also must be careful to maintain reasonable prices and tariff terms and conditions to protect customers' need for reliable utility service at reasonable rates. If this is not done, utility rates will expand beyond the ability of customers to pay, resulting in revenue constraints for utilities, which will impact their financial integrity.

Q. WHAT IS THE SIGNIFICANCE OF THESE FINDINGS?

A. This is clear evidence that the capital investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that allows for these elevated capital investments.

Q. IS THERE EVIDENCE OF ROBUST VALUATIONS OF REGULATED UTILITY EQUITY SECURITIES?

A. Yes. Robust valuations are an indication that utilities can sell securities at high prices, which is a strong signal that they can access equity capital under reasonable terms and conditions, and at relatively low cost. As shown on Exhibit CCW-1, the historical valuation of utilities followed by *The Value Line Investment Survey* ("*Value Line*"), based on a price-to-earnings ("P/E") ratio, price-to-cash flow ("P/CF") ratio, and market price-to-book value ("M/B") ratio, indicates utility security valuations today are very strong and robust relative to the last several years. These strong valuations of utility stocks indicate that utilities have access to equity capital under reasonable terms and at lower costs.

Q. WHAT CONCLUSION DO YOU DRAW FROM THIS OBSERVABLE MARKET DATA IN FORMING YOUR RECOMMENDED ROE AND OVERALL ROR?

A. Generally, authorized ROEs, credit standing, and access to capital have been quite robust for utilities over the last several years, even throughout the duration of the global

pandemic. It is critical that this Commission ensure that utility rates are increased no more than necessary to provide fair compensation and maintain financial integrity.

III.B. Federal Reserve Monetary Policy

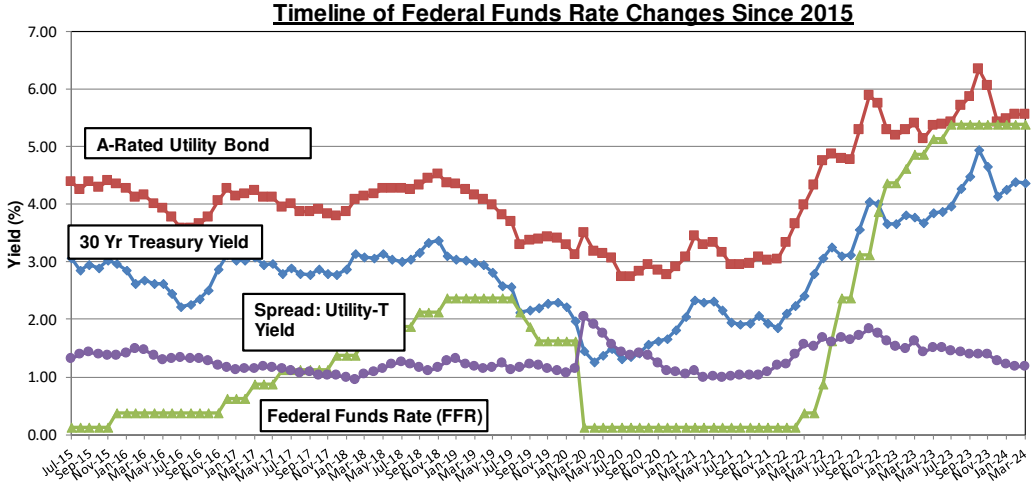
Q. ARE THE FEDERAL OPEN MARKET COMMITTEE'S ("FOMC") ACTIONS KNOWN TO THE MARKET PARTICIPANTS, AND IS IT REASONABLE TO BELIEVE THEY ARE REFLECTED IN THE MARKET'S VALUATION OF BOTH DEBT AND EQUITY SECURITIES?

A. Yes to both questions. The Fed has been transparent about its efforts to support the economy to achieve maximum employment, and to manage long-term inflation to around a 2% level. The Fed has implemented procedures to support the economy's efforts to achieve these policy objectives. Specifically, the Fed had previously lowered the Federal Overnight Rate for securities and had engaged in a Quantitative Easing program where the Fed was buying, on a monthly basis, Treasury and mortgage-backed securities in order to moderate the demand in the marketplaces and support the economy. Currently, the Fed is unwinding its Quantitative Easing program and taking actions towards monetary policy normalization. Such monetary policy actions include raising the target federal funds rate and allowing maturing bonds to roll off its balance sheet.

A visualization of the market's reaction to the Fed's actions on the federal funds rate is shown below in Figure CCW-3.

FIGURE CCW-3

Timeline of Federal Funds Rate Changes Since 2015



Fed FFR Actions:

1	December 2015	0.25	→	0.50	14	March 2020	0.00	→	0.25
2	December 2016	0.50	→	0.75	15	March 2022	0.25	→	0.50
3	March 2017	0.75	→	1.00	16	May 2022	0.75	→	1.00
4	June 2017	1.00	→	1.25	17	June 2022	1.50	→	1.75
5	December 2017	1.25	→	1.50	18	July 2022	2.25	→	2.50
6	March 2018	1.50	→	1.75	19	September 2022	3.00	→	3.25
7	June 2018	1.75	→	2.00	20	November 2022	3.75	→	4.00
8	September 2018	2.00	→	2.25	21	December 2022	4.25	→	4.50
9	December 2018	2.25	→	2.50	22	February 2023	4.50	→	4.75
10	August 2019	2.00	→	2.25	23	March 2023	4.75	→	5.00
11	September 2019	1.75	→	2.00	24	May 2023	5.00	→	5.25
12	October 2019	1.50	→	1.75	25	July 2023	5.25	→	5.50
13	March 2020	1.00	→	1.25					

Sources:
Federal Reserve Bank of New York, https://apps.newyorkfed.org/markets/autorates/fed-funds-search-page
Board of Governors of the Federal Reserve System, https://www.federalreserve.gov/datadownload/
Moody's Credit Trends, https://credittrends.moodys.com/

As shown in Figure CCW-3 above, the rise in the Federal Funds Rate has far outpaced the rise in Utility and Treasury yields while the spread of Utility bonds over Treasury bond yields have stabilized recently.

Q. HAS THE FED MADE RECENT COMMENTS CONCERNING MONETARY POLICY AND THE POTENTIAL IMPACT ON INTEREST RATES?

A. Yes. In its recent press release, the FOMC stated the following:

> Recent indicators suggest that economic activity has continued to expand at a solid pace. Job gains have remained strong, and the unemployment rate has remained low. Inflation has eased over the past year but remains elevated. In recent months, there has been a lack of further progress toward the Committee's 2 percent inflation objective.
>
> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. The Committee judges that the risks to achieving its employment and inflation goals have moved toward better balance over the past year. The economic outlook is uncertain, and the Committee remains highly attentive to inflation risks.
>
> In support of its goals, the Committee decided to maintain the target range for the federal funds rate at 5-1/4 to 5-1/2 percent. In considering any adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks. The Committee does not expect it will be appropriate to reduce the target range until it has gained greater confidence that inflation is moving sustainably toward 2 percent. In addition, the Committee will continue reducing its holdings of Treasury securities and agency debt and agency mortgage-backed securities.[2]

The above quotes suggest the FOMC has had some success in taming inflation over the last year, though not as much in recent months. It further reiterated its commitment to stabilizing consumer prices and promoting maximum employment through its monetary policy tools.

Q. WHAT DO INDEPENDENT ECONOMISTS' OUTLOOKS FOR FUTURE INTEREST RATES INDICATE?

A. Independent economists, surveyed by *Blue Chip Financial Forecasts,* expect current capital costs to increase at mixed rates over the near term, while maintaining levels that are still low by historical standards. For example, independent projections show that the consensus is the federal funds rate will increase at a rate much faster than that of

[2] Found here: https://www.federalreserve.gov/newsevents/pressreleases/monetary20240501a.htm, May 1, 2024.

long-term interest rates as measured by the 30-year Treasury bond. Inflation, as measured through the Gross Domestic Product ("GDP") price index, is expected to cool off in the near to intermediate term.

The consensus projections for the next several quarters are provided in Table CCW-4 below.

TABLE CCW-4

Blue Chip Financial Forecasts
Projected Federal Funds Rate, 30-Year Treasury Bond Yields, and GDP Price Index

Publication Date	4Q 2022	1Q 2023	2Q 2023	3Q 2023	4Q 2023	1Q 2024	2Q 2024	3Q 2024	4Q 2024	1Q 2025	2Q 2025	3Q 2025
Federal Funds Rate												
Jan-23	3.6	4.7	5.0	4.9	4.7	4.4	4.0					
Feb-23	3.7	4.7	5.0	4.9	4.7	4.3	4.0					
Mar-23	**3.7**	4.7	5.1	5.1	5.0	4.7	4.2					
Apr-23		4.5	5.0	5.1	4.9	4.6	4.2	3.8				
May-23		4.5	5.0	5.1	5.0	4.7	4.2	3.8				
Jun-23		**4.5**	5.0	5.1	5.0	4.6	4.2	3.9				
Jul-23			5.0	5.3	5.2	5.0	4.6	4.3	3.9			
Aug-23			5.0	5.4	5.4	5.2	4.9	4.4	4.0			
Sep-23			**5.0**	5.3	5.4	5.3	5.0	4.6	4.2			
Oct-23				5.3	5.4	5.4	5.1	4.7	4.3	4.0		
Nov-23				5.3	5.4	5.4	5.2	4.9	4.5	4.1		
Dec-23				**5.3**	5.4	5.4	5.2	4.9	4.6	4.2		
Jan-24					5.3	5.3	5.1	4.8	4.4	4.1	3.8	
Feb-24					5.3	5.3	5.1	4.7	4.4	4.1	3.8	
Mar-24					**5.3**	5.4	5.2	4.9	4.5	4.2	3.8	
Apr-24						5.3	5.2	5.0	4.6	4.2	3.9	3.7
T-Bond, 30 yr.												
Jan-23	3.9	4.0	4.0	3.9	3.9	3.8	3.8					
Feb-23	3.9	3.8	3.9	3.9	3.8	3.8	3.7					
Mar-23	**3.9**	3.9	4.0	3.9	3.9	3.8	3.8					
Apr-23		3.8	3.9	3.8	3.8	3.8	3.8	3.7				
May-23		3.7	3.8	3.8	3.8	3.8	3.7	3.7				
Jun-23		**3.7**	3.8	3.8	3.8	3.8	3.8	3.7				
Jul-23			3.8	3.9	3.9	3.9	3.8	3.8	3.8			
Aug-23			3.8	4.0	3.9	4.0	3.9	3.9	3.8			
Sep-23			**3.8**	4.1	4.2	4.1	4.0	4.0	3.9			
Oct-23				4.2	4.4	4.3	4.2	4.2	4.1	4.0		
Nov-23				4.2	4.8	4.7	4.5	4.5	4.3	4.2		
Dec-23				**4.2**	4.8	4.7	4.5	4.5	4.4	4.3		
Jan-24					4.6	4.3	4.3	4.2	4.1	4.0	4.0	
Feb-24					4.6	4.3	4.2	4.2	4.1	4.0	4.0	
Mar-24					**4.6**	4.4	4.3	4.2	4.2	4.1	4.1	
Apr-24						4.3	4.3	4.2	4.2	4.1	4.1	4.0
GDP Price Index												
Jan-23	4.3	3.6	3.0	2.7	2.5	2.3	2.2					
Feb-23	3.5	3.3	3.0	2.7	2.6	2.4	2.3					
Mar-23	**3.9**	3.2	2.8	2.6	2.5	2.5	2.3					
Apr-23		3.2	3.2	2.9	2.7	2.5	2.3	2.2				
May-23		4.0	3.2	2.9	2.7	2.5	2.3	2.2				
Jun-23		**4.2**	3.3	2.8	2.7	2.5	2.5	2.2				
Jul-23			3.3	2.9	2.8	2.5	2.4	2.2	2.2			
Aug-23			2.2	2.7	2.6	2.5	2.3	2.3	2.3			
Sep-23			**2.0**	2.7	2.6	2.4	2.3	2.2	2.2			
Oct-23				2.7	2.7	2.4	2.2	2.2	2.2	2.2		
Nov-23				3.5	2.7	2.4	2.3	2.2	2.2	2.3		
Dec-23				**3.6**	2.7	2.4	2.3	2.2	2.2	2.2		
Jan-24					2.7	2.3	2.3	2.3	2.2	2.2	2.1	
Feb-24					1.5	2.2	2.2	2.3	2.2	2.2	2.1	
Mar-24					**1.6**	2.2	2.3	2.2	2.2	2.1	2.1	
Apr-24						2.2	2.4	2.3	2.2	2.2	2.1	2.2

Source and Note:
Blue Chip Financial Forecasts, Jan 2022 through April 2024.
Actual Yields in Bold.

Further, the outlook for long-term interest rates in the intermediate to long term are also impacted by the current Fed actions. Long-term interest rate projections are illustrated in Table CCW-5 below.

TABLE CCW-5

30-Year Treasury Bond Yield Actual Vs. Projection

Description	Actual	Near-Term Projected*	5- to 10-Year Projected
2019			
Q1	3.01%	3.50%	
Q2	2.78%	3.17%	3.6% - 3.8%
Q3	2.30%	2.70%	
Q4	2.30%	2.50%	3.2% - 3.7%
2020			
Q1	1.88%	2.57%	
Q2	1.38%	1.90%	3.0% - 3.8%
Q3	1.36%	1.87%	
Q4	1.62%	1.97%	2.8% - 3.6%
2021			
Q1	2.07%	2.23%	
Q2	2.26%	2.77%	3.5% - 3.9%
Q3	1.93%	2.63%	
Q4	1.95%	2.70%	3.4% - 3.8%
2022			
Q1	2.25%	2.87%	
Q2	3.04%	3.47%	3.8% - 3.9%
Q3	3.26%	3.63%	
Q4	3.90%	3.87%	3.9% - 4.0%
2023			
Q1	3.74%	3.77%	
Q2	3.80%	3.70%	3.8% - 3.9%
Q3	4.24%	3.83%	
Q4	4.58%	4.17%	4.1% - 4.2%

Source and Note:
Blue Chip Financial Forecasts, January 2019 through March 2024.
*Average of all 3 reports in Quarter.

As outlined in Table CCW-5 above, the outlook for increases in interest rates has jumped more recently relative to 2020 and part of 2021, but is still relatively modest compared to time periods prior to the beginning of the worldwide pandemic. Indeed, relatively low capital market costs are expected to prevail at least in the near-term and out over the next five to ten years. While there is potential for some upward movement in the cost of capital, that upward movement is uncertain. In fact, as shown on Figure CCW-3 above, increases in the federal funds rate do not necessarily translate into increases in longer-term yields.

III.C. Market Sentiments and Utility Industry Outlook

Q. PLEASE DESCRIBE THE CREDIT RATING OUTLOOK FOR REGULATED UTILITIES.

A. All credit rating agencies see rate affordability as an important consideration in assessing utility credit, including Standard & Poor's ("S&P") and Moody's Investors Service ("Moody's"), as discussed below.

In 2024, S&P updated its utility industry outlook to "Negative," stating the following:

> **Key Takeaways**
>
> - We are updating our 2024 outlook on the investor-owned North American regulated utility industry to negative.
>
> - Given the relatively high percentage of companies with negative outlooks, we expect that 2024 will likely be the fifth consecutive year that downgrades outpace upgrades.
>
> - The industry faces rising physical risks and high cash flow deficits that may not be sufficiently funded in a credit-supportive manner.
>
> - Still, we expect that the utility industry will maintain a median investment-grade rating of 'BBB+'.

> - We also expect that a smaller percentage of companies rated 'BBB' or lower are more likely to implement measures to maintain or even improve credit quality.[3]

Specifically, in S&P's utility report, it notes that the credit quality of the industry has changed to BBB+ from an A- rating over the last few years. It notes the recently increased interest rates, which are expected to stabilize and ease the pressure on utilities financial performance. S&P also comments on the narrowing spread between utilities authorized returns and the 10-year Treasury yield, which hinders the financial performance of the industry. The credit rating agency expects continued robust capital spending for utilities, projecting over $200 billion investment in 2025.[4]

Q. HAVE CREDIT AGENCIES NOTED CONCERN ABOUT RATE AFFORDABILITY AS A CREDIT RISK TO UTILITIES?

A. Yes. Credit rating agencies have been emphasizing rate affordability, maintaining adequate financial coverages of debt obligations, and supporting utilities' overall investment grade bond ratings.

In a recent industry report, Moody's explained that the regulated utilities' outlook remains "Negative" largely due to increased pricing pressures on customers. Moody's stated that it changed its outlook from "Positive" to "Negative" due to the following:

> We have revised our outlook on the US regulated utilities sector to negative from stable. We changed the outlook because of increasingly challenging business and financial conditions stemming from higher natural gas prices, inflation and rising interest rates. These developments raise residential customer affordability issues, increasing the level of

[3] *S&P Global Ratings*: "Rising Risks: Outlook For North American Investor-Owned Regulated Utilities Weakens," February 14, 2024 at 1.
[4] *Id.*

> uncertainty with regard to the timely recovery of costs for fuel and purchased power, as well as for rate cases more broadly.[5]

Also, in a report published in January of 2024, S&P specifically mentioned commodity price volatility, in combination with significant increases in capital investments, driving utility rate increases which may strain affordability concerns. In fact, S&P concludes that "To manage regulatory risk, the industry must maintain the affordability of the customer bill."[6]

Finally, Fitch opined that the regulated utilities' outlook is deteriorating due to elevated capital expenditures that put pressure on credit metrics. Fitch also notes the bill affordability concerns for ratepayers, and regulators' ability to balance the rate requests with increasing customer bills.

Specifically, Fitch states:

> Fitch Ratings' deteriorating outlook for the North American Utilities, Power & Gas sector reflects continuing macroeconomic headwinds and elevated capex that are putting pressure on credit metrics in the high-cost funding environment. Bill affordability concerns for ratepayers continue to persist despite the pull back in natural gas prices and inflationary pressures. Fitch expects utility capex to grow by double digits in 2024, underpinned by investments needed to make the electric infrastructure more resilient against extreme weather events and to accommodate renewable generation, including distributed sources. Rate case outcomes are key to watch as regulators balance more rate requests with increases in customer bills. Authorized ROEs could prove to be sticky despite an increase in cost of capital. Higher weather-normalized retail electricity sales, driven by datacenter growth and onshoring of manufacturing activities, and tax transferability provisions of the Inflation Reduction Act could somewhat offset headwinds to utilities. Ongoing management actions to sell assets and issue equity, in some cases, is supportive of parent companies' ratings. Within Fitch's coverage, 90% of ratings hold Stable Rating Outlooks. We expect limited rating movement in 2024. The number of upgrades in 2023 so far exceeds the number of

[5] *Moody's Investors Service Outlook*: "Regulated Electric and Gas Utilities – US 2023 outlook negative due to higher natural gas prices, inflation and rising interest rates," November 10, 2022 at 1. (emphasis added).
[6] *S&P Global Ratings*: "Industry Credit Outlook 2024: North America Regulated Utilities," January 9, 2024, at 8.

> downgrades, and is driven by positive rating actions on several parent holding companies and their regulated subsidiaries.[7]

As outlined by Moody's, S&P and Fitch above, credit analysts are focusing on rate affordability as an important factor needed to support strong credit standing. Customers must be able to afford to pay their utility bills in order for utilities to maintain their financial integrity and strong investment grade credit standing. For this reason, this Commission should carefully assess the reasonableness of cost of service in this proceeding, including an appropriate overall ROR necessitated by a reasonably cost-effective balanced ratemaking capital structure, and a return on equity that represents fair compensation but also maintains competitive, just and reasonable rates.

III.D. Additional Remarks

Q. IN LIGHT OF HIGHER LEVELS OF INFLATION, AND EXPECTATIONS OF CONTINUED HIGH INTEREST RATES, HOW HAS THE MARKET PERCEIVED UTILITIES AS INVESTMENT OPTIONS?

A. Since June 30, 2021, natural gas utilities have outperformed the S&P 500, while electric utilities have somewhat lagged the broader market index. This is presented below in Figure CCW-4. However, it should be noted that the performance of the S&P 500 has largely been driven by a handful of "mega cap" companies. Because the S&P 500 is a market capitalization weighted index (meaning the higher the market capitalization a company has, the more influence it has on the index's performance). For example, in

[7] *FitchRatings.* "North American Utilities, Power & Gas Outlook 2024," December 6, 2023 at 1. (emphasis added)

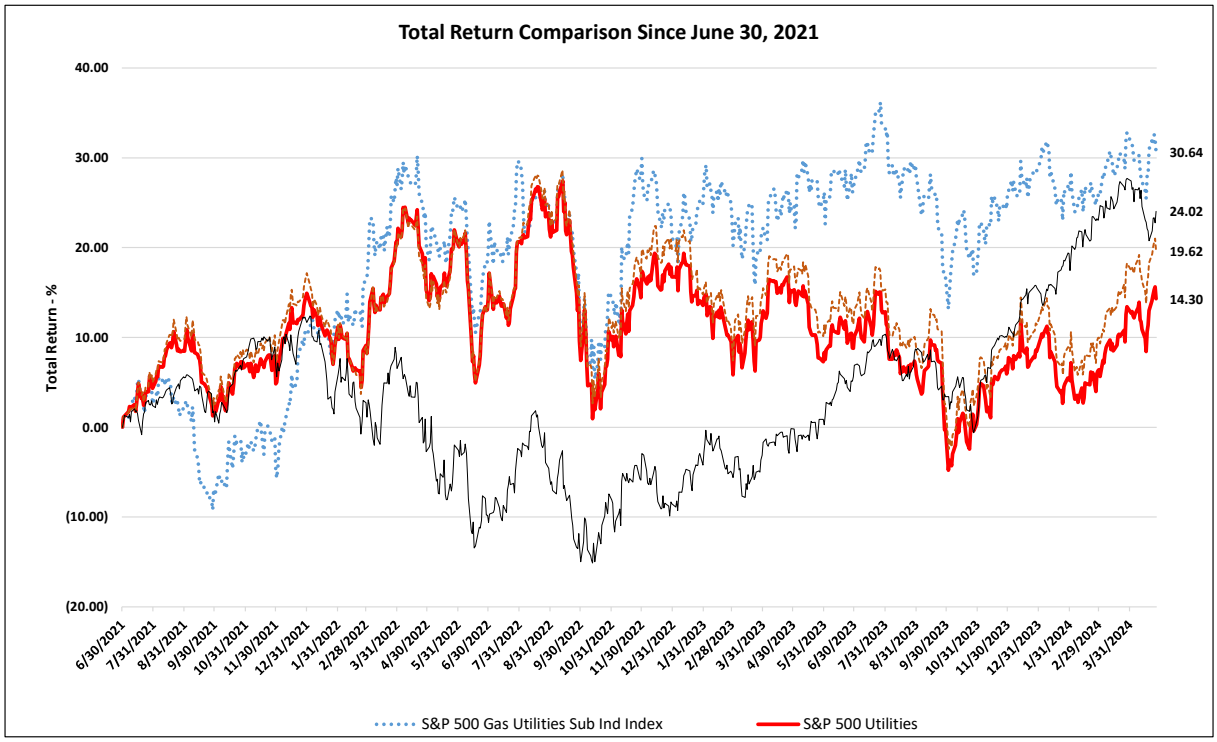
the S&P Dow Jones Indices report "U.S. Equity Market Attributes April 2024," it is noted that:

> Year-to-date, the S&P 500 remained up 5.57% (with 10 of the 11 sectors up; Real Estate was down 9.86%), as breadth declined but remained positive (302 up and 199 down, compared to last March's 369 and 134 YTD, respectively). The Magnificent 7 as a group still dominated, accounting for 51% of the index return (which included Apple's 11.5% YTD decline and Tesla's 26.2% YTD decline), as NVIDIA (up 74.5% YTD) represented 41% of the S&P 500's YTD gain.[8]

The regulated utility industry has been able to deliver generally positive and relatively stable returns during a period of elevated inflation, rising interest rates, and uncertainty because of geopolitical events around the world.

[8] https://www.spglobal.com/spdji/en/documents/commentary/market-attributes-us-equities-202404.pdf. The "Magnificent 7" is a reference to Apple, Microsoft, Amazon, Alphabet (Google), Meta Platforms, Nvidia, and Tesla. These seven stocks represent some of the largest and most influential companies in the technology sector, spanning areas like consumer electronics, cloud computing, e-commerce, social media, artificial intelligence, autonomous vehicles, and semiconductors

Figure CCW-4



IV. RETURN ON EQUITY

Q. PLEASE DESCRIBE WHAT IS MEANT BY A "UTILITY'S COST OF COMMON EQUITY."

A. A utility's cost of common equity is the expected return that investors require on an investment in the utility. Investors expect to earn their required return from receiving dividends and through stock price appreciation.

Q. PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED UTILITY'S COST OF COMMON EQUITY.

A. In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the Supreme Court found that just compensation depends on many circumstances and must be determined by fair and enlightened judgments based on relevant facts. The Court also found that a utility is entitled to such rates as would permit it to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available in other investments of corresponding risk. The Court continued that the utility has "no constitutional rights to profits" such as those "realized or anticipated in highly profitable enterprises or speculative ventures,"[9] and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[10]

As such, a fair ROR is based on the expectation that the utility costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level. Utility rates that are consistent with these standards will be just and reasonable, and compensation to the

[9] *Bluefield,* 262 U.S. at 692-93.
[10] *Id*. at 693 (emphasis added).

utility will be fair and support financial integrity and credit-standing, under economic management of the utility.

Q. PLEASE DESCRIBE THE PROCESS YOU HAVE USED TO ESTIMATE COLUMBIA GAS'S COST OF COMMON EQUITY.

A. First, I assessed the market's assessment of Columbia Gas's risk. Then, I developed a proxy group of publicly-traded utility companies that have similar risks and characteristics to Columbia Gas and compared potential differences in risks. I then performed several models based on financial theory to estimate Columbia Gas's cost of common equity. These models are: (1) a constant growth Discounted Cash Flow ("DCF") model using consensus analysts' growth rate projections; (2) a constant growth DCF model using sustainable growth rate estimates; (3) a multi-stage growth DCF model; (4) a Bond Yield Plus Risk Premium method and (5) a Capital Asset Pricing Model ("CAPM").

IV.A Columbia Gas's Investment Risk

Q. PLEASE DESCRIBE THE MARKET'S ASSESSMENT OF COLUMBIA GAS'S INVESTMENT RISK.

A. The market's assessment of a company's investment risk is generally described by credit rating analysts' reports. However, Columbia Gas is not a rated entity and is not covered by credit rating analysts. Columbia Gas's parent company, NiSource, current credit ratings are BBB+ and Baa2 from S&P and Moody's, respectively.[11]

[11] S&P Capital IQ, accessed on April 26, 2024.

IV.B. Columbia Gas's Proposed Capital Structure

Q. WHAT IS COLUMBIA GAS'S PROPOSED CAPITAL STRUCTURE?

A. Columbia Gas's proposed capital structure is summarized in Table CCW-6 below:

Table CCW-6

Investor-Supplied Capital Structure

Description	Weight
Debt	45.60%
Common Equity	54.40%
Total	100.00%

Q. DO YOU HAVE ANY COMMENTS ON COLUMBIA GAS'S PROPOSED CAPITAL STRUCTURE?

A. Yes. As I will discuss later, Columbia Gas's proposed equity ratio of 54.40% significantly exceeds the equity ratio for the proxy group used to estimate the cost of equity for Columbia Gas. As shown on Exhibit CCW-2, the proxy group has an average common equity ratio of 40.2% (including short-term debt) and 48.9% (excluding short-term debt).

Q. ARE YOU AWARE OF OTHER REGULATORY COMMISSIONS RECOGNIZING THE NEED TO ALIGN THE COST OF EQUITY WITH THE CAPITAL STRUCTURE?

A. Yes. In a recent Order, the Arkansas Public Service Commission imputed the capital structure of Southwestern Electric Power Company ("SWEPCO") to be more in-line

with the comparable companies used to estimate the cost of equity.[12] The adjustment was to recognize that there must be *congruence* between the cost of equity and the capital structure. Specifically, the Order states as follows:

> Consistent with our ruling in Order No. 10 of Docket No. 06-101-U, the Commission holds that there should be congruence between the estimated cost of equity and the [debt-to-equity] ratio, whereby a lower [debt-to-equity] ratio decreases financial risk and decreases the cost of equity. The evidence of record supports imputing the average capital structure of companies with comparable risk to SWEPCO for the purposes of determining SWEPCO's overall cost of capital.[13]

As I described above, and in more detail below, my proxy group in this case has an average common equity ratio of 40.2% (including short-term debt) and 48.9% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. In this case the Company's proposed ratemaking equity ratio of 54.40% (excluding short-term debt) exceeds that of the proxy group's equity ratio and is not reasonable for ratemaking purposes.

Q. ARE YOU RECOMMENDING AN ADJUSTMENT BE MADE TO COLUMBIA GAS'S PROPOSED CAPITAL STRUCTURE?

A. Yes. The Company has not reasonably demonstrated a need to be awarded a common equity ratio well in excess of 50.0%. As described above, as well as further below, a common equity ratio of 50.0% strikes a reasonable balance with industry norms and the book value equity ratios of the proxy group companies used to assess the Company's cost of equity. As such, I recommend this Commission authorize Columbia Gas an equity ratio of 50.0%. Should this Commission authorize Columbia Gas an equity ratio

[12] APSC Docket No. 21-170-U, Doc. No. 323, May 23, 2022, Order No. 14.
[13] *Id.* at 25.

in excess of 50.0%, I would recommend an ROE of 9.275%, which is the midpoint of the lower half of my recommended range (i.e. 9.1% to 9.45%). I would note that the Company's own filings show that its actual capital structure at November 2023 includes 54.09% common equity. The Company has not demonstrated the need to increase its equity ratio even further.

IV.C. Development of Proxy Group

Q. PLEASE BRIEFLY DESCRIBE WHY A PROXY GROUP IS NEEDED IN ESTIMATING THE COST OF EQUITY.

A. There are a few reasons why a proxy group is needed to estimate the cost of equity. As an initial matter, to be consistent with the *Hope* and *Bluefield* standards, as described above, the allowed return should be commensurate with returns on investments in other firms of comparable risk. A proxy group of similarly situated companies of comparable risk is needed to assess the Company's proposal under this standard.

Even if Columbia Gas were a publicly-traded company whose securities could be used to estimate its cost of equity, there exists the potential for certain errors and biases which would make the reliance on a single estimate undesirable and potentially less accurate. A proxy group of comparable risk companies adds reliability to the estimates by mitigating the potential for bias that may be introduced by measurement errors of model inputs.

Q. PLEASE DESCRIBE HOW YOU IDENTIFIED A PROXY UTILITY GROUP THAT COULD BE USED TO ESTIMATE COLUMBIA GAS'S CURRENT MARKET COST OF EQUITY.

A. I started with the same proxy group developed by Columbia Gas's witness, Mr. Moul, with two exceptions. First, I removed Chesapeake Utilities for not being a rated entity by S&P or Moody's, and due to its acquisition of Florida City Gas, making it a party to significant merger and acquisition ("M&A") activities. Companies involved in M&A tend to have stock prices that do not accurately reflect their underlying fundamentals and risk profile during the transaction period. In addition, not only is Chesapeake Utilities not a rated entity, neither are any of its utility subsidiaries. Credit ratings are a critical, independent assessment of total risk, and one of the most cited screening criteria used by rate of return analysts around the country.

Second, I removed NiSource Inc**.** for being a party to significant M&A activity. On June 20, 2023, NiSource announced a deal to sell Northern Indiana Public Service Company, a vertically integrated electric utility in Indiana, for $2.15 billion, which represents more than 10% of its market capitalization. The deal closed on January 2, 2024.

After the exclusion of these two utilities, that left six remaining companies to be included in the proxy group. In my opinion, I do not believe six companies represents a large enough sample. As such, in order to get a more thorough and complete analysis, I also included seven additional distribution utility companies including six water utilities and one multi-utility.

Q. HOW DOES THE INVESTMENT RISK OF COLUMBIA GAS COMPARE TO THAT OF THE PROXY GROUP?

A. As shown on my Exhibit CCW-2, the full proxy group has average credit ratings of A- and Baa1 from S&P and Moody's, respectively. Columbia Gas is not a rated entity by S&P or Moody's. As such, the proxy group's ratings are compared to that of NiSource, Columbia Gas's ultimate parent company. The full proxy group's average rating of A- from S&P is one notch higher than NiSource's rating of BBB+ from S&P. The full proxy group's average rating of Baa1 from Moody's is one notch higher than NiSource's rating of Baa2.

The capital structure of the utility, which reflects the relative proportions of debt and equity financing, has a direct bearing on the overall cost of capital. If a utility's equity ratio deviates significantly from the proxy group of comparable risk companies, it may indicate that the utility is either over-relying on costlier equity capital or taking on excessive financial risk through higher leverage. An equity ratio that is too high compared to the proxy group could suggest that the utility is paying more for its capital than similarly situated peers, potentially leading to higher costs for ratepayers. Conversely, an equity ratio that is too low may expose the utility to heightened risk of financial distress in the event of adverse economic conditions or operational challenges. Because the company is a utility operating company of a publicly traded company, it has no market value equity ratio to compare to the market value equity ratios of the proxy companies. As such, the most relevant, and only applicable capital structure to be used as a comparison is the book value capital structures.

As shown on the same exhibit, the proxy group has an average common equity ratio of 40.2% (including short-term debt) and 48.9% (excluding short-term debt) as calculated by S&P Global Market Intelligence and *Value Line*, respectively. Columbia Gas' requested common equity ratio of 54.40% significantly exceeds the proxy group's equity ratio as described above. While my recommended ratemaking equity ratio of 50.0% is still higher than that of the proxy group, it provides a more comparable basis to estimate the cost of equity than the equity ratio requested by Columbia Gas.

Given Columbia Gas is allowed to earn a return on the year-end rate base balance of its fully projected forecasted test year ("FPFTY") and its excessive common equity ratio, it is my opinion that the Company is of less risk than that of the proxy group. These observations are taken into consideration in my development of my recommended range and ROE for Columbia Gas.

IV.D. DCF Model

Q. PLEASE DESCRIBE THE DCF MODEL.

A. The DCF model posits that a stock price equals the sum of the present value of expected future cash flows discounted at the investor's required ROR or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \ldots . \frac{D_\infty}{(1+K)^\infty} \qquad \text{(Equation 1)}$$

P_0 = Current stock price
D = Dividends in periods 1 - ∞
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor-required return, known as "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend in first year
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the annual "constant growth" DCF model.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A. As shown in Equation 2 above, the DCF model requires a current stock price, the expected dividend, and the expected growth rate in dividends.

Q. WHAT STOCK PRICE HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A. I relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ending on April 26, 2024. An average stock price is less susceptible to market price variations than a price at a single point in time. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not reflect the stock's long-term value.

Q. WHAT DIVIDEND DID YOU USE IN YOUR CONSTANT GROWTH DCF MODEL?

A. I used each proxy company's most recently paid quarterly dividend as reported in *Value Line*.[14] This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above. In other words, I calculate D_1 by multiplying the annualized dividend (D_0) by (1+G).

Q. WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR CONSTANT GROWTH DCF MODEL?

A. There are several methods that can be used to estimate the expected growth in dividends. However, regardless of the method, for purposes of determining the market-required return on common equity, one must attempt to estimate investors' expectations about what the dividend, or earnings growth rate, will be, and not what an individual investor or analyst may use to make individual investment decisions.

As predictors of future returns, securities analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data.[15] That is, assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence investors' decisions, which are captured in observable stock prices, than growth rates derived only from historical data.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional securities analysts' earnings growth estimates as a proxy for investors'

[14] *The Value Line Investment Survey*.
[15] *See*, e.g., David Gordon, Myron Gordon, and Lawrence Gould, Choice Among Methods of Estimating Share Yield, The Journal of Portfolio Management, Spring 1989.

dividend growth rate expectations. I used the average of analysts' growth rate estimates from three sources: Zacks, S&P Capital IQ Market Intelligence ("MI"), and Yahoo! Finance. All such projections were available on April 26, 2024, and all were reported online.[16]

Each growth rate projection is based on a survey of independent securities analysts. There is no clear evidence whether a particular analyst is most influential on general market investors. Therefore, a single analyst's projection does not predict investor outlooks as reliably as does a consensus of market analysts' projections. The consensus of estimates is a simple arithmetic average, or mean, of surveyed analysts' earnings growth forecasts. A simple average of the growth forecasts gives equal weight to all surveyed analysts' projections. Therefore, a simple average, or arithmetic mean, of analysts' forecasts is a good proxy for investor expectations.

The growth rates I used in my DCF analysis are shown in Exhibit CCW-3. The average growth rate for my proxy group is 6.02% and a median growth rate of 5.93%.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?

A. As shown in Exhibit CCW-4, page 1, the average and median constant growth DCF returns for my proxy group for the 13-week analysis are 9.73% and 10.17%, respectively.

[16] www.zacks.com; https://finance.yahoo.com; and https://www.capitaliq.spglobal.com/.

Q. ARE THERE LIMITATIONS OF THE CONSTANT GROWTH DCF ANALYSIS?

A. Yes. The constant growth DCF analysis for my proxy group is based on a group average long-term growth rate of 6.02%. The three- to five-year growth rates are more than 50% higher than the long-term projected GDP growth rate of 4.14%, described below. In my professional opinion, I do not consider a 6.02% growth rate to be a realistic forward-looking projection. As I explain in detail below, the consensus of research on the subject finds a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the DCF model.

Q. HOW DID YOU IDENTIFY THE LONG-TERM PROJECTED GDP GROWTH RATE?

A. Although there may be short-term peaks, the long-term sustainable growth rate for a utility stock cannot exceed the growth rate of the economy in which it sells its goods and services. The long-term maximum sustainable growth rate for a utility investment is limited by the projected long-term GDP growth rate, as that reflects the projected long-term growth rate of the economy as a whole. *Blue Chip Financial Forecasts* projects that over the next 5 and 10 years, the U.S. nominal GDP will grow at an annual rate of approximately 4.14%.[17] As such, the average nominal growth rate over the next 10 years is around 4.14%, which I believe is a reasonable proxy of long-term growth.

Later in this testimony, I discuss academic and investment-practitioner support for using the projected long-term GDP growth outlook as a maximum long-term growth

[17] Blue Chip Economic Indicators, March 11, 2024 at page 14.

rate projection. Using the long-term GDP growth rate as a conservative projection for the maximum growth rate is logical, and is generally consistent with academic and economic-practitioner accepted practices.

IV.E. Sustainable Growth DCF

Q. PLEASE DESCRIBE WHAT THE SUSTAINABLE GROWTH DCF METHOD IS AND HOW YOU ESTIMATED A SUSTAINABLE GROWTH RATE FOR YOUR SUSTAINABLE GROWTH DCF MODEL.

A. The sustainable growth rate, also referred to as the internal growth rate, is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment. These reinvested earnings enhance the earnings base, also known as the rate base. The earnings grow as the plant, funded by the reinvested earnings, is put into operation, allowing the utility to receive its authorized return on the additional rate base investment.

The internal growth approach is linked to the percentage of earnings retained within the company, as opposed to being paid out as dividends. The earnings retention ratio is calculated as 1 minus the dividend payout ratio. As the payout ratio decreases, the retention ratio increases, leading to stronger growth as the company funds more investments using retained earnings.

The payout ratios of the proxy group are shown in my Exhibit CCW-5. These dividend-payout ratios and earnings-retention ratios can then be used to develop a long-term growth rate driven by earnings retention.

The data used to estimate the long-term sustainable growth rate is based on the Company's current market-to-book ratio and on *Value Line*'s three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances.

As shown in Exhibit CCW-6, the average and median sustainable growth rates for the proxy group using this internal growth rate model are 4.68% and 4.30%, respectively.

Q. WHAT IS THE DCF ESTIMATE USING THESE SUSTAINABLE GROWTH RATES?

A. A DCF estimate based on these sustainable growth rates is developed in Exhibit CCW-7. As shown there, and using the same formula in Equation 2 above, a sustainable growth DCF analysis produces proxy group average and median DCF results for the 13-week period of 8.36% and 8.24%, respectively.

IV.F. Multi-Stage Growth DCF Model

Q. HAVE YOU CONDUCTED ANY OTHER DCF STUDIES?

A. Yes. As previously noted, the DCF model is intended to represent the present value of an endless series of future cash flows. Nevertheless, the initial constant growth DCF that I described above is based on analyst growth rate projections, providing a plausible representation of rational investment expectations over the next three-to-five years as that is the time period the growth forecasts cover. The limitation of this constant growth DCF model is that it cannot reflect a reasonable expectation of a shift in growth from a high or low short-term rate to a rate that aligns more with long-term sustainable growth.

To accommodate changing growth expectations, I conducted a multi-stage DCF analysis that reflects growth rate change over time.

Q. WHY DO YOU BELIEVE GROWTH RATES CAN CHANGE OVER TIME?

A. The growth rate projections by analysts for the next three-to-five years are subject to change as the outlook for utility earnings-growth evolves. Utility companies experience fluctuations in their investment cycles. When these companies are undertaking substantial investments, the growth of their rate base accelerates, leading to an increase in earnings growth. However, once a major construction cycle reaches completion or plateaus, the growth in the utility rate base slows down, and its earnings growth rate declines, from an abnormally high three-to-five-year rate, to a lower, sustainable growth rate.

As construction cycles become longer in duration, even with an aggressive construction plan, the growth rate of the utility will naturally slow due to a decrease in rate base growth, as the utility has limited human and capital resources to expand its construction activities. Therefore, the three-to-five-year growth rate projection should be viewed as a long-term sustainable growth rate, but not without considering the current market conditions, industry trends, and determining whether the three-to-five-year growth outlook is feasible and sustainable.

Q. PLEASE DESCRIBE YOUR MULTI-STAGE DCF MODEL.

A. The multi-stage DCF model reflects the possibility of non-constant growth for a company over time. The multi-stage DCF model reflects three growth periods: (1) a

short-term growth period consisting of the first five years; (2) a transition period, consisting of the next five years (6 through 10); and (3) a long-term growth period starting in year 11 and extending into perpetuity.

For the short-term growth period, I relied on the consensus of analysts' growth projections described above in relationship to my constant growth DCF model. For the transition period, the growth rates were reduced or increased by an equal factor reflecting the difference between the analysts' growth rates and the long-term sustainable growth rate. For the long-term growth period, I assumed each company's growth would converge to the maximum sustainable long-term growth rate.

Q. WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A. Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. A utilities' earnings and dividend growth is created by increased utility investment in its rate base. Examples of what can drive such investment are: service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As such, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility.

Q. IS THERE RESEARCH THAT SUPPORTS YOUR POSITION THAT, OVER THE LONG TERM, A COMPANY'S EARNINGS AND DIVIDENDS CANNOT GROW AT A RATE GREATER THAN THE RATE OF GROWTH OF THE U.S. GDP?

A. Yes. This concept is supported in published analyst literature and academic work. Specifically, in a textbook titled "Fundamentals of Financial Management," published by Eugene Brigham and Joel F. Houston, the authors state as follows:

> The constant growth model is most appropriate for mature companies with a stable history of growth and stable future expectations. Expected growth rates vary somewhat among companies, but dividends for mature firms are often expected to grow in the future at about the same rate as nominal gross domestic product (real GDP plus inflation).[18]

The use of the economic growth rate is also supported by investment practitioners as outlined as follows:

> **Estimating Growth Rates**
>
> One of the advantages of a three-stage discounted cash flow model is that it fits with life cycle theories in regards to company growth. In these theories, companies are assumed to have a life cycle with varying growth characteristics. Typically, the potential for extraordinary growth in the near term eases over time and eventually growth slows to a more stable level.
>
> * * *
>
> Another approach to estimating long-term growth rates is to focus on estimating the overall economic growth rate. Again, this is the approach used in the *Ibbotson Cost of Capital Yearbook*. To obtain the economic growth rate, a forecast is made of the growth rate's component parts. Expected growth can be broken into two main parts: expected inflation and expected real growth. By analyzing these components separately, it is easier to see the factors that drive growth.[19]

[18] *Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at 298 (emphasis added).
[19] Morningstar, Inc., Ibbotson SBBI 2013 Valuation Yearbook at 51 and 52.

Q. HOW DID YOU DETERMINE A LONG-TERM GROWTH RATE THAT REFLECTS THE CURRENT CONSENSUS OF INDEPENDENT MARKET PARTICIPANTS?

A. I relied on the consensus of long-term GDP growth projections as projected by independent economists. *Blue Chip Financial Forecasts* publishes the consensus for GDP growth projections twice a year. These projections reflect current outlooks for GDP and are likely to be influential on investors' expectations of future growth outlooks. The consensus of projected GDP growth is about 4.14% over the next 10 years.[20]

Q. DO YOU CONSIDER OTHER SOURCES OF PROJECTED LONG-TERM GDP GROWTH?

A. Yes, and these alternative sources corroborate the consensus analysts' projections I relied on. I have reviewed several sources of projections for real GDP, GDP inflation, and nominal inflation. Real GDP measures the value of economic output by using a constant set of prices from a base year, eliminating the impact of inflation. On the other hand, nominal GDP measures the value of all goods and services produced in a given year using current market prices for that year. It does not adjust for inflation or price changes. GDP inflation, as measured by the GDP deflator or GDP price index, is a measure of inflation that reflects the change in prices of all domestically produced goods and services included in GDP and shows how much change in nominal GDP has

[20] Blue Chip Economic Indicators, March 11, 2024 at page 14.

happened due to changes in prices, rather than changes in output. Several projections are shown in Table CCW-7 below.

TABLE CCW-7

GDP Forecasts

Source	Projected Period	Real GDP	Inflation	Nominal GDP
Blue Chip Economic Indicators [1]	5-10 Yrs	1.9%	2.2%	4.1%
EIA - Annual Energy Outlook[2]	27 Yrs	1.9%	2.3%	4.3%
Congressional Budget Office[3]	30 Yrs	1.7%	2.0%	3.8%
Moody's Analytics[4]	31 Yrs	2.0%	2.1%	4.1%
Social Security Administration[5]	77 Yrs	1.6%	2.4%	4.1%
Economist Intelligence Unit[6]	31 Yrs	1.7%	2.2%	3.9%

Sources:
[1]Blue Chip Economic Indicators, March 11, 2024 at 14.
[2]U.S. EnergyInformation Administration (EIA), Annual Energy Outlook 2023, September, 2022.
[3]Congressional Budget Office, Long-Term Budget Outlook, June 28, 2023.
[4]Moody's Analytics Forecast, last updated January 8, 2024.
[5]Social Security Administration, "2023 OASDI Trustees Report," Table VI.G6. March 31, 2023.
[6]S&P MI, Economist Intelligence Unit, downloaded on January 18, 2024.

As shown in the table above, projections for real GDP and inflation fall in the range of 1.6% to 2.0% and 2.0% to 2.4%, respectively. This results in a nominal GDP (real GDP plus inflation) in the range of 3.8% to 4.3%. Therefore, the nominal GDP growth projections made by these independent sources support my use of 4.14% as a reasonable estimate of market participants' expectations for long-term GDP growth. The real GDP and nominal GDP growth projections made by these independent sources

support my use of 4.14% as a reasonable estimate of market participants' expectations for long-term GDP growth.

Q. WHAT STOCK PRICE, DIVIDEND, AND GROWTH RATES DID YOU USE IN YOUR MULTI-STAGE DCF ANALYSIS?

A. I relied on the same 13-week average stock prices and the most recent quarterly dividend payment data discussed above. For the first stage, I used the consensus of analysts' growth rate projections of 6.02% as discussed above in my constant growth DCF model. The first stage covers the first five years, consistent with the time horizon of the securities analysts' growth rate projections. The second stage, or transition stage, begins in year 6 and extends through year 10. The second stage growth transitions the growth rate from the first stage to the third stage using a straight linear trend. For the third stage, or long-term sustainable growth stage, starting in year 11, I used a 4.14% long-term sustainable growth rate based on the consensus of economists' long-term projected nominal GDP growth rate.

Q. WHAT ARE THE RESULTS OF YOUR MULTI-STAGE DCF MODEL?

A. As shown in Exhibit CCW-8, the average and median DCF ROEs for my proxy group using the 13-week average stock price are 8.20% and 8.12%, respectively.

Q. PLEASE SUMMARIZE THE RESULTS FROM YOUR DCF ANALYSES.

A. The DCF results are summarized in Table CCW-8 below. As described above, the results of the constant growth DCF using analysts' growth rates assume an average

long-term growth rate of 6.02%, which is approximately 54% higher than the long-term projected GDP growth rate of 4.14%. This is an unsustainable assumption, and likely leads to an overstatement in the cost of equity for a low-risk regulated utility. As such, it is my opinion that more weight should be given to the sustainable growth and multi-stage models of the DCF.

Table CCW-8

Summary of DCF Results

	Proxy Group	
Description	**Mean**	**Median**
Constant Growth DCF Model (Analysts' Growth)	9.73%	10.17%
Constant Growth DCF Model (Sustainable Growth)	8.36%	8.24%
Multi-Stage DCF Model	8.20%	8.12%
Average	**8.76%**	**8.84%**

IV.G. Risk Premium Model

Q. PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A. This model is based on the principle that investors require a higher return to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends or guarantee returns on common equity investments. Therefore, common equity securities are considered to be riskier than bond securities.

This risk premium model is based on two estimates of an equity risk premium. First, I quantify the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury bonds. The difference between the authorized return on common equity and the Treasury bond yield is the risk premium. I estimated the risk premium on an annual basis for each year since January 1986. The authorized ROEs were based on regulatory commission-authorized returns for utility companies. Authorized returns are typically based on expert witnesses' estimates of the investor-required return at the time of the proceeding.

The second equity risk premium estimate is based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields by Moody's. I selected the period 1986 through 2023 because public utility stocks consistently traded at a premium to book value during that period. This is illustrated in Exhibit CCW-9, which shows the market-to-book ratio since 1986 for the utility industry was consistently above a multiple of 1.0x. Over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value. This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

Based on this analysis, as shown in Exhibit CCW-10, the average indicated equity risk premium over U.S. Treasury bond yields has been 5.63%. Since the risk premium can vary depending upon market conditions and changing investor risk

perceptions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity for a risk premium methodology.

I assessed the five-year and ten-year rolling average risk premiums over the study period to gauge the variability over time of risk premiums. These rolling average risk premiums mitigate the impact of anomalous market conditions and skewed risk premiums over an entire business cycle. As shown on my Exhibit CCW-10, the five-year rolling average risk premium over Treasury bonds ranged from 4.17% to 7.17%, while the ten-year rolling average risk premium ranged from 4.30% to 6.92%.

As shown on my Exhibit CCW-11, the average indicated equity risk premium over contemporary "A" rated Moody's utility bond yields was 4.27%. The five-year and ten-year rolling average risk premiums ranged from 2.80% to 5.97% and 3.11% to 5.75%, respectively.

Q. WHY ARE THE TIME PERIODS USED TO DERIVE THESE EQUITY RISK PREMIUM ESTIMATES APPROPRIATE TO FORM ACCURATE CONCLUSIONS ABOUT CONTEMPORARY MARKET CONDITIONS?

A. Contemporary market conditions can change dramatically during the period that rates determined in this proceeding will be in effect. A relatively long period of time where stock valuations reflect premiums to book value indicates that the authorized ROEs and the corresponding equity risk premiums were supportive of investors' return expectations and provided utilities access to the equity markets under reasonable terms and conditions. Further, this time period is long enough to smooth abnormal market

movement that might distort equity risk premiums. While market conditions and risk premiums do vary over time, this historical time period is a reasonable period to estimate contemporary risk premiums.

Q. PLEASE EXPLAIN OTHER MARKET EVIDENCE YOU RELIED ON IN DETERMINING AN APPROPRIATE EQUITY RISK PREMIUM.

A. The equity risk premium should reflect the market's perception of risk in the utility industry today. I have gauged investor perceptions in utility risk today in Exhibit CCW-12, where I show the yield-spread between utility bonds and Treasury bonds since 1980. As shown in this schedule, the average utility bond yield-spreads over Treasury bonds for "A" and "Baa" rated utility bonds for this historical period are 1.48% and 1.90%, respectively.

A current 13-week average "A" rated utility bond yield of 5.62% when compared to the current Treasury bond yield of 4.45%, as shown in Exhibit CCW-13, page 1, implies a yield-spread of 1.17%. This current utility bond yield-spread is lower than the long-term average-spread for "A" rated utility bonds of 1.48%. The 13-week average yield on "Baa" rated utility bonds is 5.84%. This indicates a current spread for the "Baa" rated utility bond yield of 1.39%, which is lower than the long-term average of 1.90%.

Q. WHAT ARE THE RESULTS BASED ON YOUR RISK PREMIUM ANALYSES?

A. I give primary consideration to the Risk Premium results using Treasury bond and A-rated utility bonds. My recommendation also takes the results of adding the Baa-rated

utility bond yield to the equity risk premium over A-rated utility bonds into consideration.

Considering the current and projected economic environment, current yield spreads and equity risk premiums, as well as current levels of interest rates and interest rate projections, a more normalized equity risk premium is warranted. As such, I believe an average equity risk premium over Treasury yields of 5.63% is appropriate. Adding this risk premium to the projected Treasury yield of 4.00% produces an ROE of 9.63%.

Applying a similar methodology as described above, the average of the rolling five-year average risk premiums over A-rated utility bonds is 4.27%. The A-rated utility bond yield has averaged 5.62% over the 13-week period ending April 26, 2024 while the Baa-rated utility bond yield has averaged 5.84% over the same period. Adding this risk premium to the 13-week A-rated utility bond yield of 5.62% produces an estimated cost of equity of 9.89%. Adding this risk premium to the 13-week Baa-rated utility bond yield of 5.84% produces an estimated cost of equity of 10.11%.

The A-rated utility bond yield has averaged 5.63% over the 26-week period ending April 26, 2024 while the Baa-rated utility bond yield has averaged 5.87% over the same period. Adding this risk premium to the 26-week A-rated utility bond yield of 5.63% produces an estimated cost of equity of 9.90%. Adding this risk premium to the 26-week Baa-rated utility bond yield of 5.87% produces an estimated cost of equity of 10.14%.

The results of my risk premium analyses are summarized in Table CCW-9.

Table CCW-9

Summary of Risk Premium Results

Description	
Projected Treasury Yield	9.63%
13-Week Yields	
A-Rated Utility Bond	9.89%
Baa-Rated Utility Bond	10.11%
26-Week Yields	
A-Rated Utility Bond	9.90%
Baa-Rated Utility Bond	10.14%

IV.H. Capital Asset Pricing Model ("CAPM")

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM method of analysis is based upon the theory that the market-required ROR for a security is equal to the risk-free rate, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \times (R_m - R_f)$ where:

R_i = Required return for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Beta - Measure of the risk for stock

The term "beta" in the equation represents the stock-specific risk that cannot be reduced through diversification. In a well-diversified portfolio, specific risks related to individual stocks can be reduced by balancing the portfolio with securities that offset

the impact of firm-specific factors, such as business cycle, competition, product mix, and production limitations.

Non-diversifiable risks, on the other hand, are related to market conditions and are referred to as systematic risks. These risks cannot be reduced through diversification and are considered market risks. Conversely, non-systematic risks, also known as business risks, can be reduced through diversification.

According to the CAPM, the market does not compensate investors for taking on risks that can be diversified away. Thus, investors are only compensated for taking on systematic, or non-diversifiable, risks. Beta is a measure of these systematic risks.

Q. PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A. The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q. WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A. As published in the *Blue Chip Financial Forecasts,* the projected 30-year Treasury bond yield is 4.00%.[21] The current 30-year Treasury bond yield is 4.45%, as shown in Exhibit CCW-13 at page 1. Because the cost of equity is a forward looking exercise, I used *Blue Chip Financial Forecasts*' projected 30-year Treasury bond yield of 4.00% for my CAPM analysis.

[21] Blue Chip Financial Forecast April 1, 2024.

Q. WHY DID YOU USE LONG-TERM TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A. Treasury securities are backed by the full faith and credit of the United States government, so long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to future inflation and liquidity. In this regard, a Treasury bond yield is not entirely risk-free. Risk premiums related to unanticipated inflation and interest rates reflect systematic market risks. Consequently, for a company with a beta less than 1.0, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q. WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A. As shown in Exhibit CCW-14, the current proxy group average and median *Value Line* beta estimates are both 0.86. In my experience, these beta estimates are abnormally high and are unlikely to be sustained over the long-term. As such, I have also reviewed the historical average of the proxy group's *Value Line* betas. The historical average

Value Line beta since 2014 is 0.75 and has ranged from 0.64 to 0.83. Prior to the recent pandemic, the high end of this range was 0.76.

In addition to *Value Line*, I have also included adjusted beta estimates as provided by Market Intelligence's Beta Generator Model. This model relied on a five-year period on a weekly basis ending April 26, 2024. The average and median Market Intelligence betas are 0.74 and 0.74, respectively. Market Intelligence betas, as calculated using its Beta Generator Model, are adjusted using the Vasicek method and calculated using the S&P 500 as the proxy for the investable market. This is in stark contrast with the *Value Line* beta estimates that are adjusted using a constant weighting of 67%/35% to the raw beta/market beta and use the New York Stock Exchange ("NYSE") as the proxy for the investable market. Because I rely on the S&P 500 to estimate the expected return on the investable market, it makes sense to rely on beta estimates that are calculated using the S&P 500 as the benchmark for the market. Further, as S&P explains:

> The Vasicek Method is a superior alternative to the Bloomberg Beta adjustment. The Bloomberg adjustment is not appropriate for a vast number of situations, as it assigns constant weighting regardless of the standard error in the raw beta estimation (Bloomberg Beta = 1/3*market beta + 2/3*Raw Beta). Given the statistical fact that a larger sample size yields a smaller error, the Vasicek method more appropriately adjusts the raw beta via weights determined by the variance of the individual security versus the variance of a larger sample of comparable companies. The weights are designed to bring the raw beta closer to whichever beta estimation has the smallest error. This is a feature the Bloomberg beta cannot replicate.[22]

Notably, while S&P makes reference to the Bloomberg method of applying 2/3 and 1/3 weights to the raw beta and market beta, respectively, the comparison still

[22] S&P Market Intelligence, Beta Generator Model.

applies to *Value Line's* methodology of applying 67% and 35% weights. Both methods are forms of the Blume adjustment.[23] While the weights are slightly different between the Bloomberg and *Value Line* methods, they are similar and apply a constant weight without any regard to accuracy. As such, the criticisms of the betas offered by S&P apply to both Bloomberg betas and *Value Line* betas.

Q. HOW DID YOU DERIVE YOUR MARKET RISK PREMIUM ESTIMATES?

A. My market risk premium estimates are derived using two general approaches: a risk premium approach and a DCF approach. I also consider the normalized market risk premium of 5.50% with the normalized risk-free rate of 4.56% as recommended by Kroll, formerly known as Duff & Phelps.[24] Based on this methodology and utilizing a "normalized" risk-free rate of 4.56%, Kroll concludes that the current expected, or forward-looking, market risk premium is 5.50%, implying an expected return on the market of 10.06%.[25]

[23] The Blume adjustment is a tool used to refine a beta measurement in finance. In general, Beta attempts to explain how much a particular investment's price moves compared to the overall market. But beta is often based on historical data, which may not be an accurate method for predicting the future. The Blume adjustment tries to address this by considering the idea that, in the long run, most investments tend to become more similar in their riskiness to the overall market (represented by a beta of 1).

[24] Kroll, and its predecessor Duff & Phelps, is a provider of economic, financial, and valuation data that is often relied on by finance professionals and cited in ROR testimony.

[25] Kroll, *Kroll Increases U.S. Normalized Risk-Free Rate from 3.0% to 3.5%, but Spot 20-Year U.S. Treasury Yield Preferred When Higher*, June 16, 2022. The current 20-year yield of 4.56% exceeds the "normalized" yield of 3.5%. In accordance with Kroll's prescribed method, the greater of the two shall be used under the normalized Kroll methodology, i.e., 4.56%.

Q. PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATE DERIVED USING THE RISK PREMIUM METHODOLOGY.

A. The forward-looking risk premium-based estimate was derived by estimating the expected return on the market (as represented by the S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

The Kroll *SBBI Yearbook* is no longer being published. As such, estimates of the historical, arithmetic-average, real-market return over the period 1926 to 2023 were calculated using data from Morningstar Direct. The arithmetic-average real return on the market since 1926 is 9.02%.[26] A current consensus for projected inflation, as measured by the Consumer Price Index ("CPI"), is 2.30%.[27] Using these estimates, the expected market return is 11.53%.[28] The market risk premium then is the difference between the 11.53% expected market return and the projected risk-free rate of 4.00%, or 7.53%.

Q. PLEASE DESCRIBE YOUR MARKET RISK PREMIUM ESTIMATES DERIVED USING THE DCF METHODOLOGY.

A. I employed two versions of the constant growth DCF model to develop estimates of the market risk premium. I first employed the Federal Energy Regulatory Commission's

[26] Morningstar Direct.
[27] Blue Chip Financial Forecast April 1, 2024.
[28] [(1 +9.02%) * (1 + 2.30%) - 1] * 100.

("FERC") method of estimating the expected return on the market that was established in its Opinion No. 569-A. FERC's method for estimating the expected return on the market is to perform a constant growth DCF analysis on each of the dividend-paying companies of the S&P 500 index. The growth rate component is based on the average of the growth projections excluding companies with growth rates that were negative or greater than 20%.[29] The weighted average growth rate for the remaining companies is 11.00%. After reflecting the FERC prescribed method of adjusting the dividend yield by (1+ 0.5g), the weighted average expected dividend yield is 1.90%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.90%. The market risk premium then is the expected market return of 12.90%, less the projected risk-free rate of 4.00%, or 8.90%.

My second DCF-based market risk premium estimate was derived by performing the same DCF analysis described above, except I used all companies in the S&P 500 index rather than just the dividend-paying companies. The weighted average growth rate for these companies is 11.20%. After reflecting the FERC-prescribed method of adjusting the dividend yield by (1+ 0.5g), the weighted average expected dividend yield is 1.69%. Thus, the DCF-derived expected return on the market is the sum of those two components, or 12.89%. The market risk premium then is the expected market return of 12.89% less the projected risk-free rate of 4.00%, or 8.90%.

The average expected market return based on the DCF model is 12.90% and the average market risk premium based on the two DCF estimates is 8.90%.

[29] Opinion No. 569-A, at 210.

Q. HOW DO YOUR EXPECTED MARKET RETURNS COMPARE TO CURRENT EXPECTATIONS OF FINANCIAL INSTITUTIONS?

A. As shown in Table CCW-10, my average expected market return of 11.50%[30] exceeds long-term market expectations of several financial institutions.

TABLE CCW-10

Long-Term Expected Return on the Market

Source	Term	Expected Return Large Cap Equities
BlackRock Capital Management[1]	30 Years	7.00%
JP Morgan Chase[2]	10 - 15 Years	7.00%
Vanguard[3]	10 Years	4.2% - 6.2%
Research Affiliates[4]	10 Years	4.00%

Sources:
[1]BlackRock Investment Institute, November 2023 report.
[2]JP Morgan Chase, Long-Term Capital Market Assumptions, 2024 Report.
[3]Vanguard economic and market outlook for 2024: A Return to Sound Money.
[4]Research Affiliates, Asset Allocation Interactive. Retrieved 1/05/2024.

When compared to the expected market returns of financial institutions above, my average expected market return of 11.50% is greater than all of them. For these reasons, my expected market returns, and the associated market risk premiums, should be considered reasonable, if not high-end estimates.

[30] 11.50% = (10.06% + 12.90% + 11.53%) / 3.

Q. HOW DO YOUR ESTIMATED MARKET RISK PREMIUMS COMPARE TO THAT ESTIMATED BY KROLL?

A. Kroll' analysis indicates a market risk premium falls somewhere in the range of 5.50% and 7.17% using market returns through 2023. My market risk premium estimates are in the range of 5.50% to 8.90%.

Q. HOW DOES KROLL MEASURE A MARKET RISK PREMIUM?

A. Kroll's range is based on several methodologies. First, Kroll estimated a market risk premium of 7.17% based on the difference between the total market return on common stocks (S&P 500) less the income return on 20-year Treasury bond investments over the 1926-2023 period.[31]

Second, Kroll used the Ibbotson & Chen supply-side model which produced a market risk premium estimate of 6.22%.[32] Kroll explains that the historical market risk premium based on the S&P 500 was influenced by an abnormal expansion of P/E ratios relative to earnings and dividend growth. In order to control for the volatility of extraordinary events and their impacts on P/E ratios, Kroll takes into consideration the three-year average P/E ratio as the current P/E ratio. Therefore, Kroll adjusted this market risk premium estimate to normalize the growth in the P/E ratio to be more in line with the growth in dividends and earnings.

Finally, Kroll developed its own recommended equity, or market risk premium, by employing an analysis that takes into consideration a wide range of economic

[31] Kroll, *Cost of Capital Navigator.*
[32] *Id.*

information, multiple risk premium estimation methodologies, and the current state of the economy by observing measures such as the level of stock indices and corporate spreads as indicators of perceived risk. Based on this methodology, and utilizing a "normalized" risk-free rate of 4.56%, Kroll concludes that the current expected, or forward-looking, market risk premium is 5.50%, implying an expected return on the market of 10.06%.[33]

Q. DO YOU HAVE ANY COMMENTS ON THE EXPECTED MARKET RETURNS AND MARKET RISK PREMIUMS DESCRIBED ABOVE?

A. Yes. As described above, the average expected market return based on the DCF model is 12.90% and the average market risk premium is 8.90%. The expected market return of 12.90% is based on a constant perpetual growth rate of 11.20%. This is simply unsustainable for the same reasons described in greater detail above.

It simply is not reasonable to believe individual companies can sustain growth rate of 11.20% into perpetuity. In fact, in the CFA curriculum textbooks, the CFA Institute notes as follows with regard to earnings growth rates for companies within the composite indices (i.e., S&P 500):

> Earnings growth for the overall national economy can differ from the growth of earnings per share in a country's equity market composites. This is due to the presence of new businesses that are not yet included in the equity indices and are typically growing at a faster rate than the mature companies that make up the composites. **Thus, the earnings**

[33] *Id.*

growth rate of companies making up the composites should be lower than the earnings growth rate for the overall economy.[34]

In addition, a market risk premium in excess of 8.0% is significantly outside the range supported by empirical evidence. For example, Dr. Morin notes in his book, *Modern Regulatory Finance*, that several studies of the market risk premium have concluded that a market risk premium in the range of 5.0% to 8.0% is a reasonable estimate for the United States.[35] The Duarte and Rosa study he cites concludes that the historical mean is "quite difficult to improve upon when considering out-of-sample performance measures."[36] Dr. Morin also notes that a survey of professional practices showed that 71% of textbooks/tradebooks used a historical average as the market risk premium, and 60% of financial advisors used a market risk premium in the range of 7.0% to 7.4% (similar to a long-term arithmetic average market risk premium).[37]

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown in Exhibit CCW-15, I have provided the results of nine different applications of the CAPM. The first three results presented are based on the proxy group's current average *Value Line* beta of 0.86. The results of the CAPM based on these inputs range from 9.30% to 11.67%.

[34] CFA Program Curriculum, 2014 Level II Vol. 1, "Ethical and Professional Standards, Quantitative Methods, and Economics", Paul Kutasovic, Reading 15 – Economic Growth and the Investment Decision, page 609, footnote 5 (emphasis added).
[35] Dr. Morin references studies by Duarte & Rosa; Professors Ross, Westerfield, and Jordan; Mahera; and Brealey, Myers, and Allen. See *Modern Regulatory Finance*, Dr. Roger A. Morin, at pages 190-192. Dr. Morin notes in his textbook that there is a "slight preference" for the upper end of the range (i.e., 8%) during tumultuous times in capital markets with examples being the 2008-2009 credit crisis and the 2020 pandemic.
[36] See *Modern Regulatory Finance*, Dr. Roger A. Morin, at page 191, citing the Duarte and Rosa study.
[37] See *Modern Regulatory Finance*, Dr. Roger Morin, at page 190, footnote 35.

The next set of three results presented are based on the proxy group's historical *Value Line* beta of 0.75. The results of the CAPM based on these inputs range from 8.71% to 10.71%.

The last set of three results presented are based on the proxy group's current S&P Global Market Intelligence beta of 0.74. The results of the CAPM based on these inputs range from 8.65% to 10.62%. My CAPM results are summarized in Table CCW-11.

Because current beta estimates are based on the most recent five years of historical stock returns and volatility, they are being heavily impacted by the market fallout in early 2020 as the global pandemic set in and the market reacted, with this S&P 500 falling more than 40%. For this reason, it is not reasonable to assume current beta estimates, particularly Blume-adjusted betas such as those published by *Value Line*, are reflective of investor expectations at this time. As such, I am giving less consideration to the results of my CAPM analyses that rely on current *Value Line* betas. Finally, for the reasons detailed above, I believe it is also reasonable to give less consideration to the CAPM results that rely on market risk premium estimates of 8.90%

Table CCW-11

CAPM Results Summary

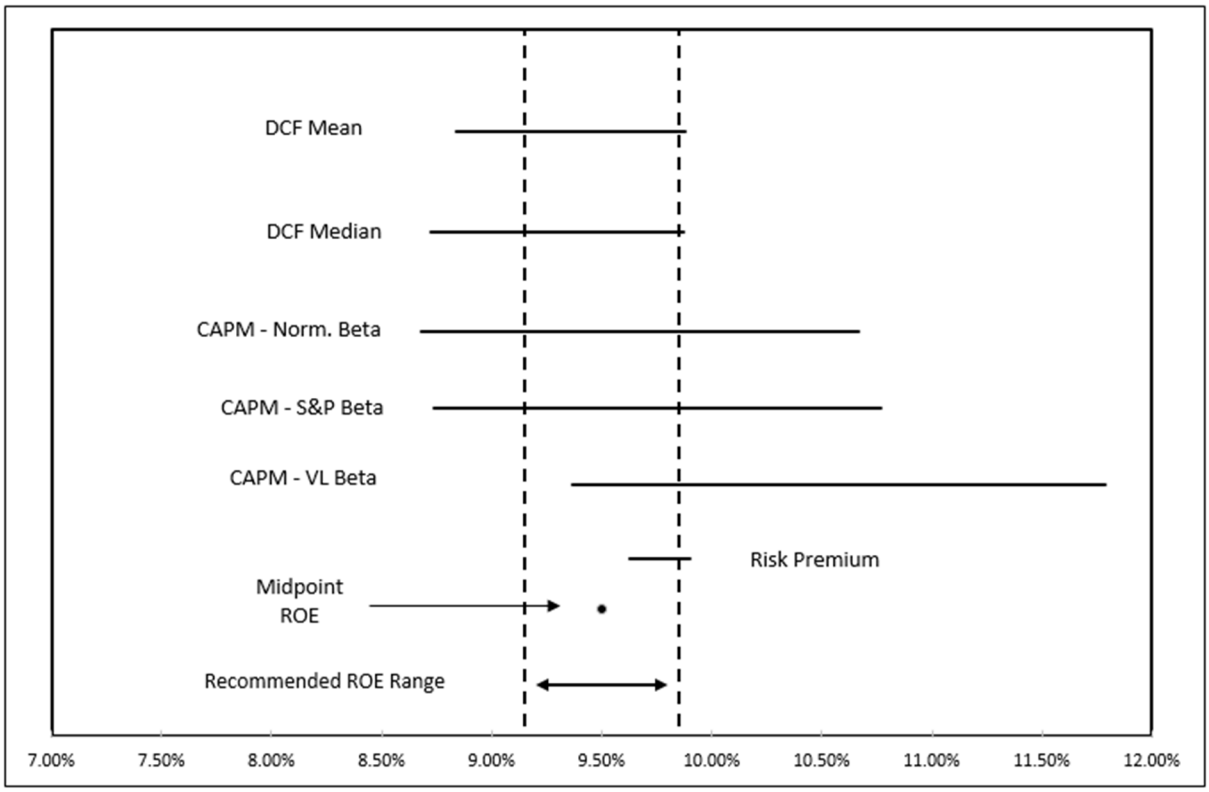
Description	Current VL Beta	Historical VL Beta	Current S&P Beta
Kroll Normalized Method	9.30%	8.71%	8.65%
Risk Premium Method	10.46%	9.65%	9.58%
FERC DCF Method	11.67%	10.71%	10.62%
Average	10.53%	9.74%	9.63%

IV.I. Return on Equity Summary

Q. BASED ON THE RESULTS OF YOUR RETURN ON COMMON EQUITY ANALYSES DESCRIBED ABOVE, WHAT RETURN ON COMMON EQUITY DO YOU RECOMMEND FOR THE COMPANY?

A. The results of my analyses are summarized in Figure CCW-5. In this figure, I present the various measures of central tendency for each of my analytical models.

FIGURE CCW-5



Based on my analyses of the various methodologies described above, I estimate the Company's current market cost of equity to be in the reasonable range of 9.10% to 9.80%. My recommended range accounts for the unsustainable growth rates assumed in the constant growth DCF model and the irrational assumption that Value Line's current beta estimates are reflective of current investor expectations. In addition, my recommended range is captured by the range of results for each of the models and is consistent with measures of central tendency of those results. Based on my assessment of Columbia Gas's overall risk profile and the results of these analytical methods, I would recommend that this Commission authorize Columbia Gas an ROE of 9.45%, which is the midpoint of the range produced by these models.

V. RESPONSE TO MR. MOUL

Q. WHAT RETURN ON COMMON EQUITY IS COLUMBIA GAS PROPOSING FOR THIS PROCEEDING?

A. Columbia Gas' proposed return on equity is supported by its witness Mr. Paul Moul. Mr. Moul recommends a return on equity for Columbia Gas of 11.75%.[38]

Q. PLEASE DESCRIBE THE METHODOLOGY MR. MOUL USED FOR HIS RETURN ON COMMON EQUITY RECOMMENDATION.

A. Mr. Moul uses a DCF analysis, a risk premium analysis, a CAPM model, and a comparable earnings approach. Mr. Moul performed these models on a gas proxy group of nine publicly traded companies. After performing his DCF and risk premium studies, Mr. Moul proposed to include a return on equity adder for flotation costs, leverage adjustments, size adjustments, and managerial performance. These return on equity adders are not reasonable, have not been justified, and substantially overstate a fair return on equity for Columbia Gas.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO MR. MOUL'S PROPOSED RETURN ON EQUITY ESTIMATE FOR COLUMBIA GAS.

A. As shown below in Table CCW-12, Mr. Moul is proposing a return on equity for Columbia Gas of 11.75%. Mr. Moul's recommendation is excessive. With reasonable and appropriate adjustments to Mr. Moul's analyses, his own studies would support my recommended return on equity of 9.45%.

[38] Statement 8 at 5-6.

TABLE CCW-12

Summary of Moul's Return on Equity Estimate

Description	Moul Results: Model Estimate (1)	Moul Results: ROE Adder (2)	Moul Results: Result (3)
DCF	10.74%	1.31%	12.05%
Risk Premium	11.50%		11.50%
CAPM	12.84%	1.02%	13.86%
Comparable Earnings	13.10%		13.10%
Recommended ROE	11.50%	0.25%	11.75%

Source: Statement 8.

V.A. Mr. Moul's DCF Analysis

Q. PLEASE DESCRIBE MR. MOUL'S DCF ANALYSIS.

A. Mr. Moul estimated a DCF return for his Gas Group of 12.05% after adjusting for differences in financial leverage. Mr. Moul's unadjusted DCF result is 10.74%. However, Mr. Moul includes a leverage adder of 131 basis points, producing his adjusted DCF result of 12.05%.

Q. PLEASE DESCRIBE THE CONCERNS YOU HAVE WITH MR. MOUL'S DCF ANALYSIS.

A. Mr. Moul's unadjusted DCF estimate for his proxy group is 10.74%. His DCF is based on an adjusted dividend yield of 3.99% and a growth rate of 6.75%. My concerns with

Mr. Moul's DCF are two-fold: (1) Mr. Moul's growth rate of 6.75% is approximately 63% greater than the expected long-term growth rate of US GDP; and, (2) his financial leverage adjustment of 1.31% to increase his DCF result from 10.74% to 12.05%.

Q. PLEASE ADDRESS YOUR CONCERNS WITH MR. MOUL'S 6.75% GROWTH RATE ASSUMED IN THE DCF MODEL.

A. Mr. Moul argues that growth rates should not be established by mathematical formulation, but rather be based on his opinion of what a reasonable growth rate should be. He observes that the average growth rate forecasts for the Gas Group range from 5.69% to 7.31%. He opines that the 6.75% growth rate is reasonable because it is within that range of analyst forecasts and supported by the expected continuation of gas utility infrastructure spending.

As an initial matter, his growth rate of 6.75% assumes that the proxy group will grow at a much faster rate, in perpetuity, than the expected growth rate of United States economy of 4.14%.[39] In other words, his proxy group's growth rate is approximately 63.0% higher than the expected growth rate of the U.S. economy. A growth rate that grossly exceeds the growth rate of GDP in the country in which the utility provides goods and services cannot be sustained. Because of the economic infirmities in his use of an assumed proxy company growth rate that grossly exceeds the expected growth of the US economy in perpetuity, Mr. Moul should have considered the results of a multi-stage DCF.

[39] Blue Chip Economic Indicators March 10, 2024.

Q. WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A. Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. Utilities' earnings and dividend growth is created by increased utility investment in its rate base. Examples of what can drive such investment are service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As a result, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run. Therefore, the U.S. GDP nominal growth rate is a conservative proxy for the highest sustainable long-term growth rate of a utility. As I explained above in regard to my own DCF analysis, there is ample research which supports the notion that, over the long-term, a company's earnings and dividends cannot grow at a rate greater than the economy.

Q. ARE YOU AWARE OF ANY RESEARCH THAT DEMONSTRATING THAT MULTI-STAGE DCF MODELS ARE USED IN THE INVESTMENT INDUSTRY?

A. Yes. The CFA Institute curriculum text states as follows:

> Multistage models are a staple valuation discipline of investment management firms using DCF valuation models.
> A survey of CFA Institute members with job responsibility for equity analysis indicates that, among respondents using a dividend discount model, two-stage and multistage models are used more often than the single-stage model (Stowe, Pinto, and Robinson 2018). Among analysts using a dividend discount model, 55% use a two-stage model, 11% use

an H-model (a type of two-stage model), and 50% use a model with more than two stages (Stowe, Pinto, and Robinson 2018).[40]

As Stowe *et al* have revealed, the majority of equity analysts rely on multi-stage models more frequently than single stage or constant growth models.

Q. PLEASE DESCRIBE MR. MOUL'S PROPOSED LEVERAGE ADJUSTMENT.

A. Mr. Moul argues that a leverage adjustment is necessary if the rate of return established in this proceeding is applied to a book value capital structure rather than a market value capital structure.[41] Mr. Moul derives a return on equity adder of approximately 1.31% based on the perception that there is more financial risk based on the proxy group's book value capital structure weights, than there is based on the market value capital structure weights.[42]

Q. IS MR. MOUL'S PROPOSED LEVERAGE RETURN ON EQUITY REASONABLE?

A No. Mr. Moul's return leverage adder is nothing more than a market-to-book ratio adjustment to the DCF return. This leverage adjustment should be rejected because it is intended to support a specific market price, rather than to fairly compensate Columbia Gas for its investment in utility plant and equipment. A market-to-book ratio adder will not result in a fair return on equity used to set rates, and in fact will provide Columbia Gas an excessive rate of return on utility plant investments, and place unnecessary and

[40] Chartered Financial Analyst Institute, 2023 CFA Program Level 2 Refresher Reading, Equity Valuation: Discounted Dividend Valuation, at 30. [footnote omitted].
[41] Statement 8 at 28-31.
[42] *Id*. at 31.

excessive cost burdens on retail customers. Mr. Moul's leverage adder is not reasonable and should be rejected.

Q. DO YOU BELIEVE THAT MR. MOUL'S CONTENTION THAT THE MARKET MEASURES LEVERAGE RISK BASED ON MARKET VALUES AND NOT BOOK VALUES IS VALID?

A. I would agree that in valuing a company, the market would be largely concerned with the market value leverage of the company. However, the independent market evidence relied on to measure Columbia Gas' current market cost of equity suggests that the market places significant weight on leverage risk based on book value factors. I state this because in their credit rating reviews of utility companies, S&P, Moody's, and Fitch all measure financial risk based on book value measures.

Second, book value leverage represents the contractual obligations of the utilities. Hence, the cash flows produced from operations must meet these book value financial obligations.

Finally, equity reports such as *Value Line* present financial data that investors find useful in making stock selections. *Value Line* presents data reflecting investment options' financial risk based on book value measures. As such, relying on the book value financial risk of the company, and identifying its total investment risk, is reasonably consistent with credit rating reports, utilities' contractual obligations, and equity reports on utilities.

For these reasons, Mr. Moul's leverage adjustment is simply not valid and not just or reasonable.

Q. HAS THIS COMMISSION PREVIOUSLY REJECTED FINANCIAL LEVERAGE ADJUSTMENTS?

A. Yes. This Commission recently rejected such an adjustment in the 2022 Aqua Pennsylvania case.[43]

Q. ARE YOU AWARE OF OTHER REGULATORY COMMISSIONS REJECTING FINANCIAL LEVERAGE ADJUSTMENTS SIMILAR TO THAT OF MR. MOUL'S PROPOSAL?

A. Yes, I am. In a recent Nicor Gas rate case (Docket No. 21-0098), the Illinois Commerce Commission explicitly rejected the application of any leverage ROE adjustments, including ones that are similar to what Mr. Moul is proposing (i.e. M&M theory and Hamada adjusted betas), stating the following:

> Additionally, the Company's leverage adjustments improperly inflated the Company's ROE recommendation, especially for the water companies. Further, the leverage adjustments are based on the flawed argument that a market-derived ROE does not produce a fair rate of return when applied to a book value rate base. In the Commission's view, an ROE derived from market-based models should be applied to the book value common equity ratio of the Illinois utility because the book value capital structure reflects the amount of capital a utility actually uses to finance the acquisition of assets for providing utility service, which are included in rate base. In contrast, market value typically includes appreciated value, which is not used in establishing the overall or weighted average cost of capital in ratemaking proceedings for Illinois utilities. The Commission has used this approach to establish utility rates for decades and the results have consistently provided Illinois utilities with adequate access to capital at reasonable costs. In contrast, allowing upward adjustments to the allowed ROE to reflect leverage adjustments would result in a never-ending upward movement in the allowed rate of return, which would not properly balance the interests of customers and the utility.

* * *

[43] Aqua Pennsylvania 2022 Order at 87-88.

> The Commission concludes that the Company's ROE recommendations should not be adopted primarily because the Company's DCF and CAPM estimates include leverage adjustments, which the Commission has routinely rejected.[44]

The Michigan Public Service Commission has taken a similar stance on financial leverage adjustments in recent rate cases as well.[45]

V.B. Mr. Moul's Risk Premium Analysis

Q. PLEASE DESCRIBE MR. MOUL'S RISK PREMIUM ANALYSIS.

A. Mr. Moul constructs a risk premium analysis by adding an equity risk premium of 6.50%, to his projected A-rated utility bond yield of 5.00% to produce a return of 11.50%.[46]

Q. HOW DID MR. MOUL ARRIVE AT A 6.50% EQUITY RISK PREMIUM FOR COLUMBIA GAS?

A. Mr. Moul calculated the achieved returns over various periods between the Large Company Common Stocks and long-term corporate bonds from *Ibbotson's 2023 SBBI Yearbook Stocks, Bonds, Bills, and Inflation*. Based on his observation throughout the various time periods, Mr. Moul concluded that the equity premium over bond yields averaged 5.96% over all time periods and falls in the range of 4.76% to 7.13%. He also concluded that the equity premium moves inversely with interest rates. He then chose

[44] Illinois Commerce Commission, Docket No. 21-0098, *Northern Illinois Gas Company d/b/a Nicor Gas Company*, Final Order at 93-94, November 18, 2021.
[45] *See* Michigan Public Service Commission, Case No. U-18014, Final Order, page 66, January 31, 2017; Case No. U-18255, Final Order, page 32, April 18, 2018.
[46] Statement 8 at 36.

a risk premium of 6.50% which is approximately the midpoint of his average (5.96%) and high-end equity risk premium (7.13%).[47]

Q. IS MR. MOUL'S 6.50% RISK PREMIUM ESTIMATE REASONABLE?

A. No. Mr. Moul's risk premium is unreasonable for two reasons. First, Mr. Moul's estimate of an equity risk premium is not an appropriate risk-adjusted equity risk premium that reasonably reflects a regulated utility company's investment risk. His risk premium estimates are based on the S&P 500. This is a stock market index that reflects the investment risk of the whole market; it does not reflect the below market risk of an investment like regulated utilities generally, and Columbia Gas specifically.

Second, his development of a 6.50% risk premium relative to an A-rated corporate bond yield is not well-defined or fully developed on his exhibits. Specifically, the risk premium should have been adjusted for the lower investment risk of Columbia Gas, compared to the large company stocks used to develop the risk premium.

Q. IS OBSERVABLE EVIDENCE TO FURTHER SUGGEST THAT MR. MOUL'S 6.50% RISK PREMIUM ESTIMATE IS UNREASONABLE?

A. Yes. In 2023, the average authorized ROE for gas utilities was 9.60% while the average 30-year Treasury yield was 4.09%. This indicates an equity risk premium of 5.51%. This compares to the long-term average equity risk premium of 5.67% since 1986.[48] In a recent report, Regulatory Research Associates notes that "while ROEs increased in

[47] *Id.* 35-36.
[48] See Exhibit CCW-10.

2023, the spread between authorized returns and US Treasury yields narrowed considerably. This narrowing spread is likely to continue through 2024 as regulators navigate the ongoing energy transition and potential affordability challenges posed by higher interest rates and rising costs."[49] The narrowing spread between authorized ROEs and Treasury yields, as highlighted by RRA, strongly suggests that regulators are likely to authorize equity risk premiums below the long-term historical average over the near-term. This trend is expected to persist as regulators grapple with the dual challenges of facilitating the energy transition while also addressing affordability concerns arising from higher interest rates and escalating costs.

Mr. Moul's Risk Premium analysis is arbitrary and unsupported. As such, it should be rejected in its entirety.

V.C. Mr. Moul's CAPM Study

Q. PLEASE DESCRIBE MR. MOUL'S CAPM.

A. Mr. Moul CAPM relies on a risk-free rate of 3.75%, a market risk premium of 8.26%, and a leverage-adjusted beta for his Gas Group of 1.10. This produces a CAPM return of 12.84%.[50] Mr. Moul then increased the CAPM for a size return adder of 1.02% to produce a CAPM return of 13.86%.[51] Mr. Moul's testimony indicates that he also included a flotation cost adjustment.[52] However, nowhere in his testimony or exhibits

[49] RRA Regulatory Focus, *Average authorized energy ROEs rise in 2023 amid record rate case activity* (Jan. 25, 2024).
[50] 3.75% + (1.10 x 8.26%) = 12.84%.
[51] 12.84% + 1.02% = 13.86%.
[52] Statement 8 at 40, lines 8-9.

does he discuss or develop a flotation cost adjustment. To my knowledge, this Commission has never allowed a flotation cost adjustment.

Mr. Moul's beta estimate of 1.10 is based on the *Value Line* proxy group beta of 0.87 and a leverage adjustment which increases the beta estimate to 1.10. His market risk premium is based on a historical market risk premium of 8.34% and a projected market risk premium of 8.18%, averaged to produce a market risk premium of 8.26%.[53]

Q. PLEASE DESCRIBE THE ISSUES YOU HAVE WITH MR. MOUL'S CAPM ANALYSIS.

A. I have several concerns with Mr. Moul's CAPM analysis. While Mr. Moul's adjusted CAPM result of 13.86% is notably higher than typical authorized returns and market data benchmarks, it warrants further examination to understand the underlying assumptions and inputs driving that outcome. My particular concerns with his inputs to the CAPM include: (1) his excessive market risk premiums, (2) his financial leverage adjusted beta, (3) his application of a size adjustment, and (4) his use of a flotation cost adjustment is not described or quantified anywhere in his testimony. Mr. Moul appears to have given very little weight to his CAPM results which establish the high-end of his range, given his recommended ROE is equal to the low-end of his recommended range. I urge this Commission to reject its results.

[53] Moul Schedule 13, page 2.

Q. PLEASE DESCRIBE MR. MOUL'S MARKET RISK PREMIUM ESTIMATES AND THE CONCERNS YOU HAVE WITH THEM.

A To arrive at his market risk premium of 8.26%, Mr. Moul averaged his historical market risk premium of 8.34% and his prospective market risk premium of 8.18%.[54] Mr. Moul's historical risk premium is obtained from *SBBI Yearbook* data. His prospective market risk premium is based on the *Value Line* Index and the S&P 500.

Mr. Moul does not provide any details underlying the development of his projected market risk premium using data from *Value Line* or the S&P 500 except for the expected market return component assumes a dividend yield of 2.20% and a long-term growth rate of 9.73%. His historical risk premium is the result of selectively averaging historical returns during subjectively determined (and unexplained) periods described as having high or low interest rates.

Similar to certain of my market risk premium estimates described above, Mr. Moul's market risk premiums fall outside the range of empirical evidence.

Q. PLEASE EXPLAIN WHY MR. MOUL'S SIZE ADJUSTMENT TO HIS CAPM IS NOT REASONABLE.

A. Mr. Moul applies a size adjustment to his CAPM result because he believes Columbia Gas's smaller size makes the Company much riskier.[55] He relies on the SBBI Yearbook to determine that an adjustment of 1.02%, which corresponds to a "midcap" size company. As an initial matter, Mr. Moul's size premium estimate for midcap companies

[54] Statement 8 at 39.
[55] Statement 8 at 13 and 43.

of 1.02% significantly exceeds the most recently published size premium of 0.66%.[56] In addition to being stale and overstated, there are several fundamental errors in Mr. Moul's application of the size adjustment.

Q. WHAT FUNDAMENTAL REASONS WHY MR. MOUL'S SIZE ADJUSTMENT DOES NOT PRODUCE A VALID CAPM RETURN ESTIMATE?

A. His size adjustment reflects risks that are not reflective of Columbia Gas. The size adjustment recommended by Mr. Moul reflects companies that have raw unadjusted beta estimates of 1.12.[57] These beta estimates are substantially higher than the average adjusted *Value* Line beta of 0.87 for the Gas Group used by Mr. Moul as reflective of Columbia Gas's investment risk. A more comparable beta estimate of the Gas Group would be to remove the adjustment Value Line makes so that you are left with a raw, unadjusted beta which can then be compared to the average 1.12 beta of the midcap companies relied on by Mr. Moul. After removing Value Line's adjustment, the Gas Group's raw unadjusted beta is 0.776, significantly lower than that of the 1.12 average beta for the midcap companies used by Mr. Moul. Therefore, his size adjustment produces a CAPM return estimate that does not produce a risk-appropriate return for Columbia Gas and therefore, is not a reasonable and fair return for Columbia Gas.

Further, there is empirical evidence which concludes that, while size premiums are present in industrial companies, such a size premium is not present in utility

[56] Kroll Cost of Capital Navigator.
[57] Moul Schedule 13, page 3.

companies, nor are they appropriate to include in valuing utilities. In the article published in the Journal of the Midwest Finance Association, Ms. Wong concludes that

> First, given firm size, utility stocks are consistently less risky than industrial stocks. Second, industrial betas tend to decrease with firm size but utility betas do not. These findings may be attributed to the fact that all public utilities operate in an environment with regional monopolistic power and regulated financial structure. As a result, the business and financial risks are very similar among the utilities regardless of their sizes. Therefore, utility betas would not necessarily be expected to be related to firm size.
>
> The objective of this study is to examine if the size effect exists in the utility industry. After controlling for equity values, there is some weak evidence that firm size is a missing factor from the CAPM for the industrial but not for the utility stocks. This implies that although the size phenomenon has been strongly documented for the industrials, the findings suggest that there is no need to adjust for the firm size in utility rate regulations.[58]

For these reasons, it is clear that Mr. Moul's size adjustment is improperly applied and should be rejected.

V.D. Mr. Moul's Comparable Earnings Analysis

Q. PLEASE DESCRIBE MR. MOUL'S COMPARABLE EARNINGS ANALYSIS.

A. Mr. Moul's comparable earnings analysis is based on the historical and projected returns on book equity for non-regulated companies followed by *Value Line*. Mr. Moul selected companies based on the *Value Line* Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Beta, and Technical Rank. Based on these criteria, as shown on his Schedule 14, page 2, Mr. Moul estimated the *Value Line* average historical earned return

[58] Wong, Annie, 1993, Utility stocks and the size effect: An empirical analysis, Journal of the Midwest Finance Association, 95-101

on equity over the period 2018 through 2022 to be 12.3%, and projected return for 2026-2028 to be 13.6%. He excluded projections of 20% or higher in the development of this range. Using this as his comparable earnings range, Mr. Moul calculated a point estimate for Columbia Gas of 13.10% ((12.6% + 13.6%) ÷ 2)**.**

Q. PLEASE DESCRIBE THE ISSUES YOU HAVE WITH MR. MOUL'S COMPARABLE EARNINGS ANALYSIS.

A. Mr. Moul's comparable earnings analysis should be rejected for several reasons. A comparable earnings analysis does not measure the return an investor requires in order to make an investment. In other words, the accounting measure of the earned ROE does not measure the opportunity cost of capital. Rather, it measures the earned return on book equity that companies have experienced in the past or are projected to achieve in the future. The returns investors require in order to assume the risk of an investment are measured from prevailing stock market prices.

In addition, FERC has recently found that this model does not satisfy the requirements of *Hope*. In part, FERC states as follows:

> As a result, the expected return on a utility's book value does not reflect "returns on investments in other enterprises" because book value does not reflect the value of any investment that is available to an investor in the market, outside of the unlikely situation in which market value and book value are exactly equal. Accordingly, we find that relying on the Expected Earnings model would not satisfy the requirements of *Hope*.
>
> The return on book value is also not indicative of what return an investor requires to invest in the utility's equity or what return an investor receives on the equity investment, because those returns are determined

> with respect to the current market price that an investor must pay in order to invest in the equity.[59]

Later in the same Opinion, FERC observes that the model does not identify investments of comparable risk. It states as follows:

> Moreover, we find that the record demonstrates that the Expected Earnings model does not identify investments of comparable risk and which alternatives will have a higher expected return as MISO TOs' witness Mr. McKenzie indicates.[footnote omitted] In particular, because the Expected Earnings model measures returns on book value, without consideration of what market price an investor would have to pay to invest in the relevant company, it does not accurately measure the investor's expected returns on its investment.[60]

Additionally, the historical and projected earned ROE for these holding companies can be significantly influenced by the financial performance of nonregulated operations. For these reasons, Mr. Moul's expected earnings analysis should be disregarded.

V.E. Flotation Cost Adder

Q DID MR. MOUL INCLUDE A FLOTATION COST ADJUSTMENT TO HIS ANALYTICAL RESULTS?

A Mr. Moul states that he did add a flotation cost adjustment to his CAPM results, which ultimately produced a cost of equity estimate for 13.86% for the Gas Group. However, it is not clear whether Mr. Moul did include a flotation cost adjustment. Nowhere else in his testimony is such an adjustment described, nor quantified. As stated above, I am unaware of this Commission approving a flotation cost adjustment. For these reasons,

[59] Opinion No. 569, 169 FERC ¶ 61,129 at p. 201-202. I note that the Comparable Earnings method employed by Mr. Moul is similar to the Expected Earnings model reference in the FERC Opinion and are used interchangeably here.
[60] *Id*. at p. 205.

to the extent Mr. Moul did include a flotation cost adjustment, I urge the Commission to reject it for being unsupported. Should Mr. Moul decide to eventually support and include a flotation cost adjustment in a later testimony, I will respond to it as necessary.

V.F. Management Performance Adder

Q. PLEASE DESCRIBE THE MANAGEMENT PERFORMANCE ADDER PROPOSED BY MR. MOUL?

A. Mr. Moul wants to reward shareholders and burden ratepayers by increasing the allowed ROE by 0.25%, or 25 basis points, for the "exemplary performance" of the Company's management team. At the Company's proposed rate base and capital structure, this 25 basis point adder increases the claimed revenue deficiency by approximately $6.25 million.

Mr. Moul's subjective decision to add a 25-basis point management adder is entirely based on the testimony of Columbia Gas' President, Mark Kempic.[61] Mr. Moul testified as follows: "In this regard, I have not made an independent evaluation of the Company's management effectiveness."[62]

As described above, the *Hope and Bluefield Standards* conclude that the utility has "no constitutional rights to profits"[63] and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and

[61] Columbia St. 8 at 2.
[62] *Id.*
[63] *Bluefield,* 262 U.S. at 692-93.

> enable it to raise the money necessary for the proper discharge of its public duties.[64]

As such, a fair ROR is based on the expectation that the utility costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level. Mr. Moul's proposal to further reward shareholders for its "exemplary performance" is counter to the *Hope and Bluefield Standards* as it is assumed the Company will operate under efficient and economical management. Adding an additional 0.25% to an ROE that would be the highest ROE allowed for a gas utility in the lower 48 United States since at least 2012 is egregious and should be rejected.

In addition, I am unaware of any financial literature or textbooks that suggest a Company's cost of equity includes a premium to compensate shareholders for exemplary management performance.

Finally, Mr. Moul's management performance adder has been rejected in a prior Columbia Gas rate case.[65]

V.G. Additional Comments

Q. ARE THERE ANY ADDITIONAL ISSUES YOU WOULD LIKE TO RESPOND TO WITH RESPECT TO MR. MOUL'S TESTIMONY?

A. Yes. At page 8 of his Direct Testimony, Mr. Moul asserts that the weather normalization adjustment mechanism ("WNA") and the newly proposed revenue normalization adjustment mechanism ("RNA") are necessary to offset the risk to the Company as a

[64] *Id*. at 693 (emphasis added).
[65] Columbia Gas 2020 Final Order at 132-134.

result of revenues that are heavily influenced by weather conditions. Mr. Moul asserts the market prices of all companies in his Gas Group reflect the expectations of investors that these companies' revenues are stabilized to some extent by a normalization mechanism. Mr. Moul asserts that if the Company is unable to obtain the RNA, a second normalization mechanism, then Columbia Gas's risk will be greater than that of the proxy group.

Mr. Moul's assertion is baseless and should be rejected by this Commission. Should the Company obtain a second revenue normalization mechanism (i.e. the RNA), there would be very little risk borne by the shareholders, while ratepayers will bear all the risk. Further, while Mr. Moul asserts that his proxy companies have revenues that are stabilized to some extent by a normalization mechanism, he does not make any reference to how many of his proxy companies have multiple revenue stabilization mechanisms and are allowed to earn a return on year-end rate base balances for a FPFTY. In my experience, it is rare for utilities outside of Pennsylvania to be allowed to earn a return on year-end rate base balances for a FPFTY. Under no circumstance is Columbia Gas going to be of higher risk than that of the proxy group absent the approval of an RNA.

Finally, the greater percentage of the Company's revenues that become normalized through mechanisms such as the WNA and RNA, the closer Columbia gets to guaranteed cost recovery. As described above, the utility shall be allowed a reasonable opportunity to earn a fair return, not be guaranteed the ability to earn its authorized return. Such conditions would shift practically the entire risk burden to ratepayers. Should the Commission authorize the RNA in addition to maintaining the

WNA, I recommend this Commission authorize an ROE in the lower half of my recommended range (i.e. 9.10% to 9.45%). The midpoint of the lower-half of this range is 9.275%.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

495142

Qualifications of Christopher C. Walters

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. PLEASE STATE YOUR OCCUPATION.

A. I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A. I received a Bachelor of Science Degree in Business Economics and Finance from Southern Illinois University Edwardsville. I have also received a Master of Business Administration Degree from Lindenwood University.

As a Principal at BAI, I perform detailed technical analyses and research to support regulatory projects including expert testimony covering various regulatory issues. Since my career at BAI began in 2011, I have held the positions of Analyst, Associate Consultant, Consultant, Senior Consultant, and Associate. Throughout my tenure, I have been involved with several regulated projects for electric, natural gas and water and wastewater utilities, as well as competitive procurement of electric power and gas supply. My regulatory project work includes estimating the cost of equity capital, capital structure evaluations, assessing financial integrity, merger and acquisition

related issues, risk management related issues, depreciation rate studies, and other revenue requirement issues.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Q. HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have sponsored testimony before state regulatory commissions including: Arizona, Arkansas, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, Oregon, South Carolina, Texas, Utah, and Wyoming. In addition, I have also sponsored testimony before the City Council of New Orleans and an affidavit before the FERC.

Q. PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A. I earned the Chartered Financial Analyst ("CFA") designation from the CFA Institute. The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting and reporting analysis, corporate finance, economics, fixed income and equity valuation, derivatives, alternative investments, risk management, and professional and ethical conduct. I am a member of the CFA Institute and the CFA Society of St. Louis.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Christopher C. Walters, 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 14, 2024

Signature: _____

Christopher C. Walters

Address: Brubaker Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

Line	Company	22-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)	2005 (20)	2004 (21)	2003 (22)	2002 (23)
										Price to Earnings (P/E) Ratio [1]													
1	ALLETE	18.14	15.40	18.10	20.60	18.30	24.70	22.20	23.00	18.60	15.10	17.20	18.60	15.90	14.70	16.00	16.10	13.90	14.80	16.55	17.91	25.21	N/A	N/A
2	Alliant Energy	16.97	16.50	21.40	21.20	21.20	21.20	19.10	20.60	22.30	18.10	16.60	15.30	14.50	14.50	12.50	13.90	13.40	15.10	16.82	12.59	14.00	12.69	19.93
3	Ameren Corp.	16.73	15.40	21.50	21.40	22.20	22.10	18.30	20.60	18.30	17.50	16.70	16.50	13.40	11.90	9.70	9.30	14.20	17.40	19.39	16.72	16.28	13.51	15.78
4	American Electric Power	15.13	14.20	21.10	17.10	19.60	21.40	18.00	19.30	15.20	15.80	15.90	14.50	13.80	11.90	13.40	10.00	13.10	16.30	12.91	13.70	12.42	10.66	12.68
5	Avangrid, Inc.	23.24	12.30	19.60	23.20	23.60	23.10	26.10	27.30	20.50	33.50	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	18.32	14.60	20.00	20.20	21.20	15.00	24.50	23.40	18.80	17.60	17.30	14.60	19.30	14.10	12.70	11.40	15.00	30.90	15.39	19.45	24.43	13.84	19.27
7	Black Hills	17.62	14.20	18.10	17.70	17.00	21.20	16.80	19.50	22.30	16.10	19.00	18.20	17.10	31.10	18.10	9.90	NMF	15.00	15.77	17.27	17.13	15.95	12.52
8	CenterPoint Energy	16.80	18.80	18.70	26.10	15.90	19.50	37.00	17.90	21.90	18.10	17.00	18.70	14.80	14.60	13.80	11.80	11.30	15.00	10.27	19.06	17.84	6.05	5.59
9	CMS Energy Corp.	18.28	17.40	22.90	23.60	23.30	24.30	20.30	21.30	20.90	18.30	17.30	16.30	15.10	13.60	12.50	13.60	10.90	26.80	22.18	12.60	12.39	N/A	N/A
10	Consol. Edison	16.10	17.30	20.30	17.20	19.00	19.70	17.10	19.80	18.80	15.60	15.90	14.70	15.40	15.10	13.30	12.50	12.30	13.80	15.49	15.13	18.21	14.30	13.28
11	Dominion Resources	18.24	16.20	18.70	19.50	22.60	18.20	17.50	22.20	21.30	22.10	23.00	19.20	18.90	17.30	14.30	12.70	13.80	20.60	15.98	24.89	15.07	15.24	12.05
12	DTE Energy	16.60	14.30	22.40	30.00	16.30	19.90	17.40	18.60	19.00	18.10	14.90	17.90	14.90	13.50	12.30	10.40	14.80	18.30	17.43	13.80	16.04	13.69	11.28
13	Duke Energy	17.12	15.30	19.60	18.90	17.10	17.70	17.00	19.90	21.30	18.20	17.90	17.40	17.50	13.80	12.70	13.30	17.30	16.10	N/A	N/A	N/A	N/A	N/A
14	Edison Int'l	17.08	14.30	40.60	29.70	34.90	16.70	N/A	17.20	17.90	14.80	13.00	12.70	9.70	11.80	10.30	9.70	12.40	16.00	12.99	11.74	37.59	6.97	7.78
15	El Paso Electric	17.68	N/A	N/A	N/A	N/A	N/A	26.85	21.78	18.66	18.33	16.38	15.88	14.47	12.60	10.72	10.79	11.89	15.26	16.92	26.72	22.03	18.26	22.99
16	Entergy Corp.	13.94	9.80	21.10	15.00	15.30	16.50	13.80	15.00	10.90	12.50	12.90	13.20	11.20	9.10	11.60	12.00	16.60	19.30	14.28	16.28	15.09	13.77	11.53
17	Eversource Energy	18.23	12.30	20.90	22.20	23.70	22.10	18.70	19.50	18.70	18.10	17.90	16.90	19.90	15.40	13.40	12.00	13.70	18.70	27.07	19.76	20.77	13.35	16.07
18	Evergy, Inc.	19.05	12.00	19.90	16.20	21.70	21.80	22.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	14.32	14.00	19.90	16.60	12.40	14.70	13.30	13.40	12.50	12.60	16.00	13.40	19.10	11.30	11.00	11.50	18.00	18.20	16.53	15.37	12.99	11.77	10.46
20	FirstEnergy Corp.	15.16	13.70	17.00	14.10	15.70	17.10	13.60	11.40	12.70	12.60	13.20	13.10	21.10	22.40	11.70	13.00	15.60	15.60	14.23	16.07	14.13	22.47	12.95
21	Fortis Inc.	19.24	16.70	21.10	21.20	20.60	19.20	17.10	16.80	21.60	18.00	24.30	20.00	20.10	18.80	18.20	16.40	17.50	21.10	17.68	N/A	N/A	N/A	N/A
22	Great Plains Energy	15.52	N/A	N/A	N/A	N/A	N/A	N/A	NMF	17.98	19.37	16.47	14.19	15.53	16.11	12.10	16.03	20.55	16.35	18.30	13.96	12.59	12.23	11.09
23	Hawaiian Elec.	17.65	6.00	18.50	18.20	21.50	21.30	18.90	20.70	13.60	20.40	15.90	16.20	15.80	17.10	18.60	19.80	23.20	21..6	20.33	18.27	19.18	13.76	13.47
24	IDACORP, Inc.	17.15	18.10	21.00	20.80	19.90	22.30	20.50	20.60	19.10	16.20	14.70	13.40	12.40	11.50	11.80	10.20	13.90	18.20	15.07	16.70	15.49	26.51	18.88
25	MGE Energy	19.98	18.60	24.70	25.50	26.40	28.40	25.10	29.40	24.90	20.30	17.20	17.00	17.20	15.80	15.00	15.10	14.20	15.00	15.88	22.40	17.98	17.55	15.96
26	NextEra Energy, Inc.	18.67	17.90	27.80	31.30	28.90	26.80	24.80	21.60	20.70	16.90	17.30	16.60	14.40	11.50	10.80	13.40	14.50	18.90	13.65	17.88	13.65	17.88	13.60
27	NorthWestern Corp	16.92	13.70	17.30	17.40	18.60	19.90	16.80	17.80	17.20	18.40	16.20	16.90	15.70	12.60	12.90	11.50	13.90	21.70	25.95	17.09	N/A	N/A	N/A
28	OGE Energy	15.31	15.30	17.20	14.30	16.20	19.00	16.50	18.30	17.70	17.70	18.30	17.70	15.20	14.40	13.30	10.80	12.40	13.80	13.68	14.95	14.13	11.84	14.12
29	Otter Tail Corp.	20.76	16.40	9.50	12.30	18.30	23.50	22.20	22.10	20.20	18.20	18.80	21.10	21.70	47.50	NMF	31.20	30.10	19.00	17.35	15.40	17.34	17.77	16.01
30	Pinnacle West Capital	15.88	15.80	17.10	14.10	16.70	19.40	17.80	19.30	18.70	16.00	15.90	15.30	14.30	14.60	12.60	13.70	16.10	14.90	13.69	19.24	15.80	13.96	14.43
31	PNM Resources	18.28	14.20	17.40	19.90	19.60	22.20	19.40	20.40	22.40	18.70	18.70	16.10	15.00	14.50	14.00	18.10	N/A	35.60	15.57	17.38	15.02	14.73	15.08
32	Portland General	16.71	14.30	18.20	17.70	16.60	22.30	18.40	20.00	19.10	17.70	15.30	16.90	14.00	12.40	12.00	14.40	16.30	11.90	23.35	N/A	N/A	N/A	N/A
33	PPL Corp.	16.23	15.90	20.00	54.10	13.90	13.30	11.30	17.60	12.80	13.90	14.10	12.80	10.90	10.50	11.90	25.70	17.60	17.30	14.10	15.12	12.51	10.59	11.06
34	Public Serv. Enterprise	14.40	16.30	18.50	16.80	15.70	18.00	16.60	16.30	15.30	14.10	12.60	13.50	12.80	10.40	10.40	10.00	13.60	16.50	17.81	16.74	14.26	10.58	10.00
35	SCANA Corp.	13.96	N/A	N/A	N/A	N/A	N/A	N/A	14.46	16.80	14.67	13.68	14.43	14.80	13.67	12.93	11.63	12.67	14.96	15.42	14.44	13.57	13.05	12.17
36	Sempra Energy	15.54	15.00	16.80	15.40	17.50	22.50	20.40	24.30	24.40	19.70	21.90	19.70	14.90	11.80	12.60	10.10	11.80	14.00	11.50	11.79	8.65	8.96	8.19
37	Southern Co.	16.18	16.60	19.60	18.40	17.90	17.60	15.10	15.50	17.80	15.80	16.00	16.20	17.00	15.80	14.90	13.50	16.10	16.00	16.19	15.92	14.68	14.83	14.63
38	Vectren Corp.	17.05	N/A	N/A	N/A	N/A	N/A	N/A	23.54	19.18	17.92	19.98	20.66	15.02	15.83	15.10	12.89	16.79	15.33	18.92	15.11	17.57	14.80	14.16
39	WEC Energy Group	17.37	15.20	21.90	22.30	24.90	23.50	19.60	20.00	19.90	21.30	17.70	16.50	15.80	14.20	14.00	13.30	14.80	16.50	15.97	14.46	17.51	12.43	10.46
40	Westar Energy	15.58	N/A	N/A	N/A	N/A	N/A	N/A	23.40	21.59	18.45	15.36	14.04	13.43	14.78	12.96	14.95	16.96	14.10	12.18	14.79	17.44	10.78	14.02
41	Xcel Energy Inc.	17.87	15.30	22.20	22.50	23.90	22.30	18.90	20.20	18.50	16.50	15.40	15.00	14.80	14.20	14.10	12.70	13.70	16.70	14.80	15.36	13.65	11.62	40.80
42	Average	16.98	14.98	20.29	20.91	19.95	20.51	19.43	19.85	18.75	17.58	16.77	16.19	15.56	15.30	13.16	13.57	15.27	17.66	16.51	16.56	16.65	13.83	14.31
43	Median	16.10	15.30	19.90	19.70	19.30	21.20	18.55	20.00	18.80	17.81	16.47	16.20	15.02	14.20	12.80	12.70	14.20	16.32	15.92	15.99	15.49	13.69	13.47

Sources:

The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.

Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

Market Price to Cash Flow (MP/CF) Ratio [1]

Line	Company	22-Year Average	2023 [2]	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003	2002
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)
1	ALLETE	9.17	6.69	7.56	8.61	8.14	11.38	10.16	10.95	8.26	7.49	8.80	9.15	8.18	7.91	8.04	8.51	9.29	10.30	11.06	11.54	11.46	N/A	N/A
2	Alliant Energy	8.25	9.43	10.43	10.31	10.66	10.74	9.71	13.21	10.67	8.86	8.40	7.52	7.50	7.21	6.59	6.23	7.49	7.92	8.00	5.09	5.52	4.76	5.20
3	Ameren Corp.	7.41	8.05	9.54	9.03	9.63	9.45	7.95	8.38	7.44	6.87	6.95	6.61	5.48	5.02	4.23	4.25	6.35	7.69	8.57	8.57	8.24	6.74	7.96
4	American Electric Power	6.72	7.68	8.67	7.57	8.41	9.34	8.03	8.81	7.57	7.09	7.00	6.57	5.93	5.46	5.54	4.71	5.71	6.84	5.54	6.07	5.50	4.69	5.19
5	Avangrid, Inc.	9.56	7.38	8.69	11.19	9.39	9.11	10.24	10.14	8.56	11.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	6.97	6.73	9.39	8.03	7.80	7.34	10.14	9.35	7.63	6.76	7.30	6.21	6.88	6.40	5.80	4.06	5.12	7.58	5.30	6.58	7.58	5.36	5.90
7	Black Hills	7.92	7.76	8.92	8.84	8.56	10.65	8.83	9.20	9.33	8.06	8.81	8.03	6.04	7.85	6.16	4.25	11.26	7.62	6.92	7.57	6.69	6.89	5.92
8	CenterPoint Energy	5.58	7.92	8.01	7.95	5.94	7.03	8.45	6.97	5.96	5.75	6.25	6.56	5.15	5.39	4.70	4.05	4.29	5.17	3.94	4.70	4.26	2.08	2.16
9	CMS Energy Corp.	6.51	8.28	9.43	9.27	9.87	9.85	8.40	8.75	8.50	7.53	7.13	6.68	6.03	5.41	4.48	3.64	3.45	5.57	4.40	4.04	3.20	2.88	NMF
10	Consol. Edison	8.22	7.85	8.70	7.26	8.35	9.46	8.73	9.64	9.39	7.96	7.89	7.77	8.31	8.15	7.39	6.72	6.89	8.31	8.65	8.59	9.31	7.90	7.64
11	Dominion Resources	9.84	8.05	9.35	11.15	14.59	13.47	10.94	11.35	11.59	11.84	12.27	10.88	9.92	9.45	8.12	6.98	8.27	8.65	7.81	10.09	7.68	7.51	6.53
12	DTE Energy	6.76	7.27	7.96	10.62	7.85	9.67	8.54	9.05	8.64	8.52	6.42	6.65	5.91	5.18	4.69	3.59	4.90	5.73	5.21	5.54	6.00	5.62	5.20
13	Duke Energy	7.61	7.15	7.75	7.89	8.06	7.40	7.65	8.40	8.57	7.95	8.12	8.11	9.53	6.56	6.01	5.96	7.13	7.16	N/A	N/A	N/A	N/A	N/A
14	Edison Int'l	6.02	5.67	6.83	7.14	7.57	7.25	13.46	7.05	6.77	5.92	5.68	5.46	4.59	4.22	4.11	3.95	5.63	7.01	5.87	5.61	6.84	2.82	2.96
15	El Paso Electric	5.93	N/A	N/A	N/A	N/A	N/A	9.43	8.54	7.46	6.47	6.33	6.19	5.78	5.16	4.31	3.98	4.95	6.44	6.25	6.67	4.65	3.90	4.39
16	Entergy Corp.	5.74	4.62	7.15	5.61	5.78	6.05	4.92	4.66	4.01	4.11	4.21	4.03	4.23	3.90	4.66	5.68	7.96	9.21	7.16	8.76	7.12	6.84	5.57
17	Eversource Energy	7.52	7.63	9.39	11.41	12.53	11.47	9.16	10.36	10.14	10.12	10.14	8.08	9.30	6.99	4.97	4.61	4.12	6.18	6.02	3.55	3.78	2.85	2.75
18	Evergy, Inc.	7.73	7.11	8.66	7.41	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	6.05	6.38	7.69	5.08	4.44	5.29	5.05	4.45	4.80	4.70	5.09	4.61	5.54	5.86	5.10	5.98	9.65	9.89	8.62	7.97	6.29	5.71	4.97
20	FirstEnergy Corp.	6.90	8.03	8.93	6.60	9.23	11.09	8.84	4.76	5.12	5.38	7.43	6.15	7.42	7.33	4.49	4.91	7.58	7.89	7.53	6.04	5.15	6.90	5.10
21	Fortis Inc.	8.47	8.34	9.10	9.57	9.50	9.46	7.97	8.23	10.46	7.29	9.25	7.93	8.09	8.38	7.40	6.76	7.58	9.18	7.89	N/A	N/A	N/A	N/A
22	Great Plains Energy	6.89	N/A	N/A	N/A	N/A	N/A	N/A	14.62	8.63	6.66	6.45	5.73	6.09	5.74	4.49	5.06	7.71	7.13	7.68	6.70	6.52	5.92	5.14
23	Hawaiian Elec.	7.96	5.70	7.95	8.23	8.69	9.30	8.34	9.21	7.44	9.25	7.64	8.15	8.05	7.73	7.81	6.95	9.10	7.95	8.47	8.29	8.44	6.12	6.20
24	IDACORP, Inc.	8.98	11.04	12.42	11.84	11.38	12.75	11.72	11.56	10.95	9.37	8.59	7.78	7.05	6.64	6.52	5.31	7.10	8.23	7.73	7.55	7.15	7.27	7.53
25	MGE Energy	11.68	12.28	13.63	N/A	14.90	15.58	15.04	17.33	15.66	12.53	11.42	11.20	10.77	9.48	9.05	8.40	8.42	9.23	9.30	11.73	11.04	10.20	8.09
26	NextEra Energy, Inc.	9.20	10.87	15.17	20.40	15.48	12.33	10.77	11.61	9.24	7.93	7.98	7.60	7.58	5.98	5.33	6.09	7.34	9.02	6.51	6.71	6.71	5.97	5.77
27	NorthWestern Corp	7.90	8.01	8.65	8.83	8.88	9.93	8.19	8.82	8.65	8.99	9.01	7.61	6.85	5.89	5.79	5.05	5.57	8.45	9.39	7.31	8.13	N/A	N/A
28	OGE Energy	7.94	7.88	8.36	7.64	8.38	10.58	9.36	10.52	9.03	9.25	10.65	9.93	7.35	7.48	6.61	5.37	6.43	7.58	7.50	7.04	6.73	5.62	5.39
29	Otter Tail Corp.	9.27	8.02	7.70	8.61	9.99	12.42	11.58	11.09	9.38	9.04	9.45	9.58	8.43	9.04	8.07	8.01	11.65	9.53	8.66	8.18	9.01	8.13	8.33
30	Pinnacle West Capital	6.21	6.47	5.19	6.19	7.49	8.30	7.09	8.73	7.89	6.91	7.03	6.85	6.34	5.80	5.65	3.84	4.19	4.76	4.48	7.48	5.88	4.80	5.21
31	PNM Resources	6.90	6.87	6.95	7.81	7.87	7.92	7.57	7.40	7.64	6.95	7.48	6.47	5.80	4.94	4.58	4.53	7.10	10.67	7.50	7.62	6.84	5.55	5.72
32	Portland General	6.00	6.56	6.65	6.48	6.72	7.65	6.56	7.45	7.12	6.73	5.49	6.06	5.08	4.86	4.13	4.63	4.81	5.34	5.74	N/A	N/A	N/A	N/A
33	PPL Corp.	7.85	8.04	8.82	13.74	7.46	7.99	7.02	10.11	8.37	8.73	7.32	6.59	5.87	5.98	7.46	8.82	9.17	8.90	7.58	7.57	6.49	5.41	5.30
34	Public Serv. Enterprise	7.95	9.61	10.53	11.32	8.22	8.72	9.48	8.67	8.56	6.66	6.48	6.40	6.40	6.03	6.04	6.20	8.46	9.83	8.41	8.59	7.17	6.79	6.24
35	SCANA Corp.	7.09	N/A	N/A	N/A	N/A	N/A	N/A	8.26	9.59	8.33	7.50	7.49	7.40	6.75	6.52	5.88	6.38	7.15	7.03	5.40	6.86	6.59	6.36
36	Sempra Energy	8.45	8.93	9.75	13.23	10.40	12.05	10.10	10.65	10.88	9.99	10.77	9.37	7.26	6.13	6.53	6.07	7.07	8.61	7.22	6.96	5.16	4.85	4.00
37	Southern Co.	8.30	8.91	9.63	8.72	8.34	8.80	7.05	7.49	8.83	8.23	8.42	8.30	8.75	8.22	7.79	7.08	8.18	8.62	8.47	8.41	8.28	8.28	7.83
38	Vectren Corp.	7.08	N/A	N/A	N/A	N/A	N/A	N/A	10.32	8.60	7.82	7.57	6.82	5.79	5.81	5.58	5.24	6.90	6.53	7.37	7.06	7.63	7.27	6.92
39	WEC Energy Group	9.24	10.12	11.81	11.99	13.67	12.88	10.82	11.04	10.95	12.90	10.27	9.58	9.24	8.43	8.15	6.87	7.57	7.84	7.27	6.40	6.27	4.91	4.27
40	Westar Energy	6.91	N/A	N/A	N/A	N/A	N/A	N/A	10.87	10.86	9.05	7.93	7.23	6.71	6.67	5.51	5.32	7.09	6.88	5.81	7.00	6.54	4.24	2.94
41	Xcel Energy Inc.	7.05	7.96	8.62	9.19	10.07	9.44	7.90	8.50	8.10	7.62	7.31	7.00	6.85	6.47	6.28	5.43	5.71	6.51	5.54	5.62	5.31	4.27	5.46
42	Average	7.65	7.93	9.00	9.28	9.26	9.78	9.03	9.41	8.68	8.07	7.90	7.41	7.01	6.56	6.02	5.61	7.01	7.77	7.17	7.18	6.82	5.75	5.58
43	Median	7.50	7.90	8.69	8.72	8.56	9.46	8.78	9.13	8.58	7.94	7.57	7.23	6.85	6.40	5.80	5.37	7.10	7.84	7.44	7.05	6.72	5.66	5.46

Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Note:
[a] Based on the average of the high and low price and the projected Cash Flow per share.

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

Market Price to Book Value (MP/BV) Ratio [1]

Line	Company	19-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)	2005 (20)
1	ALLETE	1.55	1.19	1.24	1.43	1.39	1.91	1.79	1.78	1.53	1.37	1.42	1.51	1.34	1.35	1.28	1.15	1.55	1.89	2.09	2.22
2	Alliant Energy	1.81	1.92	2.25	2.26	2.30	2.32	2.16	2.38	2.17	1.86	1.86	1.70	1.57	1.46	1.31	1.04	1.33	1.67	1.52	1.33
3	Ameren Corp.	1.60	2.00	2.15	2.13	2.21	2.26	1.95	1.93	1.67	1.46	1.45	1.29	1.18	0.90	0.83	0.78	1.25	1.60	1.62	1.68
4	American Electric Power	1.64	1.73	1.99	1.87	2.09	2.20	1.82	1.88	1.81	1.55	1.54	1.40	1.31	1.23	1.23	1.08	1.48	1.85	1.56	1.57
5	Avangrid, Inc.	0.90	0.72	0.89	1.01	0.97	1.02	1.02	0.93	0.83	0.72	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.33	1.19	1.33	1.42	1.37	1.54	1.88	1.73	1.57	1.36	1.33	1.25	1.21	1.19	1.07	0.94	1.11	1.29	1.30	1.13
7	Black Hills	1.51	1.28	1.54	1.52	1.55	1.95	1.61	2.06	1.94	1.59	1.79	1.62	1.21	1.14	1.07	0.83	1.22	1.57	1.47	1.63
8	CenterPoint Energy	2.27	1.86	1.99	1.74	1.90	2.21	2.18	2.59	2.73	2.43	2.27	2.30	1.99	1.87	1.96	1.77	2.49	3.13	2.75	3.06
9	CMS Energy Corp.	2.18	2.33	2.71	2.69	3.24	3.28	2.81	2.93	2.72	2.43	2.26	2.09	1.91	1.66	1.48	1.10	1.23	1.82	1.42	1.32
10	Consol. Edison	1.42	1.54	1.55	1.34	1.44	1.59	1.49	1.63	1.58	1.42	1.34	1.38	1.47	1.38	1.22	1.08	1.17	1.47	1.47	1.52
11	Dominion Resources	2.54	1.54	2.34	2.37	2.72	2.18	2.40	2.94	3.15	3.34	3.55	2.97	2.84	2.37	2.01	1.80	2.42	2.69	2.07	2.50
12	DTE Energy	1.65	1.97	2.41	2.82	1.80	2.07	1.91	2.01	1.82	1.65	1.62	1.51	1.35	1.20	1.16	0.89	1.10	1.35	1.29	1.39
13	Duke Energy	1.28	1.47	1.63	1.58	1.47	1.47	1.33	1.41	1.35	1.29	1.28	1.19	1.12	1.11	1.00	0.91	1.06	1.15	N/A	N/A
14	Edison Int'l	1.70	1.86	2.08	1.67	1.62	1.80	1.97	2.17	1.92	1.76	1.68	1.57	1.53	1.24	1.07	1.04	1.56	2.05	1.80	1.93
15	El Paso Electric	1.56	N/A	N/A	N/A	N/A	N/A	1.94	1.87	1.68	1.48	1.52	1.49	1.59	1.64	1.17	0.98	1.33	1.69	1.71	1.76
16	Entergy Corp.	1.74	1.45	1.81	1.75	1.93	2.03	1.74	1.76	1.67	1.40	1.33	1.21	1.31	1.35	1.62	1.66	2.44	2.65	1.89	2.01
17	Eversource Energy	1.55	1.63	1.86	2.00	2.11	1.99	1.68	1.73	1.64	1.53	1.47	1.38	1.28	1.50	1.31	1.12	1.31	1.60	1.22	1.05
18	Evergy, Inc.	1.45	1.31	1.52	1.50	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	2.08	1.54	1.88	1.37	1.20	1.43	1.31	1.20	1.20	1.14	1.28	1.17	1.46	1.95	2.07	2.57	4.39	4.79	3.89	3.60
20	FirstEnergy Corp.	2.06	2.05	2.37	2.33	2.81	3.39	2.67	3.53	2.37	1.16	1.15	1.28	1.44	1.33	1.36	1.54	2.52	2.23	1.92	1.64
21	Fortis Inc.	1.47	1.43	1.56	1.48	1.47	1.41	1.24	1.41	1.26	1.33	1.35	1.45	1.59	1.59	1.56	1.33	1.48	1.63	1.96	N/A
22	Great Plains Energy	1.21	N/A	N/A	N/A	N/A	N/A	N/A	1.33	1.17	1.12	1.11	1.02	0.96	0.93	0.87	0.80	1.11	1.66	1.77	1.86
23	Hawaiian Elec.	1.65	1.24	1.94	1.81	1.82	2.02	1.76	1.76	1.63	1.71	1.49	1.54	1.62	1.54	1.44	1.16	1.61	1.57	2.01	1.78
24	IDACORP, Inc.	1.52	1.75	1.91	1.88	1.84	2.10	1.96	1.94	1.76	1.54	1.45	1.33	1.19	1.17	1.13	0.92	1.09	1.26	1.37	1.22
25	MGE Energy	2.15	2.35	2.47	N/A	2.54	2.88	2.59	2.88	2.60	2.10	2.10	2.06	1.92	1.75	1.65	1.54	1.62	1.75	1.83	2.09
26	NextEra Energy, Inc.	2.38	2.89	4.07	4.27	3.58	2.75	2.32	2.35	2.30	2.09	2.15	1.93	1.74	1.55	1.49	1.70	2.06	2.34	1.80	1.93
27	NorthWestern Corp	1.44	1.18	1.25	1.43	1.45	1.74	1.48	1.64	1.68	1.60	1.54	1.56	1.42	1.35	1.22	1.07	1.15	1.48	1.65	1.42
28	OGE Energy	1.82	1.61	1.74	1.67	1.86	2.06	1.75	1.82	1.73	1.79	2.22	2.24	1.94	1.90	1.70	1.37	1.52	1.98	1.91	1.80
29	Otter Tail Corp.	1.93	2.55	2.30	2.33	2.04	2.62	2.49	2.33	1.90	1.78	1.90	1.96	1.58	1.35	1.19	1.18	1.71	1.93	1.76	1.74
30	Pinnacle West Capital	1.42	1.42	1.31	1.45	1.63	1.91	1.74	1.91	1.72	1.52	1.44	1.47	1.39	1.25	1.14	0.95	1.00	1.26	1.26	1.25
31	PNM Resources	1.37	1.75	1.81	1.86	1.87	2.28	1.83	1.84	1.56	1.33	1.21	1.09	0.98	0.80	0.69	0.56	0.66	1.23	1.21	1.45
32	Portland General	1.37	1.37	1.58	1.55	1.57	1.84	1.56	1.69	1.56	1.42	1.37	1.28	1.14	1.09	0.94	0.92	1.05	1.32	1.36	N/A
33	PPL Corp.	1.99	1.38	1.44	1.52	1.63	1.86	1.81	2.40	2.46	2.24	1.64	1.55	1.58	1.47	1.61	2.10	3.19	3.05	2.43	2.50
34	Public Serv. Enterprise	1.94	2.07	2.32	2.11	1.70	1.97	1.81	1.68	1.67	1.58	1.57	1.44	1.46	1.59	1.67	1.78	2.58	2.99	2.46	2.45
35	SCANA Corp.	1.51	N/A	N/A	N/A	N/A	N/A	N/A	1.65	1.74	1.47	1.48	1.48	1.48	1.36	1.33	1.20	1.45	1.62	1.64	1.72
36	Sempra Energy	1.79	1.65	1.84	1.64	1.84	2.22	2.06	2.24	2.00	2.17	2.20	1.84	1.53	1.28	1.35	1.32	1.60	1.87	1.70	1.73
37	Southern Co.	2.12	2.40	2.53	2.39	2.20	2.13	1.89	2.07	2.01	1.99	2.02	2.04	2.15	1.99	1.83	1.73	2.12	2.24	2.23	2.35
38	Vectren Corp.	1.83	N/A	N/A	N/A	N/A	N/A	N/A	2.75	2.29	2.11	2.08	1.82	1.57	1.53	1.41	1.34	1.64	1.74	1.77	1.82
39	WEC Energy Group	2.06	2.35	2.57	2.61	2.84	2.62	2.11	2.10	2.09	1.82	2.34	2.21	2.05	1.81	1.65	1.40	1.57	1.77	1.71	1.62
40	Westar Energy	1.37	N/A	N/A	N/A	N/A	N/A	N/A	1.94	1.95	1.49	1.44	1.33	1.26	1.20	1.10	0.93	1.10	1.36	1.30	1.41
41	Xcel Energy Inc.	1.73	2.00	2.22	2.27	2.46	2.34	1.97	2.06	1.88	1.66	1.55	1.50	1.51	1.41	1.32	1.19	1.30	1.53	1.40	1.38
42	Average	1.74	1.72	1.96	1.92	1.96	2.10	1.89	2.01	1.86	1.67	1.69	1.60	1.52	1.43	1.35	1.25	1.63	1.90	1.78	1.80
43	Median	1.69	1.64	1.89	1.75	1.84	2.06	1.86	1.92	1.75	1.57	1.54	1.50	1.47	1.36	1.31	1.15	1.48	1.69	1.71	1.73

Sources:

The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.

Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.

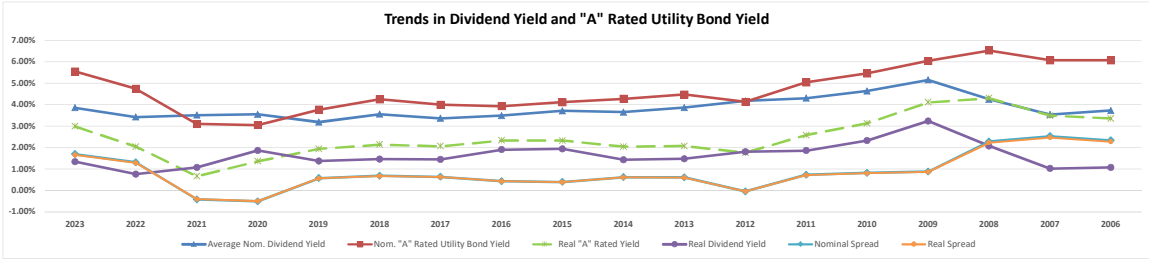
[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Notes:

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
		Dividend Yield[1]																		
1	ALLETE	4.01%	4.67%	4.47%	3.88%	4.03%	2.85%	2.99%	2.97%	3.56%	3.97%	3.92%	3.89%	4.49%	4.58%	5.03%	5.79%	4.37%	3.60%	3.16%
2	Alliant Energy	3.61%	3.57%	3.04%	2.97%	2.90%	2.88%	3.20%	3.07%	3.21%	3.60%	3.53%	3.74%	4.07%	4.28%	4.61%	5.73%	4.10%	3.13%	3.32%
3	Ameren Corp.	4.11%	3.13%	2.74%	2.74%	2.57%	2.59%	3.04%	3.12%	3.50%	3.96%	4.02%	4.61%	4.97%	5.28%	5.76%	5.98%	6.21%	4.88%	4.93%
4	American Electric Power	3.97%	4.02%	3.41%	3.61%	3.28%	3.10%	3.60%	3.42%	3.54%	3.80%	3.83%	4.23%	4.58%	4.96%	4.90%	5.50%	4.20%	3.40%	4.06%
5	Avangrid, Inc.	3.89%	4.87%	3.94%	3.53%	3.69%	3.52%	3.49%	3.79%	4.26%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	3.86%	4.85%	4.26%	3.94%	4.03%	3.48%	2.93%	3.14%	3.39%	3.97%	3.99%	4.51%	4.55%	4.54%	4.76%	4.49%	3.39%	2.68%	2.52%
7	Black Hills	3.73%	4.15%	3.44%	3.50%	3.42%	2.74%	3.31%	2.75%	2.87%	3.55%	2.84%	3.19%	4.39%	4.64%	4.79%	6.17%	4.21%	3.40%	3.79%
8	CenterPoint Energy	4.15%	2.67%	2.46%	2.77%	4.38%	2.98%	4.09%	4.79%	4.70%	5.06%	3.94%	3.57%	4.04%	4.27%	5.29%	6.37%	4.98%	3.87%	4.39%
9	CMS Energy Corp.	3.20%	3.37%	2.92%	2.92%	2.65%	2.64%	3.03%	2.88%	2.99%	3.36%	3.59%	3.76%	4.16%	4.25%	3.98%	3.97%	2.69%	1.16%	N/A
10	Consol. Edison	4.29%	3.57%	3.51%	4.10%	3.87%	3.44%	3.68%	3.40%	3.62%	4.12%	4.38%	4.25%	4.07%	4.46%	5.16%	5.99%	5.67%	4.84%	5.04%
11	Dominion Resources	4.06%	5.18%	3.66%	3.38%	4.31%	4.76%	4.72%	3.88%	3.82%	3.66%	3.43%	3.78%	4.06%	4.13%	4.41%	5.20%	3.77%	3.32%	3.60%
12	DTE Energy	3.98%	3.67%	3.17%	3.06%	3.57%	3.07%	3.34%	3.15%	3.34%	3.53%	3.54%	3.84%	4.19%	4.68%	4.75%	6.29%	5.24%	4.36%	4.86%
13	Duke Energy	4.60%	4.28%	3.98%	4.02%	4.35%	4.17%	4.54%	4.15%	4.26%	4.34%	4.26%	4.45%	4.68%	5.21%	5.71%	6.25%	5.16%	4.44%	N/A
14	Edison Int'l	3.37%	4.47%	4.45%	4.39%	4.29%	3.73%	3.84%	2.87%	2.81%	2.83%	2.62%	2.85%	2.97%	3.37%	3.66%	3.95%	2.69%	2.21%	2.58%
15	El Paso Electric	2.74%	N/A	N/A	N/A	N/A	N/A	2.55%	2.49%	2.75%	3.13%	2.97%	2.99%	2.97%	2.11%	N/A	N/A	N/A	N/A	N/A
16	Entergy Corp.	4.03%	4.36%	3.70%	3.84%	3.55%	3.52%	4.41%	4.49%	4.55%	4.59%	4.47%	5.07%	4.91%	4.85%	4.20%	3.97%	2.92%	2.39%	2.82%
17	Eversource Energy	3.27%	3.89%	3.09%	2.85%	2.63%	2.81%	3.32%	3.14%	3.22%	3.34%	3.40%	3.48%	3.52%	3.23%	3.64%	4.16%	3.25%	2.60%	3.27%
18	Evergy, Inc.	3.89%	4.42%	3.66%	3.59%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	3.75%	3.67%	2.89%	3.17%	3.82%	3.06%	3.32%	3.51%	3.75%	3.88%	3.69%	4.69%	5.73%	4.96%	4.95%	4.26%	2.78%	2.48%	2.83%
20	FirstEnergy Corp.	4.31%	4.24%	3.71%	4.39%	4.17%	3.50%	5.17%	4.62%	4.31%	4.23%	4.26%	4.26%	4.90%	5.23%	5.76%	5.09%	3.21%	3.12%	3.40%
21	Fortis Inc.	3.71%	4.09%	3.82%	3.77%	3.66%	3.60%	4.07%	3.69%	3.80%	3.76%	3.88%	3.84%	3.64%	3.58%	3.80%	4.21%	3.76%	3.01%	2.79%
22	Great Plains Energy	4.52%	N/A	N/A	N/A	N/A	N/A	N/A	3.58%	3.64%	3.76%	3.62%	3.84%	4.08%	4.15%	4.49%	5.03%	6.96%	5.49%	5.60%
23	Hawaiian Elec.	4.40%	4.09%	3.59%	3.44%	3.40%	3.02%	3.54%	3.65%	3.99%	4.05%	4.76%	4.72%	4.70%	5.04%	5.51%	6.89%	5.00%	5.18%	4.59%
24	IDACORP, Inc.	3.16%	3.18%	2.86%	2.89%	2.92%	2.49%	2.61%	2.58%	2.77%	3.06%	3.12%	3.21%	3.28%	3.10%	3.44%	4.46%	3.95%	3.55%	3.39%
25	MGE Energy	3.01%	2.25%	2.15%	N/A	2.10%	1.94%	2.16%	1.95%	2.23%	2.78%	2.78%	2.91%	3.25%	3.63%	3.98%	4.36%	4.24%	4.14%	4.25%
26	NextEra Energy, Inc.	2.89%	2.80%	2.11%	1.90%	2.10%	2.41%	2.68%	2.79%	2.91%	3.01%	3.02%	3.30%	3.65%	3.96%	3.90%	N/A	N/A	N/A	N/A
27	NorthWestern Corp	4.14%	4.78%	4.51%	4.00%	4.02%	3.28%	3.86%	3.52%	3.43%	3.61%	3.30%	3.66%	4.17%	4.51%	4.93%	5.75%	5.38%	4.09%	3.65%
28	OGE Energy	3.83%	4.63%	4.30%	4.81%	4.68%	3.54%	3.98%	3.61%	3.87%	3.51%	2.63%	2.48%	2.94%	3.06%	3.68%	4.96%	4.52%	3.77%	3.99%
29	Otter Tail Corp.	3.84%	2.33%	2.44%	2.81%	3.45%	2.74%	2.92%	3.12%	3.87%	4.33%	4.14%	4.11%	5.21%	5.57%	5.68%	5.38%	3.63%	3.46%	3.92%
30	Pinnacle West Capital	4.51%	4.51%	4.90%	4.44%	3.97%	3.29%	3.55%	3.16%	3.46%	3.88%	4.09%	3.98%	5.32%	4.81%	5.43%	6.76%	6.17%	4.75%	4.67%
31	PNM Resources	3.15%	3.27%	3.04%	2.09%	2.80%	2.45%	2.79%	2.53%	2.69%	2.90%	2.79%	2.99%	2.96%	3.19%	4.09%	4.76%	4.85%	3.36%	3.21%
32	Portland General	3.69%	4.20%	3.63%	3.62%	3.47%	2.85%	3.27%	2.92%	3.06%	3.27%	3.34%	3.67%	4.11%	4.37%	5.20%	5.36%	4.28%	3.34%	2.54%
33	PPL Corp.	4.48%	3.53%	3.23%	5.83%	5.84%	5.24%	5.61%	4.24%	4.25%	4.55%	4.45%	4.81%	5.07%	5.10%	5.12%	4.51%	3.10%	2.69%	3.41%
34	Public Serv. Enterprise	3.74%	3.83%	3.37%	3.37%	3.64%	3.19%	3.49%	3.74%	3.78%	3.81%	3.92%	4.35%	4.55%	4.24%	4.30%	4.30%	3.26%	2.73%	3.47%
35	SCANA Corp.	4.37%	N/A	N/A	N/A	N/A	N/A	N/A	4.03%	3.29%	3.90%	4.05%	4.15%	4.25%	4.78%	4.93%	5.67%	4.92%	4.29%	4.21%
36	Sempra Energy	3.00%	3.27%	2.99%	3.39%	3.24%	2.88%	3.20%	2.92%	2.92%	2.71%	2.61%	3.03%	3.71%	3.65%	3.08%	3.23%	2.62%	2.08%	2.47%
37	Southern Co.	4.58%	4.13%	3.82%	4.17%	4.36%	4.41%	5.27%	4.63%	4.42%	4.78%	4.69%	4.61%	4.29%	4.63%	5.13%	5.52%	4.58%	4.39%	4.52%
38	Vectren Corp.	4.38%	N/A	N/A	N/A	N/A	N/A	N/A	2.79%	3.31%	3.60%	3.62%	4.15%	4.82%	5.06%	5.53%	5.85%	4.79%	4.53%	4.52%
39	WEC Energy Group	3.06%	3.57%	3.08%	3.00%	2.68%	2.81%	3.38%	3.31%	3.35%	3.49%	3.40%	3.49%	3.24%	3.35%	2.97%	3.16%	2.41%	2.14%	2.18%
40	Westar Energy	4.37%	N/A	N/A	N/A	N/A	N/A	N/A	3.00%	2.90%	3.73%	3.88%	4.27%	4.57%	4.84%	5.32%	6.27%	5.22%	4.16%	4.28%
41	Xcel Energy Inc.	3.68%	3.28%	2.90%	2.81%	2.58%	2.75%	3.25%	3.10%	3.33%	3.69%	3.83%	3.86%	3.90%	4.20%	4.54%	5.14%	4.70%	4.05%	4.40%
42	**Average**	**3.83%**	**3.86%**	**3.42%**	**3.52%**	**3.56%**	**3.19%**	**3.56%**	**3.36%**	**3.49%**	**3.72%**	**3.66%**	**3.86%**	**4.18%**	**4.30%**	**4.64%**	**5.16%**	**4.25%**	**3.54%**	**3.73%**
43	Median	3.67%	3.95%	3.43%	3.50%	3.57%	3.06%	3.36%	3.16%	3.45%	3.73%	3.69%	3.84%	4.17%	4.46%	4.78%	5.20%	4.24%	3.46%	3.65%
44	20-Yr Treasury Yields[3]	3.25%	4.25%	3.30%	1.98%	1.35%	2.40%	3.02%	2.65%	2.23%	2.55%	3.07%	3.12%	2.54%	3.62%	4.03%	4.11%	4.36%	4.91%	4.99%
45	20-Yr TIPS[3]	1.07%	1.73%	0.64%	-0.43%	-0.30%	0.60%	0.94%	0.75%	0.66%	0.78%	0.87%	0.75%	0.21%	1.19%	1.73%	2.21%	2.19%	2.36%	2.31%
46	Implied Inflation[b]	2.16%	2.48%	2.64%	2.42%	1.66%	1.79%	2.06%	1.89%	1.56%	1.75%	2.19%	2.35%	2.33%	2.40%	2.26%	1.85%	2.13%	2.49%	2.62%
47	**Real Dividend Yield[c]**	**1.64%**	**1.34%**	**0.77%**	**1.07%**	**1.86%**	**1.37%**	**1.47%**	**1.44%**	**1.91%**	**1.94%**	**1.43%**	**1.48%**	**1.81%**	**1.86%**	**2.33%**	**3.24%**	**2.07%**	**1.02%**	**1.08%**
	A-Rated Utility																			
48	**Nominal "A" Rated Yield[4]**	**4.70%**	**5.55%**	**4.74%**	**3.10%**	**3.05%**	**3.77%**	**4.25%**	**4.00%**	**3.93%**	**4.12%**	**4.28%**	**4.48%**	**4.13%**	**5.04%**	**5.46%**	**6.04%**	**6.53%**	**6.07%**	**6.07%**
49	**Real "A" Rated Yield**	**2.49%**	**2.99%**	**2.05%**	**0.67%**	**1.37%**	**1.94%**	**2.14%**	**2.07%**	**2.34%**	**2.33%**	**2.04%**	**2.08%**	**1.76%**	**2.58%**	**3.13%**	**4.11%**	**4.31%**	**3.49%**	**3.36%**
	Baa-Rated Utility																			
50	**Nominal "Baa" Rated Yield**	**5.21%**	**5.85%**	**5.05%**	**3.36%**	**3.44%**	**4.19%**	**4.67%**	**4.38%**	**4.67%**	**5.03%**	**4.80%**	**4.98%**	**4.83%**	**5.57%**	**5.96%**	**7.06%**	**7.25%**	**6.33%**	**6.32%**
51	**Real "Baa" Rated Yield**	**2.98%**	**3.29%**	**2.35%**	**0.91%**	**1.74%**	**2.36%**	**2.55%**	**2.44%**	**3.07%**	**3.22%**	**2.55%**	**2.57%**	**2.44%**	**3.09%**	**3.62%**	**5.11%**	**5.01%**	**3.74%**	**3.60%**
	Spreads (A-Rated Utility Bond - Stock)																			
52	**Nominal Spread[d]**	**0.87%**	**1.69%**	**1.32%**	**-0.41%**	**-0.50%**	**0.58%**	**0.69%**	**0.64%**	**0.44%**	**0.40%**	**0.62%**	**0.61%**	**-0.05%**	**0.74%**	**0.82%**	**0.88%**	**2.28%**	**2.53%**	**2.34%**
53	**Real Spread[e]**	**0.85%**	**1.65%**	**1.28%**	**-0.40%**	**-0.49%**	**0.57%**	**0.68%**	**0.62%**	**0.43%**	**0.39%**	**0.61%**	**0.60%**	**-0.05%**	**0.72%**	**0.80%**	**0.87%**	**2.23%**	**2.47%**	**2.28%**
	Spreads (Baa-Rated Utility Bond - Stock)																			
54	**Nominal Spread[b]**	**1.37%**	**1.99%**	**1.63%**	**-0.16%**	**-0.12%**	**1.00%**	**1.11%**	**1.01%**	**1.18%**	**1.31%**	**1.14%**	**1.12%**	**0.65%**	**1.26%**	**1.32%**	**1.90%**	**3.00%**	**2.79%**	**2.58%**
55	**Real Spread[c]**	**1.34%**	**1.95%**	**1.58%**	**-0.16%**	**-0.12%**	**0.98%**	**1.09%**	**1.00%**	**1.16%**	**1.29%**	**1.12%**	**1.09%**	**0.63%**	**1.23%**	**1.29%**	**1.87%**	**2.93%**	**2.72%**	**2.52%**
	Spreads (Treasury Bond - Stock)																			
56	**Nominal[f]**	**-0.58%**	**0.40%**	**-0.12%**	**-1.54%**	**-2.20%**	**-0.79%**	**-0.54%**	**-0.71%**	**-1.27%**	**-1.17%**	**-0.58%**	**-0.74%**	**-1.63%**	**-0.68%**	**-0.61%**	**-1.05%**	**0.11%**	**1.37%**	**1.26%**
57	**Real[g]**	**-0.57%**	**0.39%**	**-0.12%**	**-1.50%**	**-2.17%**	**-0.77%**	**-0.53%**	**-0.70%**	**-1.25%**	**-1.15%**	**-0.57%**	**-0.73%**	**-1.60%**	**-0.67%**	**-0.60%**	**-1.03%**	**0.11%**	**1.33%**	**1.23%**



Sources:
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.
[3] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[4] www.moodys.com, Bond Yields and Key Indicators, through December 31, 2023.
Notes:
[a] Based on the average of the high and low price and the projected Dividends Declared per share, published in the Value Line Investment Survey.
[b] Line 47 = (1 + Line 45) / (1 + Line 46) - 1.
[c] Line 48 = (1 + Line 43) / (1 +Line 47) - 1.
[d] The spread being measured here is the nominal A-rated utility bond yield over the average nominal utility dividend yield; (Line 49 - Line 43).
[e] The spread being measured here is the real A-rated utility bond yield over the average real utility dividend yield; Line 50 - Line 48)
[f] The spread being measured here is the nominal 20-Year Treasury yield over the average nominal utility dividend yield; (Line 45 - Line 43).
[g] The spread being measured here is the real 20-Year TIPS yield over the average real utility dividend yield; Line 48 - Line 46)

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

			Dividend per Share[1]																	
Line	Company	18-Year Average	2023[2]	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	ALLETE	2.05	2.71	2.60	2.52	2.47	2.35	2.24	2.14	2.08	2.02	1.96	1.90	1.84	1.78	1.76	1.76	1.72	1.64	1.45
2	Alliant Energy	1.12	1.81	1.71	1.61	1.52	1.42	1.34	1.26	1.18	1.10	1.02	0.94	0.90	0.85	0.79	0.75	0.70	0.64	0.58
3	Ameren Corp.	1.95	2.52	2.36	2.20	2.00	1.92	1.85	1.78	1.72	1.66	1.61	1.60	1.60	1.56	1.54	1.54	2.54	2.54	2.54
4	American Electric Power	2.23	3.37	3.17	3.00	2.84	2.71	2.53	2.39	2.27	2.15	2.03	1.95	1.88	1.85	1.71	1.64	1.64	1.58	1.50
5	Avangrid, Inc.	1.75	1.76	1.76	1.76	1.76	1.76	1.74	1.73	1.73	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.25	1.84	1.76	1.69	1.62	1.55	1.49	1.43	1.37	1.32	1.27	1.22	1.16	1.10	1.00	0.81	0.69	0.60	0.57
7	Black Hills	1.75	2.50	2.41	2.29	2.17	2.05	1.93	1.81	1.68	1.62	1.56	1.52	1.48	1.46	1.44	1.42	1.40	1.37	1.32
8	CenterPoint Energy	0.85	0.76	0.72	0.66	0.90	0.86	1.12	1.35	1.03	0.99	0.95	0.83	0.81	0.79	0.78	0.76	0.73	0.68	0.60
9	CMS Energy Corp.	1.15	1.95	1.84	1.74	1.63	1.53	1.43	1.33	1.24	1.16	1.08	1.02	0.96	0.84	0.66	0.50	0.36	0.20	N/A
10	Consol. Edison	2.66	3.24	3.16	3.10	3.06	2.96	2.86	2.76	2.68	2.60	2.52	2.46	2.42	2.40	2.38	2.36	2.34	2.32	2.30
11	Dominion Resources	2.42	2.67	2.67	2.52	3.45	3.67	3.34	3.04	2.80	2.59	2.40	2.25	2.11	1.97	1.83	1.75	1.58	1.46	1.38
12	DTE Energy	2.93	3.88	3.54	3.88	4.12	3.85	3.59	3.36	3.06	2.84	2.69	2.59	2.42	2.32	2.18	2.12	2.12	2.12	2.08
13	Duke Energy	3.32	4.06	3.98	3.90	3.82	3.75	3.64	3.49	3.36	3.24	3.15	3.09	3.03	2.97	2.91	2.82	2.70	2.58	N/A
14	Edison Int'l	1.86	2.99	2.84	2.69	2.58	2.48	2.43	2.23	1.98	1.73	1.48	1.37	1.31	1.29	1.27	1.25	1.23	1.18	1.10
15	El Paso Electric	1.11	N/A	N/A	N/A	N/A	N/A	1.42	1.32	1.23	1.17	1.11	1.05	0.97	0.66	N/A	N/A	N/A	N/A	N/A
16	Entergy Corp.	3.38	4.34	4.10	3.86	3.74	3.66	3.58	3.50	3.42	3.34	3.32	3.32	3.32	3.32	3.24	3.00	3.00	2.58	2.16
17	Eversource Energy	1.62	2.70	2.55	2.41	2.27	2.14	2.02	1.90	1.78	1.67	1.57	1.47	1.32	1.10	1.03	0.95	0.83	0.78	0.73
18	Evergy, Inc.	2.33	2.48	2.33	2.18	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	1.62	1.44	1.35	1.53	1.53	1.45	1.38	1.31	1.26	1.24	1.24	1.46	2.10	2.10	2.10	2.10	2.05	1.82	1.64
20	FirstEnergy Corp.	1.77	1.60	1.56	1.56	1.56	1.53	1.82	1.44	1.44	1.44	1.44	1.65	2.20	2.20	2.20	2.20	2.20	2.05	1.85
21	Fortis Inc.	1.46	2.29	2.17	2.08	1.97	1.86	1.75	1.65	1.55	1.43	1.30	1.25	1.21	1.17	1.12	1.04	1.00	0.82	0.67
22	Great Plains Energy	1.11	N/A	N/A	N/A	N/A	N/A	N/A	1.10	1.06	1.00	0.94	0.88	0.86	0.84	0.83	0.83	1.66	1.66	1.66
23	Hawaiian Elec.	1.25	1.08	1.40	1.36	1.32	1.28	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
24	IDACORP, Inc.	1.94	3.20	3.04	2.88	2.72	2.56	2.40	2.24	2.08	1.92	1.76	1.57	1.37	1.20	1.20	1.20	1.20	1.20	1.20
25	MGE Energy	1.18	1.67	1.59	N/A	1.45	1.38	1.32	1.26	1.21	1.16	1.11	1.07	1.04	1.01	0.99	0.97	0.96	0.94	0.93
26	NextEra Energy, Inc.	0.90	1.87	1.70	1.54	1.40	1.25	1.11	0.98	0.87	0.77	0.73	0.66	0.60	0.55	0.50	0.47	0.45	0.41	0.38
27	NorthWestern Corp	1.84	2.56	2.52	2.48	2.40	2.30	2.20	2.10	2.00	1.92	1.60	1.52	1.48	1.44	1.36	1.34	1.32	1.28	1.24
28	OGE Energy	1.10	1.66	1.64	1.63	1.58	1.51	1.40	1.27	1.16	1.05	0.95	0.85	0.80	0.76	0.73	0.71	0.70	0.68	0.67
29	Otter Tail Corp.	1.31	1.75	1.65	1.56	1.48	1.40	1.34	1.28	1.25	1.23	1.21	1.19	1.19	1.19	1.19	1.19	1.19	1.17	1.15
30	Pinnacle West Capital	2.60	3.49	3.42	3.36	3.23	3.04	2.87	2.70	2.56	2.44	2.33	2.23	2.67	2.10	2.10	2.10	2.10	2.10	2.03
31	PNM Resources	0.89	1.49	1.41	0.98	1.25	1.18	1.09	0.99	0.88	0.80	0.76	0.68	0.58	0.50	0.50	0.50	0.61	0.91	0.86
32	Portland General	1.26	1.88	1.79	1.70	1.59	1.52	1.43	1.34	1.26	1.18	1.12	1.10	1.08	1.06	1.04	1.01	0.97	0.93	0.68
33	PPL Corp.	1.40	0.95	0.88	1.66	1.66	1.65	1.64	1.58	1.52	1.50	1.49	1.47	1.44	1.40	1.40	1.38	1.34	1.22	1.10
34	Public Serv. Enterprise	1.61	2.28	2.16	2.04	1.96	1.88	1.80	1.72	1.64	1.56	1.48	1.44	1.42	1.37	1.37	1.33	1.29	1.17	1.14
35	SCANA Corp.	2.00	N/A	N/A	N/A	N/A	N/A	N/A	2.45	2.30	2.18	2.10	2.03	1.98	1.94	1.90	1.88	1.84	1.76	1.68
36	Sempra Energy	2.70	2.38	4.58	4.40	4.18	3.87	3.58	3.29	3.02	2.80	2.64	2.52	2.40	1.92	1.56	1.56	1.37	1.24	1.20
37	Southern Co.	2.13	2.78	2.70	2.62	2.54	2.46	2.38	2.30	2.22	2.15	2.08	2.01	1.94	1.87	1.80	1.73	1.66	1.60	1.54
38	Vectren Corp.	1.42	N/A	N/A	N/A	N/A	N/A	N/A	1.71	1.62	1.54	1.46	1.43	1.41	1.39	1.37	1.35	1.31	1.27	1.23
39	WEC Energy Group	1.66	3.12	2.91	2.71	2.53	2.36	2.21	2.08	1.98	1.74	1.56	1.45	1.20	1.04	0.80	0.68	0.54	0.50	0.46
40	Westar Energy	1.30	N/A	N/A	N/A	N/A	N/A	N/A	1.60	1.52	1.44	1.40	1.36	1.32	1.28	1.24	1.20	1.16	1.08	0.98
41	Xcel Energy Inc.	1.33	2.08	1.95	1.83	1.72	1.62	1.52	1.44	1.36	1.28	1.20	1.11	1.07	1.03	1.00	0.97	0.94	0.91	0.88
42	**Average**	**1.76**	**2.37**	**2.33**	**2.28**	**2.23**	**2.14**	**2.03**	**1.90**	**1.79**	**1.70**	**1.61**	**1.56**	**1.54**	**1.46**	**1.42**	**1.38**	**1.39**	**1.32**	**1.24**
43	**Industry Average Growth**	**3.89%**	**1.47%**	**2.08%**	**2.47%**	**4.36%**	**5.29%**	**6.91%**	**5.99%**	**5.44%**	**5.35%**	**3.49%**	**1.01%**	**5.77%**	**2.46%**	**3.13%**	**-0.48%**	**4.89%**	**6.45%**	

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

			Earnings per Share[1]																	
Line	Company	18-Year Average	2023[2]	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	ALLETE	3.01	4.30	3.38	3.23	3.35	3.33	3.38	3.13	3.14	3.38	2.90	2.63	2.58	2.65	2.19	1.89	2.82	3.08	2.77
2	Alliant Energy	1.82	2.78	2.73	2.63	2.47	2.33	2.19	1.99	1.65	1.69	1.74	1.65	1.53	1.38	1.38	0.95	1.27	1.35	1.03
3	Ameren Corp.	2.99	4.37	4.14	3.84	3.50	3.35	3.32	2.77	2.68	2.38	2.40	2.10	2.41	2.47	2.77	2.78	2.88	2.98	2.66
4	American Electric Power	3.67	5.24	5.09	4.96	4.42	4.08	3.90	3.62	4.23	3.59	3.34	3.18	2.98	3.13	2.60	2.97	2.99	2.86	2.86
5	Avangrid, Inc.	1.88	2.05	2.32	1.97	1.88	2.26	1.92	1.67	1.98	0.86	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	1.83	2.24	2.12	2.10	1.90	2.97	2.07	1.95	2.15	1.89	1.84	1.85	1.32	1.72	1.65	1.58	1.36	0.72	1.47
7	Black Hills	2.71	3.91	3.97	3.74	3.73	3.53	3.47	3.38	2.63	2.83	2.89	2.61	1.97	1.01	1.66	2.32	0.18	2.68	2.21
8	CenterPoint Energy	1.24	1.37	1.59	0.94	1.29	1.49	0.74	1.57	1.00	1.08	1.42	1.24	1.35	1.27	1.07	1.01	1.30	1.17	1.33
9	CMS Energy Corp.	1.83	3.01	2.84	2.58	2.64	2.39	2.32	2.17	1.98	1.89	1.74	1.66	1.53	1.45	1.33	0.93	1.23	0.64	0.64
10	Consol. Edison	3.91	5.00	4.55	4.74	3.94	4.08	4.55	4.10	3.94	4.05	3.62	3.93	3.86	3.57	3.47	3.14	3.36	3.48	2.95
11	Dominion Resources	2.90	2.65	4.11	3.19	1.82	2.19	3.25	3.53	3.44	3.20	3.05	3.09	2.75	2.76	2.89	2.64	3.04	2.13	2.40
12	DTE Energy	4.57	6.76	5.52	4.10	7.08	6.31	6.17	5.73	4.83	4.44	5.10	3.76	3.88	3.67	3.74	3.24	2.73	2.66	2.45
13	Duke Energy	4.09	5.60	5.27	4.93	3.92	5.07	4.13	4.22	3.71	4.10	4.13	3.98	3.71	4.14	4.02	3.39	3.03	3.60	2.73
14	Edison Int'l	3.23	4.76	1.60	2.00	1.72	3.98	-1.26	4.51	3.94	4.15	4.33	3.78	4.55	3.23	3.35	3.24	3.68	3.32	3.28
15	El Paso Electric	2.02	N/A	N/A	N/A	N/A	N/A	2.07	2.42	2.39	2.03	2.27	2.20	2.26	2.48	2.07	1.50	1.73	1.63	1.27
16	Entergy Corp.	6.37	11.10	5.37	6.87	6.90	6.30	5.88	5.19	6.88	5.81	5.77	4.96	6.02	7.55	6.66	6.30	6.20	5.60	5.36
17	Eversource Energy	2.70	4.35	4.09	3.54	3.55	3.45	3.25	3.11	2.96	2.76	2.58	2.49	1.89	2.22	2.10	1.91	1.86	1.59	0.82
18	Evergy, Inc.	3.56	3.60	3.26	3.83	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	2.83	2.35	2.26	1.74	2.60	3.01	2.07	2.78	1.80	2.54	2.10	2.31	1.92	3.75	3.87	4.29	4.10	4.03	3.50
20	FirstEnergy Corp.	2.57	2.55	2.41	2.69	1.85	1.84	1.33	2.73	2.10	2.00	0.85	2.97	2.13	1.88	3.25	3.32	4.38	4.22	3.82
21	Fortis Inc.	2.04	3.10	2.78	2.61	2.60	2.68	2.52	2.66	1.89	2.11	1.38	1.63	1.65	1.74	1.62	1.51	1.52	1.29	1.36
22	Great Plains Energy	1.33	N/A	N/A	N/A	N/A	N/A	N/A	-0.06	1.61	1.37	1.57	1.62	1.35	1.25	1.53	1.03	1.16	1.85	1.62
23	Hawaiian Elec.	1.63	1.81	2.20	2.25	1.81	1.99	1.85	1.64	2.29	1.50	1.64	1.62	1.67	1.44	1.21	0.91	1.07	1.11	1.33
24	IDACORP, Inc.	3.73	5.14	5.11	4.85	4.69	4.61	4.49	4.21	3.94	3.87	3.85	3.64	3.37	3.36	2.95	2.64	2.18	1.86	2.35
25	MGE Energy	2.12	3.25	3.07	N/A	2.60	2.51	2.43	2.20	2.18	2.06	2.32	2.16	1.86	1.76	1.67	1.47	1.59	1.51	1.37
26	NextEra Energy, Inc.	1.55	3.17	2.90	1.81	2.10	1.94	1.67	1.63	1.45	1.52	1.40	1.21	1.14	1.21	1.19	0.99	1.02	0.82	0.81
27	NorthWestern Corp	2.70	3.22	3.29	3.60	3.06	3.53	3.40	3.34	3.39	2.90	2.99	2.46	2.26	2.53	2.14	2.02	1.77	1.44	1.31
28	OGE Energy	1.80	2.07	2.25	2.36	2.08	2.24	2.12	1.92	1.69	1.69	1.98	1.94	1.79	1.73	1.50	1.33	1.25	1.32	1.23
29	Otter Tail Corp.	2.20	7.00	6.78	4.23	2.34	2.17	2.06	1.86	1.60	1.56	1.55	1.37	1.05	0.45	0.38	0.71	1.09	1.78	1.69
30	Pinnacle West Capital	3.77	4.41	4.26	5.47	4.87	4.77	4.54	4.43	3.95	3.92	3.58	3.66	3.50	2.99	3.08	2.26	2.12	2.96	3.17
31	PNM Resources	1.58	2.82	2.69	2.27	2.15	2.28	1.66	1.92	1.65	1.64	1.45	1.41	1.31	1.08	0.87	0.58	0.11	0.76	1.72
32	Portland General	2.02	2.38	2.74	2.72	1.72	2.39	2.37	2.29	2.16	2.04	2.18	1.77	1.87	1.95	1.66	1.31	1.39	2.33	1.14
33	PPL Corp.	2.14	1.55	1.41	0.53	2.04	2.37	2.58	2.11	2.79	2.37	2.38	2.38	2.61	2.61	2.29	1.19	2.45	2.63	2.29
34	Public Serv. Enterprise	2.96	3.50	3.47	2.55	3.61	3.90	2.76	2.82	2.83	3.30	2.99	2.45	2.44	3.11	3.07	3.08	2.90	2.59	1.85
35	SCANA Corp.	3.30	N/A	N/A	N/A	N/A	N/A	N/A	4.20	4.16	3.81	3.79	3.39	3.15	2.97	2.98	2.85	2.95	2.74	2.59
36	Sempra Energy	4.96	4.61	9.21	4.01	6.58	5.97	5.48	4.63	4.24	5.23	4.63	4.22	4.35	4.47	4.02	4.78	4.43	4.26	4.23
37	Southern Co.	2.83	3.60	3.61	3.42	3.25	3.17	3.00	3.21	2.83	2.84	2.77	2.70	2.67	2.55	2.36	2.32	2.25	2.28	2.10
38	Vectren Corp.	1.94	N/A	N/A	N/A	N/A	N/A	N/A	2.60	2.55	2.39	2.02	1.66	1.94	1.73	1.64	1.79	1.63	1.83	1.44
39	WEC Energy Group	2.76	4.63	4.46	4.11	3.79	3.58	3.34	3.14	2.96	2.34	2.59	2.51	2.35	2.18	1.92	1.60	1.52	1.42	1.32
40	Westar Energy	1.96	N/A	N/A	N/A	N/A	N/A	N/A	2.27	2.43	2.09	2.35	2.27	2.15	1.79	1.80	1.28	1.31	1.84	1.88
41	Xcel Energy Inc.	2.15	3.35	3.17	2.96	2.79	2.64	2.47	2.30	2.21	2.10	2.03	1.91	1.85	1.72	1.56	1.49	1.46	1.35	1.35
42	**Average**	**2.75**	**3.82**	**3.61**	**3.24**	**3.16**	**3.28**	**2.87**	**2.90**	**2.81**	**2.68**	**2.65**	**2.52**	**2.44**	**2.43**	**2.35**	**2.17**	**2.19**	**2.25**	**2.09**
43	**Industry Average Growth**	**3.70%**	**5.83%**	**11.50%**	**2.47%**	**-3.54%**	**14.00%**	**-0.78%**	**3.26%**	**4.58%**	**1.09%**	**5.23%**	**3.58%**	**0.03%**	**3.76%**	**8.23%**	**-0.89%**	**-2.75%**	**7.36%**	

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

Line	Company	Cash Flow / Capital Spending[1] 2020 (1)	2021 (2)	2022 (3)	2023 (4)	2024[2] (5)	3 - 5 yr[2] Projection (6)
1	ALLETE	0.74x	0.80x	2.26x	1.42x	1.39x	1.33x
2	Alliant Energy	0.82x	0.97x	0.94x	0.95x	0.97x	1.20x
3	Ameren Corp.	0.51x	0.59x	0.72x	0.74x	0.84x	0.94x
4	American Electric Power	0.74x	0.69x	0.73x	0.72x	0.82x	1.09x
5	Avangrid, Inc.	0.56x	0.62x	0.61x	0.57x	0.72x	0.78x
6	Avista Corp.	0.85x	0.87x	0.83x	0.78x	0.84x	0.87x
7	Black Hills	0.72x	0.76x	0.85x	0.82x	0.68x	0.86x
8	CenterPoint Energy	0.88x	0.62x	0.62x	0.57x	0.55x	0.69x
9	CMS Energy Corp.	0.82x	0.77x	0.78x	0.92x	0.81x	0.87x
10	Consol. Edison	0.82x	0.89x	0.83x	0.72x	0.84x	0.94x
11	Dominion Resources	1.00x	0.89x	0.74x	0.63x	0.53x	0.88x
12	DTE Energy	0.67x	0.70x	0.75x	0.82x	0.87x	0.95x
13	Duke Energy	0.86x	0.93x	0.81x	0.79x	0.77x	0.90x
14	Edison Int'l	0.67x	0.74x	0.67x	0.75x	0.82x	0.88x
15	El Paso Electric	1.00x	0.83x	N/A	N/A	N/A	N/A
16	Entergy Corp.	0.81x	1.05x	0.98x	0.85x	0.83x	1.08x
17	Eversource Energy	0.95x	0.74x	0.72x	0.86x	0.81x	1.03x
18	Evergy, Inc.	1.06x	0.96x	0.94x	0.86x	0.89x	0.98x
19	Exelon Corp.	1.30x	1.32x	0.96x	0.99x	0.92x	1.07x
20	FirstEnergy Corp.	0.96x	0.91x	0.86x	0.80x	0.82x	0.95x
21	Fortis Inc.	0.60x	0.74x	0.75x	0.82x	0.85x	0.97x
22	Hawaiian Elec.	1.10x	1.42x	1.30x	1.51x	1.20x	1.09x
23	IDACORP, Inc.	1.25x	1.16x	0.83x	0.63x	0.56x	0.95x
24	MGE Energy	0.73x	0.87x	N/A	1.26x	1.09x	1.18x
25	NextEra Energy, Inc.	0.58x	0.69x	0.54x	0.59x	0.69x	0.84x
26	NorthWestern Corp	0.98x	0.82x	0.66x	0.75x	0.87x	1.04x
27	OGE Energy	1.43x	1.13x	0.99x	0.97x	1.00x	1.24x
28	Otter Tail Corp.	0.45x	1.42x	1.45x	1.08x	1.23x	1.15x
29	Pinnacle West Capital	0.98x	0.85x	0.78x	0.95x	0.74x	0.89x
30	PNM Resources	0.59x	0.51x	0.63x	0.63x	0.53x	0.64x
31	Portland General	0.75x	0.97x	1.01x	0.58x	0.62x	0.93x
32	PPL Corp.	1.06x	1.12x	1.35x	0.98x	0.96x	0.93x
33	Public Serv. Enterprise	1.00x	1.05x	0.82x	0.87x	0.92x	1.12x
34	Sempra Energy	0.92x	0.78x	0.92x	0.96x	0.63x	0.68x
35	Southern Co.	1.01x	0.93x	0.97x	0.97x	1.02x	1.23x
36	WEC Energy Group	0.70x	0.75x	0.87x	0.92x	1.01x	1.28x
37	Xcel Energy Inc.	0.99x	0.86x	0.80x	0.92x	0.65x	0.97x
38	Average	0.86x	0.88x	0.89x	0.86x	0.84x	0.98x
39	Median	0.85x	0.86x	0.83x	0.84x	0.83x	0.95x

Source:
[1] Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.
Notes:
Based on the projected Cash Flow per share and Capital Spending per share.

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

		Percent Dividends to Book Value [1]																		
Line	Company	18-Year Average	2023 [2/a]	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	ALLETE	5.90%	5.56%	5.52%	5.56%	5.61%	5.44%	5.35%	5.29%	5.45%	5.45%	5.59%	5.86%	6.04%	6.18%	6.46%	6.67%	6.78%	6.80%	6.62%
2	Alliant Energy	6.39%	6.84%	6.84%	6.73%	6.68%	6.68%	6.90%	7.32%	6.96%	6.70%	6.56%	6.36%	6.37%	6.26%	6.06%	5.98%	5.48%	5.23%	5.04%
3	Ameren Corp.	6.03%	6.26%	5.88%	5.84%	5.67%	5.87%	5.92%	6.01%	5.86%	5.78%	5.82%	5.93%	5.87%	4.76%	4.79%	4.66%	7.74%	7.84%	7.97%
4	American Electric Power	6.35%	6.95%	6.80%	6.74%	6.86%	6.82%	6.56%	6.43%	6.42%	5.90%	5.91%	5.91%	5.99%	6.10%	6.04%	5.97%	6.23%	6.28%	6.32%
5	Avangrid, Inc.	3.15%	3.49%	3.51%	3.57%	3.58%	3.57%	3.57%	3.54%	3.53%	0.00%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	5.07%	5.78%	5.65%	5.61%	5.53%	5.37%	5.52%	5.41%	5.33%	5.38%	5.33%	5.65%	5.51%	5.42%	5.07%	4.23%	3.77%	3.44%	3.26%
7	Black Hills	5.33%	5.30%	5.32%	5.32%	5.32%	5.34%	5.31%	5.67%	5.55%	5.66%	5.06%	5.17%	5.31%	5.30%	5.14%	5.10%	5.15%	5.34%	5.58%
8	CenterPoint Energy	9.31%	4.96%	4.90%	4.82%	8.35%	6.59%	8.94%	12.39%	12.82%	12.30%	8.96%	8.23%	8.05%	7.97%	10.36%	11.28%	12.40%	12.12%	12.09%
9	CMS Energy Corp.	6.71%	7.84%	7.89%	7.87%	8.57%	8.66%	8.52%	8.43%	8.14%	8.16%	8.10%	7.86%	7.94%	7.05%	5.90%	4.38%	3.31%	2.11%	0.00%
10	Consol. Edison	5.99%	5.51%	5.42%	5.48%	5.56%	5.46%	5.49%	5.55%	5.72%	5.84%	5.87%	5.88%	5.97%	6.15%	6.27%	6.47%	6.60%	7.12%	7.40%
11	Dominion Resources	10.11%	7.96%	8.54%	8.00%	11.72%	10.39%	11.31%	11.41%	12.04%	12.20%	12.16%	11.24%	11.50%	9.81%	8.86%	9.38%	9.14%	8.95%	7.46%
12	DTE Energy	6.26%	7.25%	7.64%	8.64%	6.43%	6.34%	6.38%	6.34%	6.09%	5.81%	5.72%	5.79%	5.66%	5.60%	5.49%	5.59%	5.76%	5.91%	6.28%
13	Duke Energy	5.47%	6.29%	6.47%	6.34%	6.39%	6.12%	6.04%	5.85%	5.73%	5.61%	5.45%	5.28%	5.22%	5.81%	5.72%	5.66%	5.45%	5.12%	0.00%
14	Edison Int'l	5.65%	8.30%	9.24%	7.36%	6.96%	6.73%	7.56%	6.23%	5.39%	4.97%	4.41%	4.48%	4.54%	4.16%	3.90%	4.12%	4.19%	4.53%	4.65%
15	El Paso Electric	2.94%	N/A	N/A	N/A	5.13%	N/A	4.94%	4.67%	4.62%	4.63%	4.53%	4.46%	4.72%	3.47%	0.00%	0.00%	0.00%	0.00%	0.00%
16	Entergy Corp.	6.70%	6.32%	6.68%	6.72%	6.85%	7.13%	7.65%	7.90%	7.58%	6.44%	5.95%	6.15%	6.42%	6.53%	6.82%	6.59%	7.13%	6.34%	5.34%
17	Eversource Energy	5.07%	6.34%	5.74%	5.69%	5.54%	5.59%	5.57%	5.43%	5.27%	5.12%	4.99%	4.82%	4.49%	4.86%	4.75%	4.66%	4.26%	4.16%	4.00%
18	Evergy, Inc.	5.53%	5.81%	5.57%	5.41%	5.32%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	7.03%	5.65%	5.42%	4.36%	4.62%	4.38%	4.34%	4.23%	4.51%	4.42%	4.72%	5.49%	8.38%	9.68%	10.25%	10.96%	12.21%	11.87%	11.02%
20	FirstEnergy Corp.	8.78%	8.67%	8.78%	10.26%	11.70%	11.86%	13.82%	16.34%	10.21%	4.91%	4.88%	5.44%	7.03%	6.93%	7.85%	7.84%	8.10%	6.96%	6.54%
21	Fortis Inc.	5.42%	5.84%	5.95%	5.59%	5.39%	5.08%	5.03%	5.19%	4.80%	5.00%	5.22%	5.58%	5.81%	5.70%	5.91%	5.60%	5.55%	4.90%	5.47%
22	Great Plains Energy	5.31%	N/A	N/A	N/A	N/A	N/A	N/A	4.78%	4.27%	4.21%	4.02%	3.91%	3.93%	3.84%	3.90%	4.03%	7.76%	9.13%	9.94%
23	Hawaiian Elec.	7.09%	5.07%	6.96%	6.22%	6.17%	6.12%	6.24%	6.43%	6.51%	6.91%	7.10%	7.27%	7.62%	7.77%	7.91%	7.96%	8.08%	8.11%	9.22%
24	IDACORP, Inc.	4.70%	5.57%	5.48%	5.45%	5.36%	5.24%	5.11%	5.02%	4.87%	4.70%	4.53%	4.26%	3.91%	3.62%	3.87%	4.11%	4.32%	4.48%	4.66%
25	MGE Energy	6.11%	5.30%	5.32%	N/A	5.22%	5.59%	5.60%	5.61%	5.79%	5.82%	5.84%	6.01%	6.22%	6.36%	6.56%	6.72%	6.87%	7.24%	7.77%
26	NextEra Energy, Inc.	6.70%	8.08%	8.61%	8.13%	7.51%	6.61%	6.22%	6.55%	6.69%	6.29%	6.49%	6.36%	6.34%	6.12%	5.82%	5.99%	6.30%	6.22%	6.21%
27	NorthWestern Corp	5.82%	5.63%	5.65%	5.73%	5.84%	5.69%	5.70%	5.76%	5.77%	5.78%	5.08%	5.71%	5.90%	6.08%	6.01%	6.13%	6.21%	6.06%	6.00%
28	OGE Energy	6.86%	7.46%	7.47%	8.04%	8.71%	7.28%	6.96%	6.59%	6.70%	6.30%	5.84%	5.56%	5.70%	5.81%	6.24%	6.79%	6.89%	7.47%	7.61%
29	Otter Tail Corp.	7.03%	5.95%	5.61%	6.54%	7.05%	7.19%	7.29%	7.27%	7.34%	7.70%	7.86%	8.07%	8.25%	7.52%	6.77%	6.33%	6.22%	6.67%	6.90%
30	Pinnacle West Capital	6.21%	6.41%	6.40%	6.43%	6.47%	6.29%	6.16%	6.03%	5.93%	5.91%	5.89%	5.84%	7.38%	6.00%	6.20%	6.42%	6.15%	5.98%	5.87%
31	PNM Resources	4.03%	5.72%	5.52%	3.88%	5.23%	5.59%	5.12%	4.67%	4.18%	3.85%	3.37%	3.26%	2.89%	2.55%	2.84%	2.65%	3.20%	4.13%	3.89%
32	Portland General	4.90%	5.73%	5.75%	5.61%	5.45%	5.24%	5.09%	4.94%	4.78%	4.64%	4.56%	4.70%	4.70%	4.78%	4.90%	4.93%	4.48%	4.42%	3.45%
33	PPL Corp.	8.49%	4.87%	4.66%	8.89%	9.55%	9.74%	10.13%	10.18%	10.44%	10.19%	7.28%	7.43%	8.00%	7.48%	8.24%	9.47%	9.89%	8.20%	8.27%
34	Public Serv. Enterprise	7.00%	7.93%	7.82%	7.12%	6.18%	6.28%	6.31%	6.27%	6.31%	6.03%	6.14%	6.28%	6.66%	6.75%	7.20%	7.66%	8.40%	8.15%	8.54%
35	SCANA Corp.	6.44%	N/A	N/A		N/A	N/A	N/A	6.67%	5.74%	5.72%	6.01%	6.14%	6.29%	6.48%	6.54%	6.80%	7.12%	6.94%	6.89%
36	Sempra Energy	5.33%	5.41%	5.49%	5.56%	5.96%	6.39%	6.59%	6.53%	5.83%	5.89%	5.74%	5.60%	5.66%	4.68%	4.16%	4.27%	4.18%	3.89%	4.19%
37	Southern Co.	9.58%	9.93%	9.67%	9.96%	9.59%	9.42%	9.95%	9.59%	8.89%	9.53%	9.48%	9.39%	9.22%	9.22%	9.38%	9.55%	9.74%	9.83%	10.07%
38	Vectren Corp.	7.71%	N/A	N/A	N/A	N/A	N/A	N/A	7.67%	7.60%	7.57%	7.51%	7.55%	7.57%	7.74%	7.78%	7.84%	7.85%	7.86%	7.97%
39	WEC Energy Group	6.42%	8.38%	7.92%	7.83%	7.62%	7.36%	7.12%	6.94%	7.00%	6.35%	7.96%	7.71%	6.65%	6.05%	4.92%	4.42%	3.78%	3.77%	3.72%
40	Westar Energy	5.71%	N/A	N/A	N/A	N/A	N/A	N/A	5.82%	5.66%	5.57%	5.60%	5.70%	5.77%	5.81%	5.84%	5.83%	5.75%	5.64%	5.56%
41	Xcel Energy Inc.	6.19%	6.55%	6.43%	6.38%	6.34%	6.42%	6.39%	6.38%	6.26%	6.13%	5.94%	5.78%	5.88%	5.91%	5.97%	6.09%	6.13%	6.19%	6.16%
42	Average	6.34%	6.41%	6.46%	6.50%	6.65%	6.57%	6.69%	6.73%	6.46%	6.13%	6.09%	6.11%	6.29%	6.11%	6.07%	6.13%	6.37%	6.29%	6.10%
43	Median	6.09%	6.10%	5.92%	6.34%	6.18%	6.29%	6.23%	6.25%	5.85%	5.82%	5.84%	5.84%	5.99%	6.08%	6.01%	5.99%	6.22%	6.22%	6.21%

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

[a] Based on the projected 2023 Dividend Declared per share and Book Value per share,
published in The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

		Dividends to Earnings Ratio [1]																		
Line	Company	18-Year Average	2023 [2/a]	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	ALLETE	0.69	0.63	0.77	0.78	0.74	0.71	0.66	0.68	0.66	0.60	0.68	0.72	0.71	0.67	0.80	0.93	0.61	0.53	0.52
2	Alliant Energy	0.61	0.65	0.63	0.61	0.62	0.61	0.61	0.63	0.72	0.65	0.59	0.57	0.59	0.62	0.57	0.79	0.55	0.47	0.56
3	Ameren Corp.	0.66	0.58	0.57	0.57	0.57	0.57	0.56	0.64	0.64	0.70	0.67	0.76	0.66	0.63	0.56	0.55	0.88	0.85	0.95
4	American Electric Power	0.61	0.64	0.62	0.60	0.64	0.66	0.65	0.66	0.54	0.60	0.61	0.61	0.63	0.59	0.66	0.55	0.55	0.55	0.52
5	Avangrid, Inc.	0.88	0.86	0.76	0.89	0.94	0.78	0.91	1.03	0.87	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	0.68	0.82	0.83	0.80	0.85	0.52	0.72	0.73	0.64	0.70	0.69	0.66	0.88	0.64	0.61	0.51	0.51	0.83	0.39
7	Black Hills	1.06	0.64	0.61	0.61	0.58	0.58	0.56	0.54	0.64	0.57	0.54	0.58	0.75	1.45	0.87	0.61	7.78	0.51	0.60
8	CenterPoint Energy	0.72	0.55	0.45	0.70	0.70	0.58	1.51	0.86	1.03	0.92	0.67	0.67	0.60	0.62	0.73	0.75	0.56	0.58	0.45
9	CMS Energy Corp.	0.58	0.65	0.65	0.67	0.62	0.64	0.62	0.61	0.63	0.61	0.62	0.61	0.63	0.58	0.50	0.54	0.29	0.31	N/A
10	Consol. Edison	0.68	0.65	0.69	0.65	0.78	0.73	0.63	0.67	0.68	0.64	0.70	0.63	0.63	0.67	0.69	0.75	0.70	0.67	0.78
11	Dominion Resources	0.87	1.01	0.65	0.79	1.90	1.68	1.03	0.86	0.81	0.81	0.79	0.73	0.77	0.71	0.63	0.66	0.52	0.69	0.58
12	DTE Energy	0.66	0.57	0.64	0.95	0.58	0.61	0.58	0.59	0.63	0.64	0.53	0.69	0.62	0.63	0.58	0.65	0.78	0.80	0.85
13	Duke Energy	0.80	0.73	0.76	0.79	0.97	0.74	0.88	0.83	0.91	0.79	0.76	0.78	0.82	0.72	0.72	0.83	0.89	0.72	N/A
14	Edison Int'l	0.47	0.63	1.78	1.35	1.50	0.62	- 1.93	0.50	0.50	0.42	0.34	0.36	0.29	0.40	0.38	0.38	0.33	0.35	0.34
15	El Paso Electric	0.50	N/A	N/A	N/A	N/A	N/A	0.68	0.54	0.51	0.57	0.49	0.48	0.43	0.27	N/A	N/A	N/A	N/A	N/A
16	Entergy Corp.	0.54	0.39	0.76	0.56	0.54	0.58	0.61	0.67	0.50	0.57	0.58	0.67	0.55	0.44	0.49	0.48	0.48	0.46	0.40
17	Eversource Energy	0.60	0.62	0.62	0.68	0.64	0.62	0.62	0.61	0.60	0.61	0.61	0.59	0.70	0.50	0.49	0.50	0.44	0.49	0.88
18	Evergy, Inc.	0.66	0.69	0.71	0.57	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	0.60	0.61	0.60	0.88	0.59	0.48	0.67	0.47	0.70	0.49	0.59	0.63	1.09	0.56	0.54	0.49	0.50	0.45	0.47
20	FirstEnergy Corp.	0.78	0.63	0.65	0.58	0.84	0.83	1.37	0.53	0.69	0.72	1.69	0.56	1.03	1.17	0.68	0.66	0.50	0.49	0.48
21	Fortis Inc.	0.71	0.74	0.78	0.80	0.76	0.69	0.69	0.62	0.82	0.68	0.94	0.77	0.73	0.67	0.69	0.69	0.66	0.64	0.49
22	Great Plains Energy	- 0.82	N/A	N/A	N/A	N/A	N/A	N/A	-18.33	0.66	0.73	0.60	0.54	0.63	0.67	0.54	0.81	1.43	0.90	1.02
23	Hawaiian Elec.	0.82	0.60	0.64	0.60	0.73	0.64	0.67	0.76	0.54	0.83	0.76	0.77	0.74	0.86	1.02	1.36	1.16	1.12	0.93
24	IDACORP, Inc.	0.51	0.62	0.59	0.59	0.58	0.56	0.53	0.53	0.53	0.50	0.46	0.43	0.41	0.36	0.41	0.45	0.55	0.65	0.51
25	MGE Energy	0.57	0.51	0.52	N/A	0.56	0.55	0.54	0.57	0.56	0.56	0.48	0.50	0.56	0.57	0.60	0.66	0.60	0.62	0.68
26	NextEra Energy, Inc.	0.56	0.59	0.59	0.85	0.67	0.64	0.66	0.60	0.60	0.51	0.52	0.55	0.53	0.45	0.42	0.47	0.44	0.50	0.47
27	NorthWestern Corp	0.69	0.80	0.77	0.69	0.78	0.65	0.65	0.63	0.59	0.66	0.54	0.62	0.65	0.57	0.64	0.66	0.75	0.89	0.95
28	OGE Energy	0.60	0.80	0.73	0.69	0.76	0.67	0.66	0.66	0.68	0.62	0.48	0.44	0.45	0.44	0.49	0.54	0.56	0.52	0.55
29	Otter Tail Corp.	0.98	0.25	0.24	0.37	0.63	0.65	0.65	0.69	0.78	0.79	0.78	0.87	1.13	2.64	3.13	1.68	1.09	0.66	0.68
30	Pinnacle West Capital	0.71	0.79	0.80	0.61	0.66	0.64	0.63	0.61	0.65	0.62	0.65	0.61	0.76	0.70	0.68	0.93	0.99	0.71	0.64
31	PNM Resources	0.85	0.53	0.52	0.43	0.58	0.52	0.65	0.52	0.53	0.49	0.52	0.48	0.44	0.46	0.57	0.86	5.50	1.20	0.50
32	Portland General	0.63	0.79	0.65	0.63	0.92	0.64	0.60	0.59	0.58	0.58	0.51	0.62	0.57	0.54	0.62	0.77	0.70	0.40	0.59
33	PPL Corp.	0.78	0.61	0.62	3.13	0.81	0.70	0.64	0.75	0.54	0.63	0.63	0.62	0.55	0.54	0.61	1.16	0.55	0.46	0.48
34	Public Serv. Enterprise	0.55	0.65	0.62	0.80	0.54	0.48	0.65	0.61	0.58	0.47	0.49	0.59	0.58	0.44	0.45	0.43	0.44	0.45	0.62
35	SCANA Corp.	0.61	N/A	N/A		N/A	N/A	N/A	0.58	0.55	0.57	0.55	0.60	0.63	0.65	0.64	0.66	0.62	0.64	0.65
36	Sempra Energy	0.54	0.52	0.50	1.10	0.64	0.65	0.65	0.71	0.71	0.54	0.57	0.60	0.55	0.43	0.39	0.33	0.31	0.29	0.28
37	Southern Co.	0.75	0.77	0.75	0.77	0.78	0.78	0.79	0.72	0.79	0.76	0.75	0.75	0.73	0.73	0.76	0.75	0.74	0.70	0.73
38	Vectren Corp.	0.75	N/A	N/A	N/A	N/A	N/A	N/A	0.66	0.64	0.64	0.72	0.86	0.72	0.80	0.84	0.75	0.80	0.69	0.85
39	WEC Energy Group	0.56	0.67	0.65	0.66	0.67	0.66	0.66	0.66	0.67	0.74	0.60	0.58	0.51	0.48	0.42	0.42	0.36	0.35	0.35
40	Westar Energy	0.68	N/A	N/A	N/A	N/A	N/A	N/A	0.70	0.63	0.69	0.60	0.60	0.61	0.72	0.69	0.94	0.89	0.59	0.52
41	Xcel Energy Inc.	0.62	0.62	0.62	0.62	0.62	0.61	0.62	0.63	0.62	0.61	0.59	0.58	0.58	0.60	0.64	0.65	0.64	0.67	0.65
42	Average	0.65	0.65	0.68	0.78	0.75	0.66	0.64	0.18	0.65	0.64	0.64	0.62	0.65	0.67	0.68	0.70	0.96	0.62	0.61
43	Median	0.63	0.63	0.64	0.68	0.67	0.64	0.65	0.63	0.64	0.62	0.60	0.61	0.63	0.62	0.62	0.66	0.61	0.60	0.57

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Note:

[b] Based on the projected 2023 Dividends Declared per share and Earnings per share,
published in The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Columbia Gas of Pennsylvania

Electric Utilities
(Valuation Metrics)

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
		Cash Flow to Capital Spending Ratio [1]																		
1	ALLETE	0.93	1.76	2.12	0.55	0.55	0.63	1.22	1.61	1.32	1.16	0.45	0.67	0.49	0.77	0.63	0.39	0.46	0.65	1.23
2	Alliant Energy	0.80	0.74	0.91	0.95	N/A	N/A	N/A	0.49	N/A	0.81	0.91	1.01	0.57	0.91	0.67	0.39	0.57	1.04	1.27
3	Ameren Corp.	0.87	0.77	0.71	0.62	0.62	0.79	0.80	0.75	0.75	0.75	0.75	0.89	1.07	1.31	1.36	0.81	0.66	0.97	1.21
4	American Electric Power	0.86	0.71	0.81	0.81	0.81	0.75	0.68	0.67	0.85	0.85	0.87	0.91	1.07	1.19	1.24	1.02	0.70	0.77	0.75
5	Avangrid, Inc.	0.71	0.69	0.79	0.56	0.56	0.62	0.85	0.57	0.86	0.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	Avista Corp.	0.89	0.88	0.73	0.88	0.88	0.92	0.78	0.77	0.84	0.76	0.80	0.86	0.80	0.90	0.99	1.15	0.97	0.73	1.36
7	Black Hills	0.68	0.95	0.86	0.61	0.61	0.53	0.87	1.17	0.71	0.64	0.70	0.74	0.71	0.40	0.41	0.61	0.35	0.76	0.55
8	CenterPoint Energy	0.98	0.52	0.52	0.73	0.73	0.83	0.98	1.22	1.12	0.92	1.20	1.18	1.37	1.12	0.88	0.99	1.16	0.98	1.08
9	CMS Energy Corp.	0.86	0.85	0.82	0.78	0.78	0.79	0.77	0.89	0.81	0.81	0.74	0.82	0.82	1.05	1.13	0.97	1.11	0.55	1.07
10	Consol. Edison	0.82	0.73	0.88	0.83	0.83	0.87	0.82	0.76	0.65	0.76	0.88	0.86	1.01	0.98	0.90	0.75	0.70	0.81	0.74
11	Dominion Resources	0.77	0.52	0.86	0.73	0.73	0.96	1.04	0.81	0.65	0.64	0.63	0.77	0.73	0.79	0.87	0.75	0.83	0.74	0.85
12	DTE Energy	0.98	0.85	0.86	0.74	0.74	0.83	0.84	0.94	0.93	0.84	1.02	0.96	0.93	1.09	1.51	1.50	0.98	1.07	1.03
13	Duke Energy	0.89	0.79	0.87	0.85	0.85	0.80	0.81	0.87	0.82	0.96	1.20	1.09	0.87	0.89	0.78	0.77	0.71	1.09	0.97
14	Edison Int'l	0.74	0.83	0.62	0.55	0.55	0.68	0.34	0.94	0.91	0.80	0.83	0.80	0.76	0.61	0.60	0.79	0.93	0.88	0.93
15	El Paso Electric	0.87	N/A	N/A	0.83	N/A	N/A	0.86	1.04	0.85	0.67	0.69	0.79	0.85	1.03	0.98	0.68	0.78	0.84	1.26
16	Entergy Corp.	0.96	1.03	0.62	0.74	0.74	0.79	0.73	0.76	1.08	1.05	1.19	1.03	0.88	1.15	1.24	1.02	0.93	1.14	1.13
17	Eversource Energy	0.85	0.77	0.89	0.80	0.80	0.75	0.83	0.79	0.87	0.91	0.90	1.13	0.86	0.80	1.05	0.96	0.77	0.68	0.67
18	Evergy, Inc.	0.89	0.86	0.78	1.03	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	Exelon Corp.	1.20	0.90	0.84	1.09	1.09	1.20	1.05	1.06	0.76	0.82	0.93	1.07	0.98	1.19	1.66	1.66	1.61	1.84	1.86
20	FirstEnergy Corp.	1.00	0.80	0.98	0.83	0.83	0.80	0.76	1.03	0.94	0.93	0.54	0.91	0.85	1.05	1.32	1.22	0.95	1.56	1.75
21	Fortis Inc.	0.70	0.93	0.89	0.65	0.65	0.68	0.72	0.76	0.76	0.65	0.60	0.77	0.72	0.66	0.68	0.63	0.66	0.57	0.63
22	Great Plains Energy	0.79	N/A	N/A		N/A	N/A	N/A	0.78	1.17	0.90	0.79	0.91	0.86	1.03	0.86	0.50	0.35	0.69	0.64
23	Hawaiian Elec.	1.12	1.14	1.56	1.27	1.27	1.08	0.85	0.81	1.37	0.98	1.03	0.92	0.99	1.30	1.50	0.79	0.87	1.15	1.23
24	IDACORP, Inc.	1.09	0.75	1.00	1.33	1.33	1.46	1.42	1.33	1.16	1.15	1.21	1.34	1.24	0.86	0.78	0.96	0.82	0.64	0.89
25	MGE Energy	1.08	0.99	1.12	0.82	0.82	0.97	0.66	1.19	1.44	1.60	1.31	0.96	1.05	1.56	1.57	1.13	0.87	0.59	0.80
26	NextEra Energy, Inc.	0.61	0.50	0.55	0.58	0.58	0.67	0.56	0.53	0.63	0.71	0.77	0.68	0.39	0.58	0.69	0.60	0.63	0.56	0.73
27	NorthWestern Corp	1.00	0.72	0.75	0.84	0.84	1.13	1.23	1.21	1.13	1.01	0.93	0.92	0.88	1.04	0.76	0.88	1.27	1.23	1.29
28	OGE Energy	0.91	0.96	0.87	1.24	1.24	1.27	1.30	0.81	1.00	1.18	1.19	0.69	0.63	0.51	0.69	0.61	0.60	0.79	0.84
29	Otter Tail Corp.	0.97	1.98	2.13	0.48	0.48	0.80	1.49	1.10	0.84	0.74	0.70	0.67	0.85	1.16	1.09	0.56	0.37	0.65	1.44
30	Pinnacle West Capital	0.94	0.73	0.89	0.91	0.91	1.03	1.06	0.76	0.81	0.92	0.97	0.87	0.96	0.91	0.97	1.06	0.86	0.99	1.28
31	PNM Resources	0.70	0.55	0.63	0.72	0.72	0.78	0.82	0.84	0.57	0.57	0.63	0.80	0.87	0.77	0.82	0.70	0.44	0.43	0.89
32	Portland General	0.82	0.51	0.86	0.78	0.78	1.03	1.00	1.07	0.88	0.80	0.47	0.59	1.28	1.25	0.81	0.44	0.77	0.72	0.78
33	PPL Corp.	0.97	1.03	1.05	0.90	0.90	0.98	0.93	0.82	1.00	0.72	0.75	0.69	0.91	1.07	1.11	1.07	1.25	1.13	1.18
34	Public Serv. Enterprise	1.10	0.86	1.05	1.13	1.13	1.08	0.70	0.64	0.61	0.80	1.04	0.93	0.96	1.30	1.23	1.41	1.34	1.64	1.94
35	SCANA Corp.	0.86	N/A	N/A		N/A	N/A	N/A	0.86	0.66	0.83	0.90	0.83	0.77	0.88	0.86	0.76	0.76	0.92	1.26
36	Sempra Energy	0.80	0.61	0.92	0.77	0.77	0.88	0.80	0.67	0.56	0.81	0.74	0.84	0.73	0.72	0.90	1.02	0.87	0.90	0.93
37	Southern Co.	0.90	0.96	0.97	0.99	0.99	0.88	0.83	0.90	0.77	0.88	0.80	0.86	0.93	0.94	0.93	0.78	0.87	0.91	1.00
38	Vectren Corp.	1.00	N/A	N/A		N/A	N/A	N/A	0.82	0.87	0.95	0.98	1.05	1.13	1.20	1.31	0.83	0.82	0.98	1.00
39	WEC Energy Group	0.98	0.95	1.09	0.97	0.97	0.91	0.90	0.92	1.20	0.97	1.37	1.42	1.30	1.02	0.97	0.89	0.61	0.56	0.69
40	Westar Energy	0.72	N/A	N/A		N/A	N/A	N/A	0.91	0.63	0.86	0.70	0.72	0.67	0.71	0.88	0.68	0.36	0.48	1.00
41	Xcel Energy Inc.	0.76	0.75	0.93	0.66	0.66	0.78	0.77	0.84	0.79	0.63	0.68	0.60	0.76	0.83	0.76	0.89	0.75	0.71	0.90
42	Average	0.89	0.86	0.94	0.83	0.82	0.88	0.89	0.89	0.89	0.87	0.87	0.89	0.88	0.96	0.98	0.86	0.80	0.88	1.05
43	Median	0.83	0.81	0.87	0.81	0.79	0.83	0.83	0.84	0.85	0.83	0.83	0.86	0.87	0.98	0.90	0.81	0.78	0.81	1.00

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Notes:

[c] Based on the projected Cash Flow per share and Capital Spending per share
published in The Value Line Investment Survey, February 9, and March 8, April 19, 2024.

Columbia Gas of Pennsylvania

Natural Gas Utilities
(Valuation Metrics)

Price to Earnings (P/E) Ratio [1]

Line	Company	18-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
1	Atmos Energy	17.45	17.40	19.30	18.80	22.30	23.20	21.70	22.00	20.80	17.50	16.10	15.90	15.90	14.40	13.20	12.50	13.60	15.90	13.52
2	Chesapeake Utilities	19.34	20.80	25.80	25.60	21.60	24.70	22.90	27.80	22.30	19.10	17.70	15.60	14.80	14.20	12.20	14.20	14.20	16.70	17.85
3	New Jersey Resources	17.15	15.00	17.00	17.50	17.70	24.30	15.60	22.40	21.30	16.60	11.70	16.00	16.80	16.80	15.00	14.90	12.30	21.60	16.13
4	NiSource Inc.	21.99	15.40	19.60	18.00	18.70	21.30	19.30	64.40	23.20	37.30	22.70	18.90	17.90	19.40	15.30	14.30	12.10	18.80	19.16
5	Northwest Nat. Gas	20.53	13.80	19.60	19.50	25.00	30.90	26.60	NMF	26.90	23.70	20.70	19.40	21.10	19.00	17.00	15.20	18.10	16.70	15.85
6	ONE Gas Inc.	20.79	15.20	19.90	18.90	21.70	25.30	23.10	23.50	22.70	19.80	17.80	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Southwest Gas	17.40	15.40	NMF	14.30	16.80	21.30	20.60	22.20	21.60	19.40	17.90	15.80	15.00	15.70	14.00	12.20	20.30	17.30	15.94
8	Spire Inc.	18.33	14.50	17.50	13.60	51.10	22.80	16.70	19.80	19.60	16.50	19.80	21.30	14.50	13.00	13.70	13.40	14.30	14.20	13.60
9	UGI Corp.	15.29	8.30	14.10	13.90	13.80	23.40	17.80	20.80	19.30	17.70	15.80	15.40	16.40	15.00	10.90	10.30	13.30	15.10	13.97
10	Average	18.49	15.09	19.10	17.79	23.19	24.13	20.48	27.86	21.97	20.84	17.80	17.29	16.55	15.94	13.91	13.38	14.78	17.04	15.75
11	Median	17.25	15.20	19.45	18.00	21.60	23.40	20.60	22.30	21.60	19.10	17.80	15.95	16.15	15.35	13.85	13.80	13.90	16.70	15.89

Market Price to Cash Flow (MP/CF) Ratio [1]

Line	Company	18-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
12	Atmos Energy	9.33	11.27	11.87	10.99	13.11	13.35	12.02	11.99	11.36	9.30	8.79	7.72	7.02	6.87	6.15	5.76	6.48	7.44	6.36
13	Chesapeake Utilities	10.52	12.31	14.21	14.20	12.31	14.17	12.24	13.78	12.06	10.16	9.25	8.12	7.46	7.35	6.36	9.48	7.88	8.58	9.40
14	New Jersey Resources	11.93	11.22	11.55	11.56	11.10	15.98	11.44	14.45	13.94	11.71	8.95	11.29	12.29	12.71	11.32	11.34	9.15	13.76	11.01
15	NiSource Inc.	7.85	7.21	8.13	7.89	7.83	8.81	8.91	12.11	8.56	10.38	10.56	8.71	7.81	6.81	5.09	4.06	4.87	6.69	6.87
16	Northwest Nat. Gas	12.16	7.53	8.76	8.57	10.10	13.13	11.75	59.72	11.57	9.46	8.84	8.61	9.48	9.08	8.94	8.26	8.75	8.54	7.83
17	ONE Gas Inc.	10.27	7.68	9.91	9.32	10.85	12.75	11.85	11.89	11.10	9.19	8.16	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	Southwest Gas	7.19	6.66	19.83	6.87	7.05	8.92	9.32	9.10	7.41	6.56	6.35	5.94	5.55	5.60	4.91	3.84	4.89	5.42	5.28
19	Spire Inc.	9.60	7.53	8.34	7.55	14.01	11.27	9.60	10.39	10.32	8.47	12.03	13.76	8.80	8.08	8.12	8.58	8.95	8.46	8.46
20	UGI Corp.	7.87	5.84	7.20	9.56	7.39	12.95	9.01	10.09	9.02	8.47	7.49	6.55	6.30	7.51	6.02	5.74	7.11	7.92	7.48
21	Average	9.51	8.58	11.09	9.61	10.42	12.37	10.68	17.06	10.59	9.30	8.94	8.84	8.09	8.00	7.11	7.13	7.26	8.35	7.84
22	Median	8.60	7.53	9.91	9.32	10.85	12.95	11.44	11.99	11.10	9.30	8.84	8.37	7.64	7.43	6.26	7.01	7.50	8.19	7.65

Market Price to Book Value (MP/BV) Ratio [1]

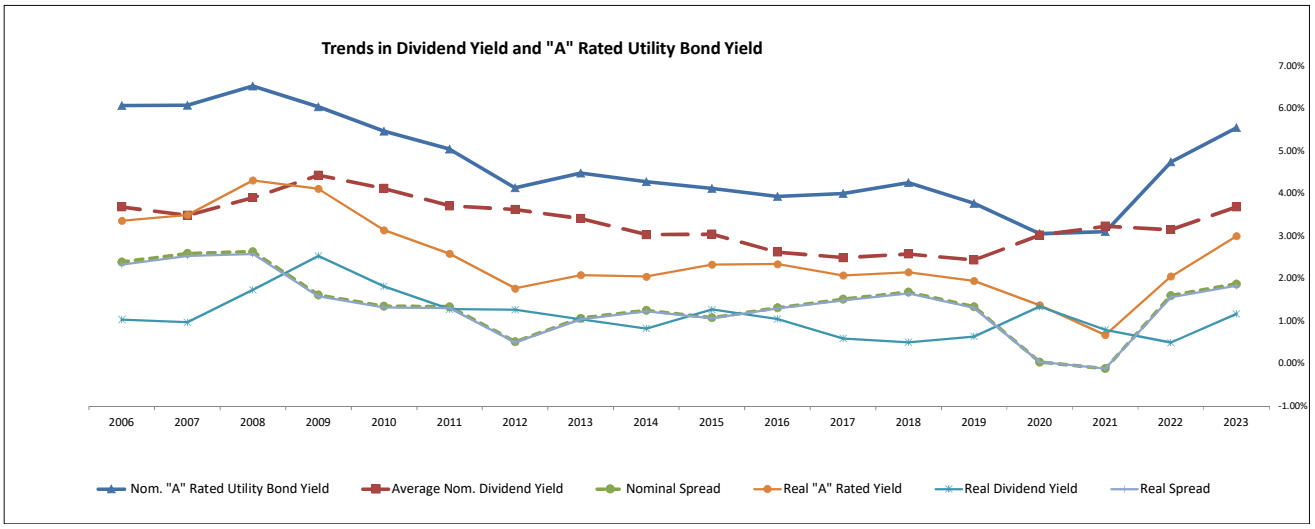
Line	Company	18-Year Average (1)	2023 [2] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
23	Atmos Energy	1.59	1.55	1.65	1.59	1.95	2.10	2.03	2.16	2.11	1.72	1.55	1.39	1.28	1.30	1.18	1.05	1.20	1.40	1.34
24	Chesapeake Utilities	2.08	2.20	2.69	2.77	2.27	2.69	2.50	2.51	2.28	2.19	2.12	1.83	1.66	1.61	1.40	1.37	1.64	1.84	1.85
25	New Jersey Resources	2.27	2.32	2.35	2.26	1.90	2.75	2.63	2.70	2.52	2.28	2.13	2.05	2.33	2.31	2.09	2.16	1.92	2.17	2.01
26	NiSource Inc.	1.55	1.33	2.15	1.86	1.95	2.09	1.92	1.96	1.84	1.95	1.94	1.58	1.37	1.15	0.92	0.69	0.94	1.16	1.19
27	Northwest Nat. Gas	1.82	1.39	1.51	1.45	1.98	2.38	2.35	2.41	1.92	1.63	1.59	1.56	1.72	1.70	1.78	1.73	1.96	2.05	1.69
28	ONE Gas Inc.	1.67	1.49	1.73	1.57	1.90	2.20	1.93	1.89	1.67	1.26	1.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Southwest Gas	1.53	1.22	1.62	1.32	1.49	1.84	1.79	2.13	1.96	1.68	1.68	1.61	1.51	1.43	1.24	0.97	1.20	1.46	1.46
30	Spire Inc.	1.54	1.29	1.43	1.47	1.67	1.78	1.63	1.65	1.64	1.44	1.33	1.34	1.51	1.46	1.39	1.68	1.71	1.66	1.71
31	UGI Corp.	1.97	1.59	1.39	1.64	1.87	2.92	2.30	2.62	2.41	2.29	1.97	1.69	1.45	1.75	1.55	1.66	2.01	2.16	2.21
32	Average	1.78	1.60	1.83	1.77	1.89	2.30	2.12	2.23	2.04	1.83	1.71	1.63	1.60	1.59	1.44	1.41	1.57	1.74	1.68
33	Median	1.68	1.49	1.65	1.59	1.90	2.20	2.03	2.16	1.96	1.72	1.68	1.59	1.51	1.54	1.40	1.51	1.67	1.75	1.70

Sources:
The current year P/E ratio is based on the forward P/E (price over expected earnings per share). All historical year P/E ratios are based on annual average share price over achieved earnings per share.
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, February 23, 2024.
Notes:
[a] Based on the average of the high and low price for year and the projected Cash Flow per share, published in The Value Line Investment Survey.
[b] Based on the average of the high and low price for the year and the projected Book Value per share, published in The Value Line Investment Survey.

Columbia Gas of Pennsylvania

Natural Gas Utilities
(Valuation Metrics)

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
		Dividend Yield[1]																		
1	Atmos Energy	3.35%	2.62%	2.46%	2.63%	2.19%	2.08%	2.23%	2.27%	2.39%	2.88%	3.11%	3.53%	4.13%	4.19%	4.70%	5.34%	4.78%	4.16%	4.66%
2	Chesapeake Utilities	2.65%	2.08%	1.61%	1.50%	1.86%	1.68%	1.76%	1.69%	1.91%	2.18%	2.44%	2.87%	3.25%	3.36%	3.91%	4.09%	4.10%	3.62%	3.76%
3	New Jersey Resources	3.22%	3.29%	3.25%	3.50%	3.47%	2.50%	2.61%	2.69%	2.86%	3.14%	3.50%	3.71%	3.38%	3.33%	3.69%	3.46%	3.35%	3.02%	3.19%
4	NiSource Inc.	3.95%	3.85%	3.33%	3.60%	3.41%	2.86%	3.10%	2.79%	2.76%	3.53%	2.69%	3.30%	3.84%	4.53%	5.66%	7.64%	5.69%	4.29%	4.21%
5	Northwest Nat. Gas	3.62%	4.40%	3.86%	3.90%	3.33%	2.81%	3.05%	3.02%	3.28%	4.01%	4.14%	4.22%	3.83%	3.85%	3.63%	3.73%	3.27%	3.12%	3.73%
6	ONE Gas Inc.	2.71%	3.72%	3.08%	3.21%	2.70%	2.25%	2.46%	2.37%	2.32%	2.71%	2.28%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Southwest Gas	3.00%	4.07%	3.20%	3.65%	3.28%	2.60%	2.74%	2.46%	2.62%	2.87%	2.72%	2.69%	2.75%	2.78%	3.15%	4.01%	3.19%	2.56%	2.60%
8	Spire Inc.	3.82%	4.44%	3.89%	3.79%	3.38%	2.95%	3.10%	3.09%	3.08%	3.53%	3.78%	3.96%	4.11%	4.31%	4.70%	3.91%	3.94%	4.43%	4.34%
9	UGI Corp.	3.00%	4.64%	3.61%	3.25%	3.56%	2.16%	2.09%	2.01%	2.35%	2.50%	2.61%	3.01%	3.68%	3.30%	3.48%	3.23%	2.85%	2.69%	2.96%
10	**Average**	**3.31%**	**3.68%**	**3.14%**	**3.23%**	**3.02%**	**2.43%**	**2.57%**	**2.49%**	**2.62%**	**3.04%**	**3.03%**	**3.41%**	**3.62%**	**3.71%**	**4.12%**	**4.43%**	**3.90%**	**3.48%**	**3.68%**
11	Median	3.39%	3.85%	3.25%	3.50%	3.33%	2.50%	2.61%	2.46%	2.62%	2.88%	2.72%	3.42%	3.75%	3.60%	3.80%	3.96%	3.65%	3.37%	3.75%
12	20-Yr Treasury Yields[3]	3.25%	4.25%	3.30%	1.98%	1.35%	2.40%	3.02%	2.65%	2.23%	2.55%	3.07%	3.12%	2.54%	3.62%	4.03%	4.11%	4.36%	4.91%	4.99%
13	20-Yr TIPS[3]	1.07%	1.73%	0.64%	-0.43%	-0.30%	0.60%	0.94%	0.75%	0.66%	0.78%	0.87%	0.75%	0.21%	1.19%	1.73%	2.21%	2.19%	2.36%	2.31%
14	Implied Inflation[b]	2.16%	2.48%	2.64%	2.42%	1.66%	1.79%	2.06%	1.89%	1.56%	1.75%	2.19%	2.35%	2.33%	2.40%	2.26%	1.85%	2.13%	2.49%	2.62%
15	**Real Dividend Yield[c]**	**1.13%**	**1.17%**	**0.49%**	**0.79%**	**1.33%**	**0.63%**	**0.50%**	**0.58%**	**1.05%**	**1.27%**	**0.82%**	**1.04%**	**1.27%**	**1.27%**	**1.82%**	**2.53%**	**1.73%**	**0.97%**	**1.03%**
	Utility																			
16	**Nominal "A" Rated Yield[4]**	**4.70%**	**5.55%**	**4.74%**	**3.10%**	**3.05%**	**3.77%**	**4.25%**	**4.00%**	**3.93%**	**4.12%**	**4.28%**	**4.48%**	**4.13%**	**5.04%**	**5.46%**	**6.04%**	**6.53%**	**6.07%**	**6.07%**
17	**Real "A" Rated Yield**	**2.49%**	**2.99%**	**2.05%**	**0.67%**	**1.37%**	**1.94%**	**2.14%**	**2.07%**	**2.34%**	**2.33%**	**2.04%**	**2.08%**	**1.76%**	**2.58%**	**3.13%**	**4.11%**	**4.31%**	**3.49%**	**3.36%**
	Spreads (Utility Bond - Stock)																			
18	**Nominal[d]**	**1.39%**	**1.87%**	**1.60%**	**-0.12%**	**0.03%**	**1.33%**	**1.68%**	**1.51%**	**1.31%**	**1.08%**	**1.25%**	**1.06%**	**0.51%**	**1.33%**	**1.35%**	**1.61%**	**2.63%**	**2.59%**	**2.39%**
19	**Real[e]**	**1.36%**	**1.82%**	**1.56%**	**-0.12%**	**0.03%**	**1.31%**	**1.64%**	**1.48%**	**1.29%**	**1.06%**	**1.22%**	**1.04%**	**0.50%**	**1.30%**	**1.32%**	**1.58%**	**2.58%**	**2.53%**	**2.33%**
	Spreads (Treasury Bond - Stock)																			
20	**Nominal[f]**	**-0.06%**	**0.57%**	**0.16%**	**-1.25%**	**-1.67%**	**-0.03%**	**0.45%**	**0.17%**	**-0.39%**	**-0.49%**	**0.05%**	**-0.29%**	**-1.08%**	**-0.09%**	**-0.09%**	**-0.32%**	**0.46%**	**1.42%**	**1.31%**
21	**Real[g]**	**-0.06%**	**0.56%**	**0.15%**	**-1.22%**	**-1.64%**	**-0.03%**	**0.44%**	**0.16%**	**-0.39%**	**-0.48%**	**0.04%**	**-0.29%**	**-1.05%**	**-0.08%**	**-0.08%**	**-0.31%**	**0.46%**	**1.39%**	**1.28%**



Sources:
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, February 23, 2024.
[3] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[4] www.moodys.com, Bond Yields and Key Indicators, through December 31, 2023.

Notes:
[a] Based on the average of the high and low price for the year and the projected Dividends Declared per share published in the Value Line Investment Survey.
[b] Line 16 = (1 + Line 14) / (1 + Line 15) - 1.
[c] Line 17 = (1 + Line 12) / (1 +Line 16) - 1.
[d] The spread being measured here is the nominal A-rated utility bond yield over the average nominal utility dividend yield; (Line 18 - Line 12).
[e] The spread being measured here is the real A-rated utility bond yield over the average real utility dividend yield; Line 19 - Line 17)
[f] The spread being measured here is the nominal 20-Year Treasury yield over the average nominal utility dividend yield; (Line 14 - Line 12).
[g] The spread being measured here is the real 20-Year TIPS yield over the average real utility dividend yield; Line 15 - Line 17)

Columbia Gas of Pennsylvania

Natural Gas Utilities
(Valuation Metrics)

		Dividend per Share[1]																				
Line	Company	18-Year Average	2023 [2]	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006	2018 CAGR	2017 CAGR
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
1	Atmos Energy	1.76	2.96	2.72	2.50	2.30	2.10	1.94	1.80	1.68	1.56	1.48	1.40	1.38	1.36	1.34	1.32	1.30	1.28	1.26	2.16%	2.25%
2	Chesapeake Utilities	1.24	2.25	2.03	1.84	1.69	1.55	1.39	1.26	1.19	1.12	1.07	1.01	0.96	0.91	0.87	0.83	0.81	0.78	0.77	2.97%	3.13%
3	New Jersey Resources	0.94	1.56	1.45	1.36	1.27	1.19	1.11	1.04	0.98	0.93	0.86	0.81	0.77	0.72	0.68	0.62	0.56	0.51	0.48	4.26%	4.95%
4	NiSource Inc.	0.88	1.00	0.94	0.88	0.84	0.80	0.78	0.70	0.64	0.83	1.02	0.98	0.94	0.92	0.92	0.92	0.92	0.92	0.92	-0.82%	-1.69%
5	Northwest Nat. Gas	1.78	1.94	1.93	1.92	1.91	1.90	1.89	1.88	1.87	1.86	1.85	1.83	1.79	1.75	1.68	1.60	1.52	1.44	1.39	1.54%	1.91%
6	ONE Gas Inc.	1.85	2.60	2.48	2.32	2.16	2.00	1.84	1.68	1.40	1.20	0.84	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6.66%	9.05%
7	Southwest Gas	1.60	2.48	2.48	2.38	2.28	2.18	2.08	1.98	1.80	1.62	1.46	1.32	1.18	1.06	1.00	0.95	0.90	0.86	0.82	4.73%	5.66%
8	Spire Inc.	1.97	2.88	2.74	2.60	2.49	2.37	2.25	2.10	1.96	1.84	1.76	1.70	1.66	1.61	1.57	1.53	1.49	1.45	1.40	2.38%	2.57%
9	UGI Corp.	0.89	1.47	1.41	1.35	1.31	1.15	1.02	0.96	0.93	0.89	0.79	0.74	0.71	0.68	0.60	0.52	0.50	0.48	0.46	4.09%	4.78%
10	**Average**	**1.39**	**2.13**	**2.02**	**1.91**	**1.81**	**1.69**	**1.59**	**1.49**	**1.38**	**1.32**	**1.24**	**1.22**	**1.17**	**1.13**	**1.08**	**1.04**	**1.00**	**0.97**	**0.94**	**3.11%**	**3.62%**
11	**Industry Average Growth**	**4.95%**	**5.28%**	**6.01%**	**5.54%**	**6.63%**	**6.56%**	**6.73%**	**7.63%**	**5.06%**	**6.54%**	**0.96%**	**4.33%**	**4.18%**	**4.04%**	**4.39%**	**3.76%**	**3.55%**	**3.02%**			

Sources:
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, February 23, 2024.

Columbia Gas of Pennsylvania

Natural Gas Utilities
(Valuation Metrics)

		Earnings per Share[1]																		
Line	Company	18-Year Average	2023 [2]	2022	2021	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008	2007	2006
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	Atmos Energy	3.33	6.10	5.60	5.12	4.72	4.35	4.00	3.60	3.38	3.09	2.96	2.50	2.10	2.26	2.16	1.97	2.00	1.94	2.00
2	Chesapeake Utilities	2.77	4.85	4.97	4.70	4.21	3.72	3.45	2.68	2.86	2.68	2.47	2.26	1.99	1.91	1.82	1.43	1.39	1.29	1.15
3	New Jersey Resources	1.71	2.70	2.50	2.16	2.07	1.96	2.72	1.73	1.61	1.78	2.08	1.37	1.36	1.29	1.23	1.20	1.35	0.78	0.93
4	NiSource Inc.	1.20	1.60	1.47	1.35	1.32	1.31	1.30	0.39	1.00	0.63	1.67	1.57	1.37	1.05	1.06	0.84	1.34	1.14	1.14
5	Northwest Nat. Gas	2.16	2.65	2.54	2.50	2.30	2.19	2.33	-1.94	2.12	1.96	2.16	2.24	2.22	2.39	2.73	2.83	2.57	2.76	2.35
6	ONE Gas Inc.	3.25	4.15	4.08	3.85	3.68	3.51	3.25	3.02	2.65	2.24	2.07	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Southwest Gas	2.90	2.85	3.10	3.80	4.14	3.94	3.68	3.62	3.18	2.92	3.01	3.11	2.86	2.43	2.27	1.94	1.39	1.95	1.98
8	Spire Inc.	3.03	3.85	3.95	4.96	1.44	3.52	4.33	3.43	3.24	3.16	2.35	2.02	2.79	2.86	2.43	2.92	2.64	2.31	2.37
9	UGI Corp.	1.98	2.84	2.90	2.96	2.67	2.28	2.74	2.29	2.05	2.01	1.92	1.59	1.17	1.37	1.59	1.57	1.33	1.18	1.10
10	**Average**	**2.41**	**3.51**	**3.46**	**3.49**	**2.95**	**2.98**	**3.09**	**2.09**	**2.45**	**2.27**	**2.30**	**2.08**	**1.98**	**1.95**	**1.91**	**1.84**	**1.75**	**1.67**	**1.63**
11	**Industry Average Growth**	**5.27%**	**1.54%**	**-0.92%**	**18.27%**	**-0.86%**	**-3.67%**	**47.72%**	**-14.80%**	**7.91%**	**-1.06%**	**10.40%**	**5.02%**	**1.90%**	**1.83%**	**3.95%**	**4.98%**	**4.94%**	**2.53%**	

Sources:

[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.

[2] The Value Line Investment Survey, February 23, 2024.

Columbia Gas of Pennsylvania

Natural Gas Utilities
(Valuation Metrics)

		Cash Flow / Capital Spending[1]						
Line	Company	2019 (1)	2020 (2)	2021 (3)	2022 (4)	2023 (5)	2024[2] (6)	3 - 5 yr[2] Projection (7)
1	Atmos Energy	0.53x	0.53x	0.53x	0.54x	0.54x	0.57x	0.68x
2	Chesapeake Utilities	0.66x	0.64x	0.82x	1.23x	0.84x	0.81x	0.96x
3	New Jersey Resources	1.41x	0.65x	0.72x	0.59x	0.68x	0.85x	0.84x
4	NiSource Inc.	0.66x	0.65x	0.69x	0.55x	0.43x	0.54x	0.63x
5	Northwest Nat. Gas	0.77x	0.75x	0.61x	0.60x	0.68x	0.66x	0.76x
6	ONE Gas Inc.	0.78x	0.88x	0.86x	0.74x	0.83x	0.82x	1.11x
7	Southwest Gas	0.62x	0.53x	0.61x	0.31x	0.84x	0.75x	0.79x
8	Spire Inc.	0.65x	0.65x	0.70x	0.80x	0.71x	0.66x	0.76x
9	UGI Corp.	1.33x	1.54x	1.66x	1.42x	1.33x	1.24x	1.20x
10	Average	0.82x	0.76x	0.80x	0.75x	0.76x	0.77x	0.86x
11	Median	0.66x	0.65x	0.70x	0.60x	0.71x	0.75x	0.79x

Sources:

[1] The Value Line Investment Survey, various report dates.

[2] The Value Line Investment Survey, February 23, 2024.

Notes:

Based on the projected Cash Flow per share and Capital Spending per share.

Columbia Gas of Pennsylvania

Natural Gas Utilities
(Valuation Metrics)

Percent Dividends to Book Value [1]

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
1	Atmos Energy	4.99%	4.04%	4.07%	4.19%	4.26%	4.36%	4.53%	4.90%	5.04%	4.96%	4.81%	4.92%	5.28%	5.44%	5.55%	5.61%	5.75%	5.82%	6.25%
2	Chesapeake Utilities	5.12%	4.56%	4.32%	4.15%	4.23%	4.53%	4.39%	4.23%	4.35%	4.78%	5.18%	5.25%	5.39%	5.42%	5.49%	5.60%	6.71%	6.66%	6.95%
3	New Jersey Resources	7.24%	7.65%	7.63%	7.92%	6.60%	6.85%	6.87%	7.26%	7.21%	7.16%	7.45%	7.60%	7.86%	7.69%	7.72%	7.48%	6.42%	6.54%	6.40%
4	NiSource Inc.	5.65%	5.14%	7.15%	6.69%	6.64%	5.99%	5.96%	5.46%	5.08%	6.89%	5.22%	5.22%	5.25%	5.19%	5.22%	5.25%	5.34%	4.97%	5.02%
5	Northwest Nat. Gas	6.47%	6.12%	5.83%	5.66%	6.57%	6.69%	7.16%	7.27%	6.30%	6.53%	6.58%	6.59%	6.57%	6.55%	6.44%	6.43%	6.41%	6.39%	6.32%
6	ONE Gas Inc.	4.49%	5.53%	5.31%	5.04%	5.14%	4.96%	4.73%	4.48%	3.88%	3.41%	2.44%	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	Southwest Gas	4.49%	4.96%	5.17%	4.80%	4.87%	4.79%	4.90%	5.25%	5.14%	4.82%	4.57%	4.33%	4.16%	3.98%	3.90%	3.89%	3.83%	3.74%	3.80%
8	Spire Inc.	5.86%	5.73%	5.58%	5.56%	5.63%	5.25%	5.06%	5.09%	5.06%	5.07%	5.04%	5.31%	6.22%	6.30%	6.53%	6.56%	6.74%	7.33%	7.43%
9	UGI Corp.	5.68%	7.35%	5.02%	5.34%	6.65%	6.30%	4.82%	5.28%	5.65%	5.72%	5.14%	5.07%	5.35%	5.77%	5.41%	5.35%	5.72%	5.82%	6.54%
10	Average	5.62%	5.68%	5.57%	5.48%	5.62%	5.52%	5.38%	5.47%	5.30%	5.48%	5.16%	5.54%	5.76%	5.79%	5.78%	5.77%	5.86%	5.91%	6.09%
11	Median	5.36%	5.53%	5.31%	5.34%	5.63%	5.25%	4.90%	5.25%	5.08%	5.07%	5.14%	5.24%	5.37%	5.61%	5.52%	5.60%	6.08%	6.11%	6.36%

Dividends to Earnings Ratio [1]

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
12	Atmos Energy	0.55	0.49	0.49	0.49	0.49	0.48	0.49	0.50	0.50	0.50	0.50	0.56	0.66	0.60	0.62	0.67	0.65	0.66	0.63
13	Chesapeake Utilities	0.47	0.46	0.41	0.39	0.40	0.42	0.40	0.47	0.42	0.42	0.43	0.45	0.48	0.48	0.48	0.58	0.58	0.61	0.67
14	New Jersey Resources	0.55	0.58	0.58	0.63	0.61	0.61	0.41	0.60	0.61	0.52	0.41	0.59	0.57	0.56	0.55	0.52	0.41	0.65	0.51
15	NiSource Inc.	0.81	0.63	0.64	0.65	0.64	0.61	0.60	1.79	0.64	1.32	0.61	0.62	0.69	0.88	0.87	1.10	0.69	0.81	0.81
16	Northwest Nat. Gas	0.65	0.73	0.76	0.77	0.83	0.87	0.81	- 0.97	0.88	0.95	0.86	0.82	0.81	0.73	0.62	0.57	0.59	0.52	0.59
17	ONE Gas Inc.	0.56	0.63	0.61	0.60	0.59	0.57	0.57	0.56	0.53	0.54	0.41	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	Southwest Gas	0.55	0.87	0.80	0.63	0.55	0.55	0.57	0.55	0.57	0.55	0.49	0.42	0.41	0.44	0.44	0.49	0.65	0.44	0.41
19	Spire Inc.	0.69	0.75	0.69	0.52	1.73	0.67	0.52	0.61	0.60	0.58	0.75	0.84	0.59	0.56	0.65	0.52	0.56	0.63	0.59
20	UGI Corp.	0.45	0.52	0.49	0.46	0.49	0.50	0.37	0.42	0.45	0.44	0.41	0.46	0.60	0.50	0.38	0.33	0.38	0.41	0.41
21	Average	0.59	0.63	0.61	0.57	0.70	0.59	0.53	0.50	0.58	0.65	0.54	0.60	0.60	0.59	0.57	0.60	0.56	0.59	0.58
22	Median	0.58	0.63	0.61	0.60	0.59	0.57	0.52	0.55	0.57	0.54	0.49	0.58	0.60	0.56	0.58	0.54	0.59	0.62	0.59

Cash Flow to Capital Spending Ratio [1]

Line	Company	18-Year Average (1)	2023 [2/a] (2)	2022 (3)	2021 (4)	2020 (5)	2019 (6)	2018 (7)	2017 (8)	2016 (9)	2015 (10)	2014 (11)	2013 (12)	2012 (13)	2011 (14)	2010 (15)	2009 (16)	2008 (17)	2007 (18)	2006 (19)
23	Atmos Energy	0.65	0.53	0.54	0.58	0.52	0.53	0.55	0.62	0.59	0.60	0.65	0.55	0.59	0.68	0.77	0.78	0.81	0.94	0.82
24	Chesapeake Utilities	0.77	0.81	1.23	0.81	0.78	0.62	0.39	0.50	0.50	0.53	0.71	0.65	0.79	1.12	1.10	1.14	0.83	0.82	0.45
25	New Jersey Resources	1.20	0.82	0.59	0.62	0.71	0.51	0.85	0.70	0.59	0.67	1.79	1.46	1.48	1.51	1.55	1.75	2.11	1.67	2.14
26	NiSource Inc.	0.73	0.45	0.55	0.68	0.66	0.61	0.58	0.41	0.59	0.53	0.56	0.57	0.65	0.75	1.11	1.06	0.94	1.11	1.37
27	Northwest Nat. Gas	0.90	0.65	0.60	0.68	0.66	0.69	0.71	0.14	1.01	1.12	1.15	0.98	1.01	1.33	0.55	1.02	1.35	1.21	1.34
28	ONE Gas Inc.	0.84	0.77	0.74	0.86	0.83	0.89	0.84	0.87	0.92	0.86	0.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29	Southwest Gas	0.82	0.71	0.31	0.86	0.69	0.53	0.56	0.68	0.83	0.84	0.99	1.05	0.90	0.82	1.37	1.28	0.85	0.78	0.72
30	Spire Inc.	1.03	0.69	0.80	0.75	0.42	0.44	0.77	0.72	0.96	0.92	0.98	0.78	0.95	1.53	1.61	1.93	1.64	1.42	1.28
31	UGI Corp.	1.45	1.18	1.42	1.32	1.59	1.22	1.64	1.29	1.35	1.48	1.53	1.32	1.52	1.28	1.36	1.52	1.72	1.62	1.69
32	Average	0.95	0.74	0.75	0.80	0.76	0.67	0.77	0.66	0.82	0.84	1.02	0.92	0.98	1.13	1.18	1.31	1.28	1.20	1.23
33	Median	0.86	0.71	0.60	0.75	0.69	0.61	0.71	0.68	0.83	0.84	0.98	0.88	0.93	1.20	1.23	1.21	1.15	1.16	1.31

Sources:
[1] Data for years 2019 and prior were retrieved from the Value Line Investment Survey Investment Analyzer Software, downloaded on June 18, 2021.
Data for the years 2020 - 2022 was retrieved from Value Line Investment Surveys.
[2] The Value Line Investment Survey, February 23, 2024.
Notes:
[a] Based on the projected Dividends Declared per share and Book Value per share, published in The Value Line Investment Survey.
[b] Based on the projected Dividends Declared per share and Earnings per share, published in The Value Line Investment Survey.
[c] Based on the projected Cash Flow per share and Capital Spending per share, published in The Value Line Investment Survey.

Columbia Gas of Pennsylvania

Proxy Group

Line	Company	Credit Ratings[1] S&P (1)	Credit Ratings[1] Moody's (2)	Common Equity Ratios MI[1] (3)	Common Equity Ratios Value Line[2] (4)
1	Atmos Energy Corporation	A-	A1	52.9%	62.1%
2	New Jersey Resources Corporation	N/A	A1	36.8%	42.2%
3	Northwest Natural Holding Company	A	Baa1	41.2%	48.5%
4	ONE Gas, Inc.	A-	A3	44.2%	49.3%
5	Southwest Gas Holdings, Inc.	BBB-	Baa2	32.7%	42.2%
6	Spire Inc.	A-	Baa2	35.8%	44.6%
7	Eversource Energy	A-	Baa2	40.0%	43.3%
8	American States Water Company	A	N/A	48.9%	60.1%
9	American Water Works Company, Inc.	A	Baa1	0.0%	41.3%
10	California Water Service Group	A+	N/A	53.9%	55.6%
11	Middlesex Water Company	A	N/A	52.4%	57.7%
12	SJW Group	A-	N/A	39.8%	42.7%
13	Essential Utilities, Inc.	A-	Baa2	43.9%	45.8%
14	**Gas Average**	**A-**	**A3**	**40.6%**	**48.2%**
15	**Gas Median**			**39.0%**	**46.6%**
16	**Total Average**	**A-**	**Baa1**	**40.2%**	**48.9%**
17	**Total Median**			**41.2%**	**45.8%**
18	**Columbia Gas of PA.[3,4]**	**BBB+**	**Baa2**		**54.4%**

Sources:

Note: If credit rating/common equity ratio unavailable for utility, subsidary data used.

[1] S&P Global Market Intelligence, Downloaded on April 26, 2024.

[2] *The Value Line Investment Survey*, February 9, February 23, and April 5, 2024.

[3] Paul R Moul Direct Testimony, page 13.

[4] Paul R Moul Direct Testimony, page 2.

Columbia Gas of Pennsylvania

Consensus Analysts' Growth Rates

Line	Company	Zacks		MI		Yahoo! Finance		Average of Growth Rates
		Estimated Growth %[1]	Number of Estimates	Estimated Growth %[2]	Number of Estimates	Estimated Growth %[3]	Number of Estimates	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Atmos Energy Corporation	7.00%	N/A	7.00%	1	7.50%	N/A	7.17%
2	New Jersey Resources Corporation	N/A	N/A	5.87%	3	6.00%	N/A	5.93%
3	Northwest Natural Holding Company	N/A	N/A	5.30%	4	2.80%	N/A	4.05%
4	ONE Gas, Inc.	5.00%	N/A	3.00%	2	5.00%	N/A	4.33%
5	Southwest Gas Holdings, Inc.	6.00%	N/A	6.30%	1	4.00%	N/A	5.43%
6	Spire Inc.	5.00%	N/A	6.50%	2	6.36%	N/A	5.95%
7	Eversource Energy	4.16%	N/A	5.11%	6	3.25%	N/A	4.17%
8	American States Water Company	6.30%	N/A	14.00%	1	4.40%	N/A	8.23%
9	American Water Works Company, Inc.	8.00%	N/A	7.75%	4	7.50%	N/A	7.75%
10	California Water Service Group	N/A	N/A	8.00%	1	10.80%	N/A	9.40%
11	Middlesex Water Company	N/A	N/A	N/A	NA	2.70%	N/A	2.70%
12	SJW Group	7.50%	N/A	7.00%	1	7.50%	N/A	7.33%
13	Essential Utilities, Inc.	5.75%	N/A	6.40%	3	5.20%	N/A	5.78%
14	**Gas Average**	**5.75%**	**N/A**	**5.66%**	**2**	**5.28%**	**N/A**	**5.48%**
15	**Gas Median**							**5.68%**
16	**Total Average**	**6.08%**	**N/A**	**6.85%**	**2**	**5.62%**	**N/A**	**6.02%**
17	**Total Median**							**5.93%**

Sources:

[1] Zacks, http://www.zacks.com/, downloaded on April 26, 2024.

[2] S&P Global Market Intelligence, https://platform.mi.spglobal.com, downloaded on April 26, 2024.

[3] Yahoo! Finance, http://www.finance.yahoo.com/, downloaded on April 26, 2024.

Columbia Gas of Pennsylvania

Constant Growth DCF Model
(Consensus Analysts' Growth Rates)

Line	Company	13-Week AVG Stock Price[1] (1)	Analysts' Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Atmos Energy Corporation	$114.80	7.17%	$3.22	3.01%	10.17%
2	New Jersey Resources Corporation	$41.96	5.93%	$1.68	4.24%	10.18%
3	Northwest Natural Holding Company	$36.81	4.05%	$1.95	5.52%	9.57%
4	ONE Gas, Inc.	$61.82	4.33%	$2.64	4.46%	8.79%
5	Southwest Gas Holdings, Inc.	$68.47	5.43%	$2.48	3.82%	9.25%
6	Spire Inc.	$59.53	5.95%	$3.02	5.38%	11.33%
7	Eversource Energy	$57.99	4.17%	$2.70	4.85%	9.02%
8	American States Water Company	$72.04	8.23%	$1.72	2.58%	10.82%
9	American Water Works Company, Inc.	$119.97	7.75%	$2.83	2.54%	10.29%
10	California Water Service Group	$46.15	9.40%	$1.12	2.65%	12.05%
11	Middlesex Water Company	$51.75	2.70%	$1.30	2.58%	5.28%
12	SJW Group	$56.61	7.33%	$1.60	3.03%	10.37%
13	Essential Utilities, Inc.	$35.69	5.78%	$1.23	3.64%	9.42%
14	**Gas Average**	**$63.90**	**5.48%**	**$2.50**	**4.40%**	**9.88%**
15	**Gas Median**					**9.87%**
16	**Total Average**	**$63.35**	**6.02%**	**$2.11**	**3.72%**	**9.73%**
17	**Total Median**					**10.17%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on April 26, 2024.
[2] Exhibit CCW-3
[3] *The Value Line Investment Survey*, February 9, February 23, and April 5, 2024..

Columbia Gas of Pennsylvania

Payout Ratios

Line	Company	Dividends Per Share		Earnings Per Share		Payout Ratio	
		2022	Projected	2022	Projected	2022	Projected
		(1)	(2)	(3)	(4)	(5)	(6)
1	Atmos Energy Corporation	$2.72	$4.25	$5.60	$8.35	48.57%	50.90%
2	New Jersey Resources Corporation	$1.45	$1.95	$2.50	$3.50	58.00%	55.71%
3	Northwest Natural Holding Company	$1.93	$1.98	$2.54	$3.25	75.98%	60.92%
4	ONE Gas, Inc.	$2.48	$2.85	$4.08	$5.00	60.78%	57.00%
5	Southwest Gas Holdings, Inc.	$2.48	$2.60	$3.10	$4.25	80.00%	61.18%
6	Spire Inc.	$2.74	$3.60	$3.95	$5.50	69.37%	65.45%
7	Eversource Energy	$2.55	$3.50	$4.09	$5.65	62.35%	61.95%
8	American States Water Company	$1.53	$2.50	$2.11	$3.90	72.51%	64.10%
9	American Water Works Company, Inc.	$2.57	$4.10	$4.51	$7.00	56.98%	58.57%
10	California Water Service Group	$1.00	$1.40	$1.77	$2.75	56.50%	50.91%
11	Middlesex Water Company	$1.18	$1.60	$2.39	$3.00	49.37%	53.33%
12	SJW Group	$1.44	$1.85	$2.43	$3.45	59.26%	53.62%
13	Essential Utilities, Inc.	$1.11	$1.75	$1.77	$2.65	62.71%	66.04%
14	**Gas Average**	**$2.30**	**$2.87**	**$3.63**	**$4.98**	**$0.65**	**58.53%**
15	**Total Average**	**$1.94**	**$2.61**	**$3.14**	**$4.48**	**62.49%**	**58.44%**

Source:
The Value Line Investment Survey, February 9, February 23, and April 5, 2024.

Columbia Gas of Pennsylvania

Sustainable Growth Rate

Line	Company	3 to 5 Year Projections: Dividends Per Share (1)	Earnings Per Share (2)	Book Value Per Share (3)	Book Value Growth (4)	ROE (5)	Adjustment Factor (6)	Adjusted ROE (7)	Payout Ratio (8)	Retention Rate (9)	Internal Growth Rate (10)	Sustainable Growth Rate (11)
1	Atmos Energy Corporation	$4.25	$8.35	$83.50	3.78%	10.00%	1.02	10.19%	50.90%	49.10%	5.00%	7.64%
2	New Jersey Resources Corporation	$1.95	$3.50	$27.00	6.03%	12.96%	1.03	13.34%	55.71%	44.29%	5.91%	6.81%
3	Northwest Natural Holding Company	$1.98	$3.25	$38.70	2.65%	8.40%	1.01	8.51%	60.92%	39.08%	3.32%	3.64%
4	ONE Gas, Inc.	$2.85	$5.00	$60.20	4.33%	8.31%	1.02	8.48%	57.00%	43.00%	3.65%	3.81%
5	Southwest Gas Holdings, Inc.	$2.60	$4.25	$55.50	2.47%	7.66%	1.01	7.75%	61.18%	38.82%	3.01%	4.05%
6	Spire Inc.	$3.60	$5.50	$66.05	5.07%	8.33%	1.02	8.53%	65.45%	34.55%	2.95%	3.55%
7	Eversource Energy	$3.50	$5.65	$52.75	2.91%	10.71%	1.01	10.86%	61.95%	38.05%	4.13%	4.30%
8	American States Water Company	$2.50	$3.90	$31.75	8.74%	12.28%	1.04	12.80%	64.10%	35.90%	4.59%	5.26%
9	American Water Works Company, Inc.	$4.10	$7.00	$62.75	- 0.02%	11.16%	1.00	11.15%	58.57%	41.43%	4.62%	4.62%
10	California Water Service Group	$1.40	$2.75	$30.90	- 0.01%	8.90%	1.00	8.90%	50.91%	49.09%	4.37%	4.37%
11	Middlesex Water Company	$1.60	$3.00	$23.70	- 0.00%	12.66%	1.00	12.66%	53.33%	46.67%	5.91%	5.91%
12	SJW Group	$1.85	$3.45	$44.15	- 0.01%	7.81%	1.00	7.81%	53.62%	46.38%	3.62%	3.62%
13	Essential Utilities, Inc.	$1.75	$2.65	$27.25	- 0.01%	9.72%	1.00	9.72%	66.04%	33.96%	3.30%	3.30%
14	**Gas Average**	**$2.87**	**$4.98**	**$55.16**	**4.05%**	**9.28%**	**1.02**	**9.47%**	**58.53%**	**41.47%**	**3.97%**	**4.92%**
15	**Gas Median**											**3.93%**
16	**Total Average**	**$2.61**	**$4.48**	**$46.48**	**2.76%**	**9.92%**	**1.01**	**10.05%**	**58.44%**	**41.56%**	**4.18%**	**4.68%**
17	**Total Median**											**4.30%**

Sources and Notes:
Cols. (1), (2) and (3): *The Value Line Investment Survey*, February 9, February 23, and April 5, 2024.
Col. (4): [Col. (3) / Page 2 Col. (2)] ^ (1/number of years projected) - 1.
Col. (5): Col. (2) / Col. (3).
Col. (6): [2 * (1 + Col. (4))] / (2 + Col. (4)).
Col. (7): Col. (6) * Col. (5).
Col. (8): Col. (1) / Col. (2).
Col. (9): 1 - Col. (8).
Col. (10): Col. (9) * Col. (7).
Col. (11): Col. (10) + Page 2 Col. (9).

Columbia Gas of Pennsylvania

Sustainable Growth Rate

Line	Company	13-Week Average Stock Price[1] (1)	2022 Book Value Per Share[2] (2)	Market to Book Ratio (3)	Common Shares Outstanding (in Millions)[2] 2022 (4)	Common Shares Outstanding (in Millions)[2] 3-5 Years (5)	Growth (6)	S Factor[3] (7)	V Factor[4] (8)	S * V (9)
1	Atmos Energy Corporation	$114.80	$66.85	1.72	140.90	175.00	3.68%	6.32%	41.77%	2.64%
2	New Jersey Resources Corporation	$41.96	$19.00	2.21	95.64	100.00	0.75%	1.65%	54.72%	0.90%
3	Northwest Natural Holding Company	$36.81	$33.08	1.11	35.53	42.00	2.83%	3.15%	10.12%	0.32%
4	ONE Gas, Inc.	$61.82	$46.69	1.32	55.35	57.00	0.49%	0.65%	24.47%	0.16%
5	Southwest Gas Holdings, Inc.	$68.47	$47.95	1.43	67.12	77.50	2.43%	3.46%	29.97%	1.04%
6	Spire Inc.	$59.53	$49.08	1.21	52.50	62.00	2.81%	3.41%	17.55%	0.60%
7	Eversource Energy	$57.99	$44.41	1.31	348.44	360.00	0.55%	0.71%	23.42%	0.17%
8	American States Water Company	$72.04	$19.20	3.75	36.96	37.50	0.24%	0.91%	73.35%	0.67%
9	American Water Works Company, Inc.	$119.97	$42.30	2.84	181.86	202.00	- 0.01%	- 0.01%	64.74%	- 0.01%
10	California Water Service Group	$46.15	$23.70	1.95	55.60	50.00	0.01%	0.01%	48.65%	0.00%
11	Middlesex Water Company	$51.75	$22.65	2.28	17.64	18.00	- 0.00%	- 0.00%	56.23%	- 0.00%
12	SJW Group	$56.61	$36.06	1.57	30.80	30.00	0.00%	0.00%	36.30%	0.00%
13	Essential Utilities, Inc.	$35.69	$20.39	1.75	263.74	288.00	- 0.00%	- 0.01%	42.87%	- 0.00%
	Gas Average	**$63.90**	**$43.78**	**1.50**	**74.51**	**85.58**	**2.16%**	**3.11%**	**29.77%**	**0.94%**
	Total Average	**$63.35**	**$36.26**	**1.88**	**106.31**	**115.31**	**1.06%**	**1.56%**	**40.32%**	**0.50%**

Sources and Notes:

[1] S&P Global Market Intelligence, Downloaded on April 26, 2024.

[2] *The Value Line Investment Survey*, February 9, February 23, and April 5, 2024.

[3] Expected Growth in the Number of Shares, Column (3) * Column (6).

[4] Expected Profit of Stock Investment, [1 - 1 / Column (3)].

Columbia Gas of Pennsylvania

Constant Growth DCF Model
(Sustainable Growth Rate)

Line	Company	13-Week AVG Stock Price[1] (1)	Sustainable Growth[2] (2)	Annualized Dividend[3] (3)	Adjusted Yield (4)	Constant Growth DCF (5)
1	Atmos Energy Corporation	$114.80	7.64%	$3.22	3.02%	10.66%
2	New Jersey Resources Corporation	$41.96	6.81%	$1.68	4.28%	11.09%
3	Northwest Natural Holding Company	$36.81	3.64%	$1.95	5.50%	9.14%
4	ONE Gas, Inc.	$61.82	3.81%	$2.64	4.43%	8.24%
5	Southwest Gas Holdings, Inc.	$68.47	4.05%	$2.48	3.77%	7.82%
6	Spire Inc.	$59.53	3.55%	$3.02	5.25%	8.80%
7	Eversource Energy	$57.99	4.30%	$2.70	4.86%	9.16%
8	American States Water Company	$72.04	5.26%	$1.72	2.51%	7.77%
9	American Water Works Company, Inc.	$119.97	4.62%	$2.83	2.47%	7.09%
10	California Water Service Group	$46.15	4.37%	$1.12	2.53%	6.91%
11	Middlesex Water Company	$51.75	5.91%	$1.30	2.66%	8.57%
12	SJW Group	$56.61	3.62%	$1.60	2.93%	6.55%
13	Essential Utilities, Inc.	$35.69	3.30%	$1.23	3.56%	6.86%
14	**Gas Average**	**$63.90**	**4.92%**	**$2.50**	**4.37%**	**9.29%**
15	**Gas Median**					**8.97%**
16	**Total Average**	**$63.35**	**4.68%**	**$2.11**	**3.67%**	**8.36%**
17	**Total Median**					**8.24%**

Sources:
[1] S&P Global Market Intelligence, Downloaded on April 26, 2024.
[2] Exhibit CCW-6, page 1.
[3] *The Value Line Investment Survey* , February 9, February 23, and April 5, 2024.

Columbia Gas of Pennsylvania

Multi-Stage Growth DCF Model

Line	Company	13-Week AVG Stock Price[1] (1)	Annualized Dividend[2] (2)	First Stage Growth[3] (3)	Second Stage Growth Year 6 (4)	Year 7 (5)	Year 8 (6)	Year 9 (7)	Year 10 (8)	Third Stage Growth[4] (9)	Multi-Stage Growth DCF (10)
1	Atmos Energy Corporation	$114.80	$3.22	7.17%	6.66%	6.16%	5.65%	5.15%	4.64%	4.14%	7.68%
2	New Jersey Resources Corporation	$41.96	$1.68	5.93%	5.63%	5.34%	5.04%	4.74%	4.44%	4.14%	8.80%
3	Northwest Natural Holding Company	$36.81	$1.95	4.05%	4.07%	4.08%	4.10%	4.11%	4.13%	4.14%	9.63%
4	ONE Gas, Inc.	$61.82	$2.64	4.33%	4.30%	4.27%	4.24%	4.20%	4.17%	4.14%	8.64%
5	Southwest Gas Holdings, Inc.	$68.47	$2.48	5.43%	5.22%	5.00%	4.79%	4.57%	4.36%	4.14%	8.23%
6	Spire Inc.	$59.53	$3.02	5.95%	5.65%	5.35%	5.05%	4.74%	4.44%	4.14%	10.03%
7	Eversource Energy	$57.99	$2.70	4.17%	4.17%	4.16%	4.16%	4.15%	4.15%	4.14%	9.00%
8	American States Water Company	$72.04	$1.72	8.23%	7.55%	6.87%	6.19%	5.50%	4.82%	4.14%	7.37%
9	American Water Works Company, Inc.	$119.97	$2.83	7.75%	7.15%	6.55%	5.95%	5.34%	4.74%	4.14%	7.23%
10	California Water Service Group	$46.15	$1.12	9.40%	8.52%	7.65%	6.77%	5.89%	5.02%	4.14%	7.67%
11	Middlesex Water Company	$51.75	$1.30	2.70%	2.94%	3.18%	3.42%	3.66%	3.90%	4.14%	6.49%
12	SJW Group	$56.61	$1.60	7.33%	6.80%	6.27%	5.74%	5.20%	4.67%	4.14%	7.74%
13	Essential Utilities, Inc.	$35.69	$1.23	5.78%	5.51%	5.24%	4.96%	4.69%	4.41%	4.14%	8.12%
14	**Gas Average**	**$63.90**	**$2.50**	**5.48%**	**5.26%**	**5.03%**	**4.81%**	**4.59%**	**4.36%**	**4.14%**	**8.84%**
15	**Gas Median**										**8.72%**
16	**Total Average**	**$63.35**	**$2.11**	**6.02%**	**5.71%**	**5.39%**	**5.08%**	**4.77%**	**4.45%**	**4.14%**	**8.20%**
17	**Total Median**										**8.12%**

Sources:

[1] S&P Global Market Intelligence, Downloaded on April 26, 2024.

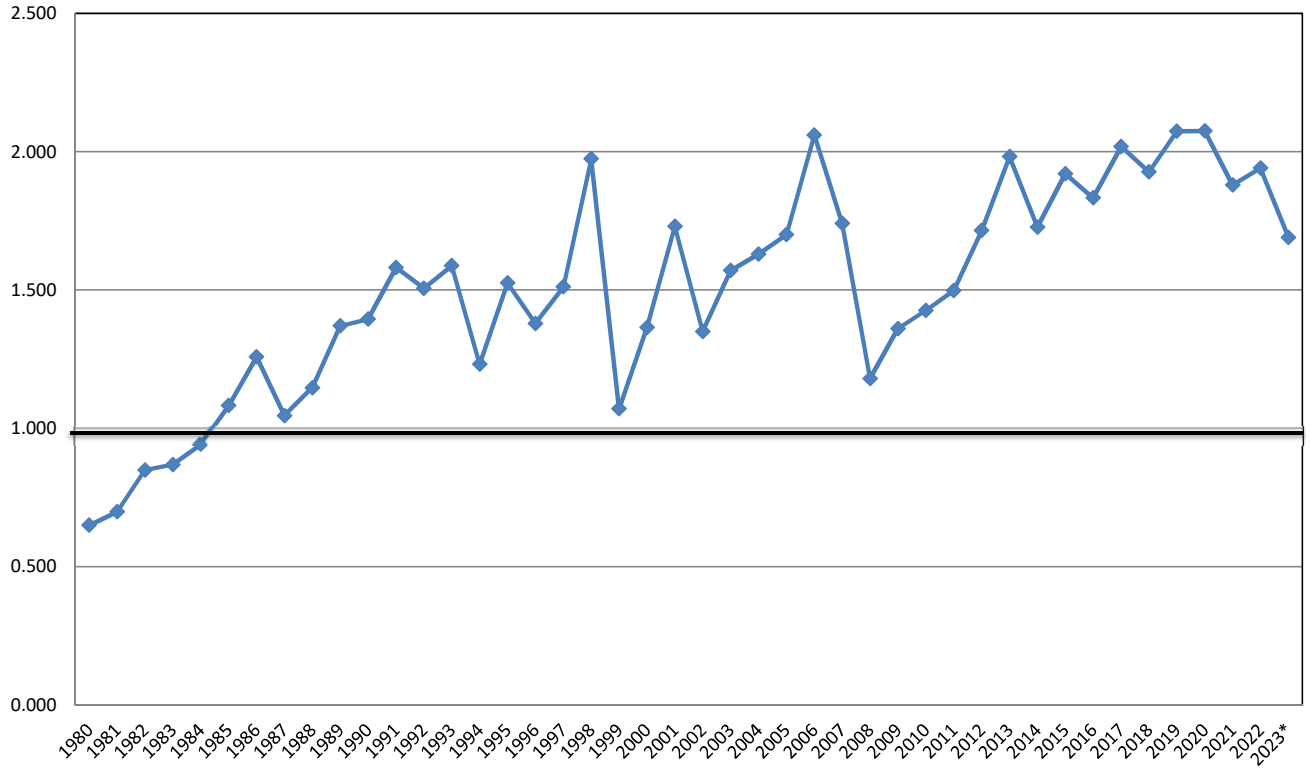
[2] *The Value Line Investment Survey*, February 9, February 23, and April 5, 2024.

[3] Exhibit CCW-3

[4] *Blue Chip Economic Indicators, March 11, 2024 at page 14.*

Columbia Gas of Pennsylvania

Common Stock Market/Book Ratio



Source:
1980 - 2000: Mergent Public Utility Manual.
2001 - 2015: AUS Utility Reports, multiple dates.
2016 - 2022: Value Line Investment Survey, multiple dates.
* Value Line Investment Survey Reports, February 9, February 23, and March 8, April 19, 2024.

Columbia Gas of Pennsylvania

Equity Risk Premium - Treasury Bond

Line	Year	Authorized Gas Returns[1] (1)	30 yr. Treasury Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.46%	7.80%	5.66%		
2	1987	12.74%	8.58%	4.16%		
3	1988	12.85%	8.96%	3.89%		
4	1989	12.88%	8.45%	4.43%		
5	1990	12.67%	8.61%	4.06%	4.44%	
6	1991	12.46%	8.14%	4.32%	4.17%	
7	1992	12.01%	7.67%	4.34%	4.21%	
8	1993	11.35%	6.60%	4.75%	4.38%	
9	1994	11.35%	7.37%	3.98%	4.29%	
10	1995	11.43%	6.88%	4.55%	4.39%	4.42%
11	1996	11.19%	6.70%	4.49%	4.42%	4.30%
12	1997	11.29%	6.61%	4.68%	4.49%	4.35%
13	1998	11.51%	5.58%	5.93%	4.73%	4.55%
14	1999	10.66%	5.87%	4.79%	4.89%	4.59%
15	2000	11.39%	5.94%	5.45%	5.07%	4.73%
16	2001	10.95%	5.49%	5.46%	5.26%	4.84%
17	2002	11.03%	5.43%	5.60%	5.45%	4.97%
18	2003	10.99%	4.96%	6.03%	5.47%	5.10%
19	2004	10.59%	5.05%	5.54%	5.62%	5.25%
20	2005	10.46%	4.65%	5.81%	5.69%	5.38%
21	2006	10.40%	4.87%	5.53%	5.70%	5.48%
22	2007	10.22%	4.83%	5.39%	5.66%	5.55%
23	2008	10.39%	4.28%	6.11%	5.68%	5.57%
24	2009	10.22%	4.07%	6.15%	5.80%	5.71%
25	2010	10.15%	4.25%	5.90%	5.81%	5.75%
26	2011	9.92%	3.91%	6.01%	5.91%	5.81%
27	2012	9.94%	2.92%	7.02%	6.24%	5.95%
28	2013	9.68%	3.45%	6.23%	6.26%	5.97%
29	2014	9.78%	3.34%	6.44%	6.32%	6.06%
30	2015	9.60%	2.84%	6.76%	6.49%	6.15%
31	2016	9.54%	2.60%	6.94%	6.68%	6.29%
32	2017	9.72%	2.90%	6.83%	6.64%	6.44%
33	2018	9.59%	3.11%	6.48%	6.69%	6.48%
34	2019	9.71%	2.58%	7.13%	6.83%	6.57%
35	2020	9.46%	1.56%	7.90%	7.05%	6.77%
36	2021	9.56%	2.05%	7.51%	7.17%	6.92%
37	2022	9.53%	3.12%	6.42%	7.08%	6.86%
38	2023	9.60%	4.09%	5.51%	6.89%	6.79%
39	2024 [3]	9.78%	4.33%	5.45%	6.55%	6.69%
40	**Average**	**10.77%**	**5.14%**	**5.63%**	**5.67%**	**5.68%**
41	**Minimum**				**4.17%**	**4.30%**
42	**Maximum**				**7.17%**	**6.92%**

Sources:

[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3. S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January - March 2024, April 19, 2024 at page 3.

[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.

[3] Data represents January - March, 2024.

Columbia Gas of Pennsylvania

Equity Risk Premium - Utility Bond

Line	Year	Authorized Gas Returns[1] (1)	Average "A" Rated Utility Bond Yield[2] (2)	Indicated Risk Premium (3)	Rolling 5 - Year Average (4)	Rolling 10 - Year Average (5)
1	1986	13.46%	9.58%	3.88%		
2	1987	12.74%	10.10%	2.64%		
3	1988	12.85%	10.49%	2.36%		
4	1989	12.88%	9.77%	3.11%		
5	1990	12.67%	9.86%	2.81%	2.96%	
6	1991	12.46%	9.36%	3.10%	2.80%	
7	1992	12.01%	8.69%	3.32%	2.94%	
8	1993	11.35%	7.59%	3.76%	3.22%	
9	1994	11.35%	8.31%	3.04%	3.21%	
10	1995	11.43%	7.89%	3.54%	3.35%	3.16%
11	1996	11.19%	7.75%	3.44%	3.42%	3.11%
12	1997	11.29%	7.60%	3.69%	3.49%	3.22%
13	1998	11.51%	7.04%	4.47%	3.64%	3.43%
14	1999	10.66%	7.62%	3.04%	3.64%	3.42%
15	2000	11.39%	8.24%	3.15%	3.56%	3.45%
16	2001	10.95%	7.76%	3.19%	3.51%	3.46%
17	2002	11.03%	7.37%	3.66%	3.50%	3.50%
18	2003	10.99%	6.58%	4.41%	3.49%	3.56%
19	2004	10.59%	6.16%	4.43%	3.77%	3.70%
20	2005	10.46%	5.65%	4.81%	4.10%	3.83%
21	2006	10.40%	6.07%	4.33%	4.33%	3.92%
22	2007	10.22%	6.07%	4.15%	4.43%	3.96%
23	2008	10.39%	6.53%	3.86%	4.32%	3.90%
24	2009	10.22%	6.04%	4.18%	4.27%	4.02%
25	2010	10.15%	5.47%	4.68%	4.24%	4.17%
26	2011	9.92%	5.04%	4.88%	4.35%	4.34%
27	2012	9.94%	4.13%	5.81%	4.68%	4.55%
28	2013	9.68%	4.48%	5.20%	4.95%	4.63%
29	2014	9.78%	4.28%	5.50%	5.22%	4.74%
30	2015	9.60%	4.12%	5.48%	5.38%	4.81%
31	2016	9.54%	3.93%	5.61%	5.52%	4.94%
32	2017	9.72%	4.00%	5.72%	5.50%	5.09%
33	2018	9.59%	4.25%	5.34%	5.53%	5.24%
34	2019	9.71%	3.77%	5.94%	5.62%	5.42%
35	2020	9.46%	3.05%	6.41%	5.80%	5.59%
36	2021	9.56%	3.10%	6.46%	5.97%	5.75%
37	2022	9.53%	4.72%	4.81%	5.79%	5.65%
38	2023	9.60%	5.55%	4.05%	5.53%	5.53%
39	2024 [3]	9.78%	5.53%	4.25%	5.19%	5.41%
39	**Average**	**10.80%**	**6.50%**	**4.27%**	**4.32%**	**4.32%**
40	**Minimum**				**2.80%**	**3.11%**
41	**Maximum**				**5.97%**	**5.75%**

Sources:

[1] *Regulatory Research Associates, Inc*., Regulatory Focus, Major Rate Case Decisions, Jan. 1997 p. 5, and Jan. 2011 p. 3.
S&P Global Market Intelligence, RRA Regulatory Focus, Major Rate Case Decisions, January - March 2024, April 19, 2024 at page 3.

[2] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The yields from 2002 to 2005 represent the 20-Year Treasury yields obtained from the Federal Reserve Bank.

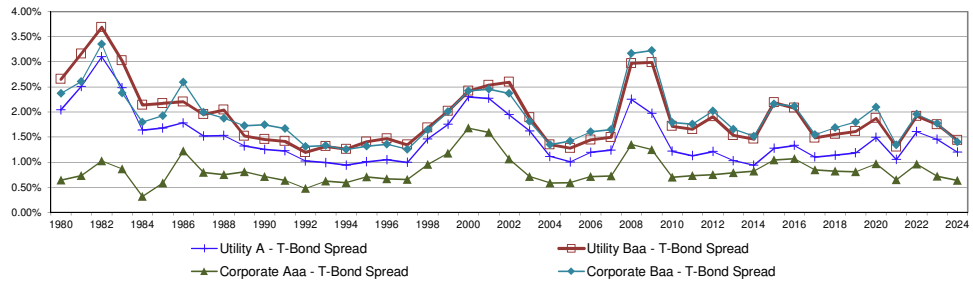
[3] Data represents January - March, 2024.

Columbia Gas of Pennsylvania

Bond Yield Spreads

			Public Utility Bond				Corporate Bond				Utility to Corporate	
Line	Year	T-Bond Yield[1] (1)	A[2] (2)	Baa[2] (3)	A-T-Bond Spread (4)	Baa-T-Bond Spread (5)	Aaa[3] (6)	Baa[3] (7)	Aaa-T-Bond Spread (8)	Baa-T-Bond Spread (9)	Baa Spread (10)	A-Aaa Spread (11)
1	1980	11.30%	13.34%	13.95%	2.04%	2.65%	11.94%	13.67%	0.64%	2.37%	0.28%	1.40%
2	1981	13.44%	15.95%	16.60%	2.51%	3.16%	14.17%	16.04%	0.73%	2.60%	0.56%	1.78%
3	1982	12.76%	15.86%	16.45%	3.10%	3.69%	13.79%	16.11%	1.03%	3.35%	0.34%	2.07%
4	1983	11.18%	13.66%	14.20%	2.48%	3.02%	12.04%	13.55%	0.86%	2.38%	0.65%	1.62%
5	1984	12.39%	14.03%	14.53%	1.64%	2.14%	12.71%	14.19%	0.32%	1.80%	0.34%	1.32%
6	1985	10.79%	12.47%	12.96%	1.68%	2.17%	11.37%	12.72%	0.58%	1.93%	0.24%	1.10%
7	1986	7.80%	9.58%	10.00%	1.78%	2.20%	9.02%	10.39%	1.22%	2.59%	-0.39%	0.56%
8	1987	8.58%	10.10%	10.53%	1.52%	1.95%	9.38%	10.58%	0.80%	2.00%	-0.05%	0.72%
9	1988	8.96%	10.49%	11.00%	1.53%	2.04%	9.71%	10.83%	0.75%	1.87%	0.17%	0.78%
10	1989	8.45%	9.77%	9.97%	1.32%	1.52%	9.26%	10.18%	0.81%	1.73%	-0.21%	0.51%
11	1990	8.61%	9.86%	10.06%	1.25%	1.45%	9.32%	10.36%	0.71%	1.75%	-0.30%	0.54%
12	1991	8.14%	9.36%	9.55%	1.22%	1.41%	8.77%	9.80%	0.63%	1.67%	-0.25%	0.59%
13	1992	7.67%	8.69%	8.86%	1.02%	1.19%	8.14%	8.98%	0.47%	1.31%	-0.12%	0.55%
14	1993	6.60%	7.59%	7.91%	0.99%	1.31%	7.22%	7.93%	0.62%	1.33%	-0.02%	0.37%
15	1994	7.37%	8.31%	8.63%	0.94%	1.26%	7.96%	8.62%	0.59%	1.25%	0.01%	0.35%
16	1995	6.88%	7.89%	8.29%	1.01%	1.41%	7.59%	8.20%	0.71%	1.32%	0.09%	0.30%
17	1996	6.70%	7.75%	8.17%	1.05%	1.47%	7.37%	8.05%	0.67%	1.35%	0.12%	0.38%
18	1997	6.61%	7.60%	7.95%	0.99%	1.34%	7.26%	7.86%	0.66%	1.26%	0.09%	0.34%
19	1998	5.58%	7.04%	7.26%	1.46%	1.68%	6.53%	7.22%	0.95%	1.64%	0.04%	0.51%
20	1999	5.87%	7.62%	7.88%	1.75%	2.01%	7.04%	7.87%	1.18%	2.01%	0.01%	0.58%
21	2000	5.94%	8.24%	8.36%	2.30%	2.42%	7.62%	8.36%	1.68%	2.42%	-0.01%	0.62%
22	2001	5.49%	7.76%	8.03%	2.27%	2.54%	7.08%	7.95%	1.59%	2.45%	0.08%	0.68%
23	2002	5.43%	7.37%	8.02%	1.94%	2.59%	6.49%	7.80%	1.06%	2.37%	0.22%	0.88%
24	2003	4.96%	6.58%	6.84%	1.62%	1.89%	5.67%	6.77%	0.71%	1.81%	0.08%	0.91%
25	2004	5.05%	6.16%	6.40%	1.11%	1.35%	5.63%	6.39%	0.58%	1.35%	0.00%	0.53%
26	2005	4.65%	5.65%	5.93%	1.00%	1.28%	5.24%	6.06%	0.59%	1.42%	-0.14%	0.41%
27	2006	4.87%	6.07%	6.32%	1.20%	1.44%	5.59%	6.48%	0.71%	1.61%	-0.16%	0.48%
28	2007	4.83%	6.07%	6.33%	1.24%	1.50%	5.56%	6.48%	0.72%	1.65%	-0.15%	0.52%
29	2008	4.28%	6.53%	7.25%	2.25%	2.97%	5.63%	7.45%	1.35%	3.17%	-0.20%	0.90%
30	2009	4.07%	6.04%	7.06%	1.97%	2.99%	5.31%	7.30%	1.24%	3.23%	-0.24%	0.73%
31	2010	4.25%	5.47%	5.96%	1.22%	1.71%	4.95%	6.04%	0.70%	1.79%	-0.08%	0.52%
32	2011	3.91%	5.04%	5.57%	1.13%	1.66%	4.64%	5.67%	0.73%	1.76%	-0.10%	0.40%
33	2012	2.92%	4.13%	4.83%	1.21%	1.90%	3.67%	4.94%	0.75%	2.02%	-0.11%	0.46%
34	2013	3.45%	4.48%	4.98%	1.03%	1.53%	4.24%	5.10%	0.79%	1.65%	-0.12%	0.24%
35	2014	3.34%	4.28%	4.80%	0.94%	1.46%	4.16%	4.86%	0.82%	1.52%	-0.06%	0.12%
36	2015	2.84%	4.12%	5.03%	1.27%	2.19%	3.89%	5.00%	1.05%	2.16%	0.03%	0.23%
37	2016	2.60%	3.93%	4.67%	1.33%	2.08%	3.66%	4.71%	1.07%	2.12%	-0.04%	0.27%
38	2017	2.90%	4.00%	4.38%	1.10%	1.48%	3.74%	4.44%	0.85%	1.55%	-0.06%	0.26%
39	2018	3.11%	4.25%	4.67%	1.14%	1.56%	3.93%	4.80%	0.82%	1.69%	-0.13%	0.32%
40	2019	2.58%	3.77%	4.19%	1.18%	1.61%	3.39%	4.38%	0.81%	1.79%	-0.18%	0.38%
41	2020	1.56%	3.05%	3.44%	1.49%	1.87%	2.53%	3.66%	0.96%	2.10%	-0.22%	0.53%
42	2021	2.05%	3.10%	3.36%	1.05%	1.30%	2.70%	3.39%	0.65%	1.34%	-0.04%	0.40%
43	2022	3.12%	4.72%	5.03%	1.61%	1.91%	4.08%	5.07%	0.96%	1.96%	-0.04%	0.65%
44	2023	4.09%	5.55%	5.84%	1.45%	1.75%	4.81%	5.86%	0.72%	1.77%	-0.02%	0.74%
45	2024 [4]	4.33%	5.53%	5.77%	1.20%	1.43%	4.97%	5.73%	0.63%	1.40%	0.04%	0.56%
46	**Average**	**6.05%**	**7.53%**	**7.95%**	**1.48%**	**1.90%**	**6.88%**	**7.95%**	**0.83%**	**1.90%**	**0.00%**	**0.65%**

Yield Spreads
Treasury Vs. Corporate & Treasury Vs. Utility



Sources:

[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.

[2] The utility yields for the period 1980-2000 were obtained from Mergent Public Utility Manual, Mergent Weekly News Reports, 2003.
The utility yields for the period 2001-2009 were obtained from the Mergent Bond Record.
The utility yields for the period 2010-2024 were obtained from http://credittrends.moodys.com/.

[3] The corporate yields for the period 1980-2009 were obtained from the St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/.
The corporate yields from 2010-2024 were obtained from http://credittrends.moodys.com/.

[4] Data represents January - March, 2024.

Columbia Gas of Pennsylvania

13-Week Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	04/26/24	4.78%	5.91%	6.14%
2	04/19/24	4.72%	5.85%	6.08%
3	04/12/24	4.61%	5.73%	5.95%
4	04/05/24	4.54%	5.67%	5.90%
5	03/28/24	4.34%	5.50%	5.72%
6	03/22/24	4.39%	5.55%	5.78%
7	03/15/24	4.43%	5.60%	5.83%
8	03/08/24	4.26%	5.48%	5.72%
9	03/01/24	4.33%	5.56%	5.79%
10	02/23/24	4.37%	5.56%	5.77%
11	02/16/24	4.45%	5.62%	5.85%
12	02/09/24	4.37%	5.56%	5.79%
13	02/02/24	4.22%	5.42%	5.66%
14	**Average**	**4.45%**	**5.62%**	**5.84%**
15	**Spread To Treasury**		**1.17%**	**1.39%**

Sources:

[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.

[2] http://credittrends.moodys.com/.

Columbia Gas of Pennsylvania

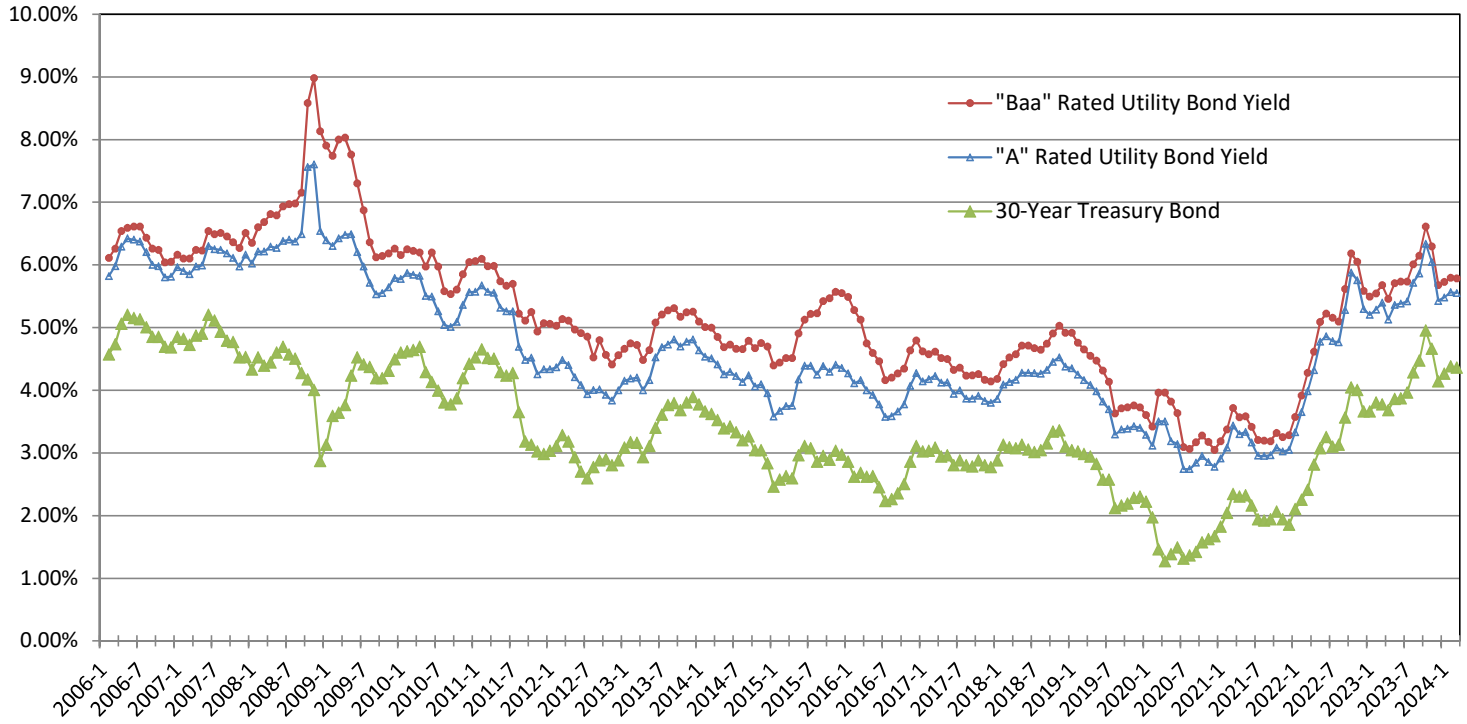
26-Week Treasury and Utility Bond Yields

Line	Date	Treasury Bond Yield[1] (1)	"A" Rated Utility Bond Yield[2] (2)	"Baa" Rated Utility Bond Yield[2] (3)
1	04/26/24	4.78%	5.91%	6.14%
2	04/19/24	4.72%	5.85%	6.08%
3	04/12/24	4.61%	5.73%	5.95%
4	04/05/24	4.54%	5.67%	5.90%
5	03/28/24	4.34%	5.50%	5.72%
6	03/22/24	4.39%	5.55%	5.78%
7	03/15/24	4.43%	5.60%	5.83%
8	03/08/24	4.26%	5.48%	5.72%
9	03/01/24	4.33%	5.56%	5.79%
10	02/23/24	4.37%	5.56%	5.77%
11	02/16/24	4.45%	5.62%	5.85%
12	02/09/24	4.37%	5.56%	5.79%
13	02/02/24	4.22%	5.42%	5.66%
14	01/26/24	4.38%	5.54%	5.78%
15	01/19/24	4.36%	5.55%	5.80%
16	01/12/24	4.20%	5.42%	5.66%
17	01/05/24	4.21%	5.47%	5.74%
18	12/29/23	4.03%	5.28%	5.54%
19	12/22/23	4.05%	5.32%	5.58%
20	12/15/23	4.00%	5.26%	5.52%
21	12/08/23	4.31%	5.62%	5.88%
22	12/01/23	4.40%	5.72%	5.97%
23	11/24/23	4.60%	5.96%	6.20%
24	11/17/23	4.59%	5.98%	6.22%
25	11/10/23	4.73%	6.15%	6.41%
26	11/03/23	4.77%	6.15%	6.41%
27	**Average**	**4.40%**	**5.63%**	**5.87%**
28	**Spread To Treasury**		**1.23%**	**1.47%**

Sources:
[1] St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org.
[2] http://credittrends.moodys.com/.

Columbia Gas of Pennsylvania

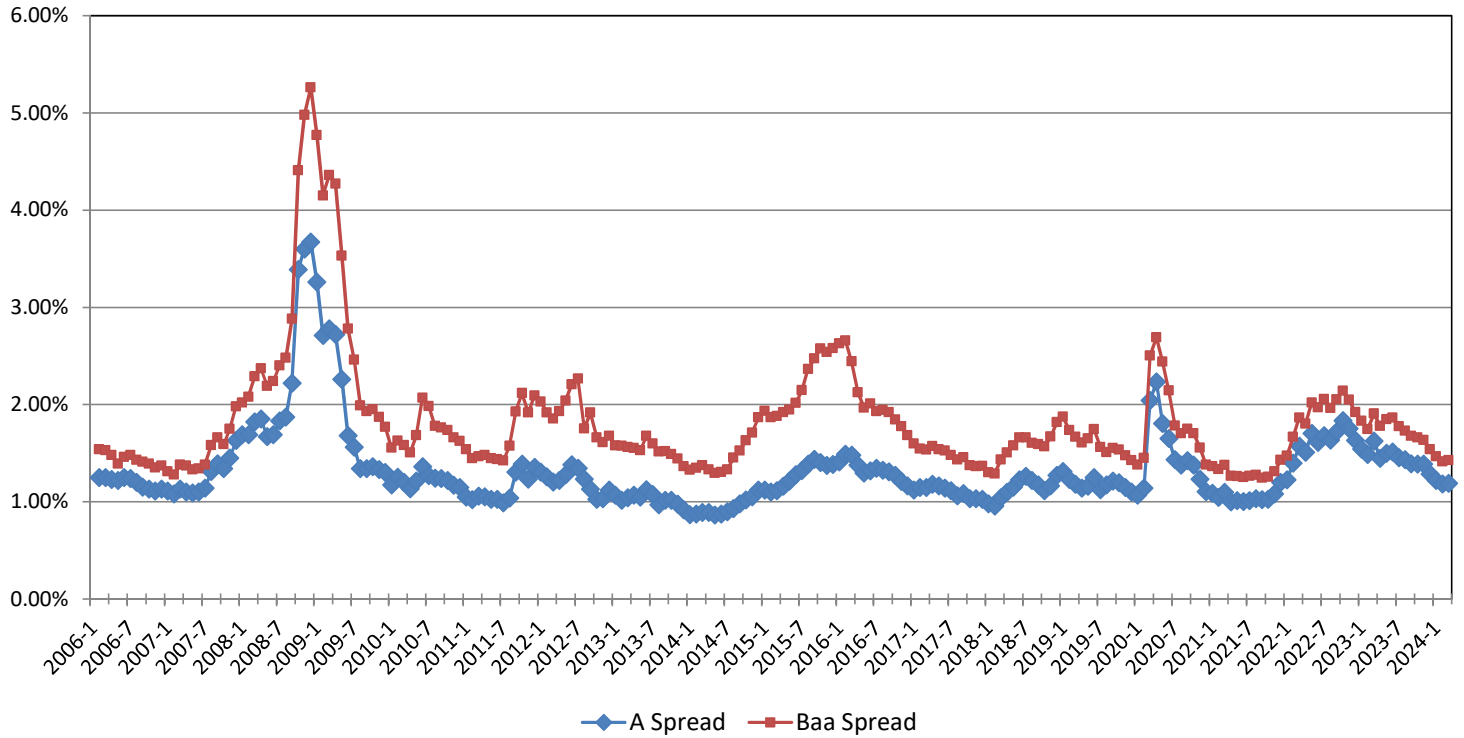
Trends in Bond Yields



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Columbia Gas of Pennsylvania

Yield Spread Between Utility Bonds and 30-Year Treasury Bonds



Sources:
Mergent Bond Record.
www.moodys.com, Bond Yields and Key Indicators.
St. Louis Federal Reserve: Economic Research, http://research.stlouisfed.org/

Columbia Gas of Pennsylvania

Beta

Line	Company	Beta[1]	S&P Global Market Intelligence Beta[2]
1	Atmos Energy Corporation	0.85	0.74
2	New Jersey Resources Corporation	0.95	0.76
3	Northwest Natural Holding Company	0.85	0.67
4	ONE Gas, Inc.	0.85	0.74
5	Southwest Gas Holdings, Inc.	0.90	0.79
6	Spire Inc.	0.85	0.77
7	Eversource Energy	0.95	0.80
8	American States Water Company	0.70	0.61
9	American Water Works Company, Inc.	0.95	0.87
10	California Water Service Group	0.75	0.65
11	Middlesex Water Company	0.75	0.70
12	SJW Group	0.85	0.74
13	Essential Utilities, Inc.	1.00	0.83
14	**Gas Average**	**0.88**	**0.75**
15	**Gas Median**	**0.85**	**0.75**
16	**Total Average**	**0.86**	**0.74**
17	**Total Median**	**0.85**	**0.74**
18	**Historical Beta[3]**	**0.75**	

Source:

[1] *The Value Line Investment Survey,* Februrary 9, February 23, and April 5, 2024.

[2] S&P Global Market Intelligence, betas for the period 4/26/2019 - 4/26/2024.

[3] Exhibit CCW-14, page 2.

Columbia Gas of Pennsylvania

Historical Betas
(Natural Gas & Water Utilites)

Line	Company	Average	4Q23	3Q23	2Q23	1Q23	4Q22	3Q22	2Q22	1Q22	4Q21	3Q21	2Q21	1Q21	4Q20	3Q20	2Q20	1Q20	4Q19	3Q19	2Q19	1Q19	4Q18	3Q18	2Q18	1Q18	4Q17	3Q17	2Q17	1Q17	4Q16	3Q16	2Q16	1Q16	4Q15	3Q15	2Q15	1Q15	4Q14	3Q14
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)	(34)	(35)	(36)	(37)	(38)	(39)
1	Atmos Energy Corporation	0.75	0.85	0.85	0.85	0.85	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.55	0.60	0.60	0.65	0.60	0.60	0.60	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.80	0.80	0.85	0.85	0.85	0.80	0.80
2	New Jersey Resources Corporation	0.84	0.95	0.95	0.95	0.95	0.95	0.95	0.95	1.00	1.00	1.00	1.00	0.95	0.95	0.90	0.90	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.80	0.75	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.85	0.80	0.80	0.80	0.80
3	Northwest Natural Holding Company	0.72	0.85	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.85	0.85	0.85	0.80	0.80	0.80	0.80	0.55	0.60	0.60	0.60	0.65	0.60	0.65	0.70	0.65	0.70	0.70	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.70
4	ONE Gas, Inc.	0.74	0.85	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.70	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
5	Southwest Gas Holdings, Inc.	0.83	0.90	0.90	0.85	0.90	0.90	0.90	0.90	0.95	0.95	0.95	0.95	0.95	0.95	0.90	0.90	0.65	0.70	0.70	0.70	0.70	0.70	0.75	0.80	0.75	0.80	0.75	0.75	0.75	0.75	0.75	0.75	0.80	0.80	0.85	0.85	0.85	0.85	0.85
6	Spire Inc.	0.74	0.85	0.85	0.80	0.85	0.85	0.80	0.80	0.85	0.85	0.85	0.85	0.85	1.00	0.80	0.80	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
7	Eversource Energy	0.76	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.55	0.55	0.60	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
8	American States Water Company	0.69	0.70	0.65	0.70	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.75	0.75	0.75	0.75	0.80	0.80	0.80	0.80	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
9	American Water Works Company, Inc.	0.74	0.95	0.90	0.90	0.90	0.90	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.70	0.70
10	California Water Service Group	0.71	0.70	0.70	0.70	0.70	0.70	0.65	0.65	0.70	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.80	0.80	0.80	0.80	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.70	0.70
11	Middlesex Water Company	0.72	0.75	0.70	0.75	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.80	0.80	0.80	0.80	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.70	0.70
12	SJW Group	0.75	0.85	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.60	0.60	0.60	0.60	0.65	0.65	0.65	0.65	0.75	0.75	0.75	0.75	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.85	0.85
13	Essential Utilities, Inc.	0.80	1.00	0.95	0.95	0.95	0.95	0.95	0.95	N/A	0.95	0.95	0.95	0.95	0.90	0.90	0.90	0.90	0.65	0.65	0.65	0.65	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.75	0.75	0.75	0.75	0.70	0.70
14	**Gas Average**	0.77	0.88	0.86	0.84	0.86	0.85	0.84	0.84	0.87	0.88	0.88	0.88	0.86	0.88	0.83	0.83	0.60	0.65	0.65	0.66	0.66	0.65	0.67	0.73	0.70	0.73	0.73	0.72	0.72	0.72	0.73	0.73	0.75	0.75	0.79	0.78	0.78	0.77	0.77
15	**Total Average**	0.75	0.85	0.83	0.83	0.83	0.82	0.81	0.81	0.82	0.83	0.83	0.83	0.82	0.83	0.80	0.80	0.67	0.64	0.65	0.65	0.65	0.67	0.68	0.71	0.70	0.73	0.73	0.73	0.73	0.71	0.71	0.72	0.73	0.74	0.76	0.75	0.75	0.75	0.75

Source: Value Line Software Analyzer

Columbia Gas of Pennsylvania

CAPM Return

Line	Description	Kroll Normalized[2] MRP (1)	Risk Premium[3] Derived MRP (2)	Average FERC S&P 500 DCF[4] Derived MRP (3)
	Current Beta			
1	Risk-Free Rate[1,2]	4.56%	4.00%	4.00%
2	Market Risk Premium	5.50%	7.50%	8.90%
3	Beta[6]	0.86	0.86	0.86
4	**CAPM**	**9.30%**	**10.46%**	**11.67%**
	Historical Beta			
5	Risk-Free Rate[1,2]	4.56%	4.00%	4.00%
6	Market Risk Premium	5.50%	7.50%	8.90%
7	Beta[6]	0.75	0.75	0.75
8	**CAPM**	**8.71%**	**9.65%**	**10.71%**
	Current S&P Global Market Intelligence Beta			
9	Risk-Free Rate[1,2]	4.56%	4.00%	4.00%
10	Market Risk Premium	5.50%	7.50%	8.90%
11	Beta[6]	0.74	0.74	0.74
12	**CAPM**	**8.65%**	**9.58%**	**10.62%**

Sources:

[1] *Kroll Cost of Capital Navigator.*

[2] *Morningstar Direct.*

[3] *Kroll 2023 SBBI Yearbook*, page 138.

[4] S&P 500 1-Step DCF through April 26, 2024 for Dividend Paying Companies.

[5] S&P 500 1-Step DCF through April 26, 2024 for all Companies.

[6] Exhibit CCW-14, page 1.

Columbia Gas of Pennsylvania

Development of the Market Risk Premium

Line	Description	MRP	
Risk Premium Based Method:			
1	Lg. Co. Stock Real Market Return	9.02%	[1]
2	Projected Consumer Price Index	2.30%	[2]
3	Expected Market Return	11.53%	
4	Risk-Free Rate	4.00%	[2]
5	Market Risk Premium	**7.50%**	
FERC S&P 500 (Dividend Companies) 1-Step DCF Based Method:			
6	S&P 500 Growth	11.00%	[3]
7	Index Dividend Yield	1.80%	[3]
8	Adjusted Yield	1.90%	
9	Expected Market Return	12.90%	
10	Risk-Free Rate	4.00%	[2]
11	Market Risk Premium	**8.90%**	
FERC S&P 500 (All Companies) 1-Step DCF Based Method:			
12	Short-Term S&P 500 Growth	11.20%	[4]
13	Index Dividend Yield	1.60%	[4]
14	Adjusted Yield	1.69%	
15	Expected Market Return	12.89%	
16	Risk-Free Rate	4.00%	[2]
17	Market Risk Premium	**8.90%**	
18	Average DCF Based MRP	**8.90%**	

Sources & Note:

[1] Morningstar Direct.

[2] *Blue Chip Financial Forecast April 1, 2024.*

[3] S&P 500 1-Step DCF through April 26, 2024 for Dividend Paying Companies.

[4] S&P 500 1-Step DCF through April 26, 2024 for all Companies.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Direct Testimony & Exhibits of

Brian C. Andrews

OCA Statement 4

On behalf of

Pennsylvania Office of Consumer Advocate

June 14, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11633

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Direct Testimony of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing on behalf of the Pennsylvania Office of Consumer Advocate ("OCA").

Q HAVE YOU TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION IN PRIOR PROCEEDINGS?

A No, I have not previously testified before the Pennsylvania Public Utility Commission ("PUC" or "Commission"), however, I have testified on this issue at the subject of this testimony in over 40 proceedings before the public utility commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Missouri, Montana, New Mexico, Nevada, Oklahoma, South Carolina, and Washington, DC.

Q PLEASE GIVE A BRIEF OVERVIEW OF YOUR TESTIMONY.

A My testimony addresses Columbia Gas of Pennsylvania's ("Columbia Gas" or "Company") proposed depreciation rates. I show that Columbia Gas has greatly overstated its proposed depreciation rates and recommend adjusting the proposed depreciation rates and test year depreciation expense downward by more than $43 million. The reduction is the result of using the Average Life Group ("ALG") (also known as the Broad Group) procedure rather than the Equal Life Group ("ELG") procedure.

My silence in regard to any issue should not be construed as an endorsement of or acquiescence to Columbia Gas' position.

SUMMARY OF RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. Columbia Gas has filed a depreciation study based on plant balances for its Fully Projected Future Test Year ("FPFTY") as of December 31, 2025 using the ELG procedure. These depreciation rates would result in excessive and burdensome depreciation expense for Columbia Gas' customers.

2. Columbia Gas' proposed 2025 depreciation and amortization expense of $136.0 million represents 25% of its total operating expenses.

3. Columbia Gas has, and will continue to have, significant capital expenditures that will substantially drive an increase to rate base and revenue requirement.

4. The use of the ALG procedure can be used to mitigate the rate increases associated with Columbia Gas' significant rate base investment that has been occurring for several years and will continue to occur. The ALG equitably spreads the annual depreciation expense on rate base investment over the generations of customers that receive service from the investments. Conversely, the ELG method assigns more depreciation expense to customers that take service early in the asset's service life and reduces the expense to customers toward the end of the asset's service life.

5. The PUC should order Columbia Gas to use depreciation rates that are based on the ALG procedure.

6. The proposed test year depreciation expense would be reduced by $43.88 million if the ALG depreciation rates are utilized.

7. The PUC should approve the depreciation rates that are presented in Exhibit BCA-3.

BOOK DEPRECIATION CONCEPTS

Q PLEASE EXPLAIN THE PURPOSE OF BOOK DEPRECIATION ACCOUNTING.

A Book depreciation is the recognition in a utility's income statement of the consumption or use of assets to provide utility service. Book depreciation is recorded as an expense and is included in the ratemaking formula to calculate the utility's overall revenue requirement.

The basic underlying principle of utility depreciation accounting is intergenerational equity, where the customers/ratepayers who benefit from the service of assets pay all the costs for those assets during the benefit period, which is over the life of those assets.[1] This concept of intergenerational equity can be achieved through depreciation by allocating costs to customers in a systematic and rational manner that is consistent with the period of time in which customers receive the service value.[2]

Book depreciation provides for the recovery of the original cost of the utility's assets that are currently providing service. Book depreciation expense is not intended to provide for replacement of the current assets, but provides for capital recovery or return of current investment. Generally, this capital recovery occurs over the average service life of the investment or assets. As a result, it is critical that appropriate average service lives be used to develop the depreciation rates so no generation of ratepayers is disadvantaged.

In addition to capital recovery, depreciation rates also contain a provision for net salvage. Net salvage is simply the scrap or reuse value less the removal cost of the asset being depreciated. Accordingly, a utility will also recover the net salvage costs over the useful life of the asset.

Q PLEASE FURTHER EXPLAIN NET SALVAGE.

A Net salvage is simply the value received from the sale or reuse of retired property (salvage value), less the cost of retiring such property (cost of removal). Net salvage

[1]Edison Electric Institute, Introduction to Depreciation for Public Utilities and Other Industries, April 2013, page viii.

[2]*Id.* at 22.

can be either positive or negative. If the salvage value exceeds the cost of removal, the net salvage is positive. If the cost of removal is greater than the salvage value received as a result of retirement, the resulting net salvage is negative. For most utilities, negative net salvage is a significant component of its depreciation rates and expense.

Q ARE THERE ANY DEFINITIONS OF DEPRECIATION ACCOUNTING THAT ARE UTILIZED FOR RATEMAKING PURPOSES?

A Yes. One of the most quoted definitions of depreciation accounting is the one contained in the Code of Federal Regulations ("CFR"):

> "Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources."
>
> 18 C.F.R., Chapter I, Subchapter F, Part 201(12)(B).

Effectively, depreciation accounting provides for the recovery of the original cost of an asset, adjusted for net salvage, over its useful life.

Q HOW DO DEPRECIATION RATES AFFECT A UTILITY'S REVENUE REQUIREMENT?

A Depreciation expense is typically one of the largest single line items in a utility's overall revenue requirement that is ultimately recovered through tariff rates. When a utility updates its depreciation rates, it is effectively updating the amount of capital that is

returned to it each year for investments that have been made to provide utility service. The depreciation rates are calculated in a depreciation study. The resulting depreciation rates are then applied to test year plant balances to determine the depreciation expense component of the utility revenue requirement.

Q HOW ARE DEPRECIATION RATES DETERMINED?

A Depreciation rates are determined in a depreciation study using a depreciation system. There are three components, each with a number of variations, used to determine a depreciation system, which is then used to estimate depreciation rates. The three basic components are: (1) methods, (2) procedures, and (3) techniques. The choice of a depreciation system can significantly affect the resulting depreciation rates, thus, the revenue requirement.

Q PLEASE FURTHER DESCRIBE THE METHODS THAT ARE USED IN A DEPRECIATION SYSTEM.

A There generally are three types of methods of spreading depreciation expense over the life of property. These are the Straight-Line Method, accelerated methods, and deferred methods. The Straight-Line Method is the method most widely used by utility companies for accounting and ratemaking purposes as it is easy to apply and does not create intergenerational inequities because it spreads an equal portion of the plant cost across each accounting period. Accelerated methods result in higher depreciation rates earlier in an asset's life, and lower depreciation rates later. Deferred methods have increasing rates over an asset's life.

Q PLEASE DESCRIBE THE GROUPING PROCEDURES THAT ARE USED IN A DEPRECIATION SYSTEM.

A There are four main grouping procedures used in a depreciation system. These four procedures are the Individual procedure, the Broad Group (more commonly known as the ALG), the Vintage Group, and the ELG.

In the ALG procedure, all units within a particular account or category are assumed to be part of a single group that exhibits the same life and retirement characteristics. This is the most commonly utilized procedure nationwide.

The Vintage Group and the ELG procedure assume that sub-groups within a particular account or category may exhibit unique life characteristics. As an example of the Vintage Group procedure, it may assume that all services installed in 1985 have a 50-year life, while all services installed in year 1995 have a 45-year life. The ELG procedure may assume that all services that will attain a life of 50 years should have one depreciation rate while services that only attain life spans of 45 years would have a different depreciation rate. The overall group depreciation rate for the account would be a composite of the ELG and vintage depreciation rates.

Q PLEASE FURTHER DESCRIBE THE TECHNIQUES THAT ARE USED IN A DEPRECIATION SYSTEM.

A There are two techniques used to calculate depreciation rates: Whole Life and Remaining Life. The Whole Life Technique spreads the original cost plus net salvage of the account over the average life of the account. This technique requires that separate

amortizations be made to correct for over- and under-accumulations due to changes in an account's average service life.

The Remaining Life Technique spreads the unrecovered cost plus net salvage over the remaining life of the account. The Remaining Life Technique is the most common technique used and it has a self-correcting nature that spreads any over- or under-accumulations over the remaining life.

Q IN YOUR EXPERIENCE, WHAT DEPRECIATION SYSTEM IS MOST COMMONLY UTILIZED TO DETERMINE UTILITY DEPRECIATION RATES FOR RATEMAKING PURPOSES?

A The most common depreciation system is one that consists of the Straight-Line Method, the ALG procedure, and the Remaining Life Technique.

Q WHAT ARE SURVIVOR CURVES AND HOW ARE THEY USED IN DEVELOPING DEPRECIATION RATES?

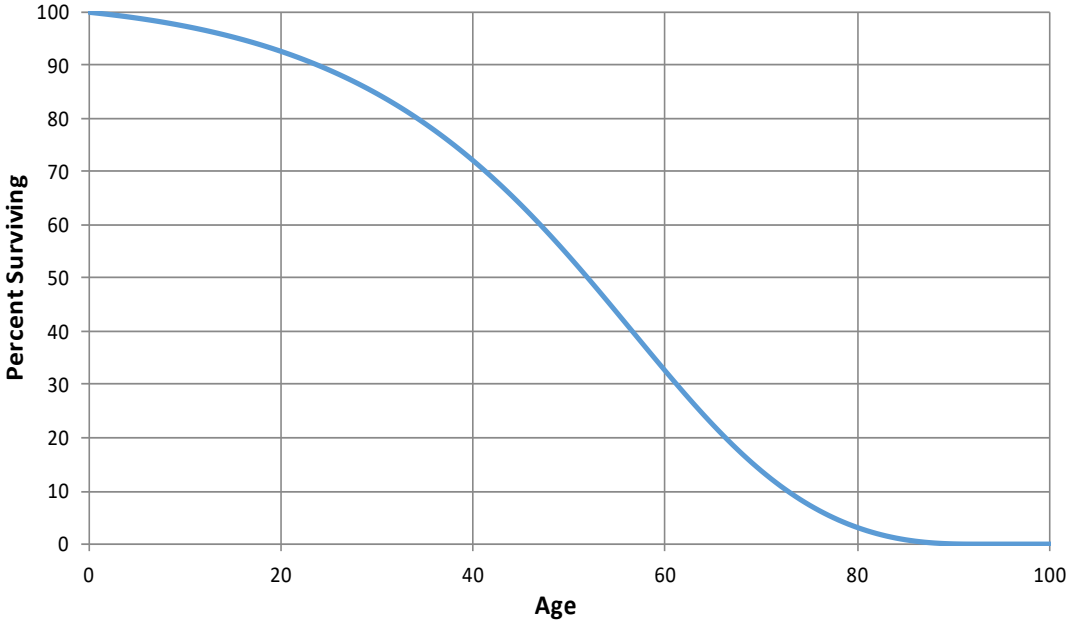
A The selection of the survivor curve is one of the most important decisions in conducting a depreciation study. A survivor curve is a graphical representation of the amount of property existing at each age interval throughout the life of a group of property. From the survivor curve, parameters required to calculate depreciation rates can be determined, such as the average service life of the group of property and the composite remaining life. For assets with an assumed lifespan or retirement date, the survivor curve is used to estimate the interim retirements that will occur between the study date and the estimated year of final retirement. These parameters directly affect the

depreciation rate calculations; therefore, informed judgment should be used in their selection.

In this proceeding, as well as the majority of utility regulatory rate case proceedings throughout the U.S. and Canada, the Iowa Curves are the general survivor curves utilized to describe the mortality characteristics of a group of property. There are four types of Iowa Curves: right-moded, left-moded, symmetrical-moded, and origin-moded. Each type describes where the greatest frequency of retirements occur relative to the average service life.

A survivor curve consists of an average service life and Iowa Curve type combination. For example, when describing property with a 50-year average service life that has mortality characteristics of the R2 Iowa Curve, the survivor curve would simply be notated as "50-R2." I present the 50-R2 survivor curve below in Figure 1.

Figure 1
50-R2
Survivor Curve



COLUMBIA GAS' DEPRECIATION STUDY

Q HAS COLUMBIA GAS PROPOSED NEW DEPRECIATION RATES IN THIS PROCEEDING?

A Yes. Columbia Gas retained Mr. John Spanos, of Gannett Fleming, to conduct a depreciation study on Columbia Gas' property as of November 30, 2023. This study is the basis of Columbia Gas' life parameters that are used to determine the depreciation rates based on the projected test year. The 2023 Depreciation Study has been filed as Exhibit No. 9, Schedule No. 1. The depreciation rates for the projected test year, based on 2025 plant balances, is filed as Exhibit No. 109, Schedule No. 1, Attachment B.

Q WHAT DEPRECIATION SYSTEM DOES COLUMBIA GAS UTILIZE IN THE CALCULATION OF ITS PROPOSED DEPRECIATION RATES?

A Columbia Gas used a depreciation system consisting of the Straight-Line Method, the ELG procedure,[3] and the Remaining Life Technique[4] to calculate its proposed depreciation rates.

Q HOW DO COLUMBIA GAS' PROPOSED DEPRECIATION RATES IMPACT THE REVENUE REQUIREMENT IN THIS PROCEEDING?

A Columbia Gas' proposed depreciation rates significantly impact the revenue requirement in this proceeding. As is shown on Columbia Gas' Exhibit No. 102, Schedule 3, Columbia Gas' depreciation and amortization expense is $136.0 million for

[3]Columbia Gas uses the ALG procedure for assets installed prior to 1976 and the ELG procedure for assets installed in 1976 and later. The 1976 and later assets represent 99% of its depreciable plant in-service.

[4]Columbia Gas Statement No. 5 at page 4, lines 15-20.

the 2025 projected test year, representing 25% of Columbia Gas' total operating expenses.[5] The same exhibit shows that the 2023 depreciation and amortization expense was $100.8 million, meaning a 35% increase in depreciation and amortization expense over a two-year period. As I will discuss later, Columbia Gas' use of the ELG procedure is exacerbating this increase. I summarize the increase by functional group below in my Table 1.

TABLE 1

Columbia Gas Annual Depreciation Expense
($ Millions)

Group	Current 12/31/2023	Proposed 12/31/2025	Delta Amount	Delta Percent
Underground Storage	$ 0.58	$ -	$ (0.58)	-100.0%
Distribution	$ 97.21	$ 120.39	$ 23.17	23.8%
General	$ 1.71	$ 1.51	$ (0.19)	-11.4%
Total Depreciable Plant	**$ 99.50**	**$ 121.90**	**$ 22.40**	**22.5%**

Sources: Exhibit 109 Schedule 3 and Exhibit 105

Q WHAT IS THE PRIMARY FACTOR DRIVING THE INCREASE TO COLUMBIA GAS' DEPRECIATION EXPENSE?

A Columbia Gas is in an extremely aggressive investment cycle, primarily due to substantial capital investments that Columbia Gas has been making since 2007 as part of its accelerated pipeline replacement program. Since 2007, Columbia Gas has replaced over 1,400 miles of cast iron and bare steel pipeline, over 274 miles of ineffectively coated steel pipe, and over 142 miles of pre-1982 plastic.[6] This program will continue through the end of the FPFTY and beyond with the third-approved Long

[5]Columbia Gas refers to this as "Operating Revenue Deductions" on its income statement.
[6]Columbia Gas Statement No. 1 at page 7, lines 6-13.

Term Infrastructure and Improvement Plan ("LTIIP"), which will see annual capital expenditures ranging from $388 million to $463 million each year from 2024-2028.[7] In Table 2, I show the increase in Columbia Gas' plant in-service and depreciation expense from 2021-2025.

TABLE 2

Columbia Gas Annual Plant in Service and Depreciation Expense
($ Millions)

Description	Currently Approved 2021	2022	2023	Proposed Parameters 2024	2025	2021 to 2025 Increase	Percent Increase
Total Plant in Service	$ 3,196.22	$ 3,551.99	$ 3,969.66	$ 4,321.12	$ 4,718.12	$ 1,521.90	47.62%
Total Depreciation Expense	$ 79.25	$ 88.45	$ 99.50	$ 113.70	$ 121.90	$ 42.65	53.82%

Sources: Exhibit 9 Schedule 3, Exhibit 109 Schedule 3, and Exhibit 105

As can be seen, Columbia Gas' total depreciation expense has increased over 53% over a 5-year period, largely coinciding with a 48% increase to plant in-service.

Q DO YOU TAKE ISSUE WITH COLUMBIA GAS' DEPRECIATION STUDY?

A Yes. Columbia Gas' proposed depreciation rates are overstated and burden Columbia Gas' customers with unnecessary and excessive depreciation expense and unnecessarily inflate the revenue requirement. In particular, Columbia Gas' reliance on the ELG procedure results in depreciation rates that are front-loaded and forces unnecessary depreciation expense on current customers. This compounds the cost of the infrastructure asset in the early years of the asset's service life by increasing both the return on the asset (because undepreciated net plant cost is highest in the early years) and the annual recovery of the asset or depreciation expense. Like most other regulatory

[7] *Id.*at pages 13 and 14, Figure 1 on page 14.

commissions, the ELG procedure should be rejected by the PUC in favor of the ALG procedure.

Q WHY SHOULD THE PUC REJECT COLUMBIA GAS' USE OF ELG DEPRECIATION RATES?

A The vast majority of utilities in the country calculate depreciation rates using the ALG procedure. As far as I am aware, only some Pennsylvania utilities and a few utilities in Texas rely on the ELG procedure presently. As I will demonstrate, the ELG procedure results in front-loaded depreciation rates that burden customers with unnecessarily high depreciation expense. Utilities in Indiana recently have made the switch to ALG rates due to the Indiana Utility Regulation Commission's ("IURC") finding that "the use of ELG in a higher than average investment cycle has the effect of unnecessarily increasing the near term depreciation expense as compared to the use of ALG."[8] Columbia Gas has more than quadrupled its plant in-service since its LTIIP began in 2007[9] and intends to continue to invest significant amounts of capital in through at least 2028. Columbia Gas has and will continue to be in a "higher than average" investment cycle. Accordingly, the PUC should reject Columbia Gas' proposed use of the ELG procedure to calculate depreciation rates and instead order the use of the ALG procedure to mitigate the rate impact of substantial rate base increases.

[8] *Petition of Duke Energy Indiana, LLC Pursuant to Ind. Code §§ 8-1-2-42.7 and 8-1-2-61,* Indiana Utility Regulatory Commission (IURC), June 29, 2020 IURC Final Order in Docket No. 45253 at page 90, file:///C:/Users/ef1/Downloads/45253%20ORDER%20062920.pdf. See Exhibit BCA-2.

[9] 2007 Annual Report Plant in Service - $788.614 million. 2023 Annual Report Plant in Service - $3.837 billion.

ELG VS. ALG DEPRECIATION RATES

Q WHAT DEPRECIATION GROUPING PROCEDURE DOES COLUMBIA GAS PROPOSE?

A Columbia Gas has used the ELG procedure to calculate its proposed depreciation rates.

Q WHAT IS THE MOST COMMONLY UTILIZED GROUPING PROCEDURE?

A The most commonly utilized depreciation grouping procedure throughout the nation is the ALG procedure. I have addressed in testimony, or reviewed depreciation studies conducted in approximately half of the states in the USA. In all states where I have experience, except for a few utilities in Texas and Pennsylvania, depreciation rates are routinely calculated using the ALG procedure.

Q HOW ARE DEPRECIATION RATES COMPUTED IN THE ELG PROCEDURE?

A When depreciation rates are computed using the ELG procedure, an attempt is made to precisely identify the exact year in which all property will retire and create a depreciation rate that ensures recovery of the property over the computed remaining life. Accordingly, property that will only have a 1-year life (according to a survivor curve) should have 100% depreciation rate; property that will have a 2-year life would have a 50% depreciation rate, property that has a 3-year life would have a 33% depreciation rate and so on. These are the ELGs, each with a unique depreciation rate to ensure recovery over the life of the ELG.

To be more specific, the Columbia Gas Depreciation Study was conducted based on 2025 plant balances. Because Columbia Gas is relying on the ELG procedure, it is essentially claiming it knows exactly how much property will retire in 2026, and established a depreciation rate for that property that ensures all unrecovered investment and net salvage is recovered in 2026. Similarly, it must know exactly how much property will retire in 2027, 2028, 2029, and every single year in the future. Each ELG for each account will have a unique depreciation rate, in an attempt to recover the cost of those ELGs over the remaining life. The annual accruals for each ELG are summed to determine the total annual accrual for each account. The depreciation rate would then be equal to the sum of annual accruals divided by the total account balance. The selection of the survivor curve has a significant impact on the amount of property assumed to be in each ELG.

Q HOW ARE DEPRECIATION RATES COMPUTED IN THE ALG PROCEDURE?

A With the ALG procedure, all assets in an account are assumed to have an average life equal to that of the proposed survivor curve. While some property will be retired before the average service life, and some will be retired after the average service life, on average, the property will exhibit life characteristics according to the survivor curve. For each vintage of property within an account, the remaining life is determined based on the age of the property and the survivor curve selected for the account. The unrecovered cost for each vintage is spread over the remaining life of that vintage, yielding an annual accrual for each vintage. The vintage annual accruals are summed

for the entire account, and the total of annual accruals is divided by the account balance to determine the depreciation rate.

Q HAVE YOU CREATED AN EXAMPLE THAT COMPARES THE ELG AND THE ALG PROCEDURES?

A Yes. I have created an example that will demonstrate the differences between the ALG and ELG procedures. It will demonstrate how the rates are calculated under each procedure and will show that the ELG is front-loaded and requires annual updates.

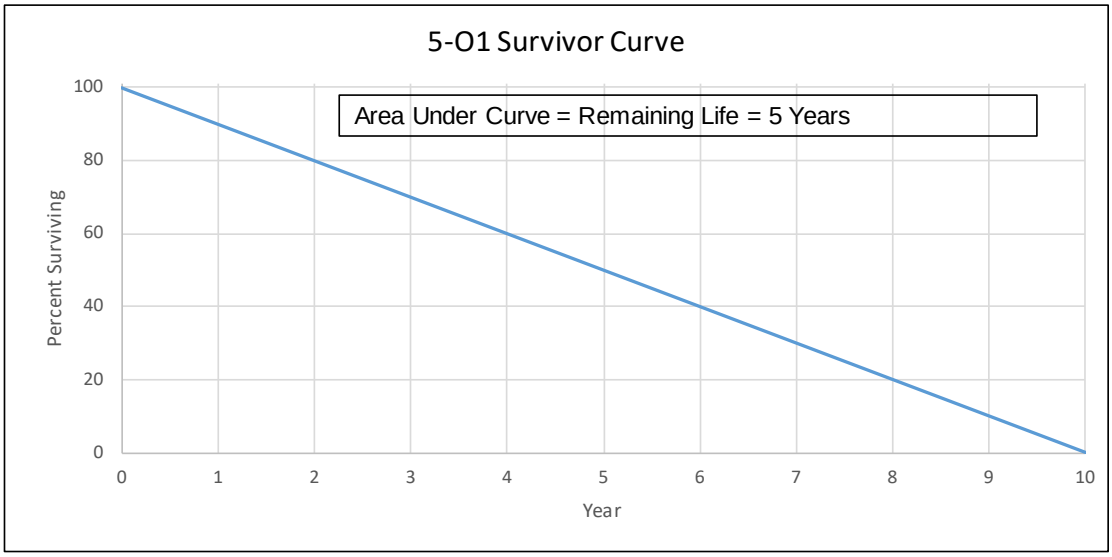
Q WHAT ASSUMPTIONS ARE YOU MAKING IN YOUR EXAMPLE?

A This example assumes that $100,000 of property is placed in-service into an account. It is the first and only property to exist in the account, and it will not be replaced as the initial $100,000 investment retires. The property will retire consistent with the 5-O1 survivor curve and has a -10% net salvage rate. This example will demonstrate how $110,000 will be recovered over the life of the property.

Q PLEASE DESCRIBE THE 5-O1 SURVIVOR CURVE.

A The 5-O1 survivor curve is presented in Figure 2.

FIGURE 2



The 5-O1 survivor curve has a 5-year average service life and assumes that all property is retired by year 10. This survivor curve assumes that 10% retires each year, therefore, in this example, it is assumed that $10,000 retires each year.

Q HOW WOULD THE ALG DEPRECIATION RATE BE CALCULATED FROM THE 5-O1 SURVIVOR CURVE?

A In the ALG procedure, the depreciation rate is calculated by ensuring recovery of the investment less net salvage over the remaining service life of the property. In this example, the net salvage rate is -10%, therefore, 110% of the investment needs to be recovered over the average service life, which in this example is 5 years. 110% divided by 5 years equals 22%. 22% is the depreciation rate that needs to be in place for 10 years to ensure the recovery of the $100,000 investment and $10,000 for net salvage over the life of the property.

Q HOW WOULD THE ELG DEPRECIATION RATE BE CALCULATED FROM THE 5-O1 SURVIVOR CURVE?

A With the ELG procedure, a different depreciation rate is needed for each year. The 5-O1 survivor curve in this example yields 10 different ELGs. The first group will have a 1-year life, the second group will have a 2-year life, and so on until the last group, which would have a 10-year life. In the first year, the total depreciation rate would allow for recovery of a portion of all 10 of the ELGs. In the second year, the depreciation rate would recover a portion of all of the ELGs except for the 1-year ELG, which according to the survivor curve is retired. The last year's depreciation rate would only provide for the last annual accrual of the 10-year ELG.

Q CAN YOU PROVIDE A COMPARISON OF THE ANNUAL DEPRECIATION EXPENSE IN YOUR EXAMPLE?

A Yes. Below in Table 3, I provide a comparison of the annual depreciation rates and expense needed to recover the $100,000 investment over its service life assuming it retires according to the 5-O1 survivor curve and has a -10% net salvage rate.

TABLE 3

Comparison of ALG Procedure and ELG Procedure
Recovery of $100,000 Investment with 10% Net Salvage and 5-O1 Survivor Curve

Year	First of Year Surviving Original Cost	ALG Rate	ALG Expense	ELG Rate	ELG Expense	Delta
1	$ 100,000	22.00%	$ 20,900	37.82%	$ 35,932	$15,032
2	90,000	22.00%	18,700	25.02%	21,265	2,565
3	80,000	22.00%	16,500	20.53%	15,398	(1,102)
4	70,000	22.00%	14,300	17.89%	11,627	(2,673)
5	60,000	22.00%	12,100	16.06%	8,833	(3,267)
6	50,000	22.00%	9,900	14.69%	6,611	(3,289)
7	40,000	22.00%	7,700	13.61%	4,765	(2,935)
8	30,000	22.00%	5,500	12.74%	3,185	(2,315)
9	20,000	22.00%	3,300	12.03%	1,805	(1,495)
10	10,000	22.00%	1,100	11.58%	579	(521)
	Total Recovered Investment:		**$ 110,000**		**$ 110,000**	**$ (0)**

Source: BCA WP-2

Q WHAT DOES YOUR EXAMPLE DEMONSTRATE?

A Table 3 above demonstrates how both the ALG and ELG procedures allow for capital recovery of the $100,000 investment and the $10,000 for net salvage over the same 10-year period. The ALG depreciation rate is 22% and held constant through the 10-year period in which this property provides service. The ELG procedure requires a 37.82% depreciation rate in year 1, a 25.02% depreciation rate in year 2, declining until there is an 11.58% depreciation rate in year 10. This example shows how the ELG depreciation rates must be adjusted every year, otherwise significant intergenerational inequities will exist, and more cost will be recovered than is necessary in the first two years. However, in ratemaking, depreciation expense that is included in customer base rates are only updated when the PUC approves new base rates, which means that the year 1 depreciation expense would essentially be utilized as the test year expense until new depreciation rates are approved in a future rate case. In my example above, this would effectively "lock in" a 37.82% depreciation rate until new rates are established in a future rate case.

Q PLEASE EXPAND ON LAST STATEMENT.

A Utilities typically only update their depreciation expense recovered from customers in the context of a base rate case, which is often not an every year occurrence. When depreciation rates for new assets are proposed using the ELG procedure, the rates put forward for approval would be analogous to the year 1 depreciation rate in this example. Therefore, if the ELG method were approved in a depreciation study, given this example and left in place for 10 years, the effective depreciation rate would be 37.82% every

year. To be just to consumers and to produce reasonable rates, ELG depreciation rates should be updated each year and the corresponding depreciation expense adjusted in base rates; however, the ELG depreciation rates are not properly implemented and create intergenerational inequities, significantly overcharging customers in base rates based on the higher depreciation rates in the earlier years. Table 4 shows an example of improperly implemented ELG depreciation rates. This table shows that if the year 1 ELG rates were left unchanged for the entire 10-year period, the utility would actually recover $79,114, or 72%, more than it is entitled to recover.

TABLE 4

Comparison of ALG Procedure and Improperly Implemented ELG Procedure
Recovery of $100,000 Investment with 10% Net Salvage and 5-O1 Survivor Curve

Year	First of Year Surviving Original Cost	ALG Rate	ALG Expense	ELG Rate	ELG Expense	Delta
1	$ 100,000	22.00%	$ 20,900	37.82%	$ 35,932	$15,032
2	90,000	22.00%	18,700	37.82%	32,149	13,449
3	80,000	22.00%	16,500	37.82%	28,367	11,867
4	70,000	22.00%	14,300	37.82%	24,585	10,285
5	60,000	22.00%	12,100	37.82%	20,803	8,703
6	50,000	22.00%	9,900	37.82%	17,020	7,120
7	40,000	22.00%	7,700	37.82%	13,238	5,538
8	30,000	22.00%	5,500	37.82%	9,456	3,956
9	20,000	22.00%	3,300	37.82%	5,673	2,373
10	10,000	22.00%	1,100	37.82%	1,891	791
	Total Recovered Investment:		**$ 110,000**		**$ 189,114**	**$79,114**

Source: BCA WP-2

Q WHY IS IT IMPORTANT TO AVOID INTERGENERATIONAL INEQUITIES?

A As I discussed earlier in my testimony, the underlying principal for determining depreciation rates is to achieve intergenerational equity. Given that traditional ratemaking sets rates on a forward-looking basis based on test year expense and remain in effect until a future rate case, the use of a depreciation system that utilizes the ELG procedure in the test year is at odds with this principle. As my example has clearly demonstrated, the ELG procedure is an accelerated form of depreciation, which causes

current customers to pay greater depreciation expense than future customers for the same level of utility service.

Q SHOULD DEPRECIATION RATES THAT ARE CALCULATED USING THE ELG PROCEDURE BE UPDATED ANNUALLY?

A Yes. The only way for depreciation expense to "accurately" charge customers under the ELG procedure is for the depreciation expense component of base rates to be updated annually. Otherwise, the depreciation expense that is left in effect will be the high year 1 depreciation rate, as demonstrated in this example. The depreciation expense is also only accurate if the utility property retires in exactly the manner dictated by the survivor curves used to calculate the ELG rates. This precision does not exist in the traditional rate setting paradigm as it would amount to impermissible single-issue ratemaking, which I understand is disfavored in Pennsylvania.

Q HOW MUCH HAS COLUMBIA GAS' UTILITY PLANT INCREASED SINCE IT STARTED ITS ACCELERATED PIPELINE REPLACEMENT PROGRAM?

A The accelerated pipeline replacement program or LTIIP started in 2007. According to Columbia Gas' 2007 Annual Report, Columbia Gas had a utility plant of $567.8 million, as of December 31, 2007. As of the most recent annual report, Columbia Gas has utility plant of $3,457.6 million for the year ending December 31, 2023. This is a 509% increase; in other words, Columbia Gas has increased its utility plant six-fold in a 16-year period. Stated differently, Columbia Gas has increased its utility plant, on average at 12.0% annually since the LTIIP started.

Q DOES COLUMBIA GAS PLAN TO CONTINUE WITH SUBSTANTIAL CAPITAL ADDITIONS THAT WILL INCREASE ITS RATE BASE?

A Yes. Company witness Mr. Kempic shows that the Company intends to continue to invest significant amounts of capital in growth, betterment, public improvement, pipeline replacement, and support services from 2024 through 2028. These investments will average $429 million annually over this period.[10] It is clear that Columbia Gas will continue to experience a higher-than-average investment cycle.

Q CAN THE RATE IMPACT OF SUBSTANTIAL INCREASES TO RATE BASE BE MITIGATED WITHOUT UNREASONABLE ADVERSE IMPACT ON THE UTILITY?

A Yes. The rate impact of substantial increases to rate base can be mitigated by depreciating these assets using depreciation rates that are determined using the ALG procedure. The ALG procedure is the most commonly used deprecation procedure in use in the country. The ALG procedure will properly allow Columbia Gas to recover the full cost of investments, including net salvage value, over the life of the assets; however, it will be at a more reasonable rate and, therefore, reduces the expense in the interest of consumers and allows for more just and affordable rates. Columbia Gas' use of ELG significantly understates the remaining life, and thus, the recovery period for its assets.

[10]Columbia Gas Statement No. 1 at page 14, Figure 1.

Q HOW DOES THE ELG UNDERSTATE THE REMAINING LIFE OF COLUMBIA'S ASSETS?

A Due to Columbia Gas' pipeline replacement program, most of its investment in distribution mains is quite new. According to the depreciation study data as of December 31, 2025, the average age of the investment contained in Account 376 is 9.5 years. Account 376 is $3.2 billion, or 68%, of Columbia Gas' $4.7 billion plant in-service. This account represents 60% of Columbia Gas' proposed depreciation expense. According to Columbia Gas, Account 376 has an average service life of 65 years. The use of the ELG procedure significantly shortens the recovery period for this account. Table 5 below shows the composite remaining life for Account 376 under the ELG and ALG procedures.

TABLE 5

Remaining Life of Account 376 with ELG vs. ALG
Depreciation Study as of 12/31/2025

Account	Composite Remaining Life ELG	ALG	Delta
Account 376	37.3	57.8	20.6

Sources: Exhibit No. 105 and Exhibit BCA-3

As can be seen, with the ELG procedure, the remaining life of Account 376 is 37.3 years. With the more commonly used ALG procedure, the remaining life, or recovery period for the investment is 57.8 years. Columbia Gas' use of the ELG procedure recovers its investment more than 20 years faster than under the ALG. Even though Columbia Gas supports a 65-year life for these assets, the use of the ELG

procedure only gives it an expected life of 46.8 years.[11] This significantly overstates the depreciation rates, and thus, the depreciation expense. This issue exists for all of Columbia Gas' depreciable accounts, due to the use of the ELG procedure.

Q ARE YOU AWARE OF PUBLIC UTILITY COMMISSIONS THAT HAVE REJECTED THE USE OF ELG?

A Yes. I can provide two examples of public utility commissions that have rejected the use of ELG, due to the excessive depreciation expense that results from its use.

The Kentucky Public Service Commission ("Kentucky PSC") found that the ELG procedure front-loads depreciation expense in earlier years and decreases it in the later years of an asset's depreciation life, creating a mismatch of revenues and expenses. The Kentucky PSC states reasoning for rejecting the ELG is as follows:

> Duke Kentucky proposes, as part of developing its depreciation rates, the continued use of the ELG procedure. The Attorney General recommends the Commission adopt the ALG procedure in developing Duke Kentucky's depreciation rates. The Attorney General contends that the ALG methodology is the predominant method that is used in the electric industry for developing depreciation rates. The Attorney General contends that, under the ELG methodology, the capital recovery periods are accelerated and shortened and, thus, the depreciation rates are greater than if the ALG procedure was used. The Attorney General argues that the ALG procedure is as accurate as the ELG procedure and the ALG procedure smooths the data so that the depreciation rates for the group of assets tend to remain constant. Use of the ALG procedure will result in a decrease in Duke Kentucky's depreciation expense of $6.920 million.
>
> Duke Kentucky requested an increase in depreciation expense of $6.920 million, based on its request to utilize the ELG procedure for computing depreciation rates. As was discussed in the rate base section of this Order, this Commission has found that the ELG procedure does not accurately match revenues and expenses, is front-loaded, and Duke

[11] 9.5 year average age + 37.3 year remaining life = 46.8 year life expectancy.

> Kentucky is the only Kentucky based utility that utilizes the ELG procedure for computing depreciation rates.
>
> Regulatory accounting requires the proper matching of revenues and expense in order to produce fair, just and reasonable rates. The Commission finds Duke Kentucky's proposed ELG procedure does not meet that criteria and that Duke Kentucky's depreciation expense should be reduced by $6.920 million.

In the Matter of: Electronic Application of Duke Energy Kentucky, Inc., Kentucky PSC, Order at pages 26-27, Case No. 2017-00321.[12]

I have included the relevant pages of the Kentucky PSC Final Order as my Exhibit BCA-1.

More recently, the IURC rejected the use of ELG in Duke Energy Indiana's rate case, stating:

> First, with respect to the question of whether the ELG or ALG method should be used, we find the evidence presented by OUCC witness Mr. Garrett and Industrial Group witness Mr. Andrews persuasive, as both witnesses showed that the **ELG method results in unreasonably high depreciation rates. ALG depreciation rates result in systematical and rational cost recovery with near term customer rate relief and full cost recovery of utility investments**. While we have determined in the past that the ELG methodology was appropriate and acknowledge the weight given to precedent in many prior decisions, we always evaluate each case as it comes before us and do not need to approve the same methodology based on prior decisions, especially in light of a changed landscape. **The use of ELG in a higher than average investment cycle has the effect of unnecessarily increasing the near term depreciation expense as compared to the use of ALG**. A review and comparison of Mr. Andrew's exhibits reflecting only the ALG verses the ELG modifications applied to Mr. Spanos' results indicate that the impact of the methodology change on a percentage basis is markedly more significant for the distribution and transmission components than the production, or generation, component. This evidence is not surprising given the increased investment cycle in these categories as highlighted by the relatively recent statutory support for such investment codified at Indiana Code ch. 8-1-39. A changed and encouraged investment cycle is a material landscape change through which we consider our previous proclamations on methodology. Furthermore, the

[12]https://psc.ky.gov/pscscf/2017%20Cases/2017-00321//20180413_PSC_ORDER.pdf.

> consideration of service affordability in the near term provides sufficient weight to temper our historical preference for ELG. Again, a recently enacted statute, Indiana Code § 8-1-2-0.5, directing the commission to consider "all practical means and measures" to balance necessary investment with service affordability enhances the regulatory landscape.
>
> IURC Final Order at page 90.[13]

I have included the relevant pages of the IURC Final Order as my Exhibit BCA-2.

Q WHY IS IT APPROPRIATE FOR THE PUC TO REJECT COLUMBIA GAS' PROPOSED USE OF THE ELG PROCEDURE AND TO REQUIRE THE USE OF THE ALG PROCEDURE AT THIS TIME?

A Just as in the 2020 Duke Electric rate case in which the IURC found that "the use of ELG in a higher-than-average investment cycle has the effect of unnecessarily increasing the near term depreciation expense as compared to the use of ALG,"[14] Columbia Gas has and will continue to substantially increase rate base and investment. As I have demonstrated above, depreciation rates calculated using the ELG procedure result in the front-loading of depreciation rates, and when the resulting depreciation rates are not updated annually, customers pay substantially more depreciation expense than is necessary for the utility to recover its investments.

[13] https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/7b316e6f-1bba-ea11-a812-001dd8018831/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=45253%20ORDER%20062920.pdf.

[14] *See n.* 8.

OCA PROPOSED DEPRECIATION RATES

Q HAVE YOU CALCULATED DEPRECIATION RATES USING THE ALG PROCEDURE FOR COLUMBIA GAS?

A Yes. In Exhibit BCA-3, I present depreciation rates that were calculated using all of Columbia Gas' proposed life and net salvage parameters but applying the ALG procedure. The PUC should approve the depreciation rates contained in Exhibit BCA-3.

Q HOW DO THE ALG DEPRECIATION RATES CHANGE THE DEPRECIATION EXPENSE BASED ON PLANT BALANCES AS OF DECEMBER 31, 2025?

A I present this comparison in my Exhibit BCA-4. The ALG depreciation rates would reduce the depreciation expense, on plant balances as of December 31, 2025, by $43.9 million. I summarize these changes by functional group in Table 6.

TABLE 6

Depreciation Expense and Rate Comparison
Depreciation Study as of 12/31/2025

	Depreciation Expense ($ Millions)				Depreciation Rate		
			Delta				
Group	Columbia	OCA	Amount	Percent	Columbia	OCA	Delta
Underground Storage	$ -	$ -	$ -	0.0%	0.00%	0.00%	0.00%
Distribution	$ 120.39	$ 76.58	$ (43.81)	-36.4%	2.58%	1.64%	(0.94%)
General	$ 1.51	$ 1.44	$ (0.08)	-5.2%	4.23%	4.01%	(0.22%)
Total Depreciable Plant	**$ 121.90**	**$ 78.02**	**$ (43.88)**	**-36.0%**	**2.58%**	**1.65%**	**(0.93%)**

Source: Exhibit BCA-4

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

QUALIFICATIONS OF BRIAN C. ANDREWS

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation and a Principal with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EMPLOYMENT EXPERIENCE.

A I received a Bachelor of Science Degree in Electrical Engineering from the Washington University in St. Louis/University of Missouri - St. Louis Joint Engineering Program. I have also received a Master of Science Degree in Applied Economics from Georgia Southern University.

I have attended training seminars on multiple topics including class cost of service, depreciation, power risk analysis, production cost modeling, cost-estimation for transmission projects, transmission line routing, MISO load serving entity fundamentals and more.

I am a member and a former President of the Society of Depreciation Professionals. I have been awarded the designation of Certified Depreciation Professional ("CDP") by the Society of Depreciation Professionals. I am also a certified Engineer Intern in the State of Missouri.

As an Associate at BAI, and as a Senior Consultant, Consultant, Associate Consultant and Assistant Engineer before that, I have been involved with several regulated and competitive electric service issues. These have included book depreciation, fuel and purchased power cost, transmission planning, transmission line routing, resource planning including renewable portfolio standards compliance, electric price forecasting, class cost of service, power procurement, and rate design. This has involved use of power flow, production cost, cost of service, and various other analyses and models to address these issues, utilizing, but not limited to, various programs such as Strategist, RealTime, PSS/E, MatLab, R Studio, ArcGIS, Excel, and the United States Department of Energy/Bonneville Power Administration's Corona and Field Effects ("CAFÉ") Program. In addition, I have received extensive training on the PLEXOS Integrated Energy Model and the EnCompass Power Planning Software. I have provided testimony on many of these issues before the Public Service Commissions in Arizona, Arkansas, California, Colorado, Florida, Illinois, Indiana, Kansas, Kentucky, Louisiana, Michigan, Minnesota, Missouri, Montana, New Mexico, Oklahoma, South Carolina, Texas, and Washington DC.

BAI was formed in April 1995. BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

499532

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF DUKE ENERGY KENTUCKY, INC. FOR: 1) AN ADJUSTMENT OF THE ELECTRIC RATES; 2) APPROVAL OF AN ENVIRONMENTAL COMPLIANCE PLAN AND SURCHARGE MECHANISM; 3) APPROVAL OF NEW TARIFFS; 4) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND 5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2017-00321

ORDER

Duke Energy Kentucky, Inc. ("Duke Kentucky") is a jurisdictional electric utility that generates, transmits, distributes, and sells electricity to approximately 140,600 consumers in Boone, Campbell, Grant, Kenton, and Pendleton counties.[1] Duke Kentucky also is a utility engaged in purchasing, selling, storing, and transporting natural gas to approximately 98,200 customers in Boone, Bracken, Campbell, Gallatin, Grant, Kenton, and Pendleton counties.[2] Its most recent general rate increase for its electric operations was granted in Case No. 2006-00172.[3]

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[1] Application at 2. *See also*, Direct Testimony of James P. Henning ("Henning Testimony") at 4.

[2] *Id.*

[3] Application at 4. Case No. 2006-00172, *Application of the Union Light, Heat and Power Company D/B/A Duke Energy Kentucky for an Adjustment of Electric Rates* (Ky. PSC Dec. 21, 2006).

extraordinary. In using this forecasted test period, the Commission has given full consideration to appropriate known and measurable changes.

Jurisdictional Rate Base Ratio

Duke Kentucky proposed a test-year-end Kentucky jurisdictional rate base of $700,204,561.[22] The Kentucky jurisdictional electric rate base is divided by Duke Kentucky's test-year-end total company electric rate base to derive the Kentucky jurisdictional electric rate base ratio ("Jurisdictional Ratio") for Duke Kentucky. This Jurisdictional Ratio is then applied to Duke Kentucky's total company electric capitalization to derive its Kentucky jurisdictional electric capitalization. The Jurisdictional Ratio uses the test-year-end rate base before any ratemaking adjustments applicable to either Kentucky jurisdictional operations or other jurisdictional operations. Duke Kentucky used a Jurisdictional Ratio of 100 percent.[23] The Commission has reviewed and agrees with the calculation of Duke Kentucky's test-year electric rate base for purposes of establishing the Jurisdictional Ratio.

Pro Forma Jurisdictional Rate Base

Duke Kentucky calculated a pro forma jurisdictional rate base of $700,204,561,[24] which reflects the types of adjustments made by the Commission in prior rate cases to determine the pro forma rate base. The Attorney General provided testimony and several adjustments to Duke Kentucky's proposed rate base as discussed below. The Commission finds seven adjustments are warranted to Duke Kentucky's rate base. The

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[22] Application, Schedule B-1.

[23] *Id.*, Schedule B-7.

[24] *Id.*, Schedule B.1. Duke Kentucky is not requesting to include recovery of Construction Work in Progress in base rates.

Commission finds that the excess amortization of the Carbon Management Research Group regulatory asset in the test year and the amortization of excess accumulated deferred income tax ("ADIT") should be added to the rate base. The Commission also finds that the East Bend Operations and Maintenance Expense ("East Bend O&M") regulatory asset, the East Bend Ash Pond Asset Retirement Obligation ("East Bend Ash Pond ARO") regulatory asset, the reduction in cash working capital ("CWC"), and the reduction in depreciation expense as discussed herein due to the Commission's decision to deny use of the Equal Life Group ("ELG") procedure and require use of the Average Life Group ("ALG") procedure for computing depreciation rates, net of the related ADIT as found reasonable herein, should be removed from rate base.

The Commission accepts Duke Kentucky's proposed amortization of the protected excess ADIT. The amortization for the protected excess ADIT is based upon the Average Rate Assumption Method ("ARAM"). For the unprotected excess ADIT, the Attorney General initially proposed a 20-year amortization period.[25] Subsequently, the Attorney General proposed a five-year amortization period for the unprotected excess ADIT but did not amend his testimony to reflect the change in the amortization period.[26] The Commission finds that a reasonable amortization period for the excess ADIT for Duke Kentucky's unprotected assets should be 10 years. A 10-year amortization period for the unprotected excess ADIT will balance the impact to Duke Kentucky's cash flow and provide ratepayers the full benefit of the reduction in the federal corporate income tax in a timely manner. As a result of the foregoing adjustments, the Commission finds the total

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[25] *Id.*

[26] March 8, 2018, Video Transcript of Evidence at 3:35:00.

test-year amortization for the total excess ADIT to be $4,471,984, which is an increase of $1,651,639 over the amount proposed by Duke Kentucky. The Commission finds that the amortization of the excess ADIT related to protected and unprotected excess ADIT found reasonable herein should be removed from Duke Kentucky's ADIT, which increases its rate base. Therefore, Duke Kentucky's rate base should be increased by $4,471,984 for this adjustment.

Duke Kentucky deferred $2 million it incurred to fund carbon management research by the Carbon Management Research Group ("CMRG"). In Case No. 2008-00308, Duke Kentucky sought and obtained authorization from the Commission to defer these costs for accounting purposes.[27] The regulatory asset, net of ADIT, is included in the capitalization in this proceeding. In the instant matter, Duke Kentucky sought to recover the amortization of the deferred asset over a five-year period at $400,000 per year. In the Commission's Order in Case No. 2008-00308, it stated that the CMRG regulatory asset will be amortized over a 10-year period or $200,000 per year. Therefore, the Commission finds that the Duke Kentucky's capitalization should be increased by $200,000 to reflect the proper amount of the regulatory asset in the rate base.

The Commission finds that the ADIT arising from its requirement to change Duke Kentucky's procedure for computing depreciation rates from the ELG to the ALG procedure should reduce Duke Kentucky's rate base. As discussed in the testimony of the Attorney General, the ELG procedure front-loads depreciation expense in earlier

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[27] Case No. 2008-00308, *Joint Application of Duke Energy Kentucky, Kentucky Utilities Company and Louisville Gas and Electric Company for an Order Approving Accounting Practices to Establish Regulatory Assets* (Ky. PSC Oct. 30, 2008).

years and decreases it in the later years of an asset's depreciable life, creating a mismatch of revenues and expenses.[28] The Attorney General states that the ALG procedure is the dominant procedure for other electric utilities, including all other electric utilities in Kentucky.[29] Therefore, the Commission finds that the Attorney General's position on this issue is reasonable and that Duke Kentucky should use the ALG procedure for computing depreciation rates, and that its rate base should be reduced by $2,733,299 to reflect the increase in ADIT.

The East Bend O&M regulatory asset was approved by the Commission in Case No. 2014-00201.[30] In addition, in that proceeding, the Commission authorized Duke Kentucky to defer carrying charges on the O&M expense at its cost of debt. The Attorney General disputed the amount of the regulatory asset and made a recommendation of the amount of amortization assuming that the regulatory asset was included in rate base.[31]

The Commission finds that the East Bend O&M regulatory asset should be removed from rate base and Duke Kentucky's request to amortize the East Bend O&M regulatory asset over a 10-year period is reasonable and should be approved. The Commission also finds that carrying charges should be based on the cost of debt approved herein. This adjustment reduces Duke Kentucky's rate base by $36,540,123.

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[28] Direct Testimony of Lane Kollen ("Kollen Testimony") beginning at 31.

[29] *Id*. at 32

[30] Case No. 2014-00201, *Application of Duke Energy Kentucky, Inc. for (1) a Certificate of Public Convenience and Necessity Authorizing the Acquisition of the Dayton Power & Light Company's 31% Interest in the East Bend Generating Station; (2) Approval of Duke Energy Kentucky, Inc.'s Assumption of Certain Liabilities in Connection with the Acquisition; (3) Deferral of Costs Incurred as part of the Acquisition; and (4) All Other Necessary Waivers, Approvals and Relief* (Ky. PSC Dec. 4, 2014).

[31] Kollen Testimony at 31.

The East Bend Ash Pond ARO was approved by the Commission in Case No. 2015-00187.[32] Duke Kentucky proposed that the East Bend Ash Pond ARO amortization be recovered through the Environmental Surcharge Mechanism ("ESM") in its application. In addition, Duke Kentucky requested a 10-year amortization period. The Attorney General proposed that the East Bend Ash Pond ARO be removed from capitalization, as it was erroneous for Duke Kentucky to include it in both its ESM rider rate base and in base rates. The Commission finds the East Bend Ash Pond ARO should not be included in base rates because that amount is proposed to be recovered through Duke Kentucky's ESM. The Commission also finds that a 10-year amortization period is reasonable and should be approved. The parties have agreed upon this issue. This adjustment reduces Duke Kentucky's rate base by $18,509,346.

The CWC allowance included in rate base shown below is based on the adjusted operation and maintenance expenses discussed in this Order, as approved by the Commission. This adjustment reduces Duke Kentucky's rate base by $2,008,320.

Based on the Commission's finding herein where it denied Duke Kentucky's proposal to use ELG procedure rather than the ALG procedure for computing depreciation rates, the Commission finds that Duke Kentucky's accumulated depreciation in its rate base should be increased by $6,919,475.

We have determined Duke Kentucky's pro forma jurisdictional rate base for rate-making purposes for the test year to be as follows:

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[32] Case No. 2015-00187, *Application of Duke Energy Kentucky, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Liabilities Associated with Ash Pond Asset Retirement Obligations* (Ky. PSC Dec. 15, 2015).

Depreciation Expense

Duke Kentucky proposes, as part of developing its depreciation rates, the continued use of the ELG procedure. The Attorney General recommends the Commission adopt the ALG procedure in developing Duke Kentucky's depreciation rates. The Attorney General contends that the ALG methodology is the predominant method that is used in the electric industry for developing depreciation rates. The Attorney General contends that, under the ELG methodology, the capital recovery periods are accelerated and shortened and, thus, the depreciation rates are greater than if the ALG procedure was used.[76] The Attorney General argues that the ALG procedure is as accurate as the ELG procedure and the ALG procedure smooths the data so that the depreciation rates for the group of assets tend to remain constant.[77] Use of the ALG procedure will result in a decrease in Duke Kentucky's depreciation expense of $6.920 million.

Duke Kentucky requested an increase in depreciation expense of $6.920 million, based on its request to utilize the ELG procedure for computing depreciation rates. As was discussed in the rate base section of this Order, this Commission has found that the ELG procedure does not accurately match revenues and expenses, is front-loaded, and Duke Kentucky is the only Kentucky based utility that utilizes the ELG procedure for computing depreciation rates.

Regulatory accounting requires the proper matching of revenues and expense in order to produce fair, just and reasonable rates. The Commission finds Duke Kentucky's

[76] *Id.* at 33.

[77] *Id.* at 35

proposed ELG procedure does not meet that criteria and that Duke Kentucky's depreciation expense should be reduced by $6.920 million.

Terminal Net Salvage – Generation Units

Duke Kentucky included an adjustment of its depreciation expense of $4.506 million to reflect the impact of terminal net salvage value.[78] Duke Kentucky's proposed depreciation rates reflect terminal net salvage, which the company contends is required under the Federal Energy Regulatory Commissions' Uniform System of Accounts.[79] Duke Kentucky further contends that, to avoid intergenerational inequity, these costs should be borne by those ratepayers who receive the benefit from the production assets.[80]

The Attorney General recommends reducing the proposed depreciation rates by removing terminal net salvage from production plant depreciation rates. The Attorney General argues that Duke Kentucky's proposed recovery of future terminal net negative salvage for production plant is unreasonable because those costs are not known with reasonable certainty today.[81] The Attorney General's recommendation is to reduce Duke Kentucky's depreciation expense by $4.506 million.[82]

The Commission finds Dukes Kentucky's recommendation on the treatment of terminal net salvage value in the computing the depreciation rates for generating units is reasonable in order to avoid intergenerational inequity and should be approved.

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[78] *Id*. at 42.

[79] John J. Spanos Rebuttal Testimony ("Spanos Rebuttal Testimony") at 4–5.

[80] Spanos Rebuttal Testimony at 4.

[81] Kollen Testimony at 39.

[82] *Id*. at 42.

ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ober	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	**CAUSE NO. 45253** **APPROVED: JUN 29 2020**

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
Sarah E. Freeman, Commissioner
David E. Veleta, Senior Administrative Law Judge

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process. Sierra Club and Joint Intervenors took issue with the retirement dates of Edwardsport IGCC and other coal units, finding that DEI should consider an earlier retirement of these units. In considering Edwardsport first, we find Mr. Gurganus' testimony persuasive. Edwardsport is the newest coal unit on the DEI system and continues to be a valuable asset for the Company's generating system, especially as the Company moves, as many utilities are, to retire older and less efficient coal plants. We also understand the many complexities and issues associated with primarily operating the plant on natural gas pointed out by Mr. Gurganus, not least of which is the requirement for new air permitting, elimination of tax incentives, and losing the optionality and diversity that operation primarily on coal provides. In contrast to the cross answering testimony of Mr. Schlissel, and based on the testimony provided by Mr. Gurganus, we find that Edwardsport has showed steadily increasing gasifier availability and capacity factor in line with expectations, and we note that the Company has invested in improvements at the plant, often at shareholder expense, to achieve these improvements, which Mr. Gurganus expects to continue.

As to the Company's other coal units, Sierra Club and Joint Intervenors criticize the Company's modeling that does not allow these units to retire prior to 2024. However, we find Mr. Pike's testimony on this point persuasive. There are clearly practical constraints and considerations to retiring units that should not be ignored by IRP modeling, such as labor force, community impacts, transmission constraints, and not least of all rate impact to customers. We also agree with Mr. Pike and Wabash Valley witnesses that it is reasonable to swap the retirement dates of Gibson Units 4 and 5, to accommodate the wishes of the joint owners of Gibson 5 and save the expense associated with the planned flue gas work for the units. Overall, we find that this moderate transition approach is reasonable and results in reasonable depreciation rates that, while increased compared to previous depreciation studies, are moderated to that which would accompany a more expedited transition.

Regarding the other Joint Intervenors' criticism of the IRP process, we find that the IRP is at issue in this proceeding only to the extent it helps support the proposed depreciation rates. We find Mr. Park's response to the various IRP issues reasonable and thorough. Further, we agree with Mr. Pike that models only inform us and do not themselves make reasoned recommendations or decisions. Rather, the Company does that through a review of various scenarios, sensitivities, and portfolios.

In sum, we find that DEI's proposed retirement dates, as revised in its rebuttal testimony for the Gibson 4/5 retirement date switch, are reasonable and prudent and will result in fair and reasonable rates for customers who benefit from the Company's rate base.

(C) <u>Depreciation Rates and Expense</u>. Mr. Spanos presented and supported a depreciation study related to DEI's electric plant as of December 31, 2018, as well as a fair value study. He testified that depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. He stated that among the causes to be given consideration are wear and tear, decay, action of the elements, obsolescence, changes in the art, changes in demand and the requirements of public authorities. He testified that in preparation of his study, he followed generally accepted practices in the field of depreciation and valuation. He

testified that his recommended depreciation rates appropriately reflect the rates at which the costs of DEI's assets are being consumed over their useful lives, and that the rates are an appropriate basis for setting electric rates in this matter and for the Company to use for booking depreciation and amortization expense going forward.

He testified the purpose of the depreciation study was to estimate the annual depreciation accruals related to electric plant in service for ratemaking purposes and determine appropriate average service lives and net salvage percentages for each plant account. He stated that in preparing his study, he used the straight line remaining life method of depreciation, with the equal life group procedure for all plant assets except some general plant accounts. He stated the annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner. He testified that for certain General Plant Accounts, he used the straight line remaining life method of amortization. He explained that the annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

To determine his recommended annual depreciation accrual rates, in the first phase of his study, he estimated the service life and net salvage characteristics for each depreciable group -- each plant account or subaccount identified as having similar characteristics. Then in the second phase of his study, he calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

He explained that in the first phase of the study he compiled historic data through 2018 from records related to DEI's plant; analyzed these data to obtain historic trends of survivor and net salvage characteristics; obtained supplementary information from DEI's management, and operating personnel concerning practices and plans as they relate to plant operations; and interpreted the above data and the estimates used by other electric utilities to form judgments regarding average service life and net salvage characteristics. To analyze the service life data, he used the retirement rate method and applied the retirement rate method to each different group of property in the study. He explained that the retirement rate method produces an original survivor curve for that property group, and that interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. He explained that widely used Iowa-type survivor curves were used to perform the interpretations. He further testified that he used the life span technique, which has been used previously for DEI, to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated.

He testified that DEI provided the production facility life span estimates based on informed judgment that incorporates factors for each facility such as the age, use, size, nature of construction, and technology of the facility; management plans and outlook for the facility; the estimates for similar facilities for other utilities; and the results of the Company's 2018 IRP. DEI witness Mr. Keith Pike discusses the life span estimates in detail, as is discussed below. Mr. Spanos also stated that he made a field review of DEI's property during November 2018 to observe representative portions of plant and that he also made field visits during prior studies since 1999. He explained that field reviews are conducted to become familiar with Company operations and

obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements.

He next discussed net salvage -- a component of the service value of capital assets that is recovered through depreciation rates. He explained that the service value of an asset is its original cost less its net salvage, and net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. He stated that when the cost to retire exceeds the salvage value, the result is negative net salvage.

He testified that inasmuch as depreciation expense is the loss in service value of an asset during a defined period, (*e.g*. one year), it must include a ratable portion of both the original cost and the net salvage. That is, he stated, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

He testified that the net salvage percentages estimated in the depreciation study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided by the Company's operating personnel; general knowledge and experience of industry practices; and trends in the industry in general. He stated that the statistical net salvage analyses incorporate the Company's actual historical data for the period 1989 through 2018 and consider the cost of removal and gross salvage ratios to the associated retirements during the 30-year period. He explained that the net salvage percentages for generating facilities were based on two components: the interim net salvage percentage, and the final net salvage percentage. He stated that the interim net salvage percentage was determined based on the historical indications from the period 1989 to 2018 of the cost of removal and gross salvage amounts as a percentage of the associated plant retired. He stated that the final net salvage, or decommissioning and dismantlement component, was determined based on the retirement activities associated with the assets anticipated to be retired at the concurrent date of final retirement. He testified that the decommissioning or dismantlement component has been included in the net salvage percentage for steam, hydro and other production facilities; the decommissioning and dismantlement component is part of the overall net salvage for each location within the production assets. He stated that based on studies for other utilities and the cost estimates of DEI, it was determined that the decommissioning or dismantlement component for steam, hydro, and other production facilities is best calculated by dividing the decommissioning or dismantlement cost by the surviving plant at final retirement. He explained that these amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location.

He testified that the decommissioning or dismantlement cost estimates are based on the decommissioning study of each generating site performed by Burns and McDonnell (discussed below). He explained that these estimates are based on the current cost (year 2018 dollars) to decommission the facilities. He noted, however, that the costs to decommission power plants have tended to increase over time (as have construction costs in general). For this reason, he testified, in order to recover the full decommissioning costs for each site, these costs need to be escalated to the time of retirement.

After Mr. Spanos estimated the service life and net salvage characteristics for each depreciable property group, he then calculated the annual depreciation accrual rates for each depreciable group based on the straight line remaining life method, using remaining lives weighted consistent with the equal life group procedure. He stated that the calculations of annual depreciation accrual rates were developed as of December 31, 2018. He explained that the straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

He testified that in the equal life group procedure, the property group is subdivided according to service life -- that is, each equal life group includes that portion of the property which experiences the life of that specific group. He stated that the relative size of each equal life group is determined from the property's life dispersion curve. He explained that this procedure eliminates the need to base depreciation on average lives, inasmuch as each group is equivalent to a unit having a single life. The full costs of short-lived units are accrued during their lives, he stated, leaving no deferral of accruals required to be added to the annual costs associated with long-lived units. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group, according to Mr. Spanos.

Mr. Spanos testified that the equal life group procedure allocates the capital cost of a group property to annual expense in accordance with the consumption of the service value of the group.

He added that the more timely return of plant investment accomplished by fully accruing each item's cost during its service life not only reduces the risk of incomplete capital recovery, but also results in less investment-related cost over the life span of a depreciable group. He explained that under the equal life group procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage, and the vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals.

Mr. Spanos stated that amortization accounting is used for accounts with a large number of units, but small asset values. In amortization accounting, he explained, units of property are capitalized in the same manner as they are in depreciation accounting; however, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, he stated, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service -- that is, there is no dispersion of retirement; all units are retired for depreciation purposes when the age of the vintage reaches the amortization period. He emphasized that amortization accounting is only appropriate for certain Common and General Plant accounts – in this case, for plant accounts which represent approximately one percent of depreciable plant.

Mr. Spanos testified that the development of the book reserve for each location has been established based on a composite rate for a group of locations within an account; thus, the actual book reserve at the location level was determined by applying a composite rate to the plant balance.

He explained that when dealing with group depreciation there are multiple parameters that affect the rate, such as interim survivor curve, probable retirement date and net salvage percent among the key factors. He further explained that in conducting a depreciation study, a more defined manner of determining the individual location rates should be established. He testified that these key factors or parameters establish the theoretical reserve which is utilized to appropriately assign the book reserve at the location and vintage level. He noted that updating retirement dates adjusts the weighting between the locations; therefore, a changed retirement date, survivor curve or net salvage percent for one location affects all the locations in the account.

Mr. Spanos next addressed depreciation rates for DEI's new solar generation assets planned by year-end 2019. He explained that the rates for these assets will be based on interim survivor curves for each account, a negative net salvage percent for some of the accounts, and a 25- year life span for all assets at the location. He stated that an estimated rate for new battery storage assets in Account 363 was also prepared.

Mr. Spanos testified concerning his fair value study. He explained that his study segregated the property by plant account consistent with the depreciation study and Company accounting system. More specifically, he first determined the Reproduction Cost New ("RCN") for the property in service at December 31, 2018, by trending the original cost and then deducting depreciation to arrive at the Reproduction Cost New Less Depreciation ("RCNLD"). He explained that for the property for which he determined the trended original cost, he used cost indexes. He calculated the RCN of the Company's electric plant in service as of December 31, 2018, to be $27,218,507,545; and he calculated the RCNLD of the Company's electric utility plant in service as of December 31, 2018 to be $11,633,493,162, which is 43% of the Reproduction Cost New. Mr. Spanos also provided the same fair value study information using the Company's forecasted electric utility plant in service as of December 31, 2020. He testified that it was calculated using the same methodology as his 2018 study and that the RCN of the Company's electric plant in service as of December 31, 2020, is $28,967,368,703 and the RCNLD is $12,054,723,694.

Company witness Mr. Jeffery Kopp sponsored the decommissioning study prepared by Burns & McDonnell for this proceeding. Mr. Kopp explained why it is necessary to demolish a generating station at the end of useful life, citing reuse of land, public safety, and environmental remediation of potential health hazards. The decommissioning study provided an estimated total cost, in 2018 dollars, of decommissioning and dismantling each Company-owned generation unit at the end of its useful life, as well as the total cost of decommissioning and dismantling the common facilities at these generating plants. The total decommissioning and dismantlement cost as determined by Burns and McDonnell and reflected in the Decommissioning Study, was net of salvage value for scrap materials at each plant. In general, the study assumed that each generating site would be restored to a condition appropriate for industrial use. This means that all sites will have above grade buildings and equipment removed, foundations removed to two feet below grade, be rough graded, and seeded. Sites also will have small diameter underground pipes capped and abandoned in place. Mr. Kopp explained that each of DEI's electric generating plants was evaluated, including steam, hydro and other facilities, including solar and that the Burns & McDonnell team visited all plants for which site-specific decommissioning and dismantlement cost estimates were prepared. Mr. Kopp described the types of costs included in the decommissioning study and how the estimates for the direct costs were developed using a bottoms-

up cost estimating approach. He explained how scrap values were determined and the necessity of including project indirect costs in the estimate, as well as the determination of the indirect costs included. He further explained that contingency costs had been included in the estimate, and that a contingency cost accounts for unspecified but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and dismantlement activities and contingency. He explained that these costs are in addition to the direct costs associated with the base decommissioning and dismantlement known scope items and that application of contingency is not only appropriate, but also standard industry practice. He further explained that DEI provided estimated remaining M&S inventory balances for inclusion in the Decommissioning Study, with a portion of the inventory given a salvage credit to reflect potential reuse or resale of remaining M&S. The estimated total net decommissioning and dismantlement cost for DEI's generation facilities included in the study is $420,569,400 in 2018 dollars. Mr. Kopp stated that the estimates used in the study were carefully prepared using standard and accepted estimating techniques and the best information available, and are consistent with Burns & McDonnell's industry experience. He stated that assumptions used were reasonable and that the inclusion of remaining M&S balance in the decommissioning and dismantlement costs is also reasonable, as maintaining an adequate inventory of M&S for the operation and maintenance of the generating units up to their end of life represents a prudently incurred cost for providing service to customers.

OUCC witness Garrett testified that he employed a depreciation system using actuarial plant analysis to statistically analyze the Company's depreciable assets and develop reasonable depreciation rates and annual accruals. In contrast to Mr. Spanos' use of the Equal Life Group ("ELG") procedure, Mr. Garrett recommends the calculation of depreciation rates under the Average Life Group ("ALG") procedure. He also proposed adjustments to the Company's proposed terminal net salvage rates. More specifically, Mr. Garrett testified that the OUCC's proposed depreciation adjustments comprise several key issues: (1) calculating rates under the ALG method; (2) removing contingency costs from DEI's decommissioning cost estimates; (3) removing inventory costs from DEI's decommissioning cost estimates; (4) removing escalation factors from DEI's terminal net salvage calculations; and (5) adjusting the Company's proposed service lives for several of its transmission and distribution accounts. During cross-examination, Mr. Garrett testified that he did not make a field visit prior to completing his depreciation recommendations.

Mr. Garrett testified that depreciation rates calculated under the ELG procedure for a particular vintage group of property will be higher in earlier years relative to later years, citing to [Wolf] and the National Association of Regulatory Utility Commissions ("NARUC") as support for his testimony. In contrast, he stated, depreciation rates calculated under the ALG procedure for a particular vintage group of property will be the same each year. Further, he testified that in order for depreciation rates calculated under the ELG procedure to be accurately applied, a utility's depreciation rates would need to be adjusted each year to reflect the decreasing depreciation rates for applicable account. He stated that under the ELG procedure, as proposed by DEI, the Company's depreciation rates would simply be applied each year until the next depreciation study is filed, regardless of the fact that depreciation rates should decrease annually during that time under the ELG procedure. He testified that this arrangement does not result in a systematic and rational cost recovery mechanism, and, by proposing depreciation rates under this scheme, DEI

has failed to meet its burden to make a convincing showing that its proposed depreciation rates are not excessive.

He stated that, in theory, the ELG could be part of a systematic and rational cost recovery system. In practice, however, it would be difficult to come to the same conclusion, because in order for the ELG procedure to be properly applied, a utility would need to revise depreciation each year. However, he stated, given the logistical realities involved with prosecuting rate cases, this would be impractical and inefficient.

He further testified that when a utility has made substantial, recent capital investments, depreciation expense calculated under the ELG method will always be higher than the expense calculated under the ALG method; the larger the amount of the investments, the larger the discrepancy will be between the two procedures. He attributed utilities' use of the ELG method to a desire by utility finance managers to increase cash flow and a desire by utility investors to reduce risk through accelerated capital recovery. He emphasized that the rules and standards governing capital recovery through depreciation require that public utilities recover their capital investments in a systematic and rational manner, accomplished by estimating service life through actuarial analysis and other objective techniques.

He noted that in the pending I&M rate case, the utility proposed depreciation rates using the ALG procedure; no party opposed the utility's use of the ALG procedure and no party proposed using the ELG procedure. He stated that, in his experience, the ALG procedure is the most commonly used procedure by analysts in depreciation proceedings. Thus, he concluded, the majority of depreciation rates approved by regulators around the country are calculated under the ALG procedure.

Mr. Garrett testified that if the IURC accepted all of DEI's substantive depreciation positions, but simply adopted the ALG procedure, it would result in depreciation rates that are much more fair and reasonable than those proposed by the Company. He further testified that it could be reasonable to use the ELG procedure if DEI was also proposing to have its depreciation rates adjusted every year in order to reflect a mathematically proper application of the ELG procedure, but that was not a part of the Company's filing. Instead, he claimed, to the extent the Company's ELG-derived rates are adopted, the Company will receive arbitrarily higher cash flows for its investors each subsequent year after this proceeding until its next depreciation study is filed. Under these circumstances, he concluded, the Company has not made a convincing showing that its proposed rates are not excessive.

Mr. Garrett next addressed the issue of contingency costs. He testified that the Company's terminal net salvage costs are estimated through demolition studies for most of its generating units. He stated that the demolition studies include contingency costs that purportedly reflect uncertainties in future demolition estimates. However, he claimed that contingency costs are unknown by definition, and therefore are not known and measurable. He stated that charging current ratepayers for speculative costs that may not even occur up to decades in the future is inherently problematic from a ratemaking perspective. Mr. Garrett stated that Duke identified no legal obligation in its testimony that requires it to demolish its power plants consistent with the activities described in the decommissioning cost estimates. He opined that in the absence of such

a legal requirement being imposed in the foreseeable future, actually incurring these costs is speculative. He also suggested that if and when Duke actually demolishes the power plants and requires more funding to do so, it can request additional funds from ratepayers when actual costs are known.

With regard to the issue of inventory costs, Mr. Garrett noted that DEI included $185 million of inventory costs as part of its decommissioning cost estimates. However, he stated, inventory costs are not typically included as part of decommissioning cost estimates, and he testified that he could not recall ever seeing such costs proposed in a decommissioning study, including those filed by Burns & McDonnell in prior cases. He noted that decommissioning studies estimate the terminal salvage and cost of removal of generating facilities, and he testified that DEI has not shown how the inclusion of inventory relates to that process. Furthermore, he stated that Burns & McDonnell has not conducted an analysis supporting the level of inventory included in the decommissioning costs.

Mr. Garrett next addressed the Company's use of escalation factors to escalate its demolition cost estimates from present-day dollars to the future retirement date of each generating unit by applying an annual cost inflation factor. According to Mr. Garrett, the problem with this approach is that current ratepayers are forced to pay for a future-value cost with present-day dollars. He claims that this "scheme" violates basic time-value-of-money principles. He testified that if future, escalated costs are allowed, they should then be discounted back to present-day dollars by the Company's weighted average cost of capital, noting that a similar approach is used to account for asset retirement obligations. He concluded, however, that it would be more straight-forward and reasonable to simply disallow the escalation factors and base the Company's decommissioning costs on present value.

Brian Andrews testified on behalf of the Industrial Group with respect to depreciation issues. His stated that DEI's proposed depreciation expense increase is excessive and unduly burdens customers.

He testified that DEI's continued reliance on the ELG procedure for calculating depreciation rates is burdensome to customers. He claimed that ELG depreciation rates are front-loaded and must be updated annually for proper implementation. He further claimed that DEI is the only Duke electric company that utilizes the ELG procedure to calculate depreciation rates, and it has the highest depreciation rate of any of the Duke electric companies. He stated that all other Duke electric companies use the ALG procedure, the most commonly utilized procedure for calculating depreciation rates.

He argued that, by rejecting ELG in favor of ALG, the Commission has an excellent opportunity to achieve the following: (1) allow Duke to retire its coal plants early according to its preferred portfolio, helping achieve significant carbon reductions in Indiana, (2) significantly reduce the rate increase while allowing those early retirements and the resources that will eventually replace them, and (3) utilize the depreciation procedure that is most commonly used in the country.

Mr. Andrews also argued that DEI is attempting to recover through depreciation rates an excessive amount of costs for the demolition of its production plants. He noted that in the decommissioning cost estimates, Duke has included net inventory costs, which is the level of inventory that existed at the plants as of June 2018. He took the position that, as Duke knows the precise retirement dates of these facilities, Duke should effectively manage this inventory and strive to eliminate these balances over the remaining life of the plants. He argued that these costs should be removed from the decommissioning costs estimates that are included in the net salvage rate and depreciation rate calculations.

He also noted that, in the decommissioning cost estimates, Duke has included contingency costs. He characterized these costs as simply a 20% adder to the demolition costs and unnecessary depreciation expense. He recommended that these contingency costs be removed from the decommissioning costs estimates that are included in the net salvage rate and depreciation rate calculations.

Mr. Andrews observed that in the net salvage rate calculations, Duke has included cost escalation. He testified that these costs were determined with an excessive and unsupported 2.5% annual inflation rate and burden current customers with unnecessary depreciation expense. He recommended that these escalation costs should be based on 2.0% inflation before being included in the net salvage rate and depreciation rate calculations.

Mr. Andrews stated that the IURC should reject Duke's ELG depreciation rates and approve the depreciation rates presented in his testimony. He testified that this will reduce the test year depreciation expense by $120 million, or by 83% of Duke's proposed increase, while still allowing coal plant retirements at Duke's proposed time schedule.

Mr. Spanos testified in rebuttal, noting that while each party proposes a fairly significant change in depreciation expense compared to the Company's proposal, the vast majority of the dollar impact of their changes is due to their deviation from Commission precedent. That is, most of their proposed reduction in depreciation expense is based on issues that the Commission has already decided. He stated that the issue with the single largest impact is the Company's use of the Equal Life Group ("ELG") procedure instead of the Average Life Group ("ALG") procedure. He noted that the Commission has clearly stated that "[w]e consider the debate between ELG and ALG to have already been resolved. This Commission has frequently and consistently expressed its preference for the use of the ELG procedure."[5] The Commission has similarly ruled that it is appropriate to include contingency in decommissioning estimates and that decommissioning estimates should be escalated to the date of retirement (for example, see NIPSCO Cause No. 43526). Accordingly, the only issues raised by OUCC and IG that have not been resolved by the Commission relate to the inclusion of inventory costs in decommissioning (which is addressed by DEI rebuttal witnesses Kopp and Mosley), Mr. Andrews' use of a lower escalation rate, and Mr. Garrett's life estimates for a few accounts.

[5] IURC 8/25/2010 Final Order in Cause No. 43526 at 51.

Mr. Spanos stated that the OUCC proposes a reduction in depreciation expense of $107 million, however, $93 million of this amount is due to the use of the ALG procedure, the removal of contingency and the removal of escalation. Similarly, he stated, the Industrial Group proposes a $120 million reduction in depreciation expense, however, $88.7 million of this is due to the use of the ALG procedure. An additional amount is the result of the parties' proposal to remove contingency.

With regard to Mr. Garrett's and Mr. Andrews' argument that ELG depreciation requires annual updates, Mr. Spanos testified the simple examples they provide to support their opinions are not reflective of real-world operations. He stated that this argument is unpersuasive for multiple reasons. First, he noted this Commission has used ELG for many years and has not required companies to update depreciation rates annually. Second, he stated that both Mr. Garrett and Mr. Andrews are incorrect that annual updates would be required. He pointed out that both examples shown to support their opinions are simplistic examples based on only a single vintage of plant. Thus, their examples do not match real-world experience. For most utility plant accounts, he stated, assets are added and retired every year. Due to this continual activity, he testified, ELG depreciation rates do not actually change as much as Mr. Garrett and Mr. Andrews claim. Third, he testified that annual updates are quite common in Pennsylvania. He stated that his firm performs depreciation studies – and annual updates – for most utilities in Pennsylvania. As a result, he has the opportunity to review changes to depreciation rates that occur each year that result from annual updates to depreciation calculations. In actual practice, he testified, ELG depreciation rates are much more stable than Mr. Garrett and Mr. Andrews claim. He stated that in aggregate, the ELG depreciation rates typically do not change dramatically from year to year and would not warrant annual updating as Mr. Garrett and Mr. Andrews assume.[6] Mr. Spanos testified that, in reality, there is little need to update depreciation rates annually when using the ELG procedure. He noted that the Commission has not been concerned enough with this issue to require annual updates in the many decades since the ELG procedure was first adopted. Accordingly, he concluded, Mr. Garrett's and Mr. Andrews' arguments to this effect are not a persuasive reason to abandon its use in Indiana.

Mr. Spanos also testified about the downsides of moving to an ALG methodology. He testified that a switch from ELG to ALG depreciation rates will result in artificially low depreciation rates due to the higher accumulated depreciation currently on the Company's books due to the historical use of ELG depreciation rates. He stated that this in turn will result in a short-term benefit that will be paid for by future customers who will also pay a return on the higher rate

[6] Mr. Spanos noted there are other aspects of depreciation that have the potential to change each year. For example, any additions to life span property result in a change to the depreciation rate (since the new asset will have a shorter life than the existing assets at the life span facility). Remaining life depreciation rates also change each year. He pointed out that Mr. Garrett proposes a change in approach from Commission precedent for terminal net salvage that would require annual updates, proposing to only include decommissioning costs at today's cost levels, which would mean the decommissioning costs would need to change each year due to changes in cost levels that occur from year to year. However, Mr. Spanos stated, for Mr. Garrett's terminal net salvage proposal (as well as other aspects of depreciation that change each year), he appears unconcerned with the potential for annual updates to depreciation rates. This gives less merit to Mr. Garrett's concerns regarding ELG, in Mr. Spanos' view.

base that will result from the proposed ALG depreciation rates. He characterized this approach as inequitable both because it will artificially reduce rates at the expense of future customers and because those customers will have to pay for the costs of generation that replaces the Company's coal-fired generation that will be retired. He concluded that Mr. Andrews' proposal would unfairly shift the costs of power plants that will soon be retired to future customers, who will receive no service from these plants. Additionally, Mr. Spanos noted, the historical use of ELG depreciation rates, as well as the inclusion of contingency and escalation in decommissioning estimates, already provides a benefit to customers as the Company transitions from coal-fired generation. While the retirement of coal-fired generation at earlier ages than previously expected does result in an increase in depreciation expense in this case, he stated that the Company has recovered more depreciation to date due to the historic use of ELG depreciation rates and more adequate levels of decommissioning (due to the inclusion of contingency and escalation) means that accumulated depreciation is higher than had Mr. Andrews' and Mr. Garrett's preferred approaches been adopted. The result, he noted, is that there is less to recover for the plants that will be retired. To put this a different way, he explained, had ALG been used in the past and no contingency or escalation included, the increase in depreciation resulting from earlier coal-fired generation would be higher than it is in the current case.

Mr. Spanos testified that Mr. Garrett is incorrect to argue that "it is preferable for regulators to ensure that assets are not depreciated before the end of their economic useful lives." While the goal is to estimate depreciation as accurately as possible, it is important to remember that depreciation is a forecast of events many years in the future and as a result estimates do not always match the actual experienced lives and net salvage of a Company's assets. Given this reality, Mr. Spanos opined, erring on the higher side for depreciation rates is preferable than the lower side because the likelihood and the risks of adverse effects on both the utility and customers are greater if depreciation is underestimated. He also added that too low of depreciation rates increases rate base, which results in customers paying higher total rates due to the return on rate base.

Mr. Spanos also took issue with Mr. Garrett's and Mr. Andrews' use of the word "accelerated" to describe the ELG methodology. He testified that ELG is a straight line method; ELG recovers costs on a straight line basis over the expected life of each equal life group.

Mr. Spanos reiterated that there are sound reasons to use the ELG procedure. He noted that this Commission has addressed this issue multiple times in the past and ruled in favor of ELG. And he noted that ELG is also discussed and supported in authoritative depreciation texts and academic literature. One such authority – and a very significant one – is Robley Winfrey, who, as a professor at Iowa State University, developed the Iowa survivor curves that are universally used in estimating service lives based on historical retirement data and is generally regarded as the father of utility depreciation practices, referred to the ELG procedure as "the only mathematically correct procedure."[7]

[7] Robley Winfrey, Depreciation of Group Properties, Bulletin 155 (Ames, IA: Iowa State University Press, 1942, reprinted 1969); p. 71.

Additionally, he emphasized that it is also important to understand that the change in depreciation resulting from the OUCC and Industrial Group's proposed change to ALG rates is not simply due to the difference between the two procedures. Rather, a portion of this change results from the fact that accumulated depreciation is higher today due to the historical use of ELG depreciation rates than it would have been had ALG depreciation rates been used. A change to ALG rates today will, therefore, result in a greater benefit to today's customers than to other generations of customers. This occurs both because depreciation rates are lower due to the historical use of ELG depreciation rates and because rate base is lower due to the higher accumulated depreciation resulting from the historical use of ELG depreciation rates. If Mr. Andrews' proposal were adopted, it will be future customers that pay the cost for this benefit given to current customers. Future customers will have to pay higher ALG depreciation rates than current customers as remaining life depreciation rates result in accumulated depreciation that will eventually revert to a lower level from the use of the ALG procedure. Future customers will also have to pay a return on the higher rate base that results from the lower ALG depreciation rates. In summary, he testified, Mr. Andrews' proposal will result in shifting costs from today's customers to future generations of customers.

Mr. Spanos next addressed the three adjustments proposed by the OUCC and Industrial Group to the decommissioning cost estimates used in the depreciation study. The first type of adjustment is related to the escalation of decommissioning costs to the time of retirement. The OUCC proposes to remove the escalation component entirely. The Industrial Group recommends the escalation of decommissioning costs, but uses a 2.0% escalation rate instead of the 2.5% escalation rate proposed by Mr. Spanos. The second proposed adjustment is that both the OUCC and Industrial Group advocate removing contingency from the decommissioning estimates. Mr. Spanos noted that both of these issues have been previously addressed by the Commission, which has ruled in favor of the Company's proposals to include escalation and contingency. The third proposed adjustment is that both parties propose the removal of inventory costs from the Company's terminal net salvage estimates. Mr. Spanos noted that he does not address this issue, which is instead addressed by rebuttal witnesses Mr. Kopp and Mr. Mosley. He also noted that Mr. Kopp also addresses the contingency issue, although Mr. Spanos briefly discussed Commission precedent regarding this issue.

With regard to the issue of including escalation in the calculation of decommissioning costs, Mr. Spanos stated that escalation is necessary in order to recover the full net salvage costs of these facilities over their service lives and has previously been accepted by the Commission. He noted that Mr. Andrews recognizes that escalation should be included in the terminal net salvage estimates, but proposes a lower escalation rate of 2.0%. Mr. Spanos testified that, in order to equitably recover the full costs of the Company's assets, including net salvage, net salvage must be based on future costs because decommissioning is going to occur in the future. He emphasized that net salvage must include the effects of future increases in costs, as recognized on multiple occasions by this Commission.

Mr. Spanos noted that Mr. Garrett makes one main argument in support of his proposal to eliminate escalation from the terminal net salvage estimates. He states that "[i]t is not proper to charge current ratepayers for a future cost that has not been discounted to present value." He supports this assertion by stating that "[t]he 'time value of money' concept is a cornerstone of

finance and valuation." Mr. Spanos testified, his opinion on this concept with regard to depreciation is incorrect. Mr. Spanos reiterated that depreciation is based on the actual cost at the time of installation or retirement. While the "time value of money" may be a cornerstone of finance and valuation, it is not a concept used in depreciation as widely practiced in the industry. Indeed, Mr. Spanos testified, failing to incorporate escalation, as Mr. Garrett proposes, will result in understating future net salvage costs, resulting in intergenerational inequity by forcing future customers to pay too much for the facilities.

Mr. Spanos next noted that, unlike Mr. Garrett, Mr. Andrews includes an escalation component in his terminal net salvage estimates. However, he uses a 2.0% escalation rate instead of the 2.5% escalation rate used by the Company which he says "has no support and is excessive." Mr. Spanos testified that his estimate of 2.5% is reasonable for a long term rate of cost increases for power plant decommissioning. He stated that his estimate is consistent with escalation rates used previously, as well as other sources including long-term averages of Consumer Price Index ("CPI") inflation and long-term inflation forecasts; the latter is compiled by the Federal Reserve in the Livingston Survey. He noted that CPI inflation has typically been lower than long-term construction cost increases and so, if anything, his estimate is conservative.

Mr. Spanos testified that Mr. Andrews only provided an analysis based on comparing the Livingston Survey to actual CPI inflation since 1991. From this analysis, he concludes that the "average forecast error is 0.6 percentage points" for this survey since 1991. Since the current 10-year median forecast is 2.26%, he subtracts 0.6 from 2.26% to get a value a 1.66%. He concludes that 1.66% is a more realistic forecast, although he proposes an escalation rate of 2.0% "to be conservative." Mr. Spanos testified that there are multiple issues with Mr. Andrews' analysis. First, he stated that the Livingston Survey is not the only support for Mr. Spanos' estimate. Second, Mr. Andrews' calculation of the forecast error is entirely the result of two periods of time. The first is from the early 1990s and the second from the late 2000s. The forecast error in the early 1990s resulted because these years followed the high inflation of the 1970s and 1980s. That is, forecasters not unreasonably expected that higher inflation to continue, but it did not. The second period is comprised of years that encompassed the Great Recession. The Great Recession resulted in very low inflation and even deflation, but was an abnormal event. Accordingly, Mr. Spanos testified, the period of time reviewed by Mr. Andrews' likely overstates any forecast error, particularly downside errors. Indeed, the last two decades have experienced low inflation by historical standards. It should be at least as likely that current forecasts would be too low rather than too high. However, he testified, Mr. Andrews only anticipates that forecasters could be estimating too high of inflation.

Mr. Spanos testified that these concepts are illustrated if we look at longer term inflation. He stated that looking at longer term inflation rates shows that there have been many years with higher inflation. As a result, he explained, simply assuming that a 2.0% inflation rate will continue into the future is not necessarily a reasonable assumption. Mr. Spanos provided data going back to 1960 and noted that the inflation that occurred over 10-year periods was greater than 2.5% in many years. Additionally, Mr. Spanos testified that while the CPI provides a good indication of changes in prices in the overall economy, it is not necessarily a good indicator of changes in decommissioning costs. A price index that serves as a better proxy for changes in decommissioning costs is the Handy Whitman construction cost index. Mr. Spanos provided a comparison of the

changes in the Handy Whitman Index for Steam Production Plant to CPI over the past 20 years; the data shows that construction costs have increased faster than CPI over this time period. Further, he stated, the data indicates that for every single long-term period ending in 1960 through 2018, the Handy Whitman index increased at an average rate that was greater than the 2.5% escalation rate he proposed. Thus, he concluded, the Handy Whitman index supports a higher escalation rate than he proposed. In summary, he testified that multiple sources support the 2.5% escalation rate he used, and, if anything, his estimate is conservative. He concluded that Mr. Andrews' estimate is, in his judgment, too low and will not fully recover the costs to retire the Company's power plants over their service lives.

Mr. Spanos next discussed the issue of contingency. He stated that Mr. Garrett and Mr. Andrews also both propose the removal of the contingency component from the decommissioning cost estimates. Mr. Spanos noted that the use of contingency has also been previously addressed by the Commission. For example, he noted the following excerpt from a NIPSCO case, in which the Commission held that the inclusion of contingency was appropriate and also noted that Commission precedent supported the inclusion of contingency:

> Mr. Selecky argued either the post-remediation value of the land in industrial condition should be an offset to the dismantlement costs or the contingency should be eliminated as a trade-off for the value of the land. Mr. Selecky did not identify the dollar value of the land after dismantlement. As a result, there is no evidence in the record to guide us in determining whether this would produce a material difference in the depreciation rates or be a reasonable trade-off for the contingency, assuming for the sake of argument it would even be proper to treat a non- depreciable asset like land as salvage. Further, we find it noteworthy that Mr. Selecky is not a licensed real estate appraiser. As a result, the record is devoid of any evidence to judge whether his proposal to equate the value of the land with the contingency is reasonable. (42356 Order at 53-54.) We also give weight to the fact that the 20% contingency factor used in the BMcD demolition cost studies is conservative compared to the 25% contingency factor we accepted in PSI Energy, Inc., Cause No. 42359, at 70-71. Also, the assumption that the sites will be remediated to industrial condition, rather than greenfield condition, is also conservative. Id. at 70. No evidence was presented that this Commission has ever used the value of land as an offset to an asset's cost of removal. In fact, Mr. Selecky did not identify to us any decision of any regulatory commission accepting his position regarding land and the contingency. Petitioner's JJS-R5; Petitioner's Ex. JJS-R6. Given that Mr. Selecky's recommendation would be such a departure from our past practice and that we have scant evidence to guide us in this exercise, we reject Mr. Selecky's proposal.

Mr. Kopp also provided rebuttal testimony regarding the appropriateness of including contingency in the decommissioning study for this proceeding. Specifically, he noted that the application of contingency is a common and prudent practice in the construction industry, and it is included in order to recognize the probability of increases in cost over the base estimated costs due to unknowns. Mr. Kopp explained that some of these costs cannot be determined until the dismantlement process has begun. Therefore, contingency is applied on top of the base estimated cost in order to formulate a reasonable estimate to dismantle the generating facilities.

Mr. Kopp explained that the 20% contingency amount he included in this decommissioning study is the same percentage as the contingencies he has prepared for decommissioning studies for other electric utilities that have been approved by regulatory agencies in other states.

Contingency is added to account for unknown, but reasonably expected to be incurred costs. These costs are related to weather delays, unknown environmental contamination, discovering equipment or materials not shown on drawings, additional dewatering requirements and changes in the manner the work is performed.

Mr. Kopp responded to Mr. Andrews' contention that DEI has no legal obligation to demolish its retired power plants by expanding on the explanation in his direct testimony of the necessity for demolition of power plants. He explained that although there may be no legal obligation to demolish a power plant, there are legal obligations to comply with environmental regulations. He also explained that the alternative to full demolition is to retire a plant in place. He explained that retiring a plant in place requires carrying costs that are necessary to maintain a safe site and be in compliance with applicable regulations. Mr. Kopp stated in his experience he has found that retiring in place is not a cost-effective long-term scenario when the carrying costs are taken into account.

Mr. Kopp concluded by stating that excluding these reasonably expected to be incurred costs by not including contingency costs will not give the full picture of decommissioning costs. If these costs are not accounted for in planning for future decommissioning, the costs will be passed on from the current ratepayers to future ratepayers.

Company witness, Mr. Mosley, provided rebuttal testimony addressing the inclusion of inventory in the decommissioning study. He explained Duke Energy has experience managing generating stations as they near the end of their useful lives and consistently attempts to deplete remaining inventory and/or transfer it to another generating facility where it can still be used. However, there are risks associated with premature depletion of inventory due to limited availability and long lead time of parts required to sustain reliable operation that must be considered.

In addition, Mr. Mosley stated that there are often limitations on the compatibility of inventoried parts that could be transferred from one station to another. For example, most spare parts that fit Gallagher's coal mills do not fit the mills at Gibson or Cayuga. Most steam turbine and generator parts are model specific and cannot be used at other facilities. Combustion turbine and generator parts have some capability with like-in-kind models, but circa-2000 machine parts would rarely be compatible with future gas-fired generators.

Mr. Mosley also explained that as the existing coal and gas-fired generators are retired, there are increasingly less remaining opportunities to transfer useful inventory. Therefore, reflecting leftover inventory in the cost of decommissioning is a reasonable means of addressing a future where increasing numbers of generating units are retired and replaced.

Mr. Kopp also provided rebuttal testimony regarding the inclusion of obsolete inventory remaining at the end of a generating station's useful life in this decommissioning study. He explained that disposing of remaining inventory is just as much a part of decommissioning a station as disposing of other equipment and plant components. It must be safely sold, moved to other locations, or scrapped. In fact, the warehouse or other portions of the plant where the supplies are held cannot be demolished until the inventory is safely removed.

Mr. Kopp then rebutted Mr. Andrews' contention that if this equipment is not placed in service, then it is not used and useful. Mr. Kopp stated that Andrews' argument ignores that inventory is required to be maintained in order to achieve appropriate reliability of the plants and to facilitate routine maintenance on the facilities. Furthermore, Mr. Kopp stated that it is necessary to purchase this inventory before it is needed, in order to reduce outage time, and even if it is not installed, it has still served a useful purpose in maintaining plant reliability.

Mr. Kopp's testimony also stated that the value of this inventory that cannot be reclaimed through sale or scrap of the inventory is directly related to the retirement of the facility. If the facility were to remain in service, this inventory would retain its value to the plant. However, when the plant is retired, the value of this inventory is reduced to the value it has as salvage or scrap. This reduction in value of the inventory is a cost associated with net salvage rates associated with retirement and demolition of the facility. In response to Mr. Garrett's contention that Mr. Kopp had never proposed including inventory in decommissioning studies before, Mr. Kopp also cited to approval of the inclusion of inventory in a decommissioning study prepared for FPL by the Florida Public Service Commission.

Company witness Ms. Douglas also responded to the recommendations of Mr. Garrett and Mr. Andrews regarding the inclusion of end-of-life generating plant M&S inventory costs as a cost of decommissioning and dismantlement. She explained that unlike other plant, property and equipment used at a generating station, which is depreciated over its useful life and the cost of which is recovered from customers served by and benefitting from the electricity generated at the station during its useful life, under the current ratemaking construct, recovery of the cost of M&S maintained in inventory occurs only once the parts and equipment in inventory are installed in the plant. She explained that when base rates are set, under traditional Indiana ratemaking practice, inventory is included in rate base for return purposes, but is not depreciated over its life like plant. Further, the current construct assumes the M&S inventory can be used up before retirement occurs and whatever amount is left can be reused elsewhere or sold, with no current ratemaking means for recovering the cost of the remaining end-of-life inventory from the customers for whose benefit the inventory held for reliability purposes at the station was maintained. As also discussed in the rebuttal testimony of Company witness Ms. Melissa B. Abernathy, without assurance of regulatory recovery of any remaining inventory costs that have now become obsolete due to the retirement, the Company must write the inventory off as an additional, one-time expense. Ms. Douglas further

explained that the Company's proposal is reasonable because it enables the forecasted costs of the end-of-life M&S inventory to be recovered in a rational and systematic way over the remaining life of the plant from the customers who are being served by the plant and benefitting from the reliability that the inventory brings to the plant. Ms. Douglas opined that this approach is a fair and balanced way to address this issue to prevent large negative financial impacts at a plant's end of life for companies who have purchased and managed their M&S reasonably for the benefit of customers. Ms. Douglas noted that the rebuttal testimony of Company witness Mr. John Sullivan addresses the negative impacts on credit quality and financing costs that may result from write-offs such as this. Ms. Douglas concluded by noting that an alternative to recovery over the life of the plant via decommissioning costs would be the pre-approval by the Commission of the use of a regulatory asset at the end of the plant's life, with the remaining value to be recovered from customers over time in a future rate case.

(1) Commission Discussion and Findings. The depreciation-related issues in this case relate to: (1) the ELG versus ALG methodology; (2) the appropriate calculation of terminal net salvage estimates; and (3) estimated useful lives for certain mass property accounts and coal generating units. We address each of these issues in turn.

First, with respect to the question of whether the ELG or ALG method should be used, we find the evidence presented by OUCC witness Mr. Garrett and Industrial Group witness Mr. Andrews persuasive, as both witnesses showed that the ELG method results in unreasonably high depreciation rates. ALG depreciation rates result in systematical and rational cost recovery with near term customer rate relief and full cost recovery of utility investments. While we have determined in the past that the ELG methodology was appropriate and acknowledge the weight given to precedent in many prior decisions, we always evaluate each case as it comes before us and do not need to approve the same methodology based on prior decisions, especially in light of a changed landscape. The use of ELG in a higher than average investment cycle has the effect of unnecessarily increasing the near term depreciation expense as compared to the use of ALG. A review and comparison of Mr. Andrew's exhibits reflecting only the ALG verses the ELG modifications applied to Mr. Spanos' results indicate that the impact of the methodology change on a percentage basis is markedly more significant for the distribution and transmission components than the production, or generation, component. This evidence is not surprising given the increased investment cycle in these categories as highlighted by the relatively recent statutory support for such investment codified at Indiana Code ch. 8-1-39. A changed and encouraged investment cycle is a material landscape change through which we consider our previous proclamations on methodology. Furthermore, the consideration of service affordability in the near term provides sufficient weight to temper our historical preference for ELG. Again, a recently enacted statute, Indiana Code § 8-1-2-0.5, directing the commission to consider "all practical means and measures" to balance necessary investment with service affordability enhances the regulatory landscape. In response to a Docket Entry question DEI confirmed that it had not identified investments that would not be recovered with the ALG methodology as described. Therefore, we find that the application of ALG serves as a reasonable regulatory mechanism to provide rate impact moderation while not limiting DEI's reasonable recovery of its investment.

With regard to the issues surrounding the calculation of terminal net salvage estimates, we note that no party has proposed depreciation rates without terminal net salvage estimates, and,

accordingly, no party appears to disagree with the concept of including terminal net salvage in depreciation rates. Instead, the differences are related to components of the estimated costs that are included. Based on the evidence presented in this case, we find that Mr. Spanos' 2.5% inflation estimate is more realistic and should be used. Mr. Spanos supported his estimate with CPI data going back to the 1960s, as well as more relevant Handy-Whitman index data, while Mr. Andrews' supported his inflation estimate with arguably selective time periods that are not representative of future conditions.

Next we address the parties' contention that contingency be removed from the decommissioning study. We disagree with the parties that the circumstances here warrant such removal. Commission precedent supports the inclusion of contingency and we find it reasonable and appropriate again here. Similar to our previous holdings, we give weight to the fact that the 20% contingency factor used in the demolition cost studies is conservative compared to the 25% contingency factor we approved in the Company's most recent rate case. Furthermore, the assumption that the sites will be remediated to industrial condition, rather than greenfield condition, is also conservative. We therefore decline to depart from our previous practice.

Regarding the parties' arguments concerning inclusion of the cost to address end-of-life inventory at retired generating plants, these type of inventory costs are not typically included as part of decommissioning cost estimates. Normally any unrecovered amount would be expensed at the time of retirement. In rebuttal, Ms. Douglas suggested an alternative in which the Commission pre-approves a regulatory asset at end of life rather than a write-off. As presented in the Industrial Group's February 6 filing this alternative would materially lower the impact of Duke Energy Indiana's rate request. In addition, the alternative affords DEI an opportunity to undertake any and all reasonable actions to minimize the end-of-life inventories as any station retirement draws nearer. Thus, we approve the use of a regulatory asset at the end of life with the understanding that any recoverable amount will be subject to a review of actions taken in advance of any associated retirement.

Based on and incorporating the findings above, we approve for use by DEI the depreciation rates presented in the revised attachment to the Industrial Group's February 6 filing.

iii. O&M Expenses (Other than Depreciation and Taxes).

(A) Production O&M Expense. Petitioner's witness Mosley testified that DEI's 2020 power production O&M forecast is $407 million, as follows:

Category	O&M ($ in millions)
Edwardsport IGCC	$139
Coal Combustion Products	$12
New Generation Resources	$0
Power Production	$229
Other Miscellaneous Power Production	$27
Total	**$407**

COLUMBIA GAS OF PENNSYLVANIA, INC.

SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

AVERAGE LIFE GROUP PROCEDURE

	DEPRECIABLE GROUP	SURVIVOR CURVE		ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
DEPRECIABLE PLANT									
UNDERGROUND STORAGE PLANT									
350.20	RIGHTS OF WAY	100-SQ	*	1,932.08	1,932	0	0	0.00	1.0
351.00	COMPRESSOR STATION STRUCTURES	65-R3	*	3,294,840.04	3,294,840	0	0	0.00	1.0
	WELLS								
352.01	CONSTRUCTION	100-SQ	*	1,126,771.92	1,126,772	(0)	0	-	-
352.02	EQUIPMENT	55-S2.5	*	1,072,969.89	1,072,970	(0)	0	-	-
	TOTAL ACCOUNT 352			2,199,741.81	2,199,742	(0)	0		
352.10	STORAGE LEASEHOLDS AND RIGHTS	100-SQ	*	206,940.78	206,941	(0)	0	0.00	-
353.00	LINES	60-R3	*	387,525.49	387,525	1	1	0.00	1.0
354.00	COMPRESSOR STATION EQUIPMENT	60-R2.5	*	947,637.58	947,638	(0)	0	-	-
355.00	MEASURING AND REGULATING EQUIPMENT	42-R1.5	*	104,476.92	104,477	(0)	0	-	-
	TOTAL UNDERGROUND STORAGE PLANT			**7,143,094.70**	**7,143,095**	**(0)**	**1**	**-**	
DISTRIBUTION PLANT									
	LAND AND LAND RIGHTS								
374.40	LAND RIGHTS	75-R2.5		8,549,393.47	1,216,872	7,332,521	111,528	1.30	65.7
374.50	RIGHTS OF WAY	80-S4		3,233,024.97	1,933,710	1,299,315	32,758	1.01	39.7
	TOTAL ACCOUNT 374			11,782,418.44	3,150,582	8,631,836	144,287	1.22	
	STRUCTURES AND IMPROVEMENTS								
375.34	MEASURING AND REGULATING	60-R0.5		7,659,844.06	1,749,979	5,909,865	108,876	1.42	54.3
375.60	INDUSTRIAL MEASURING AND REGULATING	55-R1		86,083.56	77,294	8,790	369	0.43	23.8
375.70	OTHER DISTRIBUTION SYSTEMS								
375.71	DISTRIBUTION SYSTEM STRUCTURES	90-R1.5	*	46,319,692.09	8,354,774	37,964,918	1,101,152	2.38	34.5
375.72	OTHER BUILDIINGS	38-S1.5		4,369,715.64	1,229,533	3,140,183	102,249	2.34	30.7
	TOTAL ACCOUNT 375.70			50,689,407.73	9,584,307	41,105,101	1,203,401	2.37	34.2
375.80	COMMUNICATION	45-R3		16,515.16	9,684	6,831	303	1.83	22.6
	TOTAL ACCOUNT 375			58,451,850.51	11,421,264	47,030,587	1,312,948	2.25	
376.00	MAINS								
376.30	BARE STEEL	65-R1	*	36,412,665.62	26,035,068	10,377,598	1,152,980	3.17	9.0
376.45	OTHER	65-R1		3,180,891,582.61	447,996,971	2,732,894,612	46,270,005	1.45	59.1
	TOTAL ACCOUNT 376			3,217,304,248.23	474,032,039	2,743,272,209	47,422,985	1.47	
378.00	MEASURING AND REGULATING EQUIPMENT - GENERAL	45-R0.5		238,738,145.80	35,108,872	203,629,274	4,821,537	2.02	42.2
379.10	MEASURING AND REGULATING EQUIPMENT - CITY GATE	35-S2		119,158.02	50,483	68,675	8,031	6.74	8.6

COLUMBIA GAS OF PENNSYLVANIA, INC.

SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

AVERAGE LIFE GROUP PROCEDURE

	DEPRECIABLE GROUP		SURVIVOR CURVE		ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)		(2)		(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
380.00	SERVICES									
380.30	BARE STEEL		45-R0.5	*	347,355.93	257,009	90,347	14,125	4.07	6.4
380.45	OTHER		45-R0.5		971,342,738.31	204,548,243	766,794,495	19,275,518	1.98	39.8
	TOTAL ACCOUNT 380				971,690,094.24	204,805,252	766,884,842	19,289,643	1.99	
381.00	METERS		44-S1		48,663,361.81	20,314,249	28,349,112	908,470	1.87	31.2
381.10	METERS - AMR		20-S2.5		25,165,054.68	20,659,822	4,505,233	524,237	2.08	8.6
382.00	METER INSTALLATIONS		55-R3		50,934,022.06	17,366,304	33,567,718	837,314	1.64	40.1
383.00	HOUSE REGULATORS		50-S2		20,531,392.36	6,208,193	14,323,200	359,745	1.75	39.8
384.00	HOUSE REGULATOR INSTALLATIONS		40-S4		3,538,803.18	2,985,381	553,422	42,009	1.19	13.2
385.00	INDUSTRIAL MEASURING AND REGULATING EQUIPMENT - OTHER THAN METERS		30-R0.5		9,883,926.00	3,376,029	6,507,897	263,169	2.66	24.7
	OTHER EQUIPMENT									
387.00	GENERAL		32-R1		136,698.14	92,671	44,028	2,200	1.61	20.0
387.40	COMMUNICATION EQUIPMENT		25-R1.5		16,050,396.45	4,420,512	11,629,884	598,363	3.73	19.4
387.50	GPS EQUIPMENT		10-S3		2,201,371.95	2,115,996	85,376	47,248	2.15	1.8
	TOTAL ACCOUNT 387				18,388,466.54	6,629,179	11,759,288	647,811	3.52	
	TOTAL DISTRIBUTION PLANT				**4,675,190,941.87**	**806,107,648**	**3,869,083,294**	**76,582,187**	**1.64**	
GENERAL PLANT										
390.10	STRUCTURES AND IMPROVEMENTS - COMMUNICATION		45-R2		49,821.42	49,821	0	0	0.00	17.6
	OFFICE FURNITURE AND EQUIPMENT									
391.10	FURNITURE		20-SQ		3,674,992.31	1,419,280	2,255,712	178,855	4.87	12.6
391.11	EQUIPMENT		15-SQ		91,303.67	70,925	20,379	5,032	5.51	4.0
391.12	INFORMATION SYSTEMS		5-SQ		126,594.17	125,325	1,269	846	0.67	1.5
	TOTAL ACCOUNT 391				3,892,890.15	1,615,530	2,277,360	184,733	4.75	
392.00	TRANSPORTATION EQUIPMENT - TRAILERS		13-L4		25,616.89	24,044	1,573	565	2.20	2.8
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ		25,303,257.61	8,510,197	16,793,061	992,996	3.92	16.9
394.12	CNG FACILITIES		12-S1.5		18,450.18	18,097	353	0	-	-
	TOTAL ACCOUNT 394				25,321,707.79	8,528,294	16,793,414	992,996	3.92	

COLUMBIA GAS OF PENNSYLVANIA, INC.

SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

AVERAGE LIFE GROUP PROCEDURE

	DEPRECIABLE GROUP	SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
395.00	LABORATORY EQUIPMENT	20-SQ	264,921.24	135,121	129,800	14,123	5.33	9.2
396.00	POWER OPERATED EQUIPMENT	13-L2.5	948,698.04	977,116	(28,418)	0	-	-
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	21-R2	4,290,323.34	662,207	3,628,117	181,304	4.23	20.0
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	990,093.14	680,455	309,638	61,290	6.19	5.1
	TOTAL GENERAL PLANT		**35,784,072.01**	**12,672,588**	**23,111,484**	**1,435,011**	**4.01**	
	SUBTOTAL DEPRECIABLE PLANT		**4,718,118,108.58**	**825,923,331**	**3,892,194,778**	**78,017,199**	**1.65**	
AMORTIZABLE PLANT								
303.00	MISCELLANEOUS INTANGIBLE PLANT		70,950,449.03	33,056,275	37,894,174	10,867,210 **		
303.60	MISCELLANEOUS INTANGIBLE PLANT - CLOUD		16,163,961.41	6,518,572	9,645,389	2,766,653 **		
362.10	ENVIRONMENTAL REMEDIATION		0.00	(81,773)				
375.71	STRUCTURES AND IMPROVEMENTS - LEASED		6,386,139.82	3,513,383	2,872,757	471,457 **		
	SUBTOTAL AMORTIZABLE PLANT		**93,500,550.26**	**43,006,457**	**50,412,320**	**14,105,320**		
NONDEPRECIABLE PLANT			**3,533,175.06**	**235,418**				
	TOTAL GAS PLANT		**4,815,151,833.90**	**869,165,206**	**3,942,607,098**	**92,122,519**		

* Indicates the use of an interim survivor curve and retirement date.
** Accrual rate based on individual asset amortization.

COLUMBIA GAS OF PENNSYLVANIA, INC.

COMPARISON OF COLUMBIA AND OCA DEPRECIATION MODELS
RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

	DEPRECIABLE GROUP	SURVIVOR CURVE		ORIGINAL COST AS OF DECEMBER 31, 2025	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL AMOUNT	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL RATE	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL AMOUNT	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL RATE	DELTA CALCULATED ANNUAL ACCRUAL AMOUNT	DELTA CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)		(3)	(4)	(5)=(4)/(3)	(6)	(7)=(6)/(3)	(8) = (6) - (4)	(9) = (7) - (5)
DEPRECIABLE PLANT										
UNDERGROUND STORAGE PLANT										
350.20	RIGHTS OF WAY	100-SQ	*	1,932.08	0	-	0	0.00	0	0.00
351.00	COMPRESSOR STATION STRUCTURES	65-R3	*	3,294,840.04	0	-	0	0.00	0	0.00
	WELLS									
352.01	CONSTRUCTION	100-SQ	*	1,126,771.92	0	-	0	-	0	-
352.02	EQUIPMENT	55-S2.5	*	1,072,969.89	0	-	0	-	0	-
	TOTAL ACCOUNT 352			2,199,741.81	0		0		0	
352.10	STORAGE LEASEHOLDS AND RIGHTS	100-SQ	*	206,940.78	0	0.00	0	0.00	0	0.00
353.00	LINES	60-R3	*	387,525.49	0	-	1	0.00	1	0.00
354.00	COMPRESSOR STATION EQUIPMENT	60-R2.5	*	947,637.58	0	-	0	-	0	-
355.00	MEASURING AND REGULATING EQUIPMENT	42-R1.5	*	104,476.92	0	-	0	-	0	-
	TOTAL UNDERGROUND STORAGE PLANT			**7,143,094.70**	**0**	**-**	**1**	**-**	**1**	**-**
DISTRIBUTION PLANT										
	LAND AND LAND RIGHTS									
374.40	LAND RIGHTS	75-R2.5		8,549,393.47	137,864	1.61	111,528	1.30	(26,336)	(0.31)
374.50	RIGHTS OF WAY	80-S4		3,233,024.97	34,545	1.07	32,758	1.01	(1,787)	(0.06)
	TOTAL ACCOUNT 374			11,782,418.44	172,409	1.46	144,287	1.22	(28,122)	(0.24)
	STRUCTURES AND IMPROVEMENTS									
375.34	MEASURING AND REGULATING	60-R0.5		7,659,844.06	186,200	2.43	108,876	1.42	(77,324)	(1.01)
375.60	INDUSTRIAL MEASURING AND REGULATING	55-R1		86,083.56	459	0.53	369	0.43	(90)	(0.10)
375.70	OTHER DISTRIBUTION SYSTEMS									
375.71	DISTRIBUTION SYSTEM STRUCTURES	90-R1.5	*	46,319,692.09	1,220,146	2.63	1,101,152	2.38	(118,994)	(0.25)
375.72	OTHER BUILDIINGS	38-S1.5		4,369,715.64	125,903	2.88	102,249	2.34	(23,654)	(0.54)
	TOTAL ACCOUNT 375.70			50,689,407.73	1,346,049	2.66	1,203,401	2.37	(142,648)	(0.29)
375.80	COMMUNICATION	45-R3		16,515.16	339	2.05	303	1.83	(36)	(0.22)
	TOTAL ACCOUNT 375			58,451,850.51	1,533,047	2.62	1,312,948	2.25	(220,099)	(0.37)
376.00	MAINS									
376.30	BARE STEEL	65-R1	*	36,412,665.62	1,154,594	3.17	1,152,980	3.17	(1,614)	(0.00)
376.45	OTHER	65-R1		3,180,891,582.61	72,418,288	2.28	46,270,005	1.45	(26,148,283)	(0.83)
	TOTAL ACCOUNT 376			3,217,304,248.23	73,572,882	2.29	47,422,985	1.47	(26,149,897)	(0.82)
378.00	MEASURING AND REGULATING EQUIPMENT - GENERAL	45-R0.5		238,738,145.80	8,811,177	3.69	4,821,537	2.02	(3,989,640)	(1.67)
379.10	MEASURING AND REGULATING EQUIPMENT - CITY GATE	35-S2		119,158.02	8,870	7.44	8,031	6.74	(839)	(0.70)

COLUMBIA GAS OF PENNSYLVANIA, INC.

COMPARISON OF COLUMBIA AND OCA DEPRECIATION MODELS
RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

	DEPRECIABLE GROUP	SURVIVOR CURVE		ORIGINAL COST AS OF DECEMBER 31, 2025	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL AMOUNT	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL RATE	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL AMOUNT	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL RATE	DELTA CALCULATED ANNUAL ACCRUAL AMOUNT	DELTA CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)		(3)	(4)	(5)=(4)/(3)	(6)	(7)=(6)/(3)	(8) = (6) - (4)	(9) = (7) - (5)
380.00	SERVICES									
380.30	BARE STEEL	45-R0.5	*	347,355.93	14,195	4.09	14,125	4.07	(70)	(0.02)
380.45	OTHER	45-R0.5		971,342,738.31	31,759,310	3.27	19,275,518	1.98	(12,483,792)	(1.29)
	TOTAL ACCOUNT 380			971,690,094.24	31,773,505	3.27	19,289,643	1.99	(12,483,862)	(1.28)
381.00	METERS	44-S1		48,663,361.81	1,169,284	2.40	908,470	1.87	(260,814)	(0.53)
381.10	METERS - AMR	20-S2.5		25,165,054.68	597,484	2.37	524,237	2.08	(73,247)	(0.29)
382.00	METER INSTALLATIONS	55-R3		50,934,022.06	971,345	1.91	837,314	1.64	(134,031)	(0.27)
383.00	HOUSE REGULATORS	50-S2		20,531,392.36	419,579	2.04	359,745	1.75	(59,834)	(0.29)
384.00	HOUSE REGULATOR INSTALLATIONS	40-S4		3,538,803.18	45,532	1.29	42,009	1.19	(3,523)	(0.10)
385.00	INDUSTRIAL MEASURING AND REGULATING EQUIPMENT - OTHER THAN METERS	30-R0.5		9,883,926.00	469,848	4.75	263,169	2.66	(206,679)	(2.09)
	OTHER EQUIPMENT									
387.00	GENERAL	32-R1		136,698.14	3,672	2.69	2,200	1.61	(1,472)	(1.08)
387.40	COMMUNICATION EQUIPMENT	25-R1.5		16,050,396.45	785,293	4.89	598,363	3.73	(186,930)	(1.16)
387.50	GPS EQUIPMENT	10-S3		2,201,371.95	53,631	2.44	47,248	2.15	(6,383)	(0.29)
	TOTAL ACCOUNT 387			18,388,466.54	842,596	4.58	647,811	3.52	(194,785)	(1.06)
	TOTAL DISTRIBUTION PLANT			**4,675,190,941.87**	**120,387,558**	**2.58**	**76,582,187**	**1.64**	**(43,805,371)**	**(0.94)**
GENERAL PLANT										
390.10	STRUCTURES AND IMPROVEMENTS - COMMUNICATION	45-R2		49,821.42	0	-	0	0.00	0	0.00
	OFFICE FURNITURE AND EQUIPMENT									
391.10	FURNITURE	20-SQ		3,674,992.31	178,856	4.87	178,855	4.87	(1)	(0.00)
391.11	EQUIPMENT	15-SQ		91,303.67	5,679	6.22	5,032	5.51	(647)	(0.71)
391.12	INFORMATION SYSTEMS	5-SQ		126,594.17	846	0.67	846	0.67	0	(0.00)
	TOTAL ACCOUNT 391			3,892,890.15	185,381	4.76	184,733	4.75	(648)	(0.01)
392.00	TRANSPORTATION EQUIPMENT - TRAILERS	13-L4		25,616.89	638	2.49	565	2.20	(73)	(0.29)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ		25,303,257.61	994,416	3.93	992,996	3.92	(1,420)	(0.01)
394.12	CNG FACILITIES	12-S1.5		18,450.18	0	-	0	-	0	-
	TOTAL ACCOUNT 394			25,321,707.79	994,416	3.93	992,996	3.92	(1,420)	(0.01)

COLUMBIA GAS OF PENNSYLVANIA, INC.

COMPARISON OF COLUMBIA AND OCA DEPRECIATION MODELS
RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

	DEPRECIABLE GROUP	SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2025	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL AMOUNT	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL RATE	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL AMOUNT	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL RATE	DELTA CALCULATED ANNUAL ACCRUAL AMOUNT	DELTA CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)=(4)/(3)	(6)	(7)=(6)/(3)	(8) = (6) - (4)	(9) = (7) - (5)
395.00	LABORATORY EQUIPMENT	20-SQ	264,921.24	14,122	5.33	14,123	5.33	1	0.00
396.00	POWER OPERATED EQUIPMENT	13-L2.5	948,698.04	0	-	0	-	0	-
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	21-R2	4,290,323.34	258,267	6.02	181,304	4.23	(76,963)	(1.79)
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	990,093.14	61,361	6.20	61,290	6.19	(71)	(0.01)
	TOTAL GENERAL PLANT		**35,784,072.01**	**1,514,185**	**4.23**	**1,435,011**	**4.01**	**(79,174)**	**(0.22)**
	SUBTOTAL DEPRECIABLE PLANT		**4,718,118,108.58**	**121,901,743**	**2.58**	**78,017,199**	**1.65**	**(43,884,544)**	**(0.93)**
AMORTIZABLE PLANT									
303.00	MISCELLANEOUS INTANGIBLE PLANT		70,950,449.03	10,867,210 **		10,867,210 **		0 **	
303.60	MISCELLANEOUS INTANGIBLE PLANT - CLOUD		16,163,961.41	2,766,653 **		2,766,653 **		0 **	
362.10	ENVIRONMENTAL REMEDIATION								
375.71	STRUCTURES AND IMPROVEMENTS - LEASED		6,386,139.82	471,457 **		471,457 **		0 **	
	SUBTOTAL AMORTIZABLE PLANT		**93,500,550.26**	**14,105,320**		**14,105,320**		**0**	
NONDEPRECIABLE PLANT			**3,533,175.06**						
	TOTAL GAS PLANT		**4,815,151,833.90**	**136,007,063**		**92,122,519**		**(43,884,544)**	

* Indicates the use of an interim survivor curve and retirement date.
** Accrual rate based on individual asset amortization.

Sources:
[1] Exhibit No. 105, pages 7 - 9
[2] Exhibit BCA-3

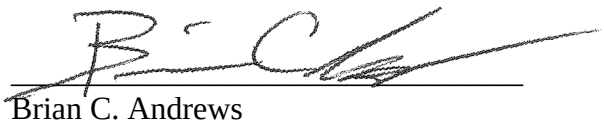
BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Brian C. Andrews, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 4, 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 14, 2024

Signature: 

Brian C. Andrews

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

OCA Statement No. 5

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	Docket No. R-2024-3046519
COLUMBIA GAS OF PENNSYLVANIA, INC.	)	

DIRECT TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

June 14, 2024

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and Vice President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I graduated from Canisius College in Buffalo, New York in 1981 with a Bachelor of Science Degree in Marketing.[1] In 1985, I received a Master's Degree in Business Administration with a concentration in finance, also from Canisius College. In July 1986, I joined National Fuel Gas Distribution Corporation ("NFGD") as a Management Trainee in the Research and Statistical Services ("RSS") Department. I was promoted to Supervisor RSS in January 1987. While employed with NFGD, I conducted various financial and statistical analyses related to the company's market research activity and state regulatory affairs. In April 1987, as part of a corporate reorganization, I was transferred to National Fuel Gas Supply Corporation's ("NFG Supply's") rate department where my responsibilities included utility cost-of-service and rate design analysis, expense and revenue requirement forecasting, and activities related to federal regulation. I was also responsible for preparing NFG Supply's Federal Energy Regulatory Commission ("FERC") Purchased Gas Adjustment ("PGA") filings and developing interstate pipeline and spot market supply gas price projections. These forecasts were utilized for internal planning purposes as well as in NFGD's 1307(f) proceedings.

[1] Effective August 1, 2023, Canisius College became Canisius University.

In April 1990, I accepted a position as a Utility Analyst with Exeter. In December 1992, I was promoted to Senior Regulatory Analyst. Effective April 1996, I became a Principal of Exeter. Since joining Exeter, I have specialized in evaluating the gas purchasing practices and policies of natural gas utilities, utility class cost-of-service and rate design analyses, sales and rate forecasting, performance-based incentive regulation, revenue requirement analysis, the unbundling of utility services, and evaluation of customer choice natural gas transportation programs.

Q. HAVE YOU PREVIOUSLY TESTIFIED ON UTILITY RATES IN REGULATORY PROCEEDINGS?

A. Yes. I have provided testimony on more than 450 occasions in proceedings before the FERC and utility regulatory commissions in Arkansas, Delaware, Georgia, Illinois, Indiana, Louisiana, Maine, Massachusetts, Montana, Nevada, New Hampshire, New Jersey, Ohio, Rhode Island, South Carolina, Texas, Utah, and Virginia, as well as before the Pennsylvania Public Utility Commission ("Commission").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. On March 15, 2024, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company") filed an application with the Commission to increase its distribution base rates by $124.1 million, or 20.3 percent. Exeter was retained by the Pennsylvania Office of Consumer Advocate ("OCA") to review the allocated cost-of-service ("ACOS") studies and rate design proposals included in Columbia's application, as well as the Company's proposals to implement a Revenue Normalization Adjustment ("RNA") mechanism, Columbia's current Weather Normalization Adjustment ("WNA") and the Company's proposal to eliminate the current WNA 3% heating degree day ("HDD") deadband, and establish a Municipal Levelization Charge ("MLC"). My testimony addresses Columbia's

ACOS studies and proposed rate design, the proposed RNA and MLC, and the Company's WNA and proposal to eliminate the WNA 3% HDD deadband.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. My findings and recommendations are as follows:

- Typical of a natural gas distribution company ("NGDC"), a significant percentage of Columbia's plant, approximately 65 percent, is comprised of distribution mains.

- Columbia is sponsoring ACOS Studies in its application using two different methodologies, each at present and proposed rates. Under one method, distribution mains investment is allocated partially based on the number of customers and partially based on design day demands ("Customer-Demand Study"). Under the second method, distribution mains investment is allocated utilizing the Peak and Average method ("Peak & Average Study"). Columbia's application also includes a third ACOS study that reflects an average of the Customer-Demand and Peak & Average ACOS Studies ("Average Study"). Columbia claims that it has relied on the Peak & Average Study to support its proposed revenue distribution among its various customer classes in this proceeding.

- Columbia's reliance on the Peak & Average Study as the basis of its proposed revenue distribution is consistent with Commission precedent and the Commission's decision in the Company's last litigated base rate proceeding (Docket No. R-2020-3018835). It is also consistent with cost of service principles. However, the revenue distribution presented by Columbia does not provide adequate movement toward cost-based rates for each customer class, and does not adequately account for the significant subsidies provided to certain customers that receive service at less than cost of service rates.

- The OCA's proposed revenue distribution in this proceeding, which is also based on the Company's Peak & Average Study, provides for reasonable movement toward cost-based rates and adequately accounts for the subsidies provided to certain customers and, therefore, should be accepted by the Commission in this proceeding.

- Columbia's proposed Residential customer charge of $26.00 is unreasonable and should be rejected and my recommendation that the existing $16.75 monthly charge be maintained should be adopted.

- The proposed RNA should be rejected.

- The proposed MLC should be rejected.

- Columbia's current WNA-pilot should be eliminated. If the Commission does not accept his recommendation, Columbia's proposal to eliminate the 3% WNA HDD deadband should be rejected.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. Including this introductory section, my testimony is divided into seven sections. In the following section, I describe the ACOS Studies presented by Columbia in this proceeding and explain why the Company's Peak & Average Study should be used to determine the distribution of the revenue increase authorized by the Commission in this proceeding. The next section addresses class revenue requirement allocations. The fourth section of my testimony addresses Columbia's proposed Residential rate design. The next section of my testimony addresses Columbia's proposed RNA. The sixth section of my testimony addresses Columbia's proposed MLC. The final section of my testimony addresses Columbia's WNA and the Company's proposal to eliminate the 3% WNA HDD deadband.

II. COST ALLOCATION

Q. BRIEFLY DESCRIBE THE COST-OF-SERVICE STUDIES SUBMITTED BY COLUMBIA IN THIS PROCEEDING.

A. Columbia submitted average embedded ACOS Studies employing two different cost allocation methodologies. These cost allocation methods differ in the approach used to allocate distribution mains investment. The Company's ACOS Studies are sponsored by Mr. Kevin L. Johnson (Columbia Statement No. 6).

Q. PLEASE IDENTIFY THE CUSTOMER RATE CLASSES INCLUDED IN THE COMPANY'S ACOS STUDIES.

A. The Company's ACOS Studies include seven rate classes:

- Residential Sales Service and Residential Distribution Service ("RSS/RDS");

- Low-Volume Small General Sales Service, Small Commercial Distribution Service, and Small General Distribution Service ("SGSS/DS-1");
- High-Volume Small General Sales Service, Small Commercial Distribution Service, and Small General Distribution Service ("SGSS/DS-2");
- Small Distribution Service and low-volume, Large General Sales Service ("SDS/LGSS");
- Large Distribution Service and high-volume, Large General Sales Service ("LDS/LGSS");
- Main Line Distribution Service ("MLDS"); and
- Flexible Rate Provisions and Negotiated Contract Service ("Flex").

Q. HOW DO THE ACOS STUDIES PREPARED BY COLUMBIA DIFFER?

A. In Columbia's ACOS Studies, the Company first identified and directly assigned the actual investment inventory of distribution mains for the MLDS rate class. The distribution mains investment not assigned to the MLDS rate class was allocated to the remaining rate classes. Columbia then prepared ACOS Studies utilizing two different methods to allocate the non-MLDS distribution mains investment to the other rate class. Both methods were used to prepare ACOS Studies at present and proposed rates.

Under the first method, which I will refer to as the Customer-Demand method, distribution mains investment was allocated to rate class partially based on the number of customers and partially based on the design peak day demands of the customers in each rate class. Under the second method, which I will refer to as the Peak & Average method, the remaining distribution mains investment was allocated 50 percent based on the design peak day demands and 50 percent based on annual, or average daily, demands of the customers in each rate class. In addition to the ACOS Studies prepared using these two methods, the Company prepared an Average ACOS Study which reflects an average of the Customer-Demand and Peak & Average ACOS Studies.

Q. WHICH ACOS STUDY DID THE COMPANY UTILIZE AS THE PRIMARY GUIDE FOR THE DISTRIBUTION OF THE REVENUE INCREASE AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING?

A. Columbia claims to have utilized the Peak & Average Study as the ACOS Study to establish rates in this proceeding. The Peak & Average Study was given primary consideration because of the Commission's decision in the Company's 2020 rate case (Docket No. R-2020-3018835) which approved the use of the Peak & Average method. In the Opinion and Order issued in that proceeding on February 19, 2021, the Commission found:

> Based on our review of the record, and as noted by the ALJ, we have consistently used the Peak & Average methodology for the allocation costs for NGDCs. In this regard, we find that the Customer-Demand method and the Average ACCOSS, which depends on the Customer-Demand methodology, would be inconsistent with Commission precedent and generally accepted principles for NGDCs because they both contain customer cost components.
>
> We are persuaded by the arguments presented by the OCA's witness, Mr. Mierzwa, on pages 6-7 of the OCA's Statement No. 4, and in the OCA's Main Brief on pages 139-145, which we adopt herein, by reference, where he describes the faults of adopting the Customer-Demand ACCOSS. In the OCA's Statement No. 4, Mr. Mierzwa explained that under the Customer-Demand method, "the distribution mains investment assigned to each category is allocated to rate class **partially based on the number of customers** and partially based on the design day demands of the customers in each rate class that are served by each of the categories of distribution mains …." OCA St. 4 at 6-7 (emphasis added). In the OCA's Main Brief, Mr. Mierzwa pointed out that the Customer-Demand ACCOSS uses "a minimum system approach where the entire distribution mains system is hypothetically comprised of only 2-inch pipe." Mr. Mierzwa continued that, "[t]he goal of such a study is to attempt to assign costs based on merely connecting customers to the system, as opposed to supplying gas to customers – which is

how the distribution system actually works on a day-to-day basis." OCA M.B. at 140. (Order at 215).

In light of the above, we remain of the opinion that although mains serve customers, it is the throughput that determines the type of main investment because it is the load that determines the main investment, not the number of customers served. The existence of one customer, five customers, or ten customers does not determine the amount of mains investment. Mains investment is driven by the loads placed upon it, not by the number of customers served.

Furthermore, distribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality. It is not reasonable to allocate distribution mains investment based solely on design peak day demands as in Columbia's Customer-Demand ACCOSS. The basic reason Columbia invests in its distribution system is to meet the annual demands for gas by customers. Additionally, a portion of the total cost of distribution service is related to installing a system with enough throughput capacity to meet design peak demands in excess of annual demands. (Order at 217).

For all these reasons, we find that the Peak & Average allocation methodology is the most appropriate allocation methodology to use in this proceeding because it is based on the premise of load-based investment. Accordingly, we shall deny Columbia's Exceptions Nos. 18 and 19, and the OSBA's Exception No. 1, and PSU's Exception No. 1 as they relate to their respective ACCOSS arguments and adopt the OCA's P&A ACCOSS as proffered by OCA Witness Mr. Mierzwa in OCA Statement No. 4, at 5-33, and the OCA's Main Brief, at 150-155. (Order at 218).

Q. PLEASE SUMMARIZE THE RESULTS OF COLUMBIA'S PEAK & AVERAGE ACOS STUDY.

A. Table 1 shows the results of Columbia's Peak & Average Study at present rates.

Table 1.
Class Rates of Return
Columbia Peak & Average ACOS Study
Results at Present Rates

	Rate of Return	
Class	**Percent**	**Relative**
SS/RDS	7.44%	1.21
SGSS/DS-1	6.69	1.09
SGSS/DS-2	6.63	1.08
SDS/LGSS	6.96	1.14
LDS/LGSS	2.10	0.34
MLDS	245.34	40.02
FLEX	(3.42)	(0.56)
Overall:	**6.13%**	**1.00**

Q. SHOULD THE COMPANY'S PEAK & AVERAGE ACOS STUDY BE APPROVED IN THIS PROCEEDING AND UTILIZED TO DETERMINE THE DISTRIBUTION OF THE REVENUE INCREASE AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING?

A. Yes.

III. CLASS REVENUE REQUIREMENTS

Q. PLEASE DESCRIBE HOW COLUMBIA IS PROPOSING TO DISTRIBUTE ITS REQUESTED REVENUE INCREASE AMONG ITS CUSTOMER CLASSES IN THIS PROCEEDING.

A. Columbia claims that it generally sought to allocate the revenue increase based the cost of service indicated by the results of its Peak & Average Study. The Company's proposed base rate revenue distribution is presented in Table 2. The relative rates of return ("ROR") at present and the Company's proposed rates are also identified in Table 2. An ROR of less than 1.0 indicates that a customer class is providing revenues that are less than that

classes' indicated cost of service, a ROR 1.0 indicates that a customer class is providing revenues that are equal to that classes' indicated cost of service, and a ROR greater than 1.0 indicates that a customer class is providing revenues that are greater than that classes' indicated cost of service.

Table 2.
Columbia Proposed Revenue Distribution

Class	Present Rates	Proposed Rates	Increase	Percent	Relative Rate of Return: Present Rates	Relative Rate of Return: Proposed Rates
RSS/RDS	$434,600,860	$520,908,055	$86,307,195	19.9%	1.21	1.20
SGSS/DS-1	50,742,083	61,984,202	11,242,119	22.2%	1.09	1.08
SGSS/DS-2	55,942,507	68,335,647	12,393,140	22.2%	1.08	1.05
SDS/LGSS	36,780,761	44,915,312	8,134,551	22.1%	1.14	1.09
LDS/LGSS	27,256,006	33,315,478	6,059,472	22.2%	0.34	0.41
MLDS	1,826,820	1,827,266	446	0.0%	4.02	28.17
FLEX	3,145,875	3,147,421	1,546	0.0%	(0.56)	(0.39)
Total:	$610,294,912	$734,433,381	$124,138,469	20.3%	1.00	1.00

Q. WHAT ARE SOME OF THE PRINCIPLES OF A SOUND REVENUE ALLOCATION?

A. A sound revenue allocation should:

- Utilize class cost-of-service study results as a guide;
- Provide stability and predictability of the rates themselves, with a minimum of unexpected changes that are seriously adverse to ratepayers or the utility (gradualism);
- Yield the total revenue requirement;
- Provide for simplicity, certainty, convenience of payment, understandability, public acceptability, and feasibility of application; and reflect fairness in the apportionment of the total cost of service among the various customer classes.[2]

[2] *Principles of Public Utility Rates*, Second Edition, James C. Bonbright, Albert L. Danielsen, David R. Kamerschen; Public Utility Reports, Inc., 1988, pages 383-384.

Q. IS COLUMBIA'S PROPOSED REVENUE ALLOCATION REASONABLE?

A. No. Although Columbia's proposed revenue allocation may be based on the results of the Company's Peak & Average Study, but it does not reflect adequate movement toward cost-based rates for each customer class and does not adequately account for the significant subsidies provided to LDS/LGSS and Flex rate customers that receive service at less than cost of service rates.

Q. PLEASE IDENTIFY THE SUBSIDIES CURRENTLY PROVIDED TO LDS/LGSS AND FLEX RATE CUSTOMERS.

A. As indicated in Table 1, LDS/LGSS customers currently provide a relative rate of return of 0.34 at present rates. To provide revenues equal to the cost of service indicated by the Company's Peak & Average Study at proposed rates, LDS/LGSS customer revenue would need to be increased from the current level of $27,256,006 (Table 2) to $48,256,006, or by $21,000,000. As such, at proposed rates, other customers would be providing a subsidy of $21,000,000 to LDS/LGSS customers. Under my subsequently discussed revenue distribution, I am recommending that LDS/LGSS customer revenues be increased to $38,344,150 (Table 3). Therefore, under my proposed revenue distribution, the subsidy being provided to LDS/LGSS customers would be reduced to $9,911,856.

As indicated in Table 1, Flex rate customers currently provide a negative relative rate of return of 0.56 at present rates. To provide revenues equal to the cost of service indicated by the Company's Peak & Average Study at proposed rates, Flex rate customer revenue would need to be increased from the current proposed level of $3,145,875 (Table 2) to approximately $41,645,875, or by $38,500,000. As such, other customers are providing a subsidy of $38,500,000 to Flex rate customers. In total, a subsidy of $59,500,000 would be being provided to LDS/LGSS and Flex rate customers at Columbia's proposed rates.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE ALLOCATION OF COLUMBIA'S PROPOSED REVENUE INCREASE?

A. Table 3 summarizes my recommended revenue distribution at the Company's proposed rates for the Company's claimed revenue deficiency and is based on Columbia's Peak & Average ACOS study. Also identified is the relative rate of return at proposed rates under my revenue distribution.

Table 3.
OCA Proposed Revenue Distribution

Class	Present Rates	Proposed Rates	Increase	Percent	Relative Rate of Return: Present Rates	Relative Rate of Return: Proposed Rates	Change
RSS/RDS	$434,600,860	$509,881,936	$75,281,076	17.3%	1.21	1.16	$(11,026,119)
SGSS/DS-1	50,742,083	63,730,590	12,988,507	25.6%	1.09	1.13	1,746,388
SGSS/DS-2	55,942,507	71,673,591	15,731,090	28.1%	1.08	1.13	3,337,950
SDS/LGSS	36,780,761	45,828,421	9,047,660	24.6%	1.14	1.13	913,109
LDS/LGSS	27,256,006	38,344,150	11,088,144	40.7%	0.34	0.55	5,028,672
MLDS	1,826,320	1,827,266	446	0.0%	40.02	28.17	0
FLEX	3,145,875	3,147,421	1,546	0.0%	(0.56)	(0.39)	0
Total:	**$610,294,912**	**$734,433,381**	**$124,138,469**	**20.3%**	**1.00**	**1.00**	**$0**

Q. HOW DID YOU DEVELOP YOUR PROPOSED REVENUE DISTRIBUTION?

A. As indicated in Table 2, the LDS/LGSS rate class is currently providing a return which is significantly lower than the indicated cost of service (ROR of 0.34). While there is no hard and fast rule with respect to applying the concept of gradualism in developing a revenue distribution, typically an increase of 1.5 to 2.0 times the system average increase is considered consistent with the concept of gradualism. Therefore, I assigned an increase of 2.0 times the system average increase to the LDS/LGSS rate class. I accepted the Company's proposal concerning distribution of the revenue increase to the MLDS class since this class is providing a return which is significantly greater than the indicated cost

of service. I also accepted the Company's proposal concerning the distribution of the revenue increase to Flex rate customers.

Due to the $59,500,000 subsidy being provided to LDS/LGSS and Flex rate customers, it is necessary for other classes to pay rates in excess of the cost of service if Columbia is entitled to collect 100 percent of its cost of service. To calculate the subsidy being paid by the other remaining customer classes, I determined the revenues at proposed rates that would yield a ROR of approximately 1.0 for each class, and subtracted the revenues at proposed rates under Columbia's revenue distribution. This analysis indicated that the RSS/RDS class was providing a subsidy, or overpaying, by $49,000,000. To provide a more reasonable sharing of the LDS/LGSS, and Flex rate customer subsidy, I allocated the subsidy to the RSS/RDS, SGSS/DS-1, SGSS/DS-2, and SDS/LGSS rate classes based on each class's cost of service. This revenue distribution resulted in significantly greater movement toward cost of service rates for the RSS/RDS rate class than was provided for under Columbia's proposed revenue distribution.

Q. WHAT DO YOU RECOMMEND WITH RESPECT TO THE SCALE-BACK OF YOUR PROPOSED REVENUE DISTRIBUTION TO REFLECT THE INCREASE ACTUALLY AUTHORIZED BY THE COMMISSION IN THIS PROCEEDING?

A. In the event that Columbia's authorized increase is less than its requested increase, I recommend a proportionate scale-back of the increase for each rate class with the exception of the MLDS and Flex rate classes.

IV. RATE DESIGN

Q. PLEASE DESCRIBE COLUMBIA'S CURRENT AND PROPOSED RESIDENTIAL DISTRIBUTION RATES.

A. Columbia's current Residential sales and transportation customer distribution rates consist of a $16.75-per-month customer charge and a charge of $9.1069 for each Dth of gas delivered. Columbia's proposed Residential rate would consist of a $26.00-per-month customer charge and a $10.2781-per-Dth delivery charge. Columbia determined its proposed Residential customer charge based on an analysis of customer costs presented on pages 24 - 26 of the cost-of-service study presented in Exhibit 111, Schedule 2. This analysis calculates a Residential customer charge of $28.71.

Q. SHOULD COLUMBIA'S PROPOSED RESIDENTIAL CUSTOMER CHARGE BE APPROVED?

A. No, for several reasons. First, Columbia's Residential customer charge proposal is out of line with the Residential customer charges of other NGDCs in the Commonwealth. Second, as discussed in the testimony of OCA witness Colton, Columbia's proposal will have a disproportionate impact on low-income customers. Third, a high fixed monthly customer charge is inconsistent with the Commission's general goal of fostering energy conservation. Finally, the Company's analysis of customer costs includes costs that are not appropriately included in a customer charge and is based on the Company's requested increase, which will be higher than the increase authorized by the Commission in this proceeding.

Q. HOW DOES COLUMBIA'S RESIDENTIAL CUSTOMER CHARGE PROPOSAL COMPARE WITH THE MONTHLY RESIDENTIAL CUSTOMER CHARGES OF OTHER NGDCs IN THE COMMONWEALTH?

A. Table 4 provides a comparison of Columbia's Residential customer charge proposal with the customer charges of other Pennsylvania NGDCs. As shown there, Columbia's current charge is already the highest in the Commonwealth, and if adopted, Columbia's proposed monthly Residential customer charge would be significantly higher than that of any other NGDC in the Commonwealth.

Table 4.
Comparison of Residential Customer Charges for Pennsylvania NGDCs

Columbia Gas of Pennsylvania – Proposed	**$26.00**
Columbia Gas of Pennsylvania – Current	**$16.75**
Philadelphia Gas Works	$16.25
Peoples Gas	$15.75
UGI Gas	$15.00
Peoples Natural Gas	$14.50
PECO Energy Company	$14.25
National Fuel Gas Company	$14.00

Q. WHY IS A HIGH FIXED MONTHLY CUSTOMER CHARGE INCONSISTENT WITH THE COMMISSION'S GENERAL GOAL OF FOSTERING ENERGY CONSERVATION?

A. The more revenue collected through the fixed monthly charge, the lower the volumetric charge. The higher the volumetric charge, the greater the incentive to lower usage.

Q. SHOULD COLUMBIA'S ANALYSIS OF CUSTOMERS COSTS UPON WHICH THE COMPANY RELIES TO SUPPORT ITS RESIDENTIAL CUSTOMER CHARGE BE RELIED UPON TO ESTABLISH THE RESIDENTIAL CUSTOMER CHARGE IN THIS PROCEEDING?

A. No. As just explained, if adopted, Columbia's proposed monthly Residential customer charge would be significantly higher than that of any NGDC in the Commonwealth, and is inconsistent with the Commissions general goal of fostering energy conservation. With respect to the Company's analysis of customer costs upon which it relies to support its proposed Residential charge of $26.00, only those costs that change directly with the addition or subtraction of a customer should be included in the calculation of a customer charge. Columbia has included uncollectible expenses (Account 904) of $9,214,766 in its calculation, which is not a direct customer cost. Eliminating uncollectible expense would reduce the calculated customer charge from $28.71 to $27.13 based on Columbia's requested increase. This calculated customer charge would be further reduced to reflect the increase authorized by the Commission in this proceeding.

Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO COLUMBIA'S MONTHLY RESIDENTIAL CUSTOMER CHARGE?

A. Columbia's currently monthly Residential customer charge is already the highest in the Commonwealth and the proposed charge is inconsistent with the Commissions' goal of encouraging energy conservation. Therefore, I recommend that the existing $16.75 monthly charge be maintained.

Q. DID COLUMBIA PROPOSE AN INCREASE IN ITS MONTHLY RESIDENTIAL CUSTOMER CHARGE IN ITS LAST LITIGATED BASE RATE CASE AND WAS THE INCREASE APPROVED?

A. Yes, an increase to the Residential customer charge was proposed but was denied by the Commission. Columbia's last litigated proceeding was Docket No. R-2020-3018835. In that proceeding Columbia proposed to increase its existing monthly customer charge from $16.75 to $23.00. In the Recommended Decision in that proceeding, the Administrative Law Judge ("ALJ") found that Columbia's proposed increase in the Residential customer charge was contrary to the Commission's goal of encouraging customers to conserve energy, and denied the Company's requested increase in the monthly customer charge. (Order, at 264). The Commission adopted the ALJ's decision regarding the Residential customer charge. (Order, at 265).

V. REVENUE NORMALIZATION ADJUSTMENT

Q. BRIEFLY DESCRIBE THE RNA PROPOSED BY COLUMBIA.

A. Under the RNA, Peak (October-March) and Off-Peak (April-September) benchmark revenue per Residential customer ("Benchmark Distribution Revenue per Bill" or "BDRB") levels would be established through a base rate case proceeding.[3] In other words, once the Company's revenue requirement is set by the Commission through a base rate case proceeding, a benchmark revenue per residential customer would be established. Through the RNA, the Company would collect or refund any amount in Residential revenues which differed from the BDRB that were not due to differences between actual and normal weather. As explained by Columbia witness Kevin L. Johnson on page 36 of his Direct Testimony, the RNA provides a benchmark distribution revenue level regardless

[3] The RNA would not apply to Residential customer assistance program customers but would be applied to low-income customers who are not enrolled in the customer assistance program.

of changes in customers' actual usage levels. The RNA would be calculated and assessed on a total Residential class revenue basis rather than an individual customer revenue basis.

Q. HAS THE COMMISSION ADOPTED A STATEMENT OF POLICY CONCERNING ALTERNATIVE RATE MAKING MECHANISMS SUCH AS THE RNA?

A. Yes. In an Order entered July 18, 2019, in Docket No. M-2015-2518883, the Commission set forth its Statement of Policy with respect to alternative ratemaking methodologies. In its Statement of Policy, the Commission identified 14 factors it would consider in evaluating an alternative ratemaking mechanism. The Statement of Policy required a utility proposing an alternative ratemaking mechanism to explain how each of these 14 factors impact the rates of each customer class.

Q. DOES THE COMPANY ADDRESS THESE 14 FACTORS IN ITS DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, the 14 factors are identified in the Direct Testimony of Mr. Johnson. Mr. Johnson also addresses how the RNA allegedly aligns with the Commission's Statement of Policy on alternative ratemaking.

Q. WHAT ARE THE 14 FACTORS FOR CONSIDERATION IDENTIFIED IN THE COMMISSION'S STATEMENT OF POLICY ON ALTERNATIVE RATEMAKING, WHAT IS MR. JOHNSON'S RESPONSE TO THE 14 FACTORS, AND WHAT IS YOUR RESPONSE TO MR. JOHNSON'S CLAIMS?

A. Each rate consideration identified in the Statement of Policy is listed below along with the claimed relevant effect of the RNA on each rate consideration. Also identified below is my response to the Company's claim:

Consideration 1 — Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

COLUMBIA: Columbia's proposed RNA is designed to recover the residential base revenues needed to satisfy the cost of service requirements determined in this proceeding while negating over or under recovery of costs.

OCA: The Company's response does not indicate how the mechanism aligns revenues with cost causation as to fixed and variable costs. The RNA provides for the recovery of fixed costs on a volumetric basis; therefore, it does not align utility revenues with cost causation principles as to both fixed and variable costs.

Consideration 2 — Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

COLUMBIA: Columbia's RNA proposal has no identifiable effect on the capacity utilization of the residential class.

OCA: The proposed RNA is unlikely to impact the fixed utility's capacity utilization.

Consideration 3 — Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

COLUMBIA: Columbia's RNA benchmark revenue includes the anticipated volumetric base revenue derived from the fully projected test year consumption.

OCA: The RNA adjustment or "true-up" mechanism creates the anomaly where customers see rate increases when they reduce consumption and rate decreases when they increase consumption.

Consideration 4 — Please explain how the ratemaking mechanism and rate design limit or eliminate inter-class and intra-class cost shifting.

COLUMBIA: Columbia's RNA minimizes inter-class cost subsidization by limiting the amount of cost recovery for the residential class to the revenue benchmark established in this case. Residential intra-class cost subsidization is reduced through Columbia's proposal of a higher customer charge for the residential class.

OCA: The RNA is only applicable to the Residential class and, therefore, does not affect traditional interclass cost shifting. The Company's higher Residential customer charge proposal, which should be rejected, is unrelated to the RNA. OCA witness Roger Colton explains that, with respect to interclass cost shifting, the RDM 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.

Consideration 5 Please explain how the RNA limits or eliminates disincentives for the promotion of efficiency programs.

COLUMBIA: Reduced throughput will not lead to revenue and earnings erosion due to under-recovery because the link between level of throughput and base revenue recoveries is broken with the implementation of the RNA.

OCA: The Company has not demonstrated that the lack of an RNA has been a major obstacle for the promotion of its voluntary energy efficiency & conservation (EE&C) activities. The Company has been able to implement methods to improve consumer efficiency without an RNA. Moreover, there has been a long-term trend of per-customer declining gas consumption (i.e. improved natural gas efficiency use) without an RNA.

Columbia has not proposed any new energy efficiency programs in this proceeding. The RNA disincentives customers to engage in energy efficiency programs because less of a customer's total bill would be subject to reduction through energy conservation. Under the RNA, the residential consumer would be required to pay the benchmark revenue level per customer regardless of the customer's efforts to increase energy efficiency. The RNA provides a disincentive to consumers to work towards more efficient energy usage by minimizing or eliminating all together bill savings related to consumption savings and in no way promotes efficiency programs.

Consideration 6 Please explain how the RNA impacts customer incentives to employ efficiency measures and distributed energy resources.

COLUMBIA: Customers will continue to have an incentive to pursue energy efficiency measures since approximately 30% of an average residential bill is still subject to volumetric usage not related to base rate revenue recovery.

OCA: The RNA reduces the incentive for Residential customers to pursue energy efficiency programs. Base rate revenue savings that would ordinarily be achieved through usage reductions will be offset by higher usage charges under the RNA.

More specifically, the proposed RNA could provide a disincentive to ratepayers to undertake energy conservation efforts because they would be required to pay for gas they did not use. Revenue savings to individual customers that would ordinarily be achieved through usage reductions would be offset by surcharges to all customers under the RNA. Hence, if customers save money on their monthly gas bill due to efficient consumption, customers will be forced to share their bill savings with the utility. Moreover, with the high and apparently never-ending rate increases that Columbia Gas has implemented and will apparently continue to seek, customers are already incented to conserve gas without a new RNA surcharge.

Consideration 7 — Please explain how the RNA impacts low-income customers and support consumer assistance programs.

COLUMBIA: Columbia's proposed RNA only applies to non-CAP customers.

OCA: The RNA will not impact CAP customers.

However, as OCA witness Colton points out, not all low- income customers are enrolled in CAP and for those customers not enrolled in CAP, the RNA will be applied to their bills and have the same effect of being a disincentive to energy efficiency as non-low-income customers. Additionally, OCA witness Colton addresses how the RNA could affirmatively harm non-CAP, low-income customers that do not have the financial means to pursue investments in energy efficiency and conservation measures.

Consideration 8 — Please explain how the RNA impacts customer rate stability principles.

COLUMBIA: Columbia's proposed RNA enables the recovery of costs established in this case and, therefore, mitigates the potential under or over recovery of costs that could require a material rate adjustment in the future.

OCA: Under the current regulatory standard in Pennsylvania, base rate cost under and over recoveries are currently not tracked

and are not eligible for recovery in future base rate proceedings. The RNA will not change this standard.

The proposed RNA would add another surcharge to customers' bills and the Company has not shown how it would reduce the frequency of Columbia Gas base rate filings. Thus, it does not appear that a new RNA surcharge would improve rate stability. In contrast, under traditional cost-of-service ratemaking, if a utility experiences sales reductions and under-recovery, it cannot simply achieve the same result as an RNA true-up by filing another base rate case with adjusted sales forecasts. When a utility files a general rate increase, all relevant information is reviewed to determine just and reasonable rates, not just sales forecasts. Traditional ratemaking produces rate stability.

Consideration 9 — Please explain how weather impacts utility revenue under the RNA.

COLUMBIA: The RNA, as proposed, will capture base revenue differences net of weather as the benchmark is based upon normal weather and the actual revenue will include billed WNA adjustments.

OCA: Weather will not impact utility revenue under the RNA.

Consideration 10 — Please explain how the RNA impacts the frequency of rate case filings and affects regulatory lag.

COLUMBIA: The RNA is designed to mitigate the over or under recovery of the residential cost of service in this case. Future rate cases would still be required to capture cost of service changes that occur beyond the residential class and the fully projected test year in this case.

OCA: Columbia files a rate case nearly every year , this is unlikely to change and an RNA does not prevent the Company from seeking additional rate increases. The RNA does not affect future revenue requirements and does not recover fixed costs that are incurred after a rate case that are over and above those 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.

Consideration 11 — Please explain if the RNA interacts 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).

COLUMBIA: Columbia's proposed RNA only applies to the recovery of costs included in determination of the residential base revenue requirement.

OCA: The RNA will not interact with other revenue sources.

Consideration 12 — Please explain whether the RNA includes appropriate consumer protections.

COLUMBIA: The RNA as proposed establishes a Benchmark Distribution Revenue per Bill ("BDRB") residential customer. Rider RNA will refund any amount over the established benchmark, and collect any amount below the benchmark. By design, the Company cannot retain revenue in excess of the BDRB, which protects the customer from being over-charged. Columbia will submit two filings per year for the RNA mechanism, which can be reviewed and audited by the Commission, similar to the process for the Company's PGC and Rider USP filings.

OCA: The RNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony and the testimony of OCA witness Colton and OCA witness Dismukes.

Consideration 13 — Please explain whether the RNA is understandable to customers.

COLUMBIA: Columbia's RNA is not a unique concept to the regulated utility industry and similar versions have been implemented successfully in other jurisdictions in which Columbia operates. Columbia is also providing an RNA tariff that clearly shows the detail how the mechanism works.

OCA: Columbia has not provided any evidence that the RNA will be understandable to customers.

Consideration 14 — Please explain how the RNA will support improvements in utility reliability.

COLUMBIA: Columbia's cost of service reflects the investments and costs made for the continued enhancement of the safety and

reliability of its system. The RNA reduces the volatility concerning the recovery of those costs.

OCA: The RNA does not provide an incentive to increase the safety and reliability of Columbia's system.

Q. SHOULD THE RNA BE APPROVED BY THE COMMISSION?

A. No. As just explained, the RNA disincentives customers to engage in energy conservation programs because less of a customer's total bill would be subject to reduction through energy conservation. In addition, the RNA should not be approved for the following reasons:

- The proposed RNA could increase earnings beyond those that the Company would ordinarily be entitled to.
- The proposed RNA unreasonably applies to customers whose usage is relatively constant over time.
- The proposed RNA embodies a take-or-pay pricing policy (*i.e.*, penalize the customer with a charge for not taking a set amount of commodity) even though customers have no immediate competitive alternatives to Columbia's distribution gas service.
- The proposed RNA inappropriately adjusts rates without considering other changes in total revenues and costs.
- Columbia has not demonstrated that its current system of rates and charges result in inadequate revenue stability.

Based on these concerns, the RNA should not be approved.

Q. PLEASE EXPLAIN HOW THE RNA COULD INCREASE EARNINGS BEYOND THOSE TO WHICH THE COMPANY WOULD ORDINARILY BE ENTITLED.

A. When Columbia adds a new Residential customer, margins from that customer are set under the RNA at the BDRB. A new customer is likely to have purchased a more energy-efficient gas appliance than an average existing customer, and would have lower usage

than an average customer, all else being equal. This would increase Columbia's earnings beyond what they would have been without the RNA because Columbia's margins would be based on average Residential customer margins.

Q. DOES THE PROPOSED RNA UNREASONABLY APPLY TO CUSTOMERS WHOSE USAGE IS RELATIVELY CONSTANT OVER TIME?

A. Yes. The RNA would collect or refund any variation in total Residential revenues that differed from the BDRB and that are not due to differences between actual and normal weather. Therefore, the RNA would unreasonably apply to those Residential customers whose usage is relatively constant over time.

Q. DOES THE PROPOSED RNA EMBODY A TAKE-OR-PAY PRICING POLICY?

A. Yes. In the marketplace, consumers pay for the goods and services they receive or consume. Under the proposed RNA, consumers would pay for distribution service they receive and distribution service that they do not receive. No matter how much distribution service is actually purchased by Columbia's Residential customers, ultimately, under the proposed RNA, those customers would pay for the set level of service whether they take delivery of the that set level of service or not. This conversion of a volumetric rate into rates that yield a given guaranteed revenue, regardless of the amount of service purchased, converts Columbia's volumetric rate into a take-or-pay billing feature.

Q. PLEASE EXPLAIN HOW THE RNA COULD RESULT IN INAPPROPRIATE RATE ADJUSTMENTS.

A. The proposed RNA operates to change rates, automatically, between rate cases, simply as a function of Residential distribution revenues being different from benchmark revenues that are set at the conclusion of a base rate case due to factors other than weather. There is no review of Columbia's costs, or the volumes and attendant revenues from other customer

classes that are not included under the RNA. For example, if Residential usage per customer were to fall over time, while SGSS/DS-1 deliveries increased, Columbia's Residential rates would be increased under the RNA with no recognition of the increased SGSS/DS-1 distribution service revenues. Moreover, if Residential customer distribution service requirements decreased over time, Residential allocated costs should also decrease, thus reducing the Residential revenue requirement. There is no provision in the proposed RNA to adjust Residential class revenue requirements as they may be affected by the very events that trigger automatic price changes under the RNA.

Q. HAS COLUMBIA DEMONSTRATED THAT ITS CURRENT SYSTEM OF RATES AND CHARGES DO NOT PROVIDE FOR ADEQUATE REVENUE STABILITY?

A. No. Columbia's current system of rates and charges, which include fixed monthly customer charges, a Purchased Gas Adjustment mechanism, a Weather Normalization Adjustment, and a Distribution System Improvement Charge, provide for revenue stability and Columbia has not demonstrated that this stability is inadequate.

Q. DID THE COMPANY PROPOSE A SIMILAR RNA IN ITS LAST LITIGATED BASE RATE PROCEEDING IN DOCKET NO. R-2020-3018835 AND WAS IT APPROVED BY THE COMMISSION?

A. The Company proposed a similar RNA in its last litigated base rate case. In that proceeding the ALJ determined that the Company failed to prove that the RNA would result in rates that were just and reasonable, were in the public interest, and the Company did not demonstrate that its current rates and systems of revenue streams failed to provided revenue stability. (Order at 264-265). The Company did not file exceptions to the ALJ's recommended rejection of its proposed RNA.

Q. ARE THERE OTHER REASONS THAT THE RNA SHOULD NOT BE APPROVED AT THIS TIME?

A. Yes. We are in a time of high inflation. Many consumers are looking for ways to reduce their expenses and energy conservation and efficiency is one such way of doing so. As discussed, the RNA reduces the ability of households to achieve bills savings from reduced energy usage as revenue benchmarks for Residential customers are set at the conclusion of the Company's base rate case by the RNA, thereby discouraging energy efficiency. Thus, among other reasons, now is simply not the time to approve alternative ratemaking mechanisms such as the RNA.

Q. THE COMPANY STATES THAT THE RNA CAN RESULT IN A CREDIT TO THE CUSTOMER. IS THIS A NET CREDIT RESULTING IN CUSTOMER SAVINGS?

A. No. The credit that a customer may possibly see under the RNA is not a net credit. If a customer reduces their consumption in an attempt to reduce their bill but the reduction is less than the reduction in usage of all other customers, the RNA will take those savings away from the customer, and in fact, the customer's bill will be higher. This is because the RNA charges all customers for usage reductions based on the aggregate reduction in usage by all customers. For a customer to continually experience bill savings under the RNA, the customer would need to ***continuously*** reduce their consumption by a ***greater amount*** than the average customer.

Q. SO WHAT DOES THIS MEAN FOR MOST CONSUMERS?

A. It means that under traditional ratemaking, a consumer can save money on their monthly water bill by improving their energy efficiency and reducing consumption, and the consumer keeps those savings. In contrast, under the RNA, the consumer will be forced to share some of their bill savings with the utility if enough customers reduce their usage such

that the Company does not meet its revenue target. For many consumers, it could mean being forced to return nearly all of their bill savings to the utility.

VI. MUNICIPAL LEVELIZATION CHARGE

Q. PLEASE DESCRIBE COLUMBIA'S PROPOSED MLC.

A. Columbia is proposing to implement an experimental MLC for customers in two of the municipalities it serves that have paving and restoration requirements for infrastructure replacement projects that exceed what other municipalities require and also exceed the statewide Pennsylvania Department of Transportation requirements. Columbia claims that the restoration requirements in these two municipalities result in costs for infrastructure replacement projects that exceed the costs incurred by Columbia in other municipalities. The revenues collected through the proposed MLC would be credited to two municipalities that have less costly infrastructure replacement paving and restoration requirements. Columbia claims that the experimental MLC will foster fairness because customers living in municipalities which do not impose costly paving and restoration requirements will no longer pay for paving and restoration costs that only benefit customers in those municipalities that impose more costly requirements.

The experimental MLC would apply to customers in the City of Pittsburgh and the Borough of Perryopolis. The credit would apply to customers located in Roscoe Borough and New Sewickley Township. More specifically, based on costs incurred by Columbia during the period 2021-2023, the Company is proposing a monthly MLC of $0.70 per bill to customers located in the City of Pittsburgh and the Borough of Perryopolis, and a monthly MLC credit of $7.44 per bill to customers located in Roscoe Borough and New Sewickley Township.

Q. SHOULD THE MLC BE APPROVED?

A. No. The proposed MLC is experimental and should be rejected. To the best of my knowledge, I have not seen an MLC or similar mechanism being charged anywhere else in the country by any public utility. The MLC is a new and novel charge that Columbia hopes to charge Pennsylvania ratepayers. The proposed MLC is intended to account for differences in costs of serving different municipalities. The rates being proposed by Columbia for distribution service are generally, although not precisely, based on the cost of providing service. The average monthly bill of a Residential customer under Columbia's proposed rates for distribution service (exclusive of purchase gas costs) is approximately $98.00. The proposed MLC is $0.70 per month and, therefore, would reflect less than 1% of Columbia's total cost of serving the average Residential customer. It is unreasonable to recognize this less than 1% difference in the cost of serving customers in different municipalities and to ignore cost differences which may exist for the remaining 99% of the cost of service. For example, to serve the City of Pittsburgh, Columbia has installed an average of 54 feet of distribution main per customer. To serve New Sewickley Township, Columbia has installed an average of 142 feet of distribution main per customer. Under the MLC, City of Pittsburgh customers would be assessed an additional charge even though based on the distribution main footage installed to serve City of Pittsburgh customers, the cost of serving City of Pittsburgh customers is less than the cost of serving New Sewickley Township customers, but New Sewickley Township customer would receive a credit under the MLC. To analyze and impose charges for differences in costs for the remaining 99% of the cost of service not addressed by the MLC would require a significant effort by the Company. This effort and assessing different charges to each municipality served by Columbia to recognize the differences in costs associated with serving each municipality

would most likely considerably increase Columbia's total cost of service and overall, in total, customers would be worse off.

In addition, the additional paving and restoration costs incurred to serve customers in the City of Pittsburgh and Borough of Perryopolis are reflected in the rates proposed by Columbia in this proceeding for all customers served by Columbia. Columbia currently serves a total of 22,604 customers in the City of Pittsburgh and the Borough of Perryopolis which would be assessed the MLC, and a total of 2,116 customers in New Sewickley Township and Roscoe Borough that would receive the MLC credit. It is unreasonable to impose a charge on 22,604 customers for additional costs incurred to serve those customers and then credit the additional charges to 2,116 customers when the additional City of Pittsburgh and Borough of Perryopolis paving and restoration costs have been reflected in the rates of all Columbia customers. The MLC should be rejected.

Q. ARE THERE OTHER REASONS THE MLC SHOULD NOT BE APPROVED?

A. Yes. The same MLC would be assessed to all customers in a municipality served by Columbia, and the MLC does not recognize differences in the costs associated with serving different customer classes.

VII. WEATHER NORMALIZATION ADJUSTMENT

Q. BRIEFLY DESCRIBE CPA'S WEATHER NORMALIZATION ADJUSTMENT.

A. The WNA adjusts a Residential customer's monthly charges to account for differences in usage attributable to variations between actual recorded heating degree days ("HDDs") and normal HDDs during the months of November through May. The WNA provides for the collection of additional revenues from Residential customers when actual HDDs experienced are less than normal HDDs and provides a revenue credit when actual HDDs

experienced are greater than normal HDDs. The formula used to develop the WNA applied to each bill is presented on pages 162 and 163 of the Company's current tariff.

Q. WHEN WAS COLUMBIA'S CURRENT WNA APPROVED?

A. The current version of Columbia's WNA was most recently approved in Columbia's 2021 base rate proceeding in Docket No. R-2021-3024296 which was resolved by settlement. In its Order approving the settlement entered December 16, 2021, the Commission approved provision 33 of Section III of the settlement which provided that "Columbia's proposal to continue its Pilot Weather Normalization Adjustment ("WNA") mechanism until a final order is entered in the Company's first rate case filed after May 31, 2026 is approved." (Opinion and Order, pages 15-16). The 2021 Settlement was referring to the pilot WNA mechanism with the 3% deadband, as was approved in 2018 base rate proceeding pursuant to settlement at R-2018-2647577. Hence, in the 2021 proceeding, the PUC approved the parties' agreement to continue the pilot WNA with the 3% deadband until a final order is entered in the Company's first rate case filed after May 31, 2026 is approved.

Q. IS COLUMBIA PROPOSING ANY CHANGES TO THE WNA APPROVED IN DOCKET NO. R-2021-3024296?

A. Yes. As discussed later in his section my testimony, Columbia is proposing to eliminate the 3% HDD deadband included in its current WNA. Therefore, Columbia is proposing to modify the WNA approved by the Commission in Docket No. R-2021-3024296. Counsel informs me that since Columbia is proposing to modify the provisions of the WNA approved in Docket No. R-2021-3024296, whether the WNA should continue in effect requires evaluation in this proceeding.

Q. SHOULD THE COMMISSION ALLOW COLUMBIA'S CURRENT WNA TO REMAIN IN EFFECT?

A. No, for numerous reasons. First, I concur in the analysis and findings of David E. Dismukes' Exhibit DED-10, which shows that over the heating seasons of the prior eleven-year period of 2013 through 2024, the Company has collected $59.1 million from Residential customers on a net basis (netting collections against refunds). In other words, as shown in Exhibit DED-10, since 2013, the WNA has had a net detrimental impact of $59.1 million on Residential customers. Table 5 below shows that over the past 5 years, since 2019, Residential customers have been charged every heating season (as opposed to receiving a refund), and the total charged over that period is $63.8 million. This detrimental impact on consumers is likely to continue.

Table 5.
Revenue Impact of WNA on Customers

Heating Season	Charge
2019/2020	$4,979,367
2020/2021	5,327,158
2021/2022	2,530,224
2022/2023	17,441,275
2023/2024	33,544,436
Total:	**$63,822,460**

Q. WHAT OTHER REASONS ARE THERE FOR NOT ALLOWING THE WNA TO REMAIN IN EFFECT?

A. A second reason that the WNA should not remain in effect is that automatic rate adjustments such as the WNA should be avoided because they weaken traditional regulatory principles and unreasonably shift risk to customers. To justify maintaining the WNA, Columbia should be required to demonstrate that it is necessary to avoid significant

financial damage to the Company and that eliminating the WNA would pose a threat to Columbia's financial stability. The Company has not presented evidence that a lack of a WNA poses a threat to Columbia's financial stability.

Third, similar to the proposed RNA, the WNA inappropriately adjusts rates without considering other changes in total revenues and costs. The WNA changes rates, automatically, between rate cases, simply due to the impact of weather on Residential distribution revenues. There is no review of Columbia's costs, or the volumes and attendant revenues from Residential customers and other customer classes. The WNA does not account for the additional revenues received by Columbia due to increases in the number of Residential customers served or increases in the number of customers served in other customer classes, or increases in the usage by customers in other customer classes. The WNA does not account for cost reductions that Columbia may experience. For example, under the WNA Residential customers will be assessed additional charges if it is warmer than normal, as determined under the WNA, and Residential customer usage is reduced. With reduced usage by Residential customers, Columbia's compressor station operating expenses will likely be reduced, and uncollectible expense is likely to decline. These cost reductions are not considered under the WNA, and the WNA may provide for the recovery of costs that are not used and useful in providing service.

Fourth, also similar to the proposed RNA, the WNA embodies a take-or-pay pricing policy. Under the WNA, Residential customers pay for distribution they actually receive, and may pay for distribution service they do not receive, despite the customer having no immediate alternatives to Columbia's distribution service.

Finally, the WNA provides disincentives for energy efficiency. If a customer reduces their consumption due to the implementation of energy conservation measures and it is warmer than normal, a portion of the savings achieve by the customer due to the energy

conservation measure will be reduced which will provide a disincentive to implement further energy conservation measures.

Q. WHAT ARE THE 14 FACTORS FOR CONSIDERATION IDENTIFIED IN THE COMMISSION'S STATEMENT OF POLICY ON ALTERNATIVE RATEMAKING AND WHAT IS YOUR RESPONSE TO THESE CONSIDERATIONS?

A. Each rate consideration identified in the Statement of Policy is listed below along with the claimed relevant effect of the WNA on each rate consideration:

Consideration 1	Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.
	OCA: The WNA represents a clear misalignment between revenue and cost causation because it bills customers based on hypothetical usage, and not based on actual cost-based usage. The WNA provides for the recovery of fixed costs on a volumetric basis; therefore, it does not align utility revenues with cost causation principles as to both fixed and variable costs.
Consideration 2	Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.
	OCA: The proposed WNA is unrelated to capacity utilization since the determining metric for the charge is weather not utilization.
Consideration 3	Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.
	OCA: 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.

Consideration 4	Please explain how the ratemaking mechanism and rate design limit or eliminate inter-class and intra-class cost shifting.
	OCA: The WNA is only applicable to the Residential class and, therefore, does not affect traditional interclass cost shifting.
Consideration 5	Please explain how the WNA limits or eliminates disincentives for the promotion of efficiency programs.
	OCA: The WNA disincentives energy efficiency programs because it imposes a disconnect between cost-savings for customers that participate in energy efficiency programs. The disincentive exists in that by relying upon temperature variances to impose a WNA regardless of reduced usage that may otherwise result from participation in an energy efficiency program, the WNA inserts an artificial variable that would mitigate at least some cost savings contingent on the weather. In addition, the Company has not demonstrated that the lack of a WNA would be a major obstacle for the promotion of its voluntary energy efficiency and conservation activities.
Consideration 6	Please explain how the WNA impacts customer incentives to employ efficiency measures and distributed energy resources.
	OCA: The WNA could provide a disincentive to employ energy efficiency measures for customers whose energy efficiency initiative takes place during periods of warmer than normal weather. This is because a portion of a customer's bill savings would be returned to the Company because the efficiency actions occurred when weather was warmer-than-normal. As such, the customer may perceive the WNA as a disincentive for deploying more energy efficiency measures.
Consideration 7	Please explain how the WNA impacts low-income customers and support consumer assistance programs.
	OCA: The impact of the WNA on Residential low-income customers would be the same as the impact on Residential non-low-income customers. The WNA does not support customer assistance programs.
Consideration 8	Please explain how the WNA impacts customer rate stability principles.
	OCA: Under the current regulatory standard in Pennsylvania, base rate cost under and over recoveries are currently not tracked

and are not eligible for recovery in future base rate proceedings. The WNA will not change this standard.

The proposed WNA would add another surcharge to customers' bills and the Company has not shown how it would reduce the frequency of Columbia Gas base rate filings. Thus, it does not appear that the WNA surcharge would improve rate stability. In contrast, under traditional cost-of-service ratemaking, if a utility experiences sales reductions and under-recovery, it cannot simply achieve the same result as a WNA by filing another base rate case with adjusted sales forecasts. When a utility files a general rate increase, all relevant information is reviewed to determine just and reasonable rates, not just sales forecasts. Traditional ratemaking produces rate stability.

In addition, the WNA decreases customer rate stability because it obscures price signals for customers by disassociating their monthly bill from their actual usage. As a result, a customer is less likely to be able to predict what their bill would be at the end of the month based off usage.

Consideration 9 — Please explain how weather impacts utility revenue under the WNA.

OCA: Weather will directly impact utility revenue under the WNA.

Consideration 10 — Please explain how the WNA impacts the frequency of rate case filings and affects regulatory lag.

OCA: Columbia files a rate case nearly every year. This is unlikely to change and a WNA does not prevent the Company from seeking additional rate increases. The WNA does not affect future revenue requirements and does not recover fixed costs that are incurred after a rate case that are over and above those approved by the Commission. Therefore, if future rate cases are driven by future investment needs or higher expenses and associated cost recovery, the WNA would not reduce the need for such cases.

Consideration 11 — Please explain if the WNA interacts 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).

OCA: The WNA will not interact with other revenue sources.

Consideration 12 — Please explain whether the WNA includes appropriate consumer protections.

OCA: The WNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony and the testimony of OCA witness Colton and OCA witness Dismukes.

Consideration 13 — Please explain whether the WNA is understandable to customers.

OCA: Columbia has not provided any evidence that the WNA is understandable to customers.

Consideration 14 — Please explain how the WNA will support improvements in utility reliability.

OCA: The WNA does not provide an incentive to increase the safety and reliability of Columbia's system.

Q. AS INDICATED EARLIER IN YOUR TESTIMONY, COLUMBIA IS PROPOSING TO ELIMINATE THE CURRENT 3% HEATING DEGREE DAY DEADBAND INCLUDED IN THE WNA. WHY IS COLUMBIA PROPOSING TO ELIMINATE THE 3% DEADBAND?

A. Under the current WNA, no adjustment is applied to customers' bills if weather during the period November through May utilized to calculate the WNA if HDDs during the period vary from normal by 3% or less. This is referred to as a 3% deadband. As explained by witness Mark Kempic in Statement No. 1, page 9, and witness Kevin L. Johnson in Statement No. 6, page 34, the 3% deadband could result in weather related billing adjustments being flowed through the RNA. To alleviate this concern, the Company is proposing to eliminate the 3% deadband.

Q. SHOULD THE 3% DEADBAND BE ELIMINATED IF THE COMMISSION DETERMINES THAT THE WNA SHOULD BE CONTINUED?

A. No. As just discussed, for a number of reasons, the RNA should not be approved. Therefore, if the Commission determines that the WNA should continue, it would be unnecessary to eliminate the 3% deadband to prevent weather related adjustments from being flowed through the RNA.

Q. SHOULD THE 3% DEADBAND BE ELIMINATED IF THE RNA IS NOT APPROVED AND THE COMMISSION DETERMINES THAT THE WNA SHOULD BE CONTINUED?

A. No, the 3% deadband should not be eliminated. It is unreasonable to assume that weather and natural gas usage is abnormal if a particular day is only a few HDDs warmer or colder than normal. If the deadband is eliminated, the WNA would be applied if actual weather was only one HDD colder or warmer than normal. Under the WNA, an HDD is determined by subtracting from 65°F the average of daily hourly temperatures, and daily usage can vary due to factors other than temperature. Therefore, if the WNA is maintained the 3% deadband should be maintained to help ensure that the assessment of the WNA is limited to changes in usage attributable to variations in temperature.

Q. ARE HDDS THE ONLY VARIABLE THAT AFFECTS ACTUAL CUSTOMER USAGE?

A. No. Variables other than temperature, or HDDs, can impact customer gas usage. These variables include windspeed, the day of the week, the percentage of daily sunshine, and temperatures on the prior day. Maintaining the 3% deadband would assist in reducing the WNA's impact on usage caused by these other variables.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does at this time.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v Columbia Gas of Pennsylvania, Inc.	: : : : :	Docket No. R-2024-3046519

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 5, are true and correct (or 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 14, 2024

Signature: Jerome D. Mierzwa

Jerome D. Mierzwa
Exeter Associates, Inc. 10480
Little Patuxent Parkway, Suite 300
Columbia, MD 21044-3575

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3046519
	:	
Columbia Gas of Pennsylvania, Inc.	:	

Direct Testimony of Roger Colton

on behalf of

Pennsylvania Office of Consumer Advocate

OCA Statement 6

Date Served: June 14, 2024

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Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, Massachusetts.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am owner of the firm of Fisher Sheehan & Colton, Public Finance and General Economics of Belmont, Massachusetts. In that capacity, I provide technical assistance to a variety of federal and state agencies, consumer organizations and public utilities on rate and customer service issues involving water/sewer, natural gas and electric utilities.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of the Office of Consumer Advocate.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND.

A. I work primarily on low-income utility issues. This involves regulatory work on rate and customer service issues, as well as research into low-income usage, payment patterns, and affordability programs. At present, I am working on various projects in the states of New Hampshire, Massachusetts, Connecticut, Maryland, Pennsylvania, Ohio, Michigan, Wisconsin, Missouri, Oregon and Washington, as well as in the Canadian provinces of Nova Scotia and British Columbia. My clients include state agencies (e.g., Pennsylvania Office of Consumer Advocate, Maryland Office of People's Counsel, Connecticut Office of Consumers Counsel), federal agencies (e.g., the U.S. Department of Health and Human Services), community-based organizations (e.g., Cleveland Legal Aid Society, Legal Action of Chicago, Sierra Club), and public and private utilities (e.g., Toledo Water, BC Hydro). Examples of my work include my current projects to assist the Connecticut Office of Consumers Counsel (OCC) in the annual generic review of the

low-income affordability initiatives of that state's utilities by the Public Utilities Regulatory Authority. I am also assisting the Massachusetts Attorney General's Office (AGO) in the generic investigation by the Department of Public Utilities (DPU) into the design of low-income affordability programs. I am currently under contract to develop a universal service plan for Nova Scotia. In addition to state-specific and utility-specific work, I engage in national work throughout the United States. For example, I have recently completed a project with the Natural Resources Defense Council to develop a tool by which to assess the financial impact of differing types of low-income bill assistance. A brief description of my professional background is provided in Exhibit RDC-1.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. After receiving my undergraduate degree in 1975 (Iowa State University), I obtained further training in both law and economics. I received my law degree in 1981 (University of Florida). I received my Master's Degree (Regulatory Economics) from the MacGregor School in 1993.

Q. HAVE YOU EVER PUBLISHED ON PUBLIC UTILITY REGULATORY ISSUES?

A. Yes. I have published three books and more than 80 articles in scholarly and trade journals, primarily on low-income utility and housing issues. I have published an equal number of technical reports for various clients on energy, water, telecommunications and other associated low-income utility issues. A summary of my publications is included in Exhibit RDC-1.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS OR OTHER UTILITY COMMISSIONS?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("PUC" or "Commission") on numerous occasions regarding utility issues affecting low-income customers and customer service. My testimony has specifically included testimony in various proceedings involving low-income program design and operation, along with various rate design issues as they affect low-income customers. I have also testified in regulatory proceedings in 43 states (other than Pennsylvania) and various Canadian provinces on a wide range of utility issues. A list of the jurisdictions in which I have testified is listed in Exhibit RDC-1.

Q. PLEASE EXPLAIN THE PURPOSE OF YOUR DIRECT TESTIMONY.

A. The purpose of my Direct Testimony is to review the impact of Columbia Gas of Pennsylvania, Inc.'s (Columbia or Company) rates on low-income customers. More specifically, I will examine the following topics:

- The overall affordability of Columbia's rates;
- The impact that the unaffordability of Columbia's bills has on collections by the Company;
- A series of recommendations regarding the appropriate procedures and operations that the Company should adopt (outside of its Universal Service and Energy Conservation Plan (USECP)) to address the unaffordability of its bills to low-income customers;
- The necessity to revise certain Columbia tariffs and practices to comply with PUC regulations;
- The Company's proposed residential customer charge;
- The Company's Weather Normalization Mechanism;

- The Company's proposed Revenue Normalization Adjustment; and

- The Company's request to increase its return on equity due to claims of "superior" management.

Q. PLEASE SUMMARIZE THE RECOMMENDATIONS YOU MAKE THROUGHOUT YOUR TESTIMONY WHICH FOLLOWS.

A. Based on the data and analysis I present throughout my testimony below, I recommend:

- That Columbia be directed to modify its policies and procedures regarding the identification of "confirmed low-income" customers to conform with the PUC's regulations. Columbia should include these modified policies and procedures in its residential tariff. The modified policies and tariff should add a new "definition" of "Confirmed Low-Income customer" which explicitly mirrors the PUC definition, stating that:

> Confirmed low-income residential account—Accounts where the Company has obtained information that would reasonably place the customer in a low-income designation. This information may include receipt of LIHEAP funds (Low-Income Home Energy Assistance Program), self-certification by the customer, income source or information obtained in § 56.97(b) (relating to procedures upon rate-payer or occupant contact prior to termination).

In addition, Columbia should add to each residential tariff under "Special Provisions," a new paragraph with the following language: "A confirmed low-income residential account, including applicants, will be afforded each protection accorded by tariff or regulation, which tariff or regulation applies to any customer or applicant with household income at or below 150% of the Federal Poverty Level."

- That, prior to the disconnection of a Confirmed Low-Income customer, Columbia adopt a procedure, developed in collaboration with its Universal Service Advisory Committee (USAC), under which it will seek to make personal contact with the customer subject to disconnection. In that personal contact, the Company shall offer the Confirmed Low-Income customer the opportunity to apply for the Company's CAP and arrearage forgiveness program. If the customer expresses a desire to make such application,

Columbia will postpone the disconnection for a reasonable period of time to allow the application process to be completed.[1]

- That before Columbia enters into a payment arrangement with a customer which the Company either: (1) knows to be a Confirmed Low-Income customer; or (2) has generated information through the payment arrangement process documenting that the customer is in the Tier 1 income range (at or below 150% FPL), it should be required to provide the customer a stand-alone Plain English notice to that customer of the customer's right to enter into CAP and an explanation of the advantages of CAP's arrearage forgiveness benefits. Columbia should develop this Plain English notice in collaboration with its USAC.

- That before Columbia enters into a payment arrangement with a customer which the Company either: (1) knows to be a Confirmed Low-Income customer; or (2) has generated information through the payment arrangement process documenting that the customer is in the Tier 1 income range (at or below 150% FPL), it should be required to provide the customer a stand-alone Plain English notice to that customer of the customer's right to enter into CAP and an explanation of the advantages of CAP's arrearage forgiveness benefits. Columbia should develop this Plain English notice in collaboration with its USAC.

- That Columbia Gas adopt a procedure under which it will provide a stand-alone Plain English notice to customers found to be without heating service at the time of the Company's Cold Weather Survey of the customer's right to enter into CAP and an explanation of CAP's arrearage forgiveness benefits. This education should *also* include a recommendation and information to be provided both about LIHEAP, its benefits and how to apply, as well as Dollar Energy Fund and any other resources that may be available in the community that can also potentially help the customer to get reconnected. Columbia should develop the Plain English notice in collaboration with its Universal Service Advisory Group.

- That when Confirmed Low-Income customers accrue an unpaid balance of $300, Columbia provide a stand-alone written Plain English notice informing

[1] It is also possible that a portion of these customers will include customers who were previously enrolled in CAP and owe a CAP catch-up amount or a customer who may have failed to recertify. These customers, too, should receive education about the benefits of CAP.

those customers of their right to enroll in the Company's CAP (along with an explanation of the advantages of CAP's arrearage forgiveness provisions).

- That, in those instances where Columbia would otherwise request a cash security deposit from a Confirmed Low-Income customer, the Company should, as an alternative to that deposit demand, provide a stand-alone written Plain English notice informing these customers of their right to enroll in the Company's CAP (along with an explanation of the advantages of CAP's arrearage forgiveness provisions).

- That Columbia be directed to extend any future use of speech analytics software to assist with the quality monitoring of phone calls involving, or potentially involving, universal service programs and other low-income customers. Columbia should be directed to involve its USAC in the identification and selection of Low-Income and Universal Service Terms to be detected by the system in order to confirm that phone calls are properly being identified and handled. Regular six-month reports on the results of the Speech Analytics reviews should be provided to the Company's USAC.

- That Columbia be directed to take four actions regarding requests for cash security deposits. First, that Columbia Gas be directed to modify its tariff so that it complies with the PUC's regulation. The tariff should reflect the regulatory requirement that a customer is to be exempt from cash security deposits "when *the customer provides income documents or other information* that he or she is eligible for state benefits based upon household income eligibility requirements that are consistent with those of the public utility's customer assistance program." Second, that Columbia Gas refund any cash security deposit to a customer who is currently categorized as "Confirmed Low-Income." By definition, under the PUC's regulations, a Confirmed Low-Income customer is a customer who the Company has received information sufficient to give rise to a reasonable belief that the customer is low-income. Third, that Columbia include in its tariff the April 2024 order of the PUC, directing that Columbia may apply an existing security deposit to the account balance only with the customer's informed consent. As part of obtaining this informed consent, Columbia must explain to the customer how applying the security deposit to the account balance would impact the customer's monthly bill. Fourth, that Columbia Gas provide a report to its Universal Service Advisory Committee every six months for three years, or until the final decision in its next base rate case, whichever is longer, of the number of low-income customers who have had

deposits waived, as well as the number of low-income customers who have had deposits refunded.

- That Columbia be directed to modify its tariff, along with its policies, practices and procedures regarding the identification of "confirmed low-income" customers to conform with the PUC's regulations, including self-certification of low-income status. Columbia should include these modified policies and procedures in its residential tariff. Within this modified tariff language should be included a list of public assistance programs, mutually agreed to by the Company and its USAC, participation in which would reasonably place the customer in a low-income designation. The Company should explicitly acknowledge that a customer *may* provide, but is *not required* to provide, either the household's actual dollar level of income or the household composition in order to provide sufficient information to reasonably place them in a low-income designation.

- That Columbia's Tariff be modified to add the following language: "that fall within the range of general industry practice, *provided that the methodology does not directly, or have the effect of, discriminating based on a protected class as set forth in the federal Equal Credit Opportunity Act.*" (new language emphasized).

- That the residential customer charge determined by OCA witness Jerome D. Mierzwa should be approved.

- That the recommendations of OCA witnesses David E. Dismukes and Jerome D. Mierzwa regarding the Company's proposed WNA be adopted.

- That the recommendations of OCA witnesses David E. Dismukes and Jerome D. Mierzwa regarding the proposed RNA should be adopted.

- That the recommendation of OCA witness Christopher C. Walters regarding an appropriate return on equity be adopted.

Part 1. The Affordability of Columbia Rates.

Q. PLEASE DESCRIBE THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. This section of my testimony examines the affordability of bills to Columbia's residential customers. I begin with an examination of the affordability of Columbia bills over time. I next consider the affordability to low-income residential customers generally. I consider the disproportionately adverse impact that inflation has on low-income customers. I finally examine the impact of Columbia's bills on residential customers in general. My testimony focuses on the impact of the proposed rate increase on low-income households and the overall impact of Columbia's bills on residential customers.

A. Columbia Rates Over Time.

Q. WHAT IS THE PURPOSE OF YOUR ANALYSIS OF COLUMBIA'S RATES OVER TIME?

A. Columbia has filed for general rate increases in 2009[2], 2010[3], 2012[4], 2014[5], 2016[6], 2019[7], 2020[8], 2021[9], and 2022[10], each of which resulted in a grant of a rate increase with an effective date somewhere near nine months of the filing date in each case. The purpose of my analysis of Columbia's rates over time is to determine the impact of the Company's ongoing and frequent rate increase on the heating burdens of Columbia's low-income

[2] R-2009-2149262
[3] R-2010-2215623
[4] R-2012-2321748
[5] R-2014-2406274
[6] R-2016-2529660
[7] R-2019-3010039
[8] R-2020-3018835
[9] R-2021-3024296
[10] R-2022-3031211

customers.[11]

Q. WHAT DID YOU FIND WITH YOUR ANALYSIS?

A. I found that, when looking at rates over time, Columbia's low-income customers are facing increasingly unaffordable heating burdens given the Company's ongoing rate increases. For Columbia's lowest income customers (with income levels at the lowest range of the Federal Poverty Level (FPL) (0 – 50%)), heating burdens are significantly higher than the affordable burden defined by the PUC of 4% of income. For Columbia's other customers in the mid (50%-100% FPL) and highest (100-150% FPL) ranges of what is considered low-income, the heating burdens under Columbia's rates exceed the affordable burden defined by the PUC of 6% of income.

Q. PLEASE DESCRIBE YOUR FINDINGS.

A. Table 1 below shows that the affordability of Columbia's bills has degraded over time. Table 1 shows that:

- At the lowest range of FPL (0 – 50%), heating burdens significantly exceed the affordable 4% of income definition. While heating burdens were 10.6% in 2012, those burdens had increased to 16.5% in 2023, before declining to 12.9% in 2024. In 2023, heating burdens for Columbia's lowest income customers were *four times higher* than the affordable burden defined by the PUC, while in 2024, they were *three times higher* than the affordable burden.

- In the mid-range (50 – 100% FPL), heating burdens for Columbia's customers exceeded the affordable burden of 6% of income beginning in 2014, and

[11] I begin my review using the utility-specific data presented in the Pennsylvania PUC's annual "Rate Comparison Reports" for 2011 through 2024. Pennsylvania PUC (annual). Rate Comparison Report (Electric Utilities Comparison), available at https://www.puc.pa.gov/filing-resources/reports/rate-comparison-reports/ To calculate the "heating" bills, I multiplied the PUC's heating bills[11] times four months and added eight months of non-heating bills. I then compare the results to the PUC's definition of an affordable heating burden. The PUC's CAP Policy Statement (52 Pa. Code § 69.265(i)(B)) defines an affordable natural gas heating burden to be 4% of income for natural gas heating customers at 0 – 50% of FPL, and 6% for customers at 50 – 150% of FPL.

became increasingly unaffordable through 2023 at 8.8% before declining to 6.9% in 2024 but remaining above the 6% affordable burden definition.

- At the highest FPL range (100 – 150% FPL), while heating burdens were 3.4% in 2012, they had increased to 5.3% of income by 2023, before somewhat declining in 2024. However, rates for this group of customers does not exceed the PUC's 6% of income definition for affordable burden.

Table 1. Columbia Heating Bills and Burdens
(2011 – 2022) (shading simply to improve readability)

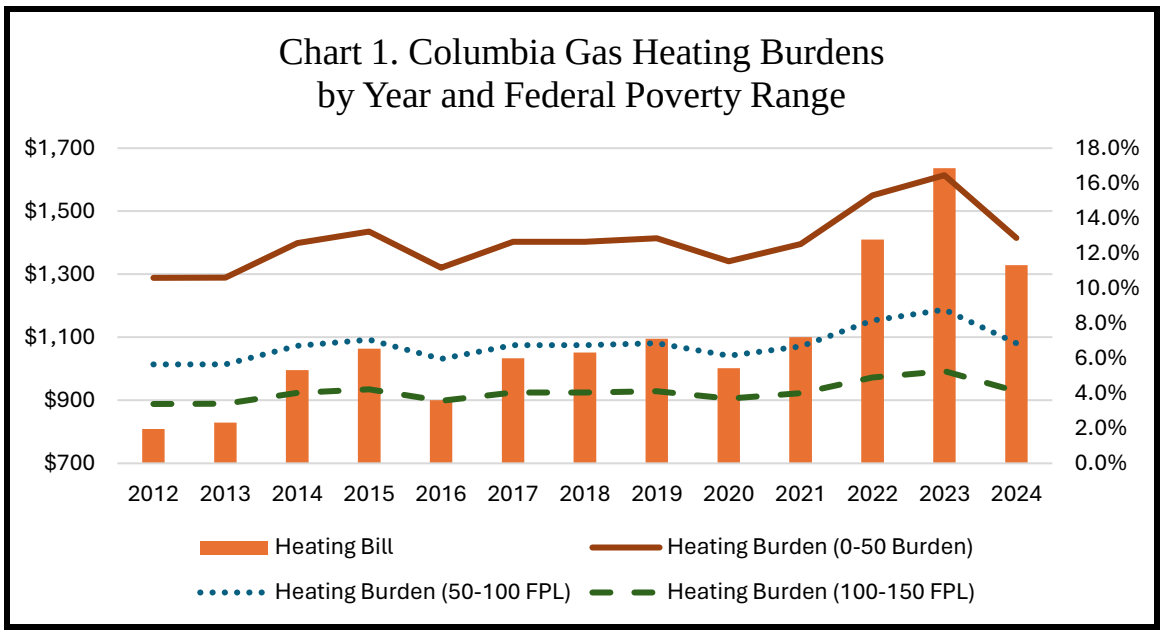
		Affordable Gas Heating Burden		Columbia Gas Heating Burden by FPL Range		
	Heating Bills (PUC Bill Comparison)	0 – 50% FPL	50 – 150% FPL	0 - 50% FPL	50 - 100% FPL	100 - 150% FPL
2012	$809	4% (2019 CAP Policy Statement)	6% (2019 CAP Policy Statement)	10.6%	5.7%	3.4%
2013	$829			10.6%	5.7%	3.4%
2014	$996			12.6%	6.7%	4.0%
2015	$1,064			13.2%	7.1%	4.2%
2016	$900			11.2%	6.0%	3.6%
2017	$1,033			12.6%	6.7%	4.0%
2018	$1,052			12.6%	6.7%	4.0%
2019	$1,095			12.9%	6.9%	4.1%
2020	$1,002			11.5%	6.2%	3.7%
2021	$1,100			12.5%	6.7%	4.0%
2022	$1,411			15.3%	8.2%	4.9%
2023	$1,637			16.5%	8.8%	5.3%
2024	$1,329			12.9%	6.9%	4.1%

Q. HOW WOULD YOU EXPLAIN THE PERCEIVED IMPROVEMENT IN THE AFFORDABILITY OF THE HEATING BURDEN FOR HOUSEHOLDS AT 100-150% FPL?

A. The improved affordability for the households at the higher income ranges (100-150% FPL) may be somewhat misleading. Net household resources will not necessarily increase as household income increases. As the household income becomes higher and higher, for example, households increasingly lose access to income supplements. These non-cash, supplemental benefits (e.g., Food Stamps, housing and medical assistance) are not counted as "income" in determining program eligibility for other assistance programs. The loss of such benefits reduces the ability of a household to pay its home energy bills.

Q. CAN YOU EXPLAIN FURTHER?

A. Chart 1 below graphically portrays the same basic information as Table 1. Importantly, Chart 1 shows how, after a dip in the Company's natural gas heating bills in 2016, gas prices again began to increase, with a sharp increase in 2022, which has not abated given the four rate increases granted by the PUC since 2016 (and this current request being the 5th rate increase request). The proposed increase in rates in this case will drive bills even higher. During the most recent three-year period shown in the graph, heating burdens at 50-100% FPL exceeded the affordable 6% of income burden defined by the PUC. At the lowest end of the FPL range (0-50% FPL), heating burdens in these three recent years were from three to four times higher than the 4% of income level defined by the PUC to be affordable.



All-in-all, the data above demonstrates that the Company's heating bills were 64% higher in 2024 than they were in 2012.[12] In contrast, incomes at the various ranges of FPL only rose 35% higher since 2012. In summary, Columbia's low-income customers are facing increasingly more unaffordable natural gas heating burdens given the Company's ongoing rate increases.

B. The Affordability of Bills to Low-Income Customers.

Q. HAVE YOU ASSESSED THE AFFORDABILITY OF COLUMBIA'S RATES TO LOW-INCOME CUSTOMERS IN PARTICULAR?

A. Yes. In Table 2 below, I examine the home energy bills imposed by Columbia's heating bills at different levels of the FPL. Table 2 shows that heating natural gas bills are

[12] In reaching this conclusion, I use assume the same consumption in each year. Changes in bills (and burdens), therefore, are a result of changes in rates, and not a result of changes in usage amounts.

unaffordable for customers with income in the two lowest ranges of poverty studied (0 – 50% FPL; 50 - 100% FPL).

Table 2. Heating Burdens at Existing and Proposed Rates
(given mean monthly usage over two 12-month periods) (OCA-2-15)

		Existing Rates	Proposed Rates
March 2022 – February 2023	0 – 50% FPL (PUC-defined affordable nat. gas heating burden is 4%)	14.6%	17.1%
	50 – 100% FPL (PUC-defined affordable nat. gas heating burden is 6%)	7.8%	9.1%
	100 – 125% FPL	4.7%	5.5%
	125 – 150% FPL	4.6%	5.4%
March 2023 – February 2024	0 – 50% FPL (PUC-defined affordable nat. gas heating burden is 4%)	13.8%	16.2%
	50 – 100% FPL (PUC-defined affordable nat. gas heating burden is 6%)	7.4%	8.6%
	100 – 125% FPL	4.4%	5.2%
	125 – 150% FPL	4.4%	5.1%

As Table 2 shows above, when customer incomes increase, bills become more affordable; however, for low-income customers at or below 100% of FPL, bills at Columbia's existing and proposed rates are unaffordable. In the two periods examined, March 2022 – February 2023 and March 2023 – February 2024, heating bills are significantly unaffordable for households with income at or below 100% of FPL. For the March 2022 – February 2023 period, at existing and proposed rates, the heating burden is 14.6% and 17.1% respectively for customers with incomes at 0-50% FPL and 7.8% and 9.1% respectively for customers with incomes at 50-100% FPL. For the March 2023 – February 2024 period, at existing and proposed rates, the heating burden is 13.8% and 16.2% respectively for customers with incomes at 0-50% FPL and 7.4% and 8.6% respectively for customers with incomes at 50-100% FPL. These actual heating burdens

are far from the PUC's definition of affordable heating burden of 4% for customers with incomes at 0-50% FPL and 6% for customers at 50-100% FPL.

Q. DOES TABLE 2 FULLY CAPTURE THE UNAFFORDABILITY OF COMPANY BILLS?

A. No. Table 2 is based on bills *at the middle* (i.e., median bills). Median bills are those bills where half of all customers have bills that are higher and half have bills that are lower.[13] As Table 3 below shows, every 25% change in usage from the median represents an increase (or decrease) in the monthly bill of roughly $16.50 ($200/year) at existing rates, and an increase (or decrease) in the monthly bill of roughly $18 ($220/year) at proposed rates.

Table 3. Columbia Gas Monthly Bills at Existing and Proposed Rates
And at Different Levels of Median Usage (OCA-2-44, OCA-2-45)

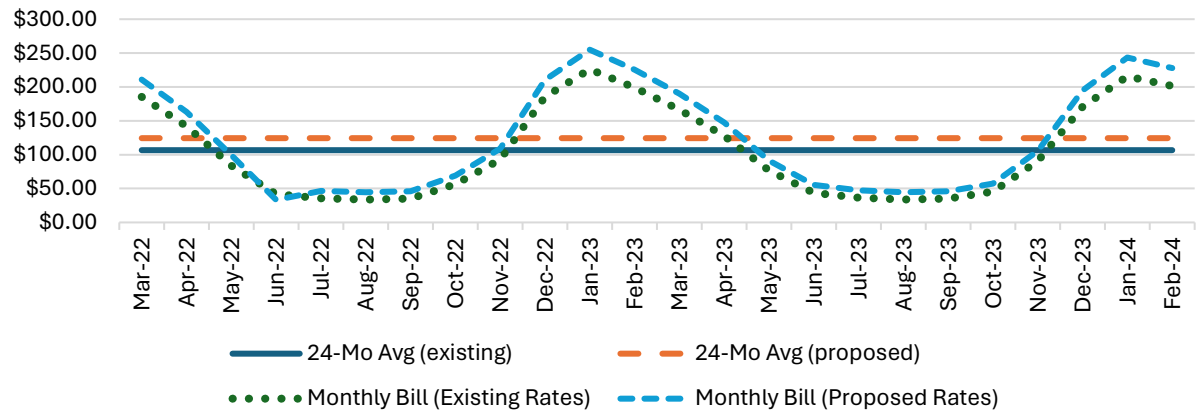
	Usage	Existing Rates	Proposed Rates
Median usage	4.60	$83.38	$98.92
50% median usage	3.45	$50.07	$62.47
75% median usage	2.30	$66.73	$80.78
125% median usage	5.75	$100.06	$117.16
150% median usage	6.90	$116.71	$135.38

[13] In preparing Table 2, I used the median monthly bills which the Company provided for the 24 months No. March 2022 through February 2024 (OCA-I-15) for heating customers. The Company provided the median monthly bills for those 24 months at both existing and proposed rates. As can be seen in the Table, I divided that 24 month period into two 12-month periods and calculated the median monthly bills for each period (multiplied by 12 to obtain an annual bill).

Q. DOES THIS DATA SHOW ANNUAL HEATING BURDENS?

A. Yes. However, it is important to avoid focusing exclusively on *annual* bills and *annual* burdens. Even if annual bills represent an affordable percentage of income, the seasonal variation in Columbia Gas bills can present an unaffordable payment obligation in any given month. Chart 2 below shows, for the same 24-month period discussed above, the median monthly bills for residential heating customers at existing rates as well as at the rates proposed by Columbia.

Chart 2.
Monthly Heating Bill at 24-Month Mean Usage and Mean Monthly Heating Bill at Monthly Mean Usage (OCA-2-015)



As can be seen, even if monthly *average* bills might be affordable (as reflected in an annual energy burden), the actual monthly bills can push payment obligations for heating needs far beyond a low-income customer's ability-to-pay.

Q. WHY IS YOUR DISCUSSION OF UNAFFORDABLE BURDENS IMPORTANT OR RELEVANT GIVEN THAT THE COMPANY'S CUSTOMER ASSISTANCE PROGRAM (CAP) IS DESIGNED AS A PERCENTAGE OF INCOME PLAN (PIP)?

A. While the design of Columbia's Customer Assistance Program (CAP) as a Percentage of Income Plan (PIP) will largely protect CAP participants from the harms of increasing rates, CAP is only helpful for those low-income customers who participate in the CAP's PIP component. The data, however, shows that the Company serves a relatively small proportion of its low-income customer base through the Company's CAP. While I make specific recommendations below with respect to how the Company might increase that participation, my observation here is limited to the fact that even given the Company's CAP, there is a significant low-income customer population that is *not* participating in CAP and that will be adversely affected by the Company's proposed rate increase.

Q. CAN YOU DESCRIBE THE SPECIFICS OF THE PROBLEM?

A. Yes. According to the Company, it has identified 70,188 Confirmed Low-Income customers on its system. (OCA-02-04). Of those Confirmed Low-Income customers, only 23,435 (33%) are CAP participants (OCA-1-04(d)). In absolute terms, Columbia has nearly 46,753 Confirmed Low-Income customers who do not participate in CAP (70,188 – 23,435 – 46,753).

Q. IS THIS THE EXTENT OF THE PROBLEM?

A. No, this is not the extent of the problem. There is more. According to the Company's most recent annual report to the PUC's Bureau of Consumer Services (BCS) (OCA-2-

01)[14] Columbia has an estimated 91,415 low-income customers. While Columbia has confirmed the low-income status of 77% of its estimated low-income customer base (70,188 / 91,415 = 0.768), the Company has then enrolled only 33% of that sub-population of Confirmed Low-Income customers into CAP. However, of the entire reported population of estimated low-income customers, Columbia has only enrolled roughly 25% or one-in-four of its estimated low-income customer population into CAP (23,435 / 91,415 = 0.256).

Q. IS YOUR OBSERVATION THAT COLUMBIA ENROLLS ONLY 25% OF ITS LOW-INCOME CUSTOMERS IN CAP A CRITIQUE OF THE COMPANY'S CAP OUTREACH?

A. Not in this proceeding. While I will make specific recommendations regarding CAP enrollment later in my testimony, my purpose here is *not* to critique or criticize the Company's CAP outreach. Instead, my purpose here is to demonstrate that CAP is not serving 75% of the estimated low-income customer population. As a result, my conclusion is that the existence of CAP cannot be used as a reason to ignore the unaffordability of Columbia's proposed rates on the low-income population.

Q. WHAT DO YOU CONCLUDE?

A. A consideration of affordability is a critical task to undertake within the structure of any utility rate case. As bills become increasingly unaffordable, the payment difficulties of those customers who face unaffordability become increasingly substantial as well. As I

[14] BCS (Sept. 2023). 2022 Report on Universal Service Programs and Collections Performance, available at https://www.puc.pa.gov/media/2573/2022-universal-service-report-final.pdf

will demonstrate later in this testimony, this conclusion can be well-documented for Columbia Gas.

Q. WHAT ARE THE IMPACTS ON AFFORDABILITY IN RELATION TO COLUMBIA'S RATE PROPOSALS?

A. One impact of the unaffordability I discuss, is its impact on the operating costs (e.g., collection costs, working capital, uncollectible expenses) that are then normalized and passed on to other ratepayers. Also, Columbia's proposals such as increasing the residential customer charge, the Weather Normalization Adjustment (WNA), and the Revenue Normalization Adjustment (RNA) have disproportionate adverse effects on low-income customers who already are facing substantial unaffordability.

Furthermore, establishing a return on equity (ROE) is fundamentally predicated on balancing customer and investor interests. It is necessary for the PUC to understand and consider the customer interests in order to appropriately balance them against the competing investor interests. The obligation of the Commission in deciding on the appropriate ROE and the reasonable capital structure should balance consumer and investor interests. (*FPC v. Natural Gas Pipeline Co.*, 315 U.S. 575, 606-607 - 608). Indeed, of the consumer issues that are important drivers of the just and reasonable ROE determination, one of the most significant is the concern about affordability. If a sizable portion of customers cannot afford to pay the rates imposed by the PUC, the PUC can hardly be said to have approved just and reasonable rates. Such concerns should bear directly on the determination of the fair ROE. In addition, as a utility such as Columbia adds more and more new and expensive plant, this increases rates, which may in turn put

downward pressure on the just and reasonable ROE not for financial reasons, but because of affordability concerns.[15]

In sum, the concerns I identify with respect to the unaffordability of Columbia's rates can (and should) be considered in determining Columbia's revenue requirement and structuring Columbia's rates, even outside the consideration of the specific proposals I advance with respect to specific low-income initiatives.

C. The Disproportionate Impact of Inflation on Low-Income Customers.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I respond to the testimony of Columbia witnesses Kempic, Bly, and Moul regarding the impacts of inflation on the Company and its investors. Columbia discusses the impact of inflation on the Company but never addresses the impact that inflation is having on ratepayers' ability to pay increased rates. Company witness Kempic, for example, cites the impact of inflation as a "driver" of the need for Columbia to seek this rate increase. (St. 1, at 18). Company witness Bly stated that Columbia's projections of future expenses are based on inflation-adjusted numbers. (St. 15, at 5, see also, St. 4, at 37). Company witness Moul explicitly stated that his "cost of equity analysis reflects the impact of high levels of inflation, which have not been seen for four decades. . ." (St. 8, at 4).

[15] *See Pa. PUC et. al v. Twin Lakes Utilities, Inc*., Docket No. R-2019-3010958 (Order entered March 26, 2020) at 48, 80 (finding the ALJ did not err in considering evidence relating to the various quality of service and rate affordability issues in the proceeding and factoring in such evidence as part of the ALJ's overall determination on which expert witnesses' cost of equity to adopt for setting just and reasonable rates).

As I testified above, the process of setting reasonable rates, however, does not exclusively consider the interests of investors. Instead, for example, the courts have noted that setting a reasonable ROE must involve a balancing of the interests of investors and ratepayers. To the extent that the impacts of inflation on investor interests are considered, therefore, the impacts of inflation on ratepayer interests must be considered as well. Moreover, decisions on issues such as the appropriate level of the residential customer charge, as well as the propriety of adopting certain alternative ratemaking mechanisms, such as the WNA and RNA, involve the PUC making explicit policy choices about how to allocate risks between ratepayers and the Company. The adverse impacts of inflation on ratepayers should be one component of those considerations.

In summary, as I will explain below, the testimony of Columbia's witnesses do not present a complete story about the stress which inflation has placed on utility ratepayers, especially low-income customers. Inflation is disproportionately affecting lower-income households. The higher ROE sought by Columbia in this proceeding, which would have the impact of driving up rates, will exacerbate this problem. Given the PUC's obligation to balance the interests of investors and ratepayers in setting a reasonable ROE, the PUC should consider the greater adverse impacts that inflation has imposed on low-income ratepayers when setting rates.

Q. DOES INFLATION HAVE A PARTICULARLY ADVERSE IMPACT ON LOWER INCOME HOUSEHOLDS?

A. The impact of inflation is felt most severely by low-income households. Research by the U.S. Department of Labor's Bureau of Labor Statistics (BLS)[16] reports that "consumers with different incomes experience inflation quite differently."[17] According to this research, the lowest earning households spend a disproportionately higher share of their household budget on household necessities such as rent, food, and medical care.

Table 4. Household budget shares of expenditure items for lowest and highest income quartiles, 2017–2018[18]

Expenditure	Lowest Income Quartile	Highest Income Quartile
Rent (including owner's equivalent rent	34.93%	27.93%
Food at home	9.44%	6.58%
Medical care	8.36%	8.09%
Household utilities	4.36%	2.73%
Motor fuels	3.46%	3.42%
Motor vehicle operation	3.44%	3.40%
Telephone service	2.32%	2.00%

While low income households pay more of their budgeted income for this basket of essential goods, it is also important to note that the BLS researchers found that, "prices

[16] BLS is the agency that calculates and reports the "rate of inflation" (i.e., the Consumer Price Index[CPI]) each month.

[17] Klick and Stockburger (December 2022). Spotlight on Statistics: Inflation Experiences for Lower and Higher Income Households, U.S. Department of Labor, Bureau of Labor Statistics, available at https://www.bls.gov/spotlight/2022/inflation-experiences-for-lower-and-higher-income-households/home.htm

[18] Id.

for motor fuel, medical care, fuel and utilities, and shelter rose faster than the overall average. . . .”[19] Thus, “[b]ecause the lowest income households dedicate more of their spending on these categories,” the BLS researchers found, “their overall inflation rates grew faster than highest income households.”

Q. WHAT IMPACT DO INFLATION PRICES HAVE ON HOUSEHOLDS?

A. Researchers at the Federal Reserve Bank of Dallas found that the “stress” being placed on households by high inflation is much greater for low-income households and low-income households have less resources and fewer options to mitigate the impact of inflation. They explained:

> Prior research suggests that inflation hits low-income households hardest for several reasons. They spend more of their income on necessities such as food, gas and rent—categories with greater-than-average inflation rates—leaving few ways to reduce spending . When prices rise, middle-income households may react by consuming cheaper goods and buying more generic brands. Low-income households do not have the same flexibility; in many cases, they are already consuming the cheapest products.
>
> Additionally, many low-income households lack the ability of higher-income households to stock up when prices are discounted, buy in bulk and save, delay purchases if there is an opportunity to save in the future or buy more cheaply online. Low-income households are also likely to have smaller cash buffers to tide them over a period of high inflation.
>
> The recent Household Pulse Survey data confirm these tendencies. Households with incomes ranging from $25,000 to $35,000 in 2021 were about 19.3 percentage points more likely to be very stressed by inflation than households with incomes in the $75,000 to $100,000 range.[20]

[19] Id.

[20] Jayashankar and Murphy (January 2023). High inflation disproportionately hurts low-income households, Federal Reserve Bank of Dallas, available at

The data is clear and consistent. Lower income families expend a greater share of their income on necessities which as a whole tend to have higher inflation rates; have smaller financial cushions to mitigate the impact of inflation; and may have less of an ability to switch to lower-priced alternatives. As Lael Brainard, a member of the Board of Governors of the Federal Reserve System, concluded, "All Americans are confronting higher prices, but the burden is particularly great for households with more limited resources."[21]

Q. WHAT DO YOU CONCLUDE?

A. The testimony of Columbia's witnesses presents only part of the story and focuses only on the stress which inflation has placed on utility stakeholders. Just as inflation may have placed stress on the utility, it has also placed stress on utility ratepayers. Indeed, the inflation experienced in recent years has placed far more stress on lower income ratepayers than it has placed on others. Given that inflation is disproportionately affecting lower-income households, the Commission must consider the fact that the higher ROE sought by Columbia in this proceeding will only exacerbate the problem by unnecessarily driving up rates. The PUC is obligated to balance the interests of investors and ratepayers in setting a reasonable ROE. In conducting this balance, the PUC should consider the greater adverse impacts that inflation has imposed on low-income ratepayers when setting rates.

https://www.dallasfed.org/research/economics/2023/0110#:~:text=Low%2Dincome%20households%20most%20stressed,few%20ways%20to%20reduce%20spending%20.

[21] Brainard (April 2022). Variations in the inflation experiences of households, available at https://www.federalreserve.gov/newsevents/speech/brainard20220405a.htm

D. The Affordability of Bills to Residential Customers Generally.

Q. DO YOU HAVE CONCERNS ABOUT THE IMPACT OF THIS COLUMBIA GAS RATE REQUEST OUTSIDE OF THE IMPACT ON LOW-INCOME CUSTOMERS?

A. Yes. The PUC is not simply to consider the impacts of rate changes on low-income customers, but also to consider the impacts of consumer interests generally. To consider the impacts of Columbia's rate case on consumers generally, I use county-wide data provided by United for ALICE[22] through the ALICE (Asset Limited, Income Constrained, Employed) Report for Pennsylvania. The ALICE data discusses the ability of households to afford the basics required for self-sufficiency.

My discussion below is complementary to the discussion of OCA witness David Dismukes (OCA St. 1). In his testimony, Professor Dismukes discusses the regulatory compact generally. That discussion supplements and complements my discussion of the legal requirement imposed on regulators to engage in a balancing of interests in reaching their ratemaking decisions. My testimony is limited to the residential ratepayer interests generally, and the low-income interests in particular, that should be taken into consideration.

Q. BRIEFLY SUMMARIZE WHAT THE ALICE DATA SHOWS.

A. The ALICE data shows that the unaffordability of Columbia Gas bills is not exclusively a concern of low-income households. The lack of sufficient resources to pay household necessities extends upward, well into the "working poor" population. The households in

[22] An overview of United for Alice is available at https://unitedforalice.org/overview.

Columbia's service territory that would struggle to pay increased Columbia Gas bills associated with this rate case is more than two times higher than the Poverty rate.

Q. WHAT ALICE DATA HAVE YOU EXAMINED?

A. In the 2023 report, using data from 2021, in Pennsylvania, a family of four would need an annual income of $65,796 to cover essentials needed to live and work, pay rent, and pay utilities.[23] Using the ALICE household survival budget of $65,796 for a family of four in Pennsylvania, I have reviewed the median household income (MHI) for the 26 counties which Columbia Gas serves in Pennsylvania. I separately considered MHIs for the total population, and for the Black population.[24] Of the 26 Columbia Gas counties, the MHI-ALL is below the ALICE survival income in 15 counties; the MHI-Black is below the ALICE survival income in 16 counties; and the MHI-Hispanic is below the ALICE survival income in 13 counties. The 15 counties where the MHI-ALL is below the ALICE survival income have a total population of 384,489. Those 15 counties have a poverty rate of 13.3%, but have an ALICE rate of 30.0%.

Q. DO YOU HAVE OTHER CONCERNS ABOUT THE IMPACTS OF COLUMBIA'S RATE REQUEST ON CONSUMERS GENERALLY?

A. Yes. The adverse impacts to consumers arise not exclusively because of what burdens Columbia's rates are imposing, but also because of the cumulative impacts of the group of utilities serving the same customers. In 2024, it is not merely Columbia Gas that is

[23] https://unitedforalice.org/state-reports-mobile

[24] I will refer to the MHI for the total population as "MHI-ALL." I will refer to the MHI for the Black population as "MHI-Black."

seeking higher rates. Multiple utilities serving overlapping service territories are seeking substantial rate hikes. In 2024:

- Pennsylvania American Water Company (PAWC) has filed a rate case that would increase typical residential water bills by 24.9% in all areas of its service territory (with some designated exceptions, some of which would face higher increases and other which would face lower), or $17.59 per month ($211.08 per year). Additional rate hikes were sought for sewer bills.
- Duquesne Light Company (DLC) has filed a rate case that would increase typical residential bills by $8.43 per month ($101.16 per year).

In addition, in May 2023, the Pittsburgh Waer and Sewer Authority (PWSA) requested an overall rate increase of $146.1 million over three years. If the Authority's entire request were approved, the total bill for water, wastewater conveyance, and stormwater management for a typical Residential customer using 3,000 gallons of water per month and charged the base rate for stormwater services would increase from $86.43 to $103.41 per month or by 19.6% in 2024. It would increase from $103.41 to $123.55 or by 19.5% in 2025 and increase from $123.55 to $146.12 or 18.3% in 2026.

These electric, water and wastewater (sewer) rate increases, on top of Columbia's requested rate increase of $18.76 per month ($225.12 per year), would, in total, increase *total* utility bills for the customers by $537.36 per year to customers in overlapping service territories.

Q. HAVE YOU IDENTIFIED THE EXTENT OF THE OVERLAP?

A. Yes. Each utility has provided a list of the zip codes which comprise its respective service territory. By matching those lists, I identified the zip codes that are served by all

three utilities. Of the 325 zip codes in which Columbia Gas has residential customers (with matching Census data), 66 are also served by DLC, while 97 are also served by PAWC. In total, more than 140,000 Columbia customers are served by both Columbia and DLC, while nearly 173,000 Columbia customers are served by both Columbia and PAWC. Nearly 81,000 Columbia customers are served by all three utilities.

Q. HAVE YOU BEEN ABLE TO ASSESS WHAT THE IMPACT ON RESIDENTIAL CUSTOMERS WILL BE FROM THIS CUMULATIVE SET OF RATE INCREASES?

A. Yes. Households that experience the combined rate increases of Duquesne, Columbia and PAWC would not be able to absorb these additional financial obligations given local wages. The National Low-Income Housing Coalition (NLIHC) publishes an annual reported titled "Out of Reach: The High Cost of Housing" (OOR).[25] I examine the results of the most recent OOR (2024) for Allegheny County and for Pittsburgh, a geographic area where the overlap of the three utilities is substantial. The mean renter wage in these areas is $20.15/hour for Pittsburgh and $22.43/hour for Allegheny County. The annual Area Median Income (AMI) is the same for both areas: $102,600.

Given these income levels, the rent affordable at 30% AMI is $770, while the rent affordable at 50% AMI is $1,283. The rent affordable at the mean renter wage (given a full-time job) is $1,048 for Pittsburgh, and$1,067 for Allegheny County.[26] Given this

[25] https://reports.nlihc.org/oor/pennsylvania

[26] Rent is affordable at a given income level if the household would be required to pay 30% or less of their income for that rent. The incomes used by OOR (30% and 50% of AMI) are standard income levels used in assessing housing affordability.

information, without considering the cumulative impacts of the three utility rate increases sought in 2024, OOR reports that the income needed to afford housing in both Pittsburgh and Allegheny County is:

- $36,160 for a one-bedroom unit;
- $43,600 for a two-bedroom unit; and
- $55,400 for a three-bedroom unit.

Given the requested utility rate increases, however, the income that would be needed to afford housing in Pittsburgh, and in Allegheny County, would be:

- $37,951 for a one-bedroom unit;
- $45,391 for a two-bedroom unit; and
- $57,231 for a three-bedroom unit.

Given the utility rate increases sought in 2024, in other words, residents seeking rental units in Pittsburgh and/or in Allegheny County would need an additional income of $1,791 each year.[27] At the mean renter wage in Pittsburgh, just to pay the increased utility bills being sought, these renters would need to work an *additional* 2¼ work weeks (89 hours) above and beyond what they already work to afford their housing, while needing to work nearly an additional two full work weeks in Allegheny County. In Pittsburgh and Allegheny County, renters (at the mean renter wage) are already required to work nearly a fulltime job (40 hours/week x 52 weeks per year) in order to afford a one-bedroom unit, and required to work more than a fulltime job in order to afford either a two-bedroom or three-bedroom unit. Any other increase in the cost of living would be in addition to this need to increase the renter work week.

[27] Each of these income levels exceed 150% FPL, the maximum income eligibility for CAP.

Part 2. Affordability and Columbia's Ability-to-Collect.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I expand upon my discussion of the impact which an increase in Columbia's rates would have on low-income customers. In particular, I examine the collections performance of Columbia with respect to the Company's Confirmed Low-Income customers.

Q. WHAT DO YOU FIND?

A. I find that the unaffordability of Columbia's rates to low-income customers results in a substantial decline in the ability-to-collect by Columbia Gas. In reaching this conclusion, I examine the following metrics: (1) average arrears for Confirmed Low-Income customers; (2) the percentage of Confirmed Low-Income customers in arrears; (3) the rate of service disconnections for nonpayment for Confirmed Low-Income customers; and (4) the write-off ratio for Confirmed Low-Income customers.

Q. PLEASE EXPLAIN THE FIRST COLLECTIONS METRIC YOU EXAMINE.

A. The first metric I examine involves the average arrears. Table 5 presents data for the average arrears of residential customers and the average arrears of Confirmed Low-Income customers by year for the three years 2020 through 2022.[28] As can be seen, in 2020, the average arrearage for a Confirmed Low-Income customer was nearly more than one-quarter larger than for a residential customer generally. From 2020 through 2022, the average arrears for a Confirmed Low-Income customer was from 21% to 27% higher.

[28] 2022 is the last year of data reported.

Accompanying the unaffordability of Columbia bills to its low-income population, in other words, is the increased nonpayment of those bills.

Table 5. Average Arrears: Residential vs. Confirmed Low-Income (2020 – 2022) (BCS 2021 & 2022 Report on Universal Service Programs and Collections Performance)[29]

	Residential	Confirmed Low-Income	Ratio (Conf'd LI to Residential)
2020	$666.06	$844.71	1.27
2021	$813.30	$1,034.34	1.27
2022	$788.61	$955.15	1.21

A higher customer arrears imposes costs on the utility, which costs must be paid by remaining ratepayers. Even setting aside any collection efforts that Columbia would direct toward customers in arrears, the higher arrears would impose a higher working capital cost. For each week/month that a bill remains unpaid, Columbia would incur either an out-of-pocket expense for borrowing replacement money, or would incur the corresponding opportunity cost for not having those funds to invest.

Q. PLEASE EXPLAIN THE SECOND METRIC YOU EXAMINE.

A. The second metric I examine involves not the size of the arrearage that is being carried, but rather the percentage of customers who are in arrears. Data from the annual BCS reports documents that Confirmed Low-Income customers are not only deeper in arrears, but a higher percentage of Confirmed Low-Income customers are in arrears. The BCS data shows that substantially more than two times the percentage of Confirmed Low-Income customers are in arrears than the percentage of residential customers as a whole

[29] Available at https://www.puc.pa.gov/filing-resources/reports/universal-service-programs-and-collections-performance-reports/

that are in arrears in 2021 and 2022. In 2022, for example, while 5.9% of all residential customers were in arrears, 13.3% of Confirmed Low-Income customers were in arrears (a ratio of 2.22-to-1). In 2020, while 7.6% of residential customers were in arrears, 17.8% of Confirmed Low-Income were (a ratio of 2.34-to-1).

Table 6.Percent of Customers in Arrears: Residential vs. Confirmed Low-Income (2020 – 2022) (BCS 2022 Report)

	Residential	Confirmed Low-Income	Ratio (Conf'd LI to Residential)
2020	7.6%	17.8%	2.34
2021	6.1%	14.2%	2.33
2022	5.9%	13.3%	2.22

What the data shows is that the higher average arrears of Confirmed Low-Income customers is not offset by a lower total percentage of accounts in arrears. Instead, exactly the opposite occurs. Not only are more Confirmed Low-Income customers in arrears, but they are, on average, further in arrears.

Q. WHAT IS THE THIRD METRIC YOU EXAMINE?

A. The third metric I examine involves service disconnections for non-payment (DNPs). According to the BCS 2022 Report on universal service programs and collections performance, "Termination of public utility service is the most serious consequence of customer nonpayment and is viewed as a last resort when customers fail to meet their payment obligations."[30] As with the level of arrears, the unaffordability of Company bills

[30] According to the annual BCS report: "The **termination rate** is calculated by dividing the number of service terminations by the number of residential customers, allowing for a comparison of termination activities regardless of the number of residential consumers. Any significant increase in a termination rate could indicate a trend or pattern that the Commission may need to investigate."

has a particular adverse impact on the Company's low-income customers. In the past two year, Confirmed Low-Income customers of Columbia Gas have had service disconnected for nonpayment at a rate 3.3 higher than the rate of service disconnections for residential customers as a whole.

Table 7. Termination Rate: Residential vs. Confirmed Low-Income (2020 – 2022) (BCS 2022 Report)

	Residential	Confirmed Low-Income	Ratio (Conf'd LI to Residential)
2020*	<0.1%	0.0%	---
2021	2.4%	8.0%	3.33
2022	2.8%	9.0%	3.33

* Disconnection rates were nearly non-existent due to COVID-related disconnection restrictions imposed by the PUC.

As with carrying arrears, nonpayment service disconnections have a rate impact on remaining customers. Not only is there an out-of-pocket cost associated with the process of disconnection, but there is the likelihood of lost future revenue as well.

Q. HAVE YOU EXAMINED A FINAL METRIC?

A. Yes. The fourth metric I have examined involves the gross write-off ratio for residential customers and Confirmed Low-Income customers. The data is set forth in the Table below. Columbia's data clearly shows that Confirmed Low-Income customers impose dollars of gross write-offs on the utility at a rate that is several times higher than the rate at which residential customers impose gross write-offs. From 2017 through 2022, the gross write-off ratio for Confirmed Low-Income customers was from nearly three to nearly five times higher than the ratio for residential customers. While the ratios were closer in 2022, a review of the six years of data demonstrates that the 2022 results were atypical.

Table 8. Gross Write-Off Ratios: Residential vs. Confirmed Low-Income (2017 – 2022) (BCS 2022 Report)			
	Residential	Confirmed Low-Income	Ratio (Conf'd LI to Residential)
2017	2.0%	7.8%	3.90
2018	1.9%	6.3%	3.32
2019	2.1%	5.6%	2.67
2020	1.1%	3.1%	2.82
2021	2.3%	11.1%	4.83
2022	1.9%	2.2%	1.16

Q. WHAT CAN YOU CONCLUDE FROM THESE FOUR METRICS?

A. The data from the four metrics examined above is not presented to criticize Columbia's credit and collection efforts. Instead, the lessons to be learned are two-fold. First, there is considerable opportunity for Columbia Gas to use its universal service programs to address the nonpayment problems of Confirmed Low-Income customers on its system. Second, in a related, although not identical line, the use of universal service programs to address collections problems does not exclusively benefit the low-income customers participating in these programs. The use of universal service programs can also operate to help Columbia Gas manage the costs of payment difficulties which are passed on to all other ratepayers. In the next section, I turn my attention to how Columbia Gas could, and should, do precisely that.

Part 3. Specific Recommendations to Respond to Low-Income Unaffordability.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF OUR TESTIMONY.

A. In this section of my testimony, I consider a series of recommendations that Columbia should adopt to respond to the unaffordability of natural gas bills that I have identified above. In my discussion below, I do not recommend changes to the structure or operation of the Columbia universal service program as filed in its most recent Universal Service and Energy Conservation Plan (USECP). Instead, I have reviewed Columbia's procedures and operations outside of its USECP to assess the ways in which such procedures and operations can be improved to integrate total Company operations more fully with the Columbia USECP.

Q. PLEASE EXPLAIN THE ROLE WHICH SUCH RECOMMENDATIONS PLAY IN A BASE RATE PROCEEDING.

A. The role of providing affordable service in a base rate proceeding has been identified throughout my discussion above. When rates are unaffordable to low-income customers, that unaffordability affects the rates charged to other customers. I have documented, for example, how the unaffordability of bills leads to higher levels of arrears by low-income customers. Those higher levels of arrears not only lead to Columbia incurring out-of-pocket expenses devoted to the collection of those arrears, they lead to higher levels of expenses associated with the revenue that has been billed but not collected. I have also documented above how the unaffordability of Columbia's rates leads to a stream of lost revenue. This lost revenue occurs as low-income customers have service disconnected with no reconnection. This process not only causes Columbia to lose the revenue that is comprised of the unpaid bills at the time of disconnection, but also causes the Company

to lose any revenue associated with the bills that would have been associated with future bills. Moreover, even when service is reconnected, each day that a low-income customer remains off-system prior to the reconnection represents a lost sale (and thus lost revenue).

My recommendations below recognize these impacts which low-income unaffordability have on rates. Without needing to propose modifications to the structure of the Columbia USECP, the recommendations explain how Columbia can improve the service it offers to low-income customers to mitigate the adverse rate impacts of unaffordable bills.

A. Identifying Confirmed Low-Income Customers.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I identify how the Company fails to comply with PUC regulations regarding the identification of "confirmed low-income" customers. I recommend changes that would bring Columbia into compliance with the PUC's regulations.

Q. HOW DOES COLUMBIA CURRENTLY IDENTIFY "CONFIRMED LOW-INCOME" CUSTOMERS?

A. When asked to "Provide a detailed written description of how the Company "confirms" the low-income status of the Company's customers, including a detailed list of the information accepted to confirm low-income status," Columbia responded by stating:

> Currently, the Company considers all customers that verbally *provide income that calculates at level 1* as confirmed low income. In addition, all customers

> that receive a LIHEAP grant including those that have not verbally provided income, are considered confirmed low income.

(OCA-2-18). This procedure by Columbia is too limited. It fails to comply with the PUC's regulations regarding how to define a "confirmed low-income" customer. The PUC's regulations explicitly define a "confirmed low-income" customer for Natural Gas Distribution Companies. The PUC regulation states:

> *Confirmed low-income residential account*—Accounts where the NGDC has obtained information that would reasonably place the customer in a low-income designation. This information may include receipt of LIHEAP funds (Low-Income Home Energy Assistance Program), self-certification by the customer, *income source* or information obtained in § 56.97(b) (relating to procedures upon rate-payer or occupant contact prior to termination).[31]

(emphasis added). As can be seen, under the regulation, "self-certification" may include not merely self-certification of the actual *level* of income, but certification of the *source* of income as well. For example, customers who receive SNAP (Supplemental Nutrition Assistance Program, formerly known as Food Stamps) assistance, Medicaid, Temporary Aid to Needy Families (TANF), free School Lunch, and other similar benefits will, by the vary receipt of those benefits, be "reasonably place[d]. . .in a low-income designation."

A customer's self-attestation of the receipt of public assistance (e.g., Supplemental Nutrition Assistance Program [SNAP], welfare, Supplemental Security Income [SSI], Medicaid), for example, would all place a customer in a "low-income designation." For purposes of establishing the customer's "Confirmed Low-Income" status, it would not matter what specific dollar level of income allows the customer to receive such assistance. The mere fact of receiving such assistance would be sufficient to meet the PUC's

[31] 52 Pa. Code § 62.2.

definition. A customer need not provide actual dollars of income that would allow Columbia to determine whether that income "calculates at a level" that would establish the customer's low-income status.

Appropriately and accurately identifying the Company's "confirmed low-income" customers is not only important from the perspective of CAP outreach, but also qualifies such customers for various fee waivers. Moreover, the PUC's regulations provide that a customer is exempt from a cash security deposit "when the customer provides *income documents or other information* that he or she is eligible for state benefits based upon household income eligibility requirements that are consistent with those of the public utility's customer assistance program."[32] (emphasis added).

Q. WHAT DO YOU RECOMMEND?

A. Columbia should modify its policies and procedures regarding the identification of "confirmed low-income" customers to conform with the PUC's regulations. Columbia should include these modified policies and procedures in its residential tariff. The modified policies and tariff should add a new "definition" of "Confirmed Low-Income customer" which explicitly mirrors the PUC definition, stating that:

> Confirmed low-income residential account—Accounts where the Company has obtained information that would reasonably place the customer in a low-income designation. This information may include receipt of LIHEAP funds (Low-Income Home Energy Assistance Program), self-certification by the customer, income source or information obtained in § 56.97(b) (relating to procedures upon rate-payer or occupant contact prior to termination).

[32] 56 Pa. Code § 56.41(4).

In addition, Columbia should add to each residential tariff under "Special Provisions," a new paragraph with the following language: "A confirmed low-income residential account, including applicants, will be afforded each protection accorded by tariff or regulation, which tariff or regulation applies to any customer or applicant with household income at or below 150% of the Federal Poverty Level."

As can be seen, this recommended language explicitly acknowledges that: (1) Columbia will recognize a customer as a "confirmed low-income" customer when the Company is provided information that would "reasonably place" the customer in a low-income designation; (2) the information can be self-attested by the customer and need not be confirmed by a third-party; (3) the information may, but need not, include household income information or may include other information attesting to the customer's eligibility for state benefits; (4) the information would be used to establish the customer's eligibility for a payment arrangement of up to five years in length (i.e., income at or below 150% FPL) pursuant to Section 1405(b) of Chapter 14 of the Public Utility Code; and (5) the information would be used to establish any other protection accorded by tariff or PUC regulation (e.g., deposit exemption or refund; cold weather protections).

B. Nonpayment Disconnections of Confirmed Low-Income Customers.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I address the need for Columbia to take more effective actions to use its universal service program to prevent the disconnection of service for nonpayment to Confirmed Low-Income customers. This discussion addresses not the

structure of the Columbia's USECP, but rather addresses how Columbia interacts with customers who do *not* participate in the programs.

Q. WHY DO YOU ADDRESS THE DISCONNECTION OF SERVICE IN PARTICULAR?

A. There are several reasons why the disconnection of service should be considered in particular. First, in all the ways I have discussed in detail above, the disconnection of service has rate implications to all customers. Minimizing disconnections would also minimize these adverse rate impacts. Second, as BCS notes in its most recent annual report on universal service programs and collection performance that "Termination of public utility service is the most serious consequence of customer nonpayment and is viewed as a last resort when customers fail to meet their payment obligations."[33] It is thus appropriate to assess whether service terminations are, in fact, being used by Columbia as a "last resort." Third, as BCS states: "Universal Service is a collective name applied to the policies, protections and services that *help low-income customers maintain electric and natural gas service*. . ." (emphasis added).[34] Given that "universal service" is intended to "help low-income customers maintain electric. . .service," it is appropriate to assess whether that objective is being achieved.

[33] 2022 BCS Report, at 15.

[34] Id., at 3, citing Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. § 2803 and Natural Gas Choice Competition Act, 66 Pa. C.S. § 2202.

Q. IS THE COLUMBIA UNIVERSAL SERVICE PROGRAM SUCCESSFUL IN "HELPING LOW-INCOME CUSTOMERS MAINTAIN ELECTRIC SERVICE"?

A. Not entirely. There is significant information documenting the extent to which the Company's universal service program is not helping low-income customers to maintain electric service. For example, I consider the extent to which Columbia is disconnecting service to Confirmed Low-Income customers. Columbia data shows not only that the Company is continuing to disconnect service to a substantial number of Confirmed Low-Income customers, but also that the average arrears at the time of disconnection remains substantial as well. After those disconnections, a substantial portion of the Confirmed Low-Income customers that have been disconnected are not reconnected.

Q. **WHAT DOES THE DISCONNECTION DATA REFLECT REGARDING THE SUCCESS OF COLUMBIA'S UNIVERSAL SERVICE PROGRAMS IN HELPING COLUMBIA'S CONFIRMED LOW-INCOME CUSTOMERS TO MAINTAIN SERVICE?**

A. The data below shows that from May 2021 through the end of that year, Columbia disconnected 5,475 Confirmed Low-Income customers, while in 2022, 6,124 Confirmed Low-Income accounts experienced a service disconnection. In 2023, Columbia disconnected 5,974 Confirmed Low-Income customers. These disconnected customers were frequently not subsequently reconnected. In the 2021 months (May – December), only 2,634 accounts were reconnected (after 5,475 had been disconnected). In 2022, only 3,273 Confirmed Low-Income accounts were reconnected (after 6,124 had been reconnected). In 2023, only 2,936 Confirmed Low-Income accounts were reconnected

(after 5,974 were disconnected). In these instances, not only will Columbia lose the dollars owed at the time of disconnection, it will also lose any future sales as well.

Q. WHAT LEVEL OF ARREARS ARE AT RISK?

A. For Confirmed Low-Income customers who had service disconnected, the average arrears at the time of disconnection ranged from a low of $185 (November 2021) and $205 (October 2023) to a high of $1,749 (July 2022) and $1,401 (June 2023).

Table 9. Confirmed Low-Income Disconnections and Average Arrears at Time of Disconnection (OCA-1-21)

	Nonpayment Service Disconnections	Average Arrears at Time of Disconnection	Reconnections after Nonpayment Disconnection
202205	1,096	$361.81	447
202206	1,126	$227.69	372
202207	995	$1,749.23	452
202208	704	$693.75	358
202209	427	$252.86	371
202210	300	$208.98	410
202211	273	$185.33	327
202212	0	No LI disconnections	101
202301	0	No LI disconnections	14
202302	0	No LI disconnections	10
202303	0	No LI disconnections	12
202304	907	$576.77	176
202305	924	$225.38	360
202306	781	$1,400.68	272
202307	978	$386.41	340
202308	922	$302.25	409
202309	653	$679.11	442
202310	516	$205.10	450
202311	293	$543.54	355
202312	0	No LI disconnections	96
202401	0	No LI disconnections	31
202402	0	No LI disconnections	13
202403	0	No LI disconnections	3

To assume that Columbia has effectively communicated the possibility of enrolling in CAP, and making pre-program arrears subject to forgiveness, to Confirmed Low-Income

customers, one would need to assume that nearly 11,000 Confirmed Low-Income customers –remember a "Confirmed Low-Income" customer is a customer from whom the Company has already received information that would reasonably identify that customer as "low-income"—would ***choose*** to have their service disconnected rather than to enroll in the Company's CAP. One would further need to assume that these nearly 11,000 customers would choose to pay all or part of their arrears in order to reconnect their service, and to retain those pre-disconnection arrears on their accounts to be paid in the future rather than subjecting those arrears to forgiveness.

This data is consistent with the data presented in Table 7 above. That Table shows that the termination rate (i.e., number of nonpayment disconnections divided by the number of customers) remains more than 330% higher for Confirmed Low-Income customers than it is for residential customers in general.

Despite the number of Confirmed Low-Income customers who are disconnected ***without*** subsequently being reconnected, the data shows that roughly half (from a low of 48% in 2021 to a high of 53% in 2022) of all Confirmed Low-Income customers experiencing a disconnection are reconnected. These reconnections demonstrate that the Company can and does make contact with these Confirmed Low-Income customers.

Q. WHAT DO YOU FIND?

A. The data above demonstrates that the current procedures Columbia uses to enroll Confirmed Low-Income customers –i.e., those customers that Columbia ***knows*** to be low-income-- are not effectively working to help these customers enroll in CAP and to stay in CAP to retain utility service (i.e., in the words of the Natural Gas Competition statute, to "help low-income customers maintain natural gas. . .service"). Notwithstanding the statutory goal for Columbia's universal service program, thousands of Confirmed Low-Income customers are having their service disconnected for nonpayment, and a large proportion of those disconnected customers do not have their service reconnected.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that, prior to the disconnection of a Confirmed Low-Income customer, Columbia adopt a procedure, developed in collaboration with its Universal Service Advisory Committee (USAC), under which it will seek to make personal contact with the customer subject to disconnection. In that personal contact, the Company shall offer the Confirmed Low-Income customer the opportunity to apply for the Company's CAP and arrearage forgiveness program. If the customer expresses a desire to make such application, Columbia will postpone the disconnection for a reasonable period of time to allow the application process to be completed.[35]

[35] It is also possible that a portion of these customers will include customers who were previously enrolled in CAP and owe a CAP catch-up amount or a customer who may have failed to recertify. These customers, too, should receive education about the benefits of CAP.

C. Deferred Payment Agreements for Confirmed Low-Income Customers.

Q. PLEASE EXPLAIN YOUR THIRD RECOMMENDATION.

A. My third recommendation is that Confirmed Low-Income customers who are negotiating a deferred payment agreement (DPA) with the Company, as well as customers from whom the Company receives information placing them in an income tier of 0% to 150% FPL, should be provided a stand-alone written Plain English notice informing those customers of their right, in the alternative, to enroll in the Company's CAP (along with an explanation of the advantages of CAP's arrearage forgiveness provisions). Through that opportunity, rather than needing to agree to retire their arrears over an extended period of time, the Confirmed Low-Income customer would be allowed to enroll in CAP and, upon making appropriate payments, receive forgiveness for their underlying arrearages. This written communication would be provided to Confirmed Low-Income customers, those customers from whom Columbia had either previously, or during the process of discussing a payment arrangement, received sufficient information to reasonably establish their low-income status.

Q. IS THERE A STATUTORY BASIS FOR IMPOSING THIS REQUIREMENT?

A. Yes. Pennsylvania statutes provide that:

> No public utility shall, directly or indirectly, by any device whatsoever, or in anywise, demand or receive from any person, corporation, or municipal corporation a greater or less rate for any service rendered or to be rendered by such public utility than that specified in the tariffs of such public utility applicable thereto. The rates specified in such tariffs shall be the lawful rates of such public utility until changed, as provided in this part. *Any public utility, having more than one rate applicable to service rendered to a patron,*

> *shall, after notice of service conditions, compute bills under the rate most advantageous to the patron*.[36]

(emphasis added). Columbia should not, in other words, require a customer, known to be a Confirmed Low-Income customer, to pay off arrears through a payment arrangement which arrears would be subject to forgiveness under the Company's CAP.

Q. HAS THIS OR ANY SIMILAR ISSUE BEEN RECENTLY ADDRESSED BY THE COMMISSION?

A. Yes. In the April 4, 2024 decision regarding Columbia's Universal Service and Energy Conservation Plan (USECP), the PUC considered whether Columbia could apply an existing deposit against a low-income customer's outstanding arrears before refunding the difference pursuant to statute and regulation. The PUC held that the Company could *not* do so, stating:

> Commission regulations also state that a public utility must "refund a deposit, along with any applicable interest, within 60 days upon determining that the customer or applicant from whom a deposit was collected is not subject to a deposit…." *See* 52 Pa. Code § 56.53(f). The regulations do not permit the public utility to apply a deposit to a delinquent account balance if it is determined the customer was not responsible for paying the deposit prior to accruing the balance.
>
> Accordingly, we direct Columbia to refund security deposits, with applicable interest, collected from customers who are income–eligible for CAP. Columbia may apply the security deposit to the account balance only with the customer's informed consent. As part of obtaining this informed consent, Columbia must explain to the customer how applying the security deposit to the account balance would impact the customer's monthly bill.[37]

[36] 66 Pa. Stat. and Cons. Stat. Ann. § 1303 (West).

[37] Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2024 - 2028 Submitted in Compliance with 52 Pa. Code § 62.4, Docket M-2023-3039487, Order, at 31 (April, 2024). (hereafter 2024 Columbia USECP Order).

In a similar fashion, Columbia should be allowed to require a Confirmed Low-Income customer to pay off arrears through a payment arrangement "only with the customer's informed consent." Moreover, as the PUC stated with respect to applying deposits against arrearage balances, "as part of obtaining this informed consent," Columbia must explain to the customer how enrolling in CAP and making the customer's arrearage subject to arrearage forgiveness "would impact the customer's monthly bill."

Q. PLEASE EXPLAIN THE SUBSTANTIVE NEED FOR SUCH COMMUNICATION.

A. Columbia reports that it enrolls significant numbers of Confirmed Low-Income customers in deferred payment arrangements through which customers agree to retire arrearages over an extended period of time. The data shows that Columbia entered into 25,986 newly-initiated payment arrangements with Confirmed Low-Income customers in 2022 (April – December); 36,533 newly-initiated payment arrangements with Confirmed Low-Income customers in 2023 (January – December), and 6,653 newly-initiated payment arrangements with Confirmed Low-Income customers in 2024 (January through April). (OCA-02-17).[38]

These payment arrangements, however, are not often successful. The data which Columbia reports to BCS each year on collections performance indicates that in 2021, while the Company entered into 16,550 payment arrangements with Confirmed Low-Income customers, only 4,598 payment arrangements with Confirmed Low-Income

[38] The time period represents the most recent 24 months at the time discovery was propounded.

customers were successful. In 2022, while Columbia entered into 13,401 payment arrangements, only 4,226 were successful. In 2023, while Columbia entered into 14,659 payment arrangements, only 4,493 were successful.

Table 10. Confirmed Low-Income Payment Arrangements and Successful Payment Arrangements (OCA-2-11) (Attachments C, D, E)

	2021	2022	2023
Payment Arrangements	16,550	13,401	14,659
Successful Payment Arrangements	4,598	4,226	4,493

Additional insights can be gained into the number of Confirmed Low-Income customers that default on their payment plans by examining the number of "payment-troubled customers." [39] The Columbia data reported to BCS on payment-troubled Confirmed Low-Income customers is set forth in Table 11 below.

[39] According to BCS, "A payment troubled customer is a customer who has failed to maintain one or more payment arrangements in a 1-year period." BCS 2022 Report (2022), at 11, citing 52 Pa. Code § 54.72 or § 62.2 .

Table 11. Number of Confirmed Low-Income Customers with Arrears on Arrangement and Number of Payment-Troubled Customers (Confirmed Low-Income Customers) (Columbia Gas) (2021 – 2023) (OCA-2-02)

	2021		2022		2023	
	On Arrangement	Payment Troubled	On Arrangement	Payment Troubled	On Arrangement	Payment Troubled
January	6,309	8,463	5,741	5,241	5,630	5,050
February	6,814	5,611	6,955	5,411	7,446	5,291
March	7,059	5,647	7,684	6,029	8,273	6,096
April	7,578	6,390	8,113	6,529	8,578	6,640
May	8,411	7,309	8,189	6,812	8,714	7,261
June	8,605	8,669	7,907	7,512	8,422	7,919
July	8,279	9,413	7,342	7,768	7,981	8,125
August	7,585	9,952	6,681	7,647	7,443	8,259
September	6,777	10,069	5,971	7,725	6,918	8,373
October	6,016	10,148	5,448	7,579	6,475	8,195
November	5,443	10,180	5,079	7,649	6,125	8,511
December	5,496	11,027	5,150	8,428	6,011	9,339

As can be seen, for the most recent three years reported to BCS (2021 – 2023), the number of Confirmed Low-Income customers who are "payment-troubled" (i.e., had defaulted on one or more payment plans in a 12-month period) far exceeds the number of Confirmed Low-Income customers who are on payment plans.

Q. HOW SHOULD COLUMBIA USE THIS INFORMATION?

A. Company customer service representatives should generate information through the DPA process that would demonstrate whether a customer would be eligible for CAP. Columbia states, for example: "The customer's income level (Level 1, 2, 3 or 4) determines the length of the payment arrangement the Company would offer. For example, the Company would offer a Level 1 customer, whose income level falls below

150% Federal Poverty Guidelines (FPIG) a 60-month payment arrangement. The customer *may* also be referred to the Customer Assistance Program (CAP)." (OCA-2-20). If customer service representatives know that a household's income and household size would place the customer in Income Tier 1 (at or below 150% FPL) for purposes of negotiating a DPA, they would also know that the customer's income and household size would qualify that customer for CAP (and the corresponding arrearage forgiveness).

Q. WHAT DO YOU FIND?

A. Offering a low-income customer a deferred payment arrangement, even a long-term deferred payment arrangement, is not a recipe for success if the reason the customer is in arrears in the first instance is that bills for current service are unaffordable. In those situations, all a deferred payment arrangement does is to begin with the unaffordable bill and *add* an additional installment payment through which to retire the arrears. In those instances, it should not be surprising that far fewer Confirmed Low-Income payment arrangements succeed in any given year than do not. It is no surprise that there are far more Confirmed Low-Income customers that are "payment-troubled" than there are on payment arrangements at any given time. The remedy for unpaid bills by low-income customers is not to place those customers on a deferred payment arrangement, but rather to enroll those customers in CAP (with its arrearage forgiveness provisions). Through that remedy, Columbia would not merely address the unpaid bill, but would also address the underlying cause of the unpaid bill. Doing so would not only benefit the low-income customer, but would also benefit the Company and its remaining customers as well.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that before Columbia enters into a payment arrangement with a customer which the Company either: (1) knows to be a Confirmed Low-Income customer; or (2) has generated information through the payment arrangement process documenting that the customer is in the Tier 1 income range (at or below 150% FPL), it should be required to provide the customer a stand-alone Plain English notice to that customer of the customer's right to enter into CAP and an explanation of the advantages of CAP's arrearage forgiveness benefits. Columbia should develop this Plain English notice in collaboration with its USAC.

D. Cold Weather Survey CAP Enrollment.

Q. PLEASE EXPLAIN YOUR FOURTH RECOMMENDATION.

A. My fourth recommendation is that customers who have had service disconnected for nonpayment, and who remain disconnected at the time of the Company's Cold Weather Survey (CWS) undertaken for the PUC, should be provided a written, stand-alone, Plain English notice of their right to enroll in the Company's CAP (along with an explanation of the advantages of CAP's arrearage forgiveness provisions). The data shows that a substantial number of customers, nearly one-in-four, who have service disconnected during the course of the year remain without heating service at the start of the next winter heating season. This lack of access to service could be remedied for income-eligible customers through enrollment in CAP.

Q. UPON WHAT DO YOU BASE THIS RECOMMENDATION?

A. I have reviewed the results of the PUC's Cold Weather Survey performed at the beginning of the winter heating season each year.[40] I examined data from the three years 2021 through 2023. The data in Table 12 below shows the extent to which residential customers which the Company has disconnected during the non-cold weather months remain without service at the beginning of the next cold weather heating season. Over the past three years, between 1,000 (2021) and 1,200 (2023) customers who have had service terminated for nonpayment remain without heating service. While the percentage of customers remaining without heating service declined in 2022 relative to 2021 (from 22.6% to 20.3%), the percentage of customers that had service disconnected, and who remained disconnected, increased again in 2023 (from 20.3% to 23.4%). Between 1-in-5 (20.3%, 22.6%) and nearly 1-in-4 (23.4%) Columbia customers surveyed remain without heating at the start of the cold weather months each year for the past three years.

Table 12. Cold Weather Survey Results (2021 – 2023)
(Columbia Gas)

	2021	2022	2023
Number surveyed	4,385	5,087	5,104
Vacant	769	695	549
Reconnected (DPA or other)	2,624	3,361	3,360
Not contacted	485	439	599
Occupied with service off	507	592	596
Using alternative source of heating	209	258	257
No heating	992	1,031	1,195
Percent without heat	22.6%	20.3%	23.4%

[40] Electric, Gas and Water Cold Weather Survey Results, available at https://www.puc.pa.gov/filing-resources/reports/electric-gas-water-cold-weather-survey-results/

It would seem unreasonable to assume that, if given a meaningful choice either to enter the cold weather season without heating service or to enroll in a program that would not only limit their future bills to an affordable percentage of income, along with providing a forgiveness of their pre-existing arrears, customers would choose to enter the winter months without heating service.

Q. WHY SHOULD COLUMBIA FIND IT IMPORTANT TO OFFER CAP ENROLLMENT AS AN OPTION TO CUSTOMERS WHO WOULD OTHERWISE ENTER THE COLD WINTER MONTHS WITHOUT HEATING SERVICE?

A. As I note above, the statutory purpose of Pennsylvania's universal service programs is to "help low-income customers maintain electric and natural gas service. . ."[41] This purpose would be furthered by helping to identify customers who have had their heating service disconnected by Columbia, and who remain without heat, as low-income and then facilitating their enrollment in CAP (along with its arrearage forgiveness). Columbia does not currently do this. At most what it does is to suggest that customers who remain without service contact the Company's Customer Care Center. (OCA-3-011).

Q. WHAT DO YOU RECOMMEND?

A. I recommend that Columbia Gas adopt a procedure under which it will provide a stand-alone Plain English notice to customers found to be without heating service at the time of the Company's Cold Weather Survey of the customer's right to enter into CAP and an

[41] BCS 2022 Report, at 3, citing Electricity Generation Customer Choice and Competition Act, 66 Pa. C.S. § 2803 and Natural Gas Choice Competition Act, 66 Pa. C.S. § 2202.

explanation of CAP's arrearage forgiveness benefits. This education should *also* include a recommendation and information to be provided both about LIHEAP, its benefits and how to apply, as well as Dollar Energy Fund and any other resources that may be available in the community that can also potentially help the customer to get reconnected. Columbia should develop the Plain English notice in collaboration with its USAC.

E. Confirmed Low-Income Customers with Substantial Arrears.

Q. PLEASE EXPLAIN YOUR FOURTH RECOMMENDATION.

A. My fourth recommendation is that Confirmed Low-Income customers achieving a minimum arrears should receive a stand-alone written Plain English notice of their right to enter into CAP along with an explanation of CAP's arrearage forgiveness benefits. Doing so will improve the payment patterns of these Confirmed Low-Income customers. The PUC has previously observed how enrollment of low-income customers into CAP can be expected to help low-income customers improve their payment patterns, stating that "enrolling low-income customers into CAPs as early as possible generally puts them in the best position to maintain good payment habits and avoid accruing utility debt."[42]

There is no question that Columbia has substantial numbers of Confirmed Low-Income customers that have high arrears. According to the Company's own data, in the twelve months ending April 2023, as set forth in Table 13 below, Columbia had between 3,900 (November 2022) and nearly 13,000 (March 2023) Confirmed Low-Income customers

[42] 2019 Amendments to Policy Statement on Customer Assistance Program, 52 Pa. Code § 69.261–69.267, M-2019-3012599, Final Policy Statement and Order, at 46 (September 19, 2019).

with arrears exceeding $300 in any given month. In the corresponding period ending March 2024, Columbia had between 4,600 ((November 2023) and nearly 11,600 (May 2023) Confirmed Low-Income customers with arrears exceeding $300.[43]

Table 13. Number of Confirmed Low-Income (non-CAP) Accounts with Arrears $300+ (by month) (OCA-02-14) (February 2021 – December 2023)

202205	202206	202207	202208	202209	202210	202211	202212	202301	202302	202303	202304
9,581	8,618	6,922	6,295	4,856	4,155	3,869	4,688	8,009	10,212	12,957	10,620
202305	202306	202307	202308	202309	202310	202311	202312	202401	202402	202403	202404
11,553	9,846	8,112	7,444	5,676	5,444	4,611	4,701	8,312	10,486	10,292	xxx

Consistently through their independent evaluations of CAP programs, Pennsylvania utilities have found that enrollment in CAP will improve the percentage of bills paid. Columbia's data, for example, shows that CAP participants over the past five years have, with the exception of 2022, paid between 70% and 80% of the total CAP bills they have received.

Table 14. Percentage of CAP Bills Paid by Year (2019 – 2023) (OCA-2-1, Attachment A – Attachment E)

2019	2020	2021	2022	2023
$14,299,197	$14,198,242	$15,258,779	$17,078,681	$18,529,098
$11,066,661	$9,995,468	$11,734,002	$10,716,318	$12,635,348
77%	70%	77%	63%	68%

This payment pattern is precisely what the PUC was referencing when it observed that CAP "would generally put [low-income customers] in the best position to maintain good payment habits and avoid accruing utility debt." My recommendation below is designed

[43] I choose $300 as the lower threshold to examine because $300 is roughly equal to the average of the monthly median Confirmed Low-Income arrears (excluding CAP participants) of $343 in 2022 and of $329 in 2023. (OCA-02-11).

to place Columbia's Confirmed Low-Income customers in the best position to maintain good payment habits and avoid accruing *additional* utility debt.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that when Confirmed Low-Income customers accrue an unpaid balance of $300, Columbia provide a stand-alone written Plain English notice informing those customers of their right to enroll in the Company's CAP (along with an explanation of the advantages of CAP's arrearage forgiveness provisions).

F. Request for Deposits from Existing Customers.

Q. PLEASE EXPLAIN YOUR SIXTH RECOMMENDATION.

A. My sixth recommendation is tied to the Company's Tariff setting forth provisions regarding deposits for residential customers. The data below documents that thousands of Confirmed Low-Income customers meet the criteria set forth in Columbia's tariff for imposing a cash security deposit. While the Company acknowledges that, as a Confirmed Low-Income customer, they are entitled to an exemption from posting any deposit, the Company should go further, not merely to refrain from imposing a deposit, but also by affirmatively soliciting the participation of these customers, *known to be low-income*, in CAP.

Q. PLEASE EXPLAIN THE BASIS FOR YOUR RECOMMENDATION.

A. Columbia's current tariff reads:

> A Customer or Applicant who is confirmed to be eligible for the Customer Assistance Program shall not be asked to provide a cash deposit.
>
> (A) When applicable, a deposit for residential service may be required from the following: 1. An Applicant who previously received utility distribution

> services and was a customer of the Company and whose service was terminated for any of the following reasons: (a) Nonpayment of an undisputed delinquent account. (b) Failure to complete payment of a deposit, provide a guarantee or establish credit. (c) Failure to permit access to meters, service connections or other property of the Company for the purpose of replacement, maintenance, repair or meter reading. (d) Unauthorized use of the utility service delivered on or about the affected dwelling. (e) Failure to comply with the material terms of a settlement or payment arrangement. (f) Fraud or material misrepresentation of identity for the purpose of obtaining utility service. (g) Tampering with meters, including, but not limited to, bypassing a meter or removal of an automatic meter reading device or other public utility equipment. (h) Violating tariff provisions on file with the commission so as to endanger the safety of a person or the integrity of the delivery system of the public utility.

Columbia's tariff further provides that a deposit may be imposed on "A customer who fails to comply with a material term or condition of a settlement or payment arrangement."

My testimony above establishes, in detail, that Columbia has thousands of Confirmed Low-Income customers who are substantially in arrears (having missed two consecutive bills or three or more bills within the preceding 12 months); who have negotiated, but defaulted on, a deferred payment arrangement (i.e., are "payment-troubled"); or who have had service terminated and seek reconnection. Having been identified as a "Confirmed Low-Income customer" means that, by definition, the customer has provided Columbia with sufficient information to reasonably lead Columbia to conclude that the customer is low-income.

By PUC regulation, these customers should be exempt from having a cash security deposit imposed. (52 Pa. Code § 56.41(B)(4)). Columbia, however, should also take the opportunity to solicit the enrollment of such Confirmed Low-Income customers into

CAP. I recommend that, in those instances where Columbia would otherwise request a cash security deposit from a Confirmed Low-Income customer, the Company should, as an alternative to that deposit demand, provide a stand-alone written Plain English notice informing these customers of their right to enroll in the Company's CAP (along with an explanation of the advantages of CAP's arrearage forgiveness provisions).

Q. PLEASE EXPLAIN WHY YOUR RECOMMENDATIONS ABOVE ARE DUPLICATIVE OF EACH OTHER?

A. They are intentionally duplicative because experience in multiple programs documents that more effective program outreach is associated with making multiple "touches" with the potential participant population. Through adoption of the four recommendations I advance above, Columbia increases the number of touches with its Confirmed Low-Income customers, and does so in different, yet interdependent, circumstances. The recommendations involve Columbia telling its Confirmed Low-Income customers: (1) enrollment in CAP is an alternative to having your service disconnected for nonpayment; (2) enrollment in CAP is an alternative to entering into an unaffordable deferred payment arrangement; (3) enrollment in CAP is an alternative to entering the winter heating season without heating service; and (4) enrollment in CAP is an alternative to continuing to carry arrears (with the costs and stresses that those arrears impose). The multiple touches through adoption of these four recommendations can reasonably be expected to increase CAP enrollment without the need to adopt modifications to the Company's underlying universal service program. As I have discussed throughout my testimony, this improved enrollment not only benefits the low-income customers who choose to enroll in CAP, but

will also benefit the Company and all remaining ratepayers by reducing costs and enhancing revenues.

G. Utilizing Speech Analytics to Identify Potential CAP Enrollees.

Q. PLEASE EXPLAIN YOUR FINAL FIFTH RECOMMENDATION.

A. My final recommendation involves the use of new technology by Columbia to help the Company's customer service representatives to identify low-income customers who might be eligible for enrollment in CAP. In particular, this technology could be used in particular to help identify customers who are low-income and facing payment difficulties.

Q. PLEASE EXPLAIN YOUR FOCUS ON IDENTIFYING LOW-INCOME CUSTOMERS HAVING PAYMENT HAVING PAYMENT DIFFICULTIES.

A. In its 2019 Order revising the CAP Policy Statement, the PUC discussed the role of payment-troubled status in enrolling low-income customers in CAP.[44] While the general consensus of the parties providing comments to the PUC was that payment-troubled status should not be an eligibility requirement for CAP,[45] the Commission was encouraged to use payment-troubled status as a *targeting* criteria. Available technology can assist Columbia in fulfilling the goal of CAP to "maintain good payment habits" by identifying customers potentially eligible for CAP early in the process of responding to payment difficulties. By identifying these customers early in the process, not only will Columbia best serve its low-income customer base, but it will also maximize the use of

[44] Penn PUC, Final Policy Statement and Order, Docket M-2019-3012599 (September 19, 2019).

[45] Id., at 42, 43 – 45 (Most EDCs and NGDCs do not currently require income-eligible households to be payment-troubled to qualify for their CAPs.)

CAP to help control the costs of nonpayment that I have discussed throughout my testimony (e.g., collection costs, uncollectibles, working capital, and the like).

Available technology can assist Columbia in fulfilling the goal of CAP to "maintain good payment habits" by identifying customers potentially eligible for CAP early in the process of responding to payment difficulties. By identifying these customers early in the process, not only will Columbia best serve its low-income customer base, but it will also maximize the use of CAP to help control the costs of nonpayment that I have discussed throughout my testimony (e.g., collection costs, uncollectibles, working capital, and the like).

Q. WHAT "TECHNOLOGY" WOULD ASSIST COLUMBIA TO IDENTIFY LOW-INCOME CUSTOMERS HAVING PAYMENT DIFFICULTIES?

A. One important technology which Pennsylvania utilities are adopting is the use of software using speech and linguistics analysis to identify the extent to which either in-house customer service representatives, or contracted call center personnel, are identifying customers contacting the companies with particular attributes or problems. The use of such speech and linguistic analytics can help identify low-income customers and enroll them in the Company's universal service programs.

Consider, for example, the use of technology by Peoples Natural Gas. Peoples uses Verint Automated Call Monitoring and Speech Analytics (hereafter "Verint") as a software package through which it engages in speech pattern analytics or linguistic analytics, used to review call center conversations. Peoples describes its use of Verint in the call center context when it stated in relevant part:

> The Company utilizes Speech Analytics in order to assist with the Quality Monitoring of emergency phone calls. The Emergency Call Terms below are detected by the system in order to confirm that the phone call is properly categorized as an emergency call. The phrases, beginning with "Greeting" and ending with "Closing", below are what the system listens for in order to confirm the call was handled properly. Company representatives are required to communicate all of these points over the course of the emergency phone call. A Quality Monitoring Associate will then review the results and listen to the phone call to ensure the system captured all results accurately.[46]

The software, in other words, "listens" for particular phrases in a call center conversation "in order to confirm the call was handled properly." In using Verint to review calls to assess whether "emergency calls" are properly handled, Peoples uses the software to search for key terms. Peoples states that its "emergency call terms" include: "Smell Gas, Smell, power NEAR equipment, Hit NEAR Line, Leak, Odor, Evacuate, Vacate, Headache, NEAR Shortness, Carbon NEAR Alarm, Carbon NEAR Detector, Symptoms NEAR headache, Understand NEAR precautions, Hissing, Hit NEAR line AND smell, May or may not, unable to vacate, Smell NEAR inside, Smell NEAR outside, Overheating appliance."[47]

Q. HOW COULD SPEECH ANALYTICS SOFTWARE BE USED TO FACILITATE CAP ENROLLMENT AND THE IDENTIFICATION OF CONFIRMED LOW-INCOME CUSTOMERS?

A. While Peoples currently uses Verint only to "confirm that the phone call is properly categorized as an emergency call," using the terms that Peoples deems to be associated

[46] Pennsylvania Public Utility Commission v. Peoples Natural Gas Company, LLC, Docket No. 2024-3044549, OCA St. 6 (Direct Testimony of Roger Colton), at 45 – 46 (citing OCA-10-010).

[47] Id.

with "emergency calls," Columbia Gas need not impose those same limitations. Speech pattern analytics could also be used by Columbia to determine whether calls to the Company's call center are "handled properly" for purposes of identifying Confirmed Low-Income customers and customers who would benefit from enrollment in the Company's universal service programs. Terms, phrases and speech patterns associated with low-income status, payment difficulties, unaffordability, or seeking low-income assistance for energy or other life necessities (e.g., food, housing, medical care) could be identified such that the linguistics analysis software would search for them to identify universal service calls. "Proper handling" would include approving delays in collection activities pending applications for and approval of program enrollment; identification in the Company's information technology of Confirmed Low-Income customers; and extending available low-income protections.

Q. WHY DO YOU CITE PEOPLES GAS AS AN EXAMPLE RATHER THAN TECHNOLOGY NOW IN USE BY COLUMBIA GAS?

A. When Columbia Gas was asked what types of software it had used within the immediately preceding 36 months, or intended to be used in the coming 36 months, by the Company which engages in speech pattern analytics or linguistic analytics for either "in-house call center staff" or "third party contractor call center staff," Columbia responded for both in-house call center staff, and third party contractor call center staff, that it "is currently investigating speech analytics tools for the inbound calls from customers, but presently does not incorporate these tools in its business model." (OCA-3-025). Now would be the ideal time for the Company to be directed to incorporate universal service considerations into its "investigation" into "speech analytics tools for

the inbound call from customers." The Company is in the process of "investigating" such technology, but has apparently not yet made decisions on precisely how to use it. For all the reasons I discuss above with respect to nonpayment disconnections of Confirmed Low-Income customers; unsuccessful payment arrangements for Confirmed Low-Income customers; disproportionate arrears carried by Confirmed Low-Income customers, and other payment difficulties, this technology would not only serve the interests of the low-income customers, it also would serve the interests of all customers.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that Columbia be directed to extend any future use of speech analytics software to assist with the quality monitoring of phone calls involving, or potentially involving, universal service programs and other low-income customers. Columbia should be directed to involve its USAC in the identification and selection of Low-Income and Universal Service Terms to be detected by the system in order to confirm that phone calls are properly being identified and handled. Regular six-month reports on the results of the Speech Analytics reviews should be provided to the Company's USAC.

Part 4. Modifications to Columbia's Residential Tariff and Practices.

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I identify certain aspects of Columbia's residential tariffs and practices which need to be modified to bring them into compliance with PUC regulations. These modifications are not part of the Company's Universal Service and Energy Conservation Plan (USECP) and, even if they are, incorporation of these practices into the USECP would not ameliorate the need to bring the tariff and practices into regulatory compliance.

Q. WHAT IS THE FIRST PROBLEM YOU HAVE IDENTIFIED?

A. In its residential customer tariff, Columbia Gas addresses what customers the Company will exempt from deposit demands. The tariff (page 44) provides: "A Customer or Applicant who is confirmed to be eligible for the Customer Assistance Program shall not be asked to provide a cash deposit." Columbia explains that "the Company does not charge a security deposit for any customer that verbally attests to being a level 1 *by providing a verbal account of monthly income*." (OCA-2-020) (emphasis added).

This tariff provision does not comply with the PUC's regulation regarding what customers are exempt from residential deposit demands. The PUC's regulations provide that a customer is exempt from a cash security deposit "when *the customer provides income documents or other information* that he or she is eligible for state benefits based upon household income eligibility requirements that are consistent with those of the public utility's customer assistance program."[48] (emphasis added).

Columbia's deposit tariff conflict with several aspects of this regulation.

- First, the language in the Tariff is more restrictive than it needs to be.. Indeed, rather than needing to have information "confirmed" in some way, the regulation provides that a deposit exemption can be based upon information which "the customer provides."

- Second, the tariff inappropriately requires that a customer be confirmed to be eligible for Columbia's CAP. That is considerably stricter than the PUC regulation, which requires only that the customer provide information that he or she is "eligible for state benefits" that are "consistent with" the Company's CAP.

- Third, in order to be confirmed to be eligible for CAP, a customer must provide specific household income and household composition data. That requirement

[48] 56 Pa. Code § 56.41(4).

goes beyond the PUC's regulation, which allows the customer to provide "income documents *or other information*" (emphasis added). Providing information documenting receipt of benefits such as SNAP (Food Stamps) or Medicaid, for example, would fulfill the requirements of the PUC's regulation, but not be sufficient pursuant to the Columbia gas tariff.

- Finally, the Tariff provides only that customers "shall not be *asked to provide* a cash deposit." (emphasis added). The PUC's tariff, however, is not exclusively forward-looking. If a customer has previously provided a cash security deposit, and is found to be meet the requirements of the regulation, that customer is entitled to a refund of their deposit.

Q. WHAT DO YOU RECOMMEND?

A. I recommend four remedies to the Company's non-compliant tariff. First, I recommend that Columbia Gas be directed to modify its tariff so that it complies with the PUC's regulation and practice. The tariff should reflect the regulatory requirement that a customer is to be exempt from cash security deposits "when *the customer provides income documents or other information* that he or she is eligible for state benefits based upon household income eligibility requirements that are consistent with those of the public utility's customer assistance program." Second, I recommend that Columbia Gas refund any cash security deposit to a customer who is currently categorized as "Confirmed Low-Income." By definition, under the PUC's regulations, a Confirmed Low-Income customer is a customer who the Company has received information sufficient to give rise to a reasonable belief that the customer is low-income. Third, I recommend that Columbia include in its tariff the April 2024 order of the PUC, directing that Columbia may apply an existing security deposit to the account balance only with the customer's informed consent. As part of obtaining this informed consent, Columbia must explain to the customer how applying the security deposit to the account balance would impact the customer's monthly bill. Finally, I recommend that Columbia Gas provide a

report to its Universal Service Advisory Committee every six months for three years, or until the final decision in its next base rate case, whichever is longer, of the number of low-income customers who have had deposits waived, as well as the number of low-income customers who have had deposits refunded.

Q. WHAT IS THE SECOND PROBLEM YOU HAVE IDENTIFIED?

A. Columbia Gas unduly restricts the customers who it identifies as a "Confirmed Low-Income" customer. Contrary to this Commission regulation, when Columbia was asked to "provide a detailed written description of how the Company 'confirms' the low-income status of the Company's customers, including a detailed list of the information accepted to confirm low-income status," the Company responded that "Currently, the Company considers all customers that verbally provide income that calculates at level 1 as confirmed low income. In addition, all customers that receive a LIHEAP grant including those that have not verbally provided income, are considered confirmed low income." (OCA-2-18).

In contrast, the PUC regulation states:

> *Confirmed low-income residential account*—Accounts where the NGDC has obtained information that would reasonably place the customer in a low-income designation. This information may include receipt of LIHEAP funds (Low-Income Home Energy Assistance Program), self-certification by the customer, income source or information obtained in § 56.97(b) (relating to procedures upon rate-payer or occupant contact prior to termination).[49]

As can be seen, nothing in this regulation requires the customer to provide, or allows the utility to require, that a customer provide actual dollars of household income to the utility.

[49] 52 Pa. Code § 62.2.

Indeed, for example, the regulation allows the customer to identify an "income source" that would reasonably place the customer in a low-income designation. Pursuant to the Commission's regulation, a customer is not required to provide Columbia, even through a self-attestation, what their exact income is. All that is required is that the customer provide the Company with information that would "reasonably place the customer in a low-income designation." A customer's self-attestation of the receipt of public assistance (e.g., Supplemental Nutrition Assistance Program [SNAP], welfare, Supplemental Security Income [SSI], Medicaid), for example, would all place a customer in a "low-income designation." For purposes of establishing the customer's "Confirmed Low-Income" status, it would not matter what specific dollar level of income allows the customer to receive such assistance. The mere fact of receiving such assistance would be sufficient to meet the PUC's definition.

As can be seen from the Company's data request response, even if self-attested, Columbia currently requires customers to disclose their actual dollar levels of income and household composition to be identified as "low-income." It is only through such a disclosure that Columbia can "calculate [that income] at Level 1. . ." That requirement goes beyond what the PUC's regulation allows.

Columbia's reference to accepting "customers that verbally provide income" is not sufficient to comply with the PUC regulation. Allowing customers to "verbally provide income" does not resolve the problem of the Company's non-compliance with the PUC regulation regarding the identification of Confirmed Low-Income customers.

Q. WHAT DO YOU RECOMMEND?

A. I reiterate the recommendation I made with respect to my discussion of deposit exemptions above. Columbia should modify its tariff, along with its policies, practices and procedures regarding the identification of "confirmed low-income" customers to conform with the PUC's regulations, including self-certification of low-income status. Columbia should include these modified policies and procedures in its residential tariff. Within this modified tariff language should be included a list of public assistance programs, mutually agreed to by the Company and its USAC, participation in which would reasonably place the customer in a low-income designation. The Company should explicitly acknowledge that a customer *may* provide, but is *not required* to provide, either the household's actual dollar level of income or the household composition in order to provide sufficient information to reasonably place them in a low-income designation.

Q. WHAT IS THE THIRD PROBLEM YOU FIND WITH THE COLUMBIA GAS RESIDENTIAL TARIFF?

A. The Columbia Gas Tariff provides that the Company may require an expanded deposit if, among other things, "Any Applicant or Customer. . .is unable to establish creditworthiness to the satisfaction of the public utility through the use of a generally accepted credit scoring methodology which employs standards for using the methodology that fall within the range of general industry practice."

This provision, standing alone, carries with it an elevated risk of discriminatory results, even if unintentionally so. Under federal equal credit opportunity law, for example, it is unlawful to discriminate against a person in a credit transaction --the ECOA makes clear a utility transaction is a "credit transaction" under the statute—based on the consumer's

receipt of public assistance. To the extent that a Columbia's "credit scoring methodology" considers whether a consumer is employed and, if so, for how long, that reliance on the lack of employment (or the lack of long-term employment) may have the effect of discriminating against consumers who lack employment because they receive public assistance (one of the protected classes under ECOA).

In addition, any consideration of whether a consumer is a homeowner, as well as about whether a consumer is banked or unbanked, has a high probability of having racially disparate impacts. It will come as no surprise, for example, that the National Association of Realtors found that the homeownership gap for Blacks and Hispanics has grown even bigger in recent years.[50] So, does the question of whether a consumer has a bank account (credit card, loan or other credit reference) have distinct racial implications.[51]

Q. WHAT DO YOU RECOMMEND?

A. I recommend that Columbia's Tariff be modified to add the following language: "that fall within the range of general industry practice, *provided that the methodology does not directly, or have the effect of, discriminating based on a protected class as set forth in the federal Equal Credit Opportunity Act.*" (new language emphasized).

[50] Meredith Dunn, et al. 2023). 2023 Snapshot of Race and Home Buying in America, National Association of Realtors.

[51] Fairness in Financial Service: Racism and Discrimination in Banking, Testimony of Lisa Rice, President and CEO of National Fair Housing Alliance, Before the Committee on Banking, Housing and Urban Affairs, U.S. Senate, December 1, 2022.

Part 5. Columbia's Proposed Residential Customer Charge.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. This section of my testimony addresses Columbia's proposal to increase its residential customer charge by more than 55%, from $16.75 to $26.00 per month. (St. 6, at 21). Columbia's proposal will have a disproportionate adverse impact on low-income customers. Particularly given the affordability issues I have discussed in detail above relating to Columbia's low-income customers, this additional burden on these customers should not be approved.

As I discuss above with respect to the overall increase in rates, the offer of a percentage of income-based CAP by Columbia does not adequately protect low-income customers. Only a small fraction of Columbia's low-income customers participate in the Company's CAP. Two-thirds (67%) of Columbia's estimated number of low-income customers, and three-quarters (74%) of Columbia's Confirmed Low-Income customers, are not enrolled in CAP. Moreover, not all CAP participants are enrolled in the Percentage of Income Program (PIP) component of CAP. In the first three months of 2024, an average of only 16% of all Columbia CAP participants were PIP participants. (OCA-6-32). In contrast, more than twice that number (35%) were enrolled in the percentage of budget CAP component (Id.), in which enrollees would be subject to higher bills given the rates proposed in this proceeding.[52]

[52] In the April 4, 2024 Columbia USECP Order, at 16 – 17, approving Columbia most recent USECP, the Commission described the Company's CAP as follows: "Columbia currently calculates a customer's CAP bill using three separate payment options: (1) a PIP [percentage of income], (2) an average payment amount (based on payments received in the 12 months prior to enrolling in CAP), and (3) a POBB [percentage of budget bill] (adjusted

Q. DOES THE IMPACT ON CAP CUSTOMERS AFFECT OTHER LOW-INCOME CUSTOMERS THAT ARE NOT PARTICIPATING IN CAP?

A. Yes. Even though the percentage of low-income customers participating in CAP is small, increasing the customer charge to these customers has an adverse impact on other low-income customers. When the residential customer charge is increased, the total cost of the CAP program increases as well. This occurs because the increased bills to the CAP customers participating in the percentage of income program component of CAP will be passed through to other ratepayers on a dollar-for-dollar basis. Increased CAP credits through the remaining three CAP program components[53]will also be paid by other customers including low-income customers who are not participating in CAP. While the individual (percentage of income) CAP participants are protected from the increased fixed customer charge, in other words, the CAP program as a whole is not. Other ratepayers, including non-participating low-income ratepayers, will pay this increase. Even with LIURP and other conservation activities by CAP customers, these increased costs will remain.

annually). Columbia is proposing to eliminate the average payment option and modify the remaining payment options. . .” The structure of Columbia’s CAP, along with the level of its PIP burdens and POBB discounts, is not placed at issue in my testimony.

[53] In addition to the PIP, Columbia’s CAP has a percentage of budget component, an average payment component, and a minimum bill component.

Q. DOES THE COLUMBIA PROPOSAL TO INCREASE ITS RESIDENTIAL CUSTOMER CHARGE IMPOSE PARTICULAR HARMS ON LOW-INCOME CUSTOMERS?

A. Yes. The proposed 55% increase in its fixed monthly charge will have serious implications for low-income customers. Increasing the fixed monthly customer charge increases the portion of a bill that a low-income customer cannot avoid by adjusting the customer's usage. The dollars of annual residential bills that are comprised of unavoidable fixed charges clearly increases with Columbia's proposed increase in the residential customer charge. As Table 15 documents below, the percentage of revenues derived from fixed charges increases from roughly one-fifth of residential revenues to substantially more than one-quarter.

Table 15. Percentage of Residential Revenue from Fixed and Volumetric Rates (Existing Rates and Proposed Rates) (OCA-02-048, OCA-02-049)

	Existing Rates		Proposed Rates	
	% Residential Revenue from Fixed Charges	% Residential Revenue from Volumetric Charges	% Residential Revenue from Fixed Charges	% Residential Revenue from Volumetric Charges
Historic Test Year (TME 11/30/2023)	21.45%	78.55%	27.30%	72.70%
Future Test Year (TME 11/30/2024)	21.06%	78.94%	26.85%	73.15%
Fully Projected Future Test Year (TME 12/31/2025)	21.17%	78.83%	26.97%	73.03%

This increase in the part of the total bill that is comprised of fixed charges impedes the ability of low-income customers to control their bills through a reduction in their usage.

Q. WHAT DO YOU MEAN WHEN YOU DISCUSS LOW-INCOME EFFORTS TO "REDUCE CONSUMPTION?

A. "Reducing consumption" is not merely associated with energy efficiency improvements. Low-income households, particularly vulnerable low-income households (e.g., elderly,

disabled, families with children), will take actions to try to reduce their bills to more affordable levels, frequently involving substantial household deprivation or the undertaking of substantial risks. Available research documents that low-income households also seek to reduce bills by reducing consumption, through actions such as closing parts of their home; reducing heating temperatures (even if to unsafe or unhealthy levels); or substituting the use of ovens or stoves to heat limited areas of their homes rather than using their heating systems to heat the entire home. The National Energy Assistance Directors Association (NEADA) performs a periodic Congressionally-funded survey of the impacts of unaffordable home energy bills. The most recent survey, known as the National Energy Assistance (NEA) Survey, was performed in 2018 (published in December 2018).[54] Data on three actions which low-income households take to reduce their energy consumption when they do not have sufficient money to pay their utility bills is presented in the Table below.

Two observations are readily apparent from this data. First, taking dramatic actions to reduce home energy consumption is not at all uncommon within the low-income population when those customers do not have sufficient money to pay their home energy bills. From one-in-five (21%: 100 – 150% of Poverty) to one-in-three (34%: 0 – 50% of Poverty) customers close off parts of their home in almost every month, or in "some months," when they cannot afford to heat their homes. From one-in-four customers (26%: 0 – 50% of Poverty) reduce the temperature in their homes to unsafe or unhealthy

[54] Apprise, Inc., 2018 National Energy Assistance Survey, Final Report, available at RESOURCE LIBRARY – Selected Reports – Energy Survey Research and Policy Analysis – APPRISE – Applied Public Policy Research Institute for Study and Evaluation

levels in almost every month or in some months. One-in-ten (or more) low-income customers use their kitchen stove or oven to heat their homes when they have insufficient money to pay their utility bills. Second, the extent to which these actions occur increases as incomes decrease in nearly every instance. Households with incomes less than 50% of the FPL more frequently take these actions in almost every month or some months than do households with income at 100% to 150% of FPL.

Table 16. Energy Reduction Actions in Response to Inability-to-Pay by Range of Federal Poverty Level (each attributed to "not having enough money to pay energy bill")[55]

	Closed Off Part of Home			Kept Temp at Unsafe or Unhealthy Level			Used Kitchen Stove or Oven to Heat		
	0-50%	51-100%	100-150%	0-50%	51-100%	100-150%	0-50%	51-100%	100-150%
Almost every month	10%	14%	7%	8%	3%	3%	1%	1%	1%
Some months	24%	13%	14%	18%	12%	10%	14%	11%	8%
1 – 2 months	12%	10%	11%	7%	8%	9%	22%	19%	14%
Never / No	54%	63%	67%	67%	76%	76%	63%	69%	77%
Don't know/refused	0%	0%	<1%	0%	1%	2%	0%	0%	1%

As this Table exemplifies, in their efforts to reduce bills to more affordable levels, low-income customers frequently take unsafe and unhealthy actions. It is unreasonable for Columbia Gas to make it even more difficult for low-income households to reduce their bills when those households are already forced to resort to heating their homes (or only a portion of their homes) using their kitchen stove or oven. It is unreasonable to make it even more difficult for low-income households to reduce their bills when they are already

[55] Apprise, Inc., 2018 National Energy Assistance Survey, Final Report, available at RESOURCE LIBRARY – Selected Reports – Energy Survey Research and Policy Analysis – APPRISE – Applied Public Policy Research Institute for Study and Evaluation

being forced to keep their homes at unsafe or unhealthy temperatures because they cannot afford to pay their bills.

These households who are forced into engaging in these unsafe and unhealthy activities in their struggle to keep their home energy bills affordable are impeded in their efforts by Columbia's proposal to increase its fixed monthly customer charge by 55%. Columbia's proposal makes a higher part of the customer's monthly bill unavoidable through reduced consumption. Those low-income customers taking such actions, in other words, will face a smaller bill reduction as a result of their action should Columbia's proposed increase in the fixed monthly customer charge be approved, potentially incentivizing more dangerous usage-reduction measures.

Q. TO WHAT EXTENT DO LOW-INCOME CUSTOMERS FACE AN INABILITY-TO-PAY?

A. In addition to my examination of energy burdens discussed above, I have also considered inability-to-pay by reference to Pennsylvania data report in the Census Bureau's most recent PULSE Household Survey. As of the time I write this testimony, the most recent PULSE Household Survey was for the time period ending April 1, 2024.[56] While the Census Bureau does not report data for specific utility service territories, it does provide state-specific information or Pennsylvania.

The Pennsylvania PULSE Survey data shows that one-of-three households (33.7%) with annual income less than $25,000 had a "very difficult" time paying for their usual

[56] Available at https://www.census.gov/data/tables/2024/demo/hhp/cycle03.html

household expenses “in the past seven days” (as of the time of the Survey). Three-of-five households (59.6%) at that income level had either a “very difficult” time or a “somewhat difficult” time paying their usual household expenses. As incomes increased, the difficulty in paying usual household expenses decreased, but nonetheless remained high. For households with annual income between $25,000 and $35,000, one0quarter (23.7%) had a “very difficult” time, but 55.6% had either a “very difficult” or a "somewhat difficult” time in paying their usual household expenses. It was not until annual incomes exceeded $35,000 that the percentage of households finding it “not at all difficult” or just “a little difficult” exceeded the percentage of households finding it “somewhat difficult” or “very difficult” to pay their usual household expenses.

Table 17. Difficulty Paying for Usual Household Expenses in Last 7 Days (Pennsylvania) (period ending April 1, 2024)

	Difficulty paying for usual household expenses in the last 7 days				
	Not at all difficult	A little difficult	Somewhat difficult	Very difficult	Total
Less than $25,000	21.1%	19.3%	25.9%	33.7%	100.0%
$25,000 - $34,999	14.7%	29.8%	31.7%	23.8%	100.0%
$35,000 - $49,999	25.6%	36.1%	21.5%	16.8%	100.0%
$50,000 - $74,999	37.1%	30.3%	20.0%	12.5%	100.0%
$75,000 - $99,999	39.7%	28.6%	14.5%	17.2%	100.0%
$100,000 - $149,999	45.1%	36.7%	12.0%	6.2%	100.0%
$150,000 - $199,999	68.8%	21.2%	4.1%	5.9%	100.0%
$200,000 and above	74.0%	14.6%	6.8%	1.7%	97.2%[57]

Given this PULSE Household Survey data, it is unreasonable to make it even more difficult for Columbia's residential customers to be able to reduce their monthly utility bills by reducing their consumption.

Q. CAN YOU PLACE THE PROPOSED INCREASE IN THE COLUMBIA RESIDENTIAL CUSTOMER CHARGE INTO SOME CONTEXT RELATING TO ITS IMPACT ON LOW-INCOME CUSTOMERS?

A. Yes. Columbia serves an estimated 91,415 low-income customers in its customer base. An increase in the residential monthly customer charge from $16.75 to $26.00 ($9.25 per month), therefore, imposes an increased financial burden on these customers of $111 per year. Even after subtracting the 3,800 CAP participants participating in Columbia's PIP

[57] Total does not equal 100% because some respondents did not report.

from this low-income customer base,[58] the remaining low-income customer base, therefore would be charged an additional $9.725 million each year in unavoidable charges ([91,445 – 3,800] x ($9.25/month x 12 months = $9,725,265). Remember, this is *not* the total customer charge, but rather is *only* the *increase* in the customer charge. To place this dollar figure in context, Columbia customers received $6.6 million in LIHEAP cash grants in the 2020-2021 program year, $8.8 million in the 2022-2023 program year, and $5.4 million in LIHEAP cash grants in the 2023 – 2024 program year to date. (OCA-02-34).[59]

Table 18. LIHEAP Cash/Supplemental Grants Received by Columbia Gas Customers (OCA-02-34)

Program Year	Cash	Supplement
2020-2021	$4,152,609.71	$2,457,750.00
2021-2022	$10,182,365.29	$3,940,500.00
2022-2023	$6,398,936.66	$2,424,450.00
2023-2024 (YTD)	$5,382,341.00	$0.00

[58] In the first three months of 2024, Columbia had 3,776 low-income customers participating in its PIP. (OCA-06-032).

[59] Comparisons should not be made to the 2021 – 2022 LIHEAP program years. In those years, federal LIHEAP appropriations were significantly increased in response to the economic crisis associated with the COVID-19 health pandemic. For example, one White House announcement stated:

> Pennsylvania has received a record $480.5 million for the Low Income Home Energy Assistance Program (LIHEAP) available this fiscal year (October 2021 to September 2022). As part of a state-by-state breakdown of funding, the Administration reported that in addition to an annual appropriation of $182.8 million for Pennsylvania, the state received an additional $297.7 million in funds from the American Rescue Plan – *more than double the state's typical annual funding*. The total of $480.5 million *is the highest amount Pennsylvania has ever received in LIHEAP* to help families struggling with the costs of home heating.

(emphasis added), available at LIHEAP-pennsylvania.pdf (whitehouse.gov) According to a White House announcement, the American Rescue Plan more than doubled LIHEAP funding nationally. It noted that "This is the largest appropriation in a single year since the program was established in 1981." (Id.)

The increase in the unavoidable charges that would be imposed on low-income Columbia customers due to the proposed increase in the residential customer charge, in other words, is higher than the *total* LIHEAP funding historically available for basic cash grants (including supplemental grants) received by Columbia customers. The increase in the unavoidable charges would exceed the LIHEAP grants received by thus far in Program Year 2024 (starting in October 2023) by more than 80%.[60] In the 2023 – 2024 program year, in other words, for every $1 in LIHEAP funding that is being provided to Columbia's low-income customers, the Company proposes to take $1.80 away from those low-income customers in the form of an increased unavoidable fixed monthly customer charge.

Q. WHY ISN'T THIS PROBLEM ASSOCIATED WITH THE RATE INCREASE AS A WHOLE RATHER THAN ASSOCIATED WITH THE INCREASED CUSTOMER CHARGE IN PARTICULAR?

A. In part, the problem *is* associated with the rate increase when viewed as a whole. In large part, however, the problem is associated with the increased customer charge because there is nothing that a household can do to avoid this monthly fee. Even if low-income customers could reduce their usage, they would not be able to avoid any part of the proposed increase associated with the fixed monthly customer charge.

[60] Columbia customers received additional LIHEAP Crisis funding. This funding, however, is not used to pay bills for current service, but rather used to help retire arrears which lead to the loss, or threatened loss, of service due to nonpayment disconnections.

Q. DOES COLUMBIA'S PROPOSED INCREASE TO THE FIXED MONTHLY CUSTOMER CHARGE ALSO IMPEDE USING LOW-INCOME ENERGY EFFICIENCY TO REDUCE OVERALL BILL INCREASES?

A. Yes. The types of barriers to low-income investments in energy efficiency are precisely the types of barriers that are made even more problematic by an increase in the fixed monthly customer charge. As a result of it being more difficult to reduce bills by reducing consumption, low-income customers lack the ability to avoid the difficulties imposed upon them because of their inability-to-pay.

Q. PLEASE EXPLAIN THE BARRIERS WHICH YOU HAVE CONSIDERED.

A. In assessing these barriers to low-income energy efficiency investments, I matched the zip codes which Columbia listed as comprising its service territory (OCA-2-03) to Census data for the same zip codes. This data analysis demonstrates that:

- Columbia's zip codes have high penetrations of low-income and very low-income households.[61] At these income levels, Columbia customers have insufficient discretionary funds to invest in energy efficiency, even if such investments would be cost-effective in the short- or medium-term. The extent of low-income households in Columbia's service territory was discussed in detail above. The increase in fixed monthly customer charges makes it more difficult for investments to be cost-effective, making the lack of discretionary investment income an even greater impediment.
- Columbia's zip codes reveal high mobility within the low-income population. Mobility is primarily measured by the percentage of households that have changed residences within the past year.[62] Frequent mobility makes it more difficult for low-income households to invest in energy efficiency. A low-income household will not make an energy efficiency investment that has a

[61] The number of households by income are provided in Table B19001 of the American Community Survey (5-year data). The population by Poverty Level is provided in ACS Table C17002 (5-year).

[62] American Community Survey, 5-year, 2020, Table B07010.

three-year payback if that household does not expect to live in its home for three years.

- Columbia's zip codes have an extremely high prevalence of low-income households with high and extremely high shelter burdens.[63] High burdens are shelter burdens that exceed 30% of income. Extremely high burdens are shelter burdens that exceed 50% of income. Data for the Columbia service territory demonstrates that as household incomes decrease, the prevalence of high shelter burdens, and extremely high shelter burdens, dramatically increase. High shelter burdens make it difficult for low-income households to invest in energy efficiency. A low-income household that is struggling to pay its underlying housing costs does not have the discretionary income to invest in usage reduction measures, even if that investment might be cost-effective. Since, by definition, fixed monthly customer charges cannot be reduced by reducing consumption, increasing the fixed monthly customer charge by 50% makes it less likely that energy efficiency investments would be cost-effective in a time period that would allow low-income households to recover their investment in a resource-constrained environment.

Q. HAVE YOU BEEN ABLE TO REVIEW THE HARMS THAT ARISE FOR LOW-INCOME CUSTOMERS AS A RESULT OF THEIR INABILITY TO RESPOND TO BILL UNAFFORDABILITY BY REDUCING BILLS THROUGH REDUCED USAGE?

A. Yes. I have examined various indicators of bill payment difficulties for low-income customers as compared to residential customers as a whole. The data is presented in the Table below. Overall, the payment patterns of Columbia's Confirmed Low-Income customers are consistently worse than the payment patterns of the Company's residential customers as a whole. The percentage of accounts in arrears is consistently two or more times higher for Confirmed Low-Income customers than for residential customers. The average arrearage level for Confirmed Low-Income customers is consistently

[63] American Community Survey, 5-year, 2020, Table B25074.

substantially higher than the average arrearage level for residential customers as a whole. As can be seen, the very customers for whom the Company is making it more difficult to respond to an inability-to-pay are those customers that have the greatest payment difficulties.

Table 19. Columbia Collections: Residential vs. Confirmed Low-Income (2020 – 2022)

	Residential		Confirmed Low-Income	
	2021	2022	2021	2022
Pct accounts in debt	6.1%	5.9%	14.2%	13.3%
Average arrears	$813.30	$788.61	$1,034.31	$955.15

As I have previously noted, not only are more low-income customers (than residential customers) behind on their bills, but those that are behind, are further behind than residential customers generally.

Q. DO THESE PAYMENT DIFFICULTIES COST LOW-INCOME CUSTOMERS ADDITIONAL MONEY IN INCREASED BILLS?

A. Yes. When low-income customers have an inability to pay their bills in a full and timely fashion, as is documented above, the Company's response is to increase those unpaid bills even further. The Company imposes a late payment charge of 1.25% a month on the full, unpaid balance.[64] This monthly fee is an annualized fee of 16.075% per year.

[64] Columbia Tariff, Section 2.10 (Supplement No. 221 to Tariff Gas – Pa. P.U.C. No. 9, Twelfth Revised Page No. 192).

Q. WHAT DO YOU CONCLUDE?

A. I recommend that the residential customer charge determined by OCA witness Mierzwa should be approved.

Part 6. Columbia's Weather Normalization Mechanism.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I address the adverse impacts which Columbia's Weather Normalization Adjustment mechanism (WNA) has on low-income customers. According to Columbia witness Johnson, "The WNA normalizes the impact of weather on the recovery of residential usage based on base revenue during the winter months that the WNA is in effect." (St. 6, at 29). Mr. Johnson asserts that the "goal of the WNA" is "to improve customer bill and revenue stability. . ." (St. 6, at 35). I find that the WNA adversely affects low-income customers in particular. The removal of the deadband, as proposed by the Company, exacerbates these problems even more. Increased use of budget billing represents a more effective way to provide consumer protections against weather volatility. Despite the effectiveness of budget billing, Columbia does not effectively use this payment option.

Q. WHAT IS THE HARM OF THE WNA TO LOW-INCOME CUSTOMERS?

A. While Columbia asserts that its WNA can adjust rates either up or down in response to weather, the reality is that WNAs implemented in Pennsylvania have largely resulted in higher charges for residential consumers. In Fiscal Year 2023, for example, the PGW

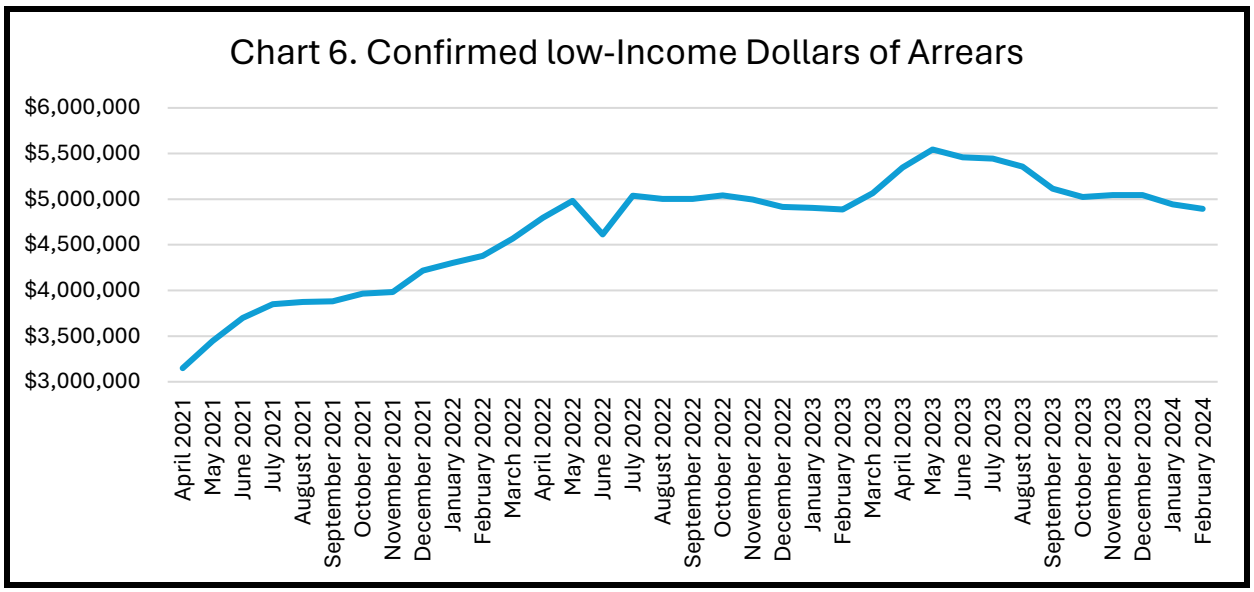
WNA imposed additional charges of $32,396,102 on customers.[65] In FY 2022, the PGW WNA imposed additional charges of $23,159,935,[66] while in FY 2021, the added PGW charges were $11,761,938.[67] A similar story has emerged for Columbia Gas. In only one year since the 2018 – 2019 winter heating season has the WNA produced a credit for customers. During the winter seasons 2018-2019 through 2022-2023, the WNA has added $83.96 to customers' bills. During the period 2019-2020 through 2022-2023, the WNA has added $97.47 to customer bills.

As I have discussed throughout my testimony, Columbia's low-income customers already face substantial difficulties paying their unaffordable bills. Chart 6 below shows the increasing dollars of arrears incurred by the Company's Confirmed Low-Income customers. (OCA-2-33).

[65] R-2017-2586783, PGW Weather Normalization Adjustment Annual Report, January 2, 2024.

[66] R-2017-2586783, PGW Weather Normalization Adjustment Annual Report, January 10, 2023.

[67] R-2017-2586783, PGW Weather Normalization Adjustment Annual Report, January 4, 2022.



The Columbia WNA proposal, which is more likely than not to increase bills even further, will exacerbate these difficulties. In addition, as I note above, to the extent that customers increase their arrears, the Company will impose ever-increasing dollars of late payment charges to exacerbate the unaffordability even further.

Q. WAS THERE PUBLIC INPUT HEARING TESTIMONY THAT ADDRESSED THE IMPACTS OF THE WNA?

A. Yes. Customers at the May 22, 2024 Public Input Hearing expressed concerns about the impact which the pilot WNA has had on their bills. See Exhibit RDC-2 for a summary of the testimony.

Q. IS THERE A BETTER WAY TO PROTECT RESIDENTIAL CUSTOMERS GENERALLY AND LOW-INCOME CUSTOMERS IN PARTICULAR FROM BILL VOLATILITY DUE TO WEATHER VOLATILITY THAN THE WNA?

A. Yes. Enrolling residential customers on budget billing would provide more transparent and consistent protections to residential customers from the volatility in home heating

bills. Budget billing allows a customer to spread annual bills in equal installments over an 11-month period (with Month 12 being a reconciliation month).[68] By enrolling in budget billing, a customer will know from month-to-month what their natural gas bill will be. The bills become more predictable, and thus more payable.

Q. DOES COLUMBIA GAS IMPOSE RESTRICTIONS THAT IMPEDE LOW-INCOME UTILIZATION OF BUDGET BILLING?

A. Yes. When Columbia Gas was asked to "provide a list of all policies establishing whether or not residential customers may or may not enter into a levelized monthly Budget Billing plan," the Company responded by stating that "[t]he 12-month budget plan is available for residential customers with a zero/credit balance or their current bill due. Arrears must be paid in full prior to establishing a budget plan." (OCA-03-03). However, as described in detail above (see, Table 19), low-income customers are not only two or more times more likely to be in arrears than residential customers generally, but they are also substantially further in arrears. The very customers who would most benefit from budget billing, in other words, are those who would be excluded by the Company's budget billing restrictions.

[68] Budget bills may be re-calculated three times a year to prevent a substantial over- or under-payment by the end of the year. If the projected budget is (+or -) $5.00, the budget will increase or decrease keeping the customer on track. (OCA-03-07).

Q. DO YOU HAVE REASON TO BELIEVE THAT COLUMBIA GAS UNDERSERVES ITS LOW-INCOME CUSTOMER BASE WITH BUDGET BILLING?

A. Yes. The data set forth in Table 20 below shows the participation in Columbia's budget billing by non-low-income residential customers compared to low-income customers. As can be seen, the percentage of budget billing participants who are comprised of low-income customers is small compared to the percentage of low-income customers in the population as a whole. From May 2022 through March 2024, between 6.4% and 7.7% of all budget billing participants were low-income.[69] This low participation rate stands in contrast to the fact that in its most recent filing with BCS (2023) providing data on universal service programs, as well as credit and collection performance, Columbia reported that it had an average of 411,279 residential customers and 72,231 Confirmed Low-Income customers (17.6% of customer identified as Confirmed Low-Income).

[69] This sets aside the month of April 2023 when Columbia reports that its total number of budget billing participants inexplicably dipped from 111,745 in March 2023 to 22,581 in April 2023, increasing back to 113,587 in May 2023.

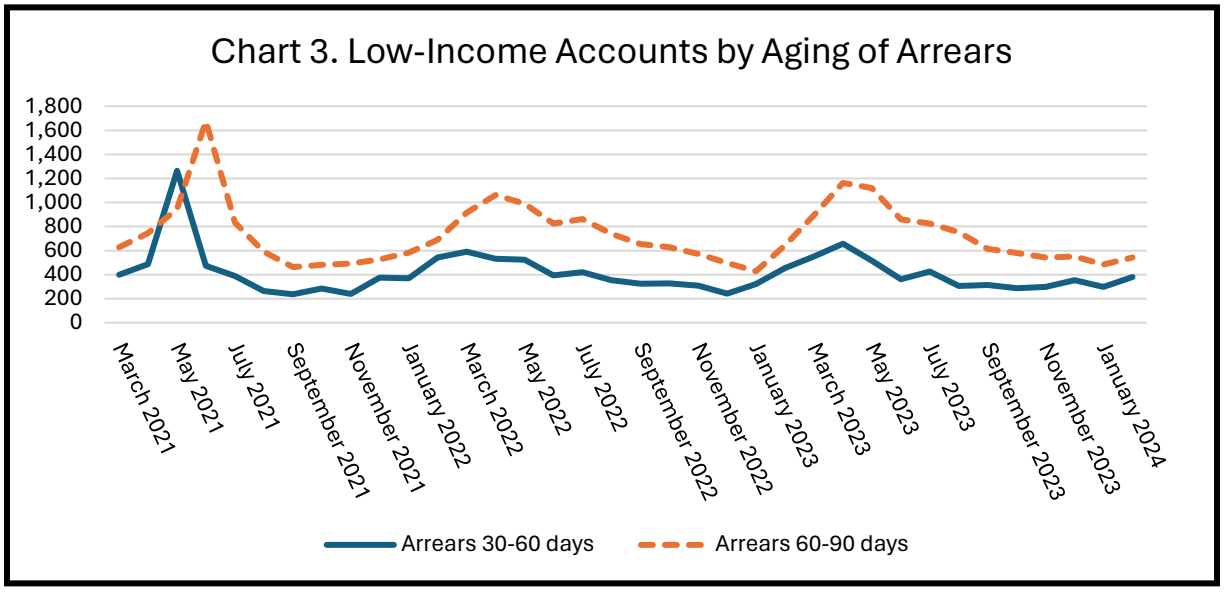
Table 20. Residential and Low-Income Participants in Budget Billing
(by month May 2022 – March 2024) (OCA-03-04)

	Budget Billing Participants			
YYYYMM	# All Residential	# Residential (excluding Low Income)	# Low-Income (excluding CAP)	Percent Low-Income (excluding CAP)
202403	109,165	102,267	6,898	
202402	113,088	105,755	7,333	6.9%
202401	115,096	107,542	7,554	7.0%
202312	99,682	93,653	6,029	6.4%
202311	101,089	94,878	6,211	6.5%
202310	112,997	106,112	6,885	6.5%
202309	100,831	94,534	6,297	6.7%
202308	116,834	109,549	7,285	6.6%
202307	103,362	96,650	6,712	6.9%
202306	112,592	105,138	7,454	7.1%
202305	113,587	105,624	7,963	7.5%
202304	22,581	19,830	2,751	13.9%
202303	111,745	103,709	8,036	7.7%
202302	104,266	97,058	7,208	7.4%
202301	104,567	97,344	7,223	7.4%
202212	95,433	89,263	6,170	6.9%
202211	92,212	86,376	5,836	6.8%
202210	96,777	90,777	6,000	6.6%
202209	96,302	90,340	5,962	6.6%
202208	105,747	99,143	6,604	6.7%
202207	93,566	87,549	6,017	6.9%
202206	101,762	95,073	6,689	7.0%
202205	97,901	91,286	6,615	7.2%

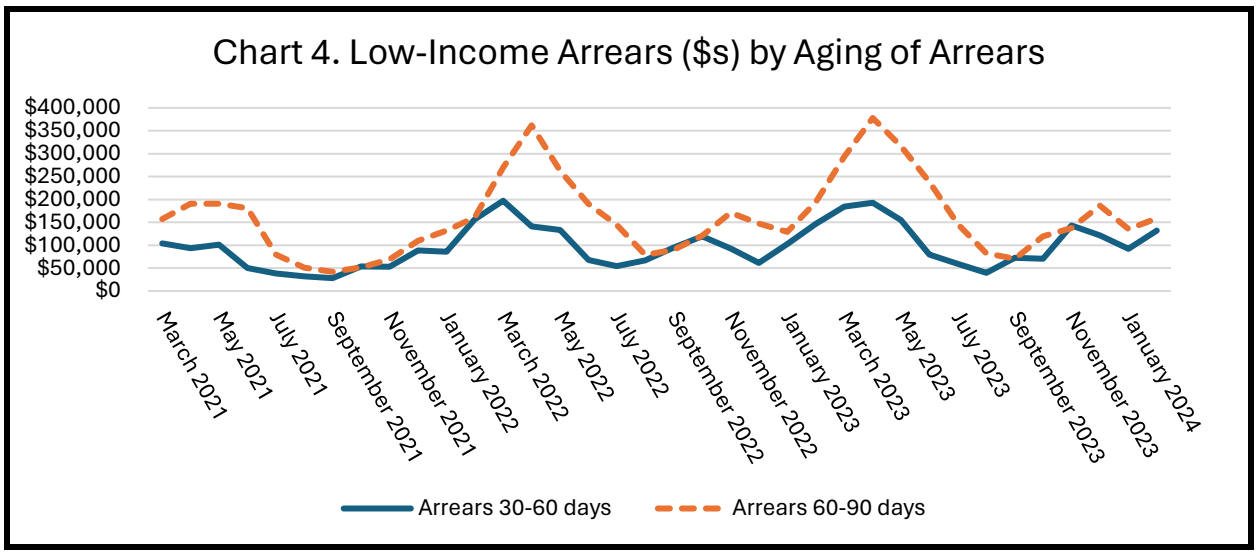
Q. DO YOU HAVE REASON TO BELIEVE THAT LOW-INCOME CUSTOMERS WOULD BENEFIT FROM LEVELIZING THEIR MONTHLY BILLS THROUGH BUDGET BILLING?

A. Yes. Chart 3 below shows the variability in the aging of arrears for low-income residential accounts from March 2021 through February 2024 (nearly three complete heating seasons). In each complete cold weather season, the number of low-income

accounts experiencing short-term nonpayment (30 days arrears) increases, only to decline in the subsequent warm weather months. While the 2023 – 2024 heating seasons is not yet complete (data available only through February 2024), the same pattern appears to again exist.



The fact that this variation in payment patterns can be attributed to volatility in the level of cold weather bills can be seen in Chart 4 below. This Chart, too, shows the aging of arrears from March 2021 through February 2024. It shows, however, that the variability in dollars of arrears is even higher than the numbers of accounts in arrears. Moreover, while the number of accounts in arrears either 30 or 60 days remains relatively constant throughout the winter heating seasons, the number of dollars 30 to 60 days in arrears shows the same seasonal volatility that the number of dollars 30 – 60 days in arrears shows. While implementation of the Columbia Gas WNA would not address these problems, emphasized focus on enrolling low-income residential customers in budget billing would be much more likely to do so than the WNA.



Q. WHAT DO YOU CONCLUDE?

A. Based on the data above, I conclude that the Columbia Gas WNA does not increase the "stability" of natural gas heating bills to customers. Indeed, continuing the WNA, particularly with the deadband removed, will impose substantial harms on low-income customers in particular. The benefits of the WNA flow not to customers, and particularly not to low-income customers, but rather to the Company.

The existing Budget Billing program provides a more than satisfactory opportunity to customers who seek to use it. It provides greater benefits to customers without imposing the same risks. Moreover, Budget Billing has the effect of being able to address the volatility in bill payment that arises as a result of variations in cold weather monthly heating bills. The Budget Billing program would play that role in a much more efficient and effective fashion than would the WNA.

More generally, I conclude first that the recommendations of OCA witnesses Dismukes and Mierzwa regarding the Company's proposed WNA be adopted. In addition, the disproportionate adverse impact on low-income customers I have identified provides an

additional basis for the recommendations I make below regarding an increased effort to enroll low-income customers in the Company's CAP.

Part 7. Columbia's Revenue Normalization Adjustment.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. This section of my testimony examines the impact of Columbia's proposed Revenue Normalization Adjustment (RNA) on low-income customers. Columbia explains its RNA as follows:

> Columbia is proposing the implementation of a RNA for the residential class in this case. The RNA provides a benchmark distribution revenue level regardless of changes in customers' actual usage levels. Rider RNA would adjust actual non-gas distribution revenue for the non-CAP residential customer class. Columbia's proposed RNA is designed to "break the link" between residential non-gas revenue received by the Company and gas consumed by non-CAP residential customers.

(St. 6, at 36). I find that the proposed RNA will have a particular adverse impact on low-income customers.

Q. WAS THERE PUBLIC INPUT HEARING TESTIMONY THAT ADDRESSED THE RNA?

A. Yes. Customers at the May 22, 2024 Public Input Hearing expressed concerns about the RNA and how it will serve as a disincentive for consumers to engage in energy efficiency and conservation. See Exhibit RDC-2 for a summary of the testimony.

Q. WOULD THE PROPOSED REVENUE NORMALIZATION ADJUSTMENT AFFIRMATIVELY HARM LOW-INCOME CUSTOMERS?

A. Yes. The Revenue Normalization Adjustment results in a transfer of costs from higher income customers to lower income households. This occurs because the actions that households take to reduce natural gas consumption, thus resulting in a readjustment of rates to that consumption which remains, are actions that are disproportionately taken by higher income households. In my discussion below, I consider three different actions to reduce space heating usage: (1) insulating one's home; (2) air-sealing your home (as measured by the how "drafty" the home is); and (3) installing a programmable thermostat. The data is taken from the 2020 Residential Energy Consumption Survey (RECS) undertaken by the Energy Information Administration of the U.S. Department of Energy (EIA/DOE). 2020 is the most recent RECS data for which data has been published. Data is Pennsylvania-specific.

Table 21 below shows the distribution of how well insulated homes are by household income. The Table shows the percentage of households at the different income levels in the entire population. For example, 15.1% of all households have income below $20,000. Households at that income level are under-represented in those homes that are adequately-insulated (15.1% in total population vs. 11.2% in households with adequately insulated homes) and over-represented in both those households that are poorly insulated (22.1% with income below $20,000) and completely lacking insulation (33.6% with income below $20,000).

Table 21. Insulation by Income for Households Heating with Natural Gas (Pennsylvania) (2020)

	Well Insulated	Adequate Insulation	Poorly Insulated	Not Insulated	Total
<$20,000	14.8%	11.2%	22.1%	33.6%	15.1%
$20,000 - $39,999	12.4%	15.2%	22.8%	36.1%	16.7%
$40,000 - $59,999	8.5%	20.6%	16.9%	13.6%	16.3%
$60,000 - $74,999	13.2%	13.6%	11.0%	0.0%	12.5%
$75,000 - $99,999	13.9%	13.6%	9.1%	10.7%	12.7%
$100,000 - $149,999	17.8%	13.5%	8.0%	5.9%	13.3%
$150,000+	19.4%	12.3%	10.1%	0.0%	13.4%
Grand Total	100.0%	100.0%	100.0%	100.0%	100.0%

Table 22 below reveals the same pattern with the extent to which homes have been air-sealed. The Table presents data on how frequently a home feels drafty, disaggregated by income ranges. Low-income households are substantially over-represented in those populations of households whose homes are drafty "all the time" (15.1% of total population with income below $20,000 vs. 24.2 of the population with homes that are drafty all the time) and 27.7% of households whose homes are drafty "most of the time." Even households with income between $20,000 and $40,000 are over-represented in those populations with homes that are not well air-sealed (31.6% of population whose homes are draft "all of the time" vs. 16.7% of total population).

Table 22. Percentage of Gas Heating Households by How Frequently Home Feels Drafty By Income (2020) (Pennsylvania)

Drafty	All the time	Most of the time	Some of the time	Never	1 Total
<$20,000	24.2%	27.7%	12.6%	12.9%	15.1%
$20,000 - $39,999	31.6%	17.4%	16.1%	14.9%	16.7%
$40,000 - $59,999	12.7%	21.0%	18.3%	13.2%	16.3%
$60,000 - $74,999	12.7%	10.7%	9.8%	16.1%	12.5%
$75,000 - $99,999	5.8%	7.5%	15.3%	12.3%	12.7%
$100,000 - $149,999	0.0%	10.9%	13.3%	15.9%	13.3%
$150,000+	13.1%	4.7%	14.6%	14.7%	13.4%
Grand Total	100.0%	100.0%	100.0%	100.0%	100.0%

Finally, Table 23 documents that low-income households are over-represented in those populations lacking a programmable thermostat while being under-represented in those populations having a programmable thermostat. Very few households with income below $40,000 have "smart" thermostats (7.2% and 2.2% for incomes with less than $20,000 and income of $20,000 to $39,999 compared to a total of 15.1% and 16.7% respectively). Those with programmable thermostats are substantially under-represented in the population with (13.0% and 11.1% vs. 15.1% and 16.7% for households with income below $20,000 and between $20,000 and $39,999). In contrast, households with incomes of $100,000 or more are over-represented in both the populations having programmable thermostats and those with smart thermostats.

Table 23. Gas Heated Households with Programmable Thermostat Installed by Income (Pennsylvania) (2020)

Programmable Thermostat	No Therm	Manual	Programmable	Smart	Total
<$20,000	23.4%	16.9%	13.0%	7.2%	15.1%
$20,000 - $39,999	16.3%	23.8%	11.1%	2.2%	16.7%
$40,000 - $59,999	16.7%	17.6%	15.0%	14.4%	16.3%
$60,000 - $79,999	14.8%	12.5%	13.6%	5.0%	12.5%
$80,000 - $99,999	7.3%	12.9%	14.3%	7.6%	12.7%
$100,000 - $119,999	15.8%	9.2%	14.6%	29.0%	13.3%
$120,000 - $139,999	5.8%	7.1%	18.3%	34.6%	13.4%
$140,000+	23.4%	16.9%	13.0%	7.2%	15.1%
Grand Total	100%	100%	100%	100%	100%

Q. HOW DOES THIS DATA RELATE TO THE COLUMBIA GAS REVENUE NORMALIZATION ADJUSTMENT PROPOSAL?

A. Columbia Gas' proposed Revenue Normalization Adjustment in essence takes revenue that has historically been billed to all customers and, as more customers take steps to reduce their consumption (and thus reduce the revenue billed to them) reallocates those dollars to those customers (and their consumption) that remain. The data above shows that the customers who are left behind by such a "normalization" process are disproportionately low-income customers. In other words, Columbia Gas proposes to take those revenues that had been billed to higher income households and to reallocate those dollars to those low-income households who do not have the financial capacity to pursue investments in energy efficiency measures (such as insulation, air sealing, and programmable thermostats).

Q. WHY DOESN'T COLUMBIA'S LIURP PROGRAM ADDRESS THE PROBLEMS YOU HAVE IDENTIFIED ABOVE?

A. LIURP serves a small portion of the Columbia low-income population eligible for LIURP program investments. According to the PUC's 2024 Columbia USECP Order,[70] the Company reports an estimated 24,933 "potential LIURP recipients." At the same time, Columbia proposes a LIURP budget that will serve 455 low-income customers per year through 2025, dropping to 425 customers per year thereafter.[71] At that rate, it would take Columbia nearly 60 years to reach all potential LIURP participants. Even that assumes that no-one would need to be re-weatherized in that time period. LIURP does not address the inability of low-income customers to invest in energy efficiency as I have identified above.

Q. DOESN'T COLUMBIA'S PROPOSAL TO APPLY THE REVENUE NORMALIZATION ADJUSTMENT ONLY TO NON-CAP REVENUES ADDRESS THESE ISSUES?

A. No. The issues I describe above apply to low-income customers generally, not to CAP customers in particular. Exempting CAP customers from the proposed RNA has an entirely separate justification (i.e., CAP revenues are not tied to CAP usage even in the absence of the proposed Revenue Normalization Adjustment). As I document in detail above, CAP customers represent a small portion of the low-income customer base of

[70] See, note 37, supra. At 101.

[71] Id., at 107.

Columbia Gas. Exempting CAP billings and usage from the RNA does not address the shortcomings I have identified.

Q. IS THERE ANY OTHER REASON WHY THE REVENUE NORMALIZATION ADJUSTMENT OPERATION BREAKS DOWN AS APPLIED TO LOW-INCOME CUSTOMERS?

A. Yes. The RNA proposed by Columbia Gas examines only one aspect of the ratemaking process, the determination of revenues. Rates, however, are not set simply through an examination of the level of revenues, but rather through an examination of the relationship between revenues and expenses. With low-income customers, in particular, reducing usage would not only reduce billed revenue, but would reduce the expenses associated with billed revenue. Table 19 above shows the difference between payment patterns for residential customers and for low-income customers. Both the percentage of accounts in arrears and average dollars of arrears are more than two times higher for Columbia Gas' low-income customers than for its residential customers as a whole.

When low-income customers reduce their consumption, Columbia Gas will not only reduce its revenue, but it will reduce its expenses as well. Usage reduction is a particularly effective mechanism to use to control expenses because arrears do not have to be reduced to $0 in order to achieve expense reductions. For example, with working capital, Columbia Gas would experience a reduction in expenses by decreasing the level of arrears; by decreasing the percentage of either accounts or billings in arrears; or by accelerating payments. A $200 arrearage imposes fewer working capital costs than a $300 arrearage all other things equal. Moreover, a 90-day arrears will impose fewer

working capital costs than a 150-day arrears all other things equal. It doesn't matter whether the usage reduction can be attributed to energy efficiency investments, to weather, or to some other cause. The results are the same.

By implementing the RNA to take into consideration the reduction in revenue, without also considering the corresponding reduction in expenses, Columbia Gas is not making an accurate adjustment to maintain stability in earnings. Since the greatest potential for expense reductions lies with low-income usage reduction, low-income customers will be most adversely affected by this failure.

Q. IS THERE ANY FINAL REASON WHY THE RATIONALE FOR A REVENUE NORMALIZATION ADJUSTMENT DOES NOT APPLY TO LOW-INCOME CUSTOMERS?

A. Yes. Columbia Gas proposes to base its Revenue Normalization Adjustment on the revenue that has been previously billed to its customers. Columbia Gas states quite explicitly that the Revenue Normalization Adjustment involves looking at the "Actual Distribution Revenue per Bill (ADRB). In turn, Columbia states that the ADRB "is based on the *amount of billed distribution revenue* during the respective months of the RNA calculation period from the non-CAP rate schedules." (OCA-6-38) (emphasis added). Columbia states further that it "is proposing to set the "Benchmark Distribution Revenue per Bill" ("BDRD") using the weather normalized test year *billed revenues* for the Fully Project Future Test Year approved in this proceeding." (OCA-6-39) (emphasis added). Making that comparison for low-income customers does not reveal the amount of revenue that is being "lost" to Columbia Gas from its low-income customers.

Again, as documented noted in Table 19, if Columbia Gas were to apply the Revenue Normalization Adjustment to low-income billings, as the Company acknowledges they would, the Company would be adjusting for the loss of revenues that it was not receiving in the first instance. It would, in other words, be adjusting for a "loss of revenue" that did not occur.

Q. WHAT DO YOU CONCLUDE?

A. I conclude that the Company's proposed RNA is unreasonable. Moreover, the proposed RNA will impose disproportionate adverse impacts on low-income customers. The recommendation of OCA witnesses Dismukes and Mierzwa regarding the proposed RNA should be adopted.

Part 8. Columbia's Requested Increase to its Equity Return for "Superior" Management.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I review Columbia's claims that it exhibits sufficiently superior management to justify an increased equity return. Company witness Moul states that his "return on equity includes a provision of 0.25% in recognition of management effectiveness. That is to say, the cost of equity that [he is] proposing is comprised of an 11.50% market-determined rate plus 0.25% for management performance." (St. 8, at 1). Mr. Moul goes on to state, however, that "[i]n this regard, I have not made an independent evaluation of the Company's management effectiveness. Company witness Mark Kempic, President of the Company, describes the superior performance of its management in his testimony." (Id.)

Based on my review of Columbia's management actions below, and their impacts, I conclude that no increase in Columbia's equity return is warranted. I focus my attention on the universal service and credit and collection attributes of Columbia's operations.

Q. DOES COLUMBIA GAS EXERCISE SUPERIOR MANAGEMENT WITH RESPECT TO ITS UNIVERSAL SERVICE PROGRAMS?

A. No. I have explained above, in detail, many of the management problems that Columbia exhibits with respect to its universal service programs:

1. Columbia has enrolled a fraction of its estimated low-income customers in its CAP (25.6%).

2. In the most recent 36 months for which data is available, while Columbia disconnected 17,573 non-CAP Confirmed Low-Income customers, it reconnected only 8,843.

3. In the most recent 36 months for which data is available, Columbia entered into 44,610 payment arrangements with non-CAP Confirmed Low-Income customers, but had only 13,317 of those successfully completed.

Based on this data, I find that rather than enrolling its customers which the Company has a reasonable basis to believe to be low-income, Columbia continues to resort to collection efforts directed toward its non-CAP Confirmed Low-Income customers even when those collection efforts have been proven to be ineffective. I find that these collection efforts are ineffective based on the collections outcomes set forth in Table 5, Table 6, Table 8, Table 9, and Table 13.

Q. HAS COLUMBIA TAKEN EFFORTS TO DETERMINE CUSTOMER SATISFACTION WITH HOW IT OFFERS ITS UNIVERSAL SERVICE PROGRAMS AND PROVIDES FOR ENROLLMENT?

A. No. Given the statutory mandate that universal service programs are to be designed to be programs that "help low-income customers maintain natural gas. . .service," Columbia's failure to enroll three-out-of-four of its estimated low-income customers into its CAP, its primary universal service program, while continuing to pursue ineffective collection activities, would seem to call-out for Columbia to determine how it might engage in more extensive, more effective, activities to identify its Confirmed Low-Income customers and to enroll those customers into the Company's CAP. However, it does not.

Q. DOES COLUMBIA GAS UNDERTAKE EFFORTS TO DETERMINE CUSTOMER SATISFACTION WITH ASSISTANCE THE COMPANY PROVIDES TO CUSTOMERS WHO WOULD BENEFIT FROM ENROLLMENT IN CAP OR OTHER UNIVERSAL SERVICE PROGRAMS?

A. No. Despite the low enrollment of its estimated low-income population in CAP, and the extent to which Columbia directs its ineffective collection actions toward customers it has a reasonable belief to be low-income, Columbia Gas takes no action to understand how its customers view the actions of the Company with respect to enrolling in CAP. When asked to provide all point-of-contact surveys with customers who had contact with the Company to negotiate a payment plan, respond to a shutoff notice, or to attempt to enroll in CAP, the Company indicated that pursued no such surveys. The Company was asked which of its customer satisfaction surveys were directed specifically to customers who contacted Columbia: (1) to negotiate a deferred payment arrangement; (2) in response to

a notice of a nonpayment service disconnection; (3) regarding an inability-to-pay an outstanding bill; (4) to enroll in CAP; (5) seeking usage reduction assistance; or (6) seeking assistance in identifying and/or applying for assistance to help pay a bill. The Company could provide no such information. It responded:

> All customer satisfaction surveys focus on residential and small business customers who have recently contacted the company to discuss any problems, concerns, or issues. The above categories listed from letters a through f would fall within the credit related group. There is no further distinction detailing what the customer called the company about for the survey to be completed." (OCA-3-14, OCA-3-15).

Despite the ineffectiveness of its actions, both to enroll customers in CAP and to pursue collection activities directed toward low-income customers, Columbia does not know where, or how, it is falling short because it does not seek out such knowledge.

Q. HOW DO YOU RESPOND TO COLUMBIA'S TESTIMONY THAT ITS AVERAGE CAP BILL IS LOWER THAN THE AVERAGE CAP BILL STATEWIDE FOR NATURAL GAS UTILITIES?

A. Company witness Kempic argues that Columbia's administration of its universal service programs is one of the areas where the Company exhibits superior management. Mr. Kempic argues that that management is evidenced by the fact that the Company's monthly CAP bill is $12 less than the statewide average, and the Company's annual CAP credit is $353 more than the statewide average. (St. 1, at 46,47). What Mr. Kempic does not address, however, is that the results of Columbia's CAP program, which can be addressed through management activity, do not reflect his discussion of dollars. Despite providing lower bills, and higher credits, in 2022 (the last year for which data has been reported), Columbia Gas had the ***worst*** "CAP Payment Rate" of all Pennsylvania natural

gas utilities.[72] The Columbia CAP Payment Rate was nearly 16% lower than the statewide average (44.7% for Columbia vs. 60.1% statewide average). Four of the five other natural gas utilities reported CAP Payment Rates of more than 50%, with the fifth one having a CAP Payment Rate of 49.0%.[73]

When addressing the operation of its CAP, neither did Mr. Kempic report that while the average program cost of its CAP (per CAP customer) has nearly doubled from 2020 to 2022 (from $705 to $1,337, an increase of 90%),[74] its CAP Payment Rate *declined* (from 51.5% in 2020 to 44.7% in 2022).[75] At the same time the statewide average CAP Payment Rate increased during the same time period (from 57.4% in 2020 to 60.1% in 2022).[76]

Q. DOES COLUMBIA GAS EXERCISE SUPERIOR MANAGEMENT WITH RESPECT TO ITS CREDIT AND COLLECTION ACTIVITIES?

A. No. Aside from its less -than-superior performance on universal service issues, Columbia Gas does not exhibit superior performance with respect to credit and collection aspects of the Company's operations either. Since 2016, for example, the average residential arrears for Columbia has nearly doubled, from $440.53 (2016) to $788.61 (80% increase).

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[72] Bureau of Consumer Services, 2022 Report on Universal Service Programs and Collections Performance, at 67,

[73] Id.

[74] Id., at 71.

[75] Id., at 67.

[76] Id.

One reason for the high, and increasing, arrears is that Columbia does not manage its collections process well. From May 2022 through March 2024, for example, Columbia disconnected service to 19,522 residential customers. (OCA-2-16). Over the same time period, however, the Company issued 268,830 disconnection notices. (OCA-2-16). The Company, in other words, issued 14 disconnection notices for every one disconnection it actually performed.

The counter-productive nature of over-noticing shutoffs has been recognized by the federal courts as well. In a case involving Columbia Gas in Ohio, the court found that when a utility repeatedly issues shutoff notices warning customers of an imminent pending service disconnection unless bills are paid in full, without following up those notices by performing the threatened collection activity, it conveys the message that customers may ignore the shutoff notice with no adverse result arising.[77] Sending multiple shutoff notices when the Company has no present intent to disconnect results in a "wolf-like" notice being issued.

The provision of a notice of a service disconnection when there is no present intent to engage in the disconnection is counterproductive to the entire purpose of notice. The purpose of a shutoff notice is to provide a clear and believable warning that a service

[77] In *Palmer v. Columbia Gas*, 479 F.2d 153 (6th Cir. 1973), the court found that the company issued between 120,000 and 140,000 notices per year, only about 4% of which were followed by actual terminations. The Federal Circuit Court held that "it is clear that the flood of final notices sent out by the company was, as the District Court expressed it, "a wolf kind of notice" which does not conform to the constitutional requirements that notice be truly informative and be given at a meaningful time." As the *Palmer* court noted: "what we have here is a wolf kind of notice that is very convenient for the computer to issue, but is not, I think, what the statute contemplates, which. . .is a meaningful notice that applies to the person who is going to be affected by it and will be followed by some action."

termination is about to occur. In response to such a notice, the customer must either take the steps necessary to prevent the service termination or take those steps needed to protect himself or herself against the dangers to life, health and property that might result from the loss of service.

The customer receiving a wolf-like notice has no basis upon which to make a decision as to which notice requires a response. The result is a tendency to delay. Delay occurs because, after sending multiple notices falsely warning of an impending disconnection of service if payment-in-full is not made by a date certain, Columbia does not send a notice saying "*this* time, we really mean it" or "this time, we really, *really* mean it."

Notices lose their believability. When a disconnection actually does occur, it thus often comes as a surprise. The customer is never placed in the position of responding to a notice of a pending disconnection with the notice saying that "*this* time, it's real." Recognizing the growing immunity to the efficacy of a warning when that warning is repeatedly given without follow-through does not require a familiarity with childhood fables, however. The impact is referred to as "psychological habituation" (becoming inured to a stimulus after repeated exposure with a resulting decrease in response).[78] When the Company sends out "false" shutoff notices on which it has no intention of following through, people learn to ignore those notices.

[78] W. Frost and E. Megalou (2009). Encyclopedia of Neuroscience. ("Habituation is a universal form of nonassociative learning. In habituation, behavioral responsiveness to a test stimulus decreases with repetition. It has the important function of enabling us to ignore repetitive, irrelevant stimuli so that we can remain responsive to sporadic stimuli, typically of greater significance.")

Effective management of Columbia's distribution of disconnection notices involves the provision of a clear and meaningful notice of a pending shutoff. The Company's shutoff notices should be made at a meaningful time, in a meaningful manner, and provide accurate information as to what the customer must do to avoid shutoff. In short, the Company should give a clear and believable warning that termination is about to occur, which Columbia does not currently do.

Q. DOES THE OVER-NOTICE OF DISCONNECTIONS GIVE RISE TO A HARM WHICH ARISES TO SOMEONE OTHER THAN THE CUSTOMER RECEIVING THE FALSE DISCONNECT NOTICE?

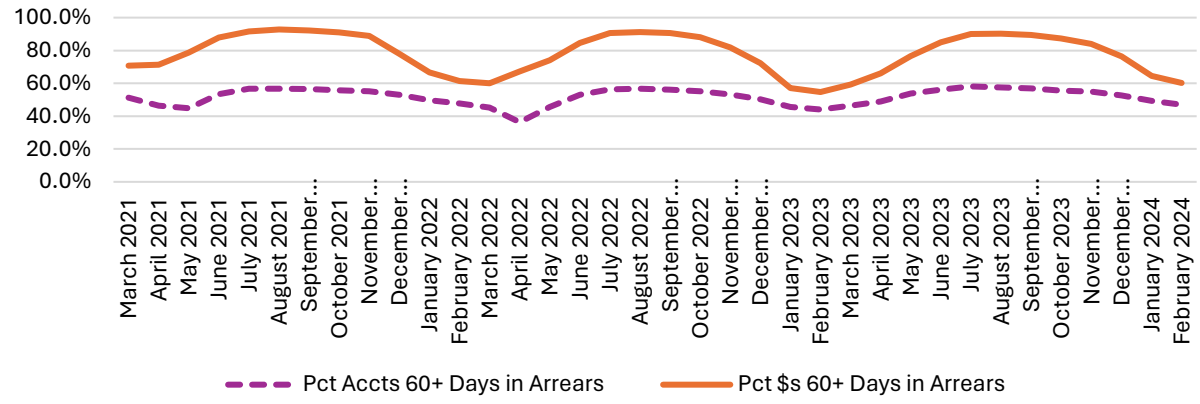
A. Yes. The Company's poor management of its disconnection process results in real costs to all remaining customers. Of the 19,522 disconnections the Company pursued, the average arrears at the time of those disconnections was $853.21. (OCA-2-23). That is significant in that after those 19,522 disconnections, the Company reconnected only 11,695 accounts (60% of those disconnected). The Company thus places in jeopardy not only any future sales to those disconnected customers not reconnected, it places in jeopardy the arrears that were the subject of the underlying disconnection.

Q. IS IT ONLY DISCONNECTIONS THAT COLUMBIA GAS FAILS TO EFFECTIVELY MANAGE?

A. No. Columbia is also failing to manage its overall collection of long-term arrears. Carrying long-term arrears imposes a cost on remaining ratepayers. The Company's lack of "superior management" of these long-term arrears thus imposes adverse impacts on all customers. Chart 5 presents, by month, the percentage of *accounts* in arrears that are, in fact, 60 or more days in arrears (the solid line). The Chart also presents the percentage of

dollars of arrears that are, in fact, 60 or more days in arrears (the dashed line). (OCA-2-30, OCA-2-32). The Chart supports two important observations about Columbia's management of arrears. First, the proportion of Columbia's arrears that are, in fact, long-term arrears is quite high, ranging from a low of roughly 60% being 60 or more days old to a high of more than 90%. The arrears which Columbia carries from month-to-month, in other words, are not situations where a customer misses a bill one month, only to make that past due payment the next month (thus falling into the 30-day arrears bucket).

Chart 5. Dollars and Accounts 60+ Days in Arrears (March 2021 - February 2024)



The second observation that is evident from the Chart above is that the percentage of dollars in long-term arrears is much higher than the percentage of accounts in long-term arrears. The significance of that is that the accounts in arrears are those accounts with higher bills with which to begin. If the accounts in long-term arrears all had an average bill, the percentage of accounts in arrears and the percentage of dollars in arrears would be the same. Only given the fact that accounts with higher bills have longer-term arrears will generate a result where a higher percentage of dollars are in long-term arrears than the percentage of bills in long-term arrears.

Q. WHAT DO YOU CONCLUDE BASED ON THE ABOVE DATA?

A. For all of the reasons I discuss above, I find that Columbia Gas does not exhibit a level of "superior management" that would justify an increase in the Company's allowed return on equity. I recommend that the recommendation of OCA witness Christopher C. Walters regarding an appropriate return on equity be adopted.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes, it does.

Exhibit RDC-1: Summary Vitae

Roger Colton
Fisher, Sheehan & Colton
Public Finance and General Economics
Belmont, MA

* *

Education:

J.D. (Phi Kappa Phi, Order of the Coif) University of Florida (1981)

M.A. (Regulatory Economics), McGregor School, Antioch University (1993)

B.A. Iowa State University (1975) (journalism, political science, speech)

Professional Experience:

Fisher, Sheehan and Colton, Public Finance and General Economics: 1985 – present.

As a co-founder of this economics consulting partnership, Colton provides services in a variety of areas, including regulatory economics, poverty law and economics, public benefits, fair housing, community development, energy efficiency, utility law and economics (energy, telecommunications, water/sewer), government budgeting, and planning and zoning.

Colton has testified in state and federal courts in the United States and Canada, as well as before regulatory and legislative bodies in more than forty (40) states. He is particularly noted for creative program design and implementation within tight budget constraints.

Professional Affiliations:

Past Chair:	Belmont Zoning By-law Review Working Committee (climate change)
Member:	Board of Directors, Massachusetts Rivers Alliance
Columnist:	Belmont Citizen-Herald
Producer:	Belmont Media Center: BMC Podcast Network
Host:	Belmont Media Center: Belmont Journal
Member:	Belmont Town Meeting
Vice-chair:	Belmont Light General Manager Screening Committee
Past Chair:	Belmont Goes Solar
Coordinator:	BelmontBudget.org (Belmont's Community Budget Forum)

Coordinator: Belmont Affordable Shelter Fund (BASF)
Past Chair: Belmont Solar Initiative Oversight Committee
Past Member: City of Detroit Blue Ribbon Panel on Water Affordability
Past Chair: Belmont Energy Committee
Member: Massachusetts Municipal Energy Group (Mass Municipal Association)
Past Chair: Housing Work Group, Belmont (MA) Comprehensive Planning Process
Past Chair: Board of Directors, Belmont Housing Trust, Inc.
Past Chair: Waverley Square Fire Station Re-use Study Committee (Belmont MA)
Past Member: Belmont (MA) Energy and Facilities Work Group
Past Member: Belmont (MA) Uplands Advisory Committee
Past Member: Advisory Board: Fair Housing Center of Greater Boston.
Past Chair: Fair Housing Committee, Town of Belmont (MA)
Past Member: Aggregation Advisory Committee, New York State Energy Research and Development Authority.
Past Member: Board of Directors, Vermont Energy Investment Corporation.
Past Member: Board of Directors, National Fuel Funds Network
Past Member: Board of Directors, Affordable Comfort, Inc.
Past Member: National Advisory Committee, U.S. Department of Health and Human Services, Administration for Children and Families, Performance Goals for Low-Income Home Energy Assistance.
Past Member: Editorial Advisory Board, International Library, *Public Utility Law Anthology*.
Past Member: ASHRAE Guidelines Committee, GPC-8, *Energy Cost Allocation of Comfort HVAC Systems for Multiple Occupancy Buildings*
Past Member: National Advisory Committee, U.S. Department of Housing and Urban Development, Calculation of Utility Allowances for Public Housing.
Past Member: National Advisory Board: Energy Financing Alternatives for Subsidized Housing, New York State Energy Research and Development Authority.

Professional Associations:

National Association of Housing and Redevelopment Officials (NAHRO)
National Society of Newspaper Columnists (NSNC)
Association for Enterprise Opportunity (AEO)
Iowa State Bar Association
Energy Bar Association
Association for Institutional Thought (AFIT)
Association for Evolutionary Economics (AEE)
Society for the Study of Social Problems (SSSO)
Association for Social Economics

Books

Colton, *et al.,* ***Access to Utility Service***, National Consumer Law Center: Boston (4th edition 2008).

Colton, *et al.*, ***Tenants' Rights to Utility Service***, National Consumer Law Center: Boston (1994).

Colton, ***The Regulation of Rural Electric Cooperatives***, National Consumer Law Center: Boston (1992).

Book Chapters

Colton (2018). The equities of efficiency: distributing energy usage reduction dollars, Chapter in Energy Justice: US and International Perspectives (Edited by Raya Salter, Carmen Gonzalez and Elizabeth Ann Kronk Warner), Edward Elgar Publishing (London, England).

Journal Publications

65 publications in industry and academic journals, primarily involving utility regulation and affordable housing. (list available upon request)

Technical Reports

200 technical reports for public-sector and private-sector clients (list available upon request)

Jurisdictions in which Expert Witness Provided

1. Maine	17. Tennessee	33. Montana
2. New Hampshire	18. Kentucky	34. Colorado
3. Vermont	19. Ohio	35. New Mexico
4. Massachusetts	20. Indiana	36. Arizona
5. Rhode Island	21. Michigan	37. Utah
6. Connecticut	22. Wisconsin	38. Idaho
7. New Jersey	23. Illinois	39. Nevada
8. Maryland	24. Minnesota	40. Washington
9. Pennsylvania	25. Iowa	41. Oregon
10. Washington D.C.	26. Missouri	42. California
11. Virginia	27. Kansas	43. Hawaii
12. North Carolina	28. Louisiana	**Canadian Provinces**
13. South Carolina	29. Arkansas	1. Nova Scotia
14. Florida (Federal Court)	30. Texas (Federal Court)	2. Ontario
15. Alabama	31. South Dakota	3. Manitoba
16. Mississippi	32. North Dakota	4. British Columbia

Exhibit RDC-2

May 22, 2024, 1:00 PM, Public Input Hearing

Summary of Consumer Testimony

Rate Increase (General)

- Renee Rothwell: Tr. 154-155. Consumers are being impacted by expenses significantly exceeding the published rate of inflation. Consumers' incomes are not increasing, which forces consumers to control expenses. Public utilities likewise should be required to control expenses. Instead, they just continue to raise prices and rates while expenses and profits go largely unchecked. Utilities are a basic necessity not a luxury. Customer choice on the natural gas supply is fruitless since the actual cost of natural gas supply is a fraction of the total cost of distribution service.

- Daniel Skvarla: Tr. 174. Columbia's rate request is shocking and what's the reason for such a large increase? Shame on the PUC for allowing the utility to become part of a multi-billion-dollar company (as part of NiSource). It is not the only one – American Water is my water company, and they are similar-sized.

- Phillip Bloch: Tr. 182-185, 188-189. Nobody would order home delivery of groceries from the supermarket if they charged six or seven times the cost of the groceries to deliver them to your home. Nobody would order a computer from Amazon if they charged you six or seven times the cost of the computer to shit it to you. No sane person would purchase anything under those conditions. Yet customers of Columbia do that very thing. The lion's share of the bill is the distribution charges, not the supply charges. These rates only look reasonable to the highly paid (millions per year) executives of Columbia and its parent company, NiSource, but not to the low and fixed-income consumers struggling to make ends meet. The Commission should turn down this rate increase request and send a message to the executives of no raises this year and to the Company to start controlling costs, cut out waste, and save money.

- Linda Mosley: Tr. 193-196. Everybody who testified before her (above) hit on the spots that she wanted to bring up. As a retiree, Ms. Mosley is on a fixed income, and the Company's rising rates are unfair. She had to use money she would have used to pay her property tax to pay her gas bill and now must figure out how to pay this year's property tax.

Overall Utility Burden

- Linda Mosley: Tr. 195-196, 202. As a retiree, Ms. Mosley is on a fixed income, and the Company's rising rates are unfair. In addition to Columbia's requested rate increase, she either experienced a recent rate increase or will experience a rate increase in the near future in her water and electric bills.

Weather Normalization Adjustment (WNA)

- Renee Rothwell: Tr. 155-157, 161-164. The WNA "seems to be completely misunderstood by the utility user. Most people aren't aware of it…" It does not seem that once the WNA was approved that anybody understood the intent of this charge or how it was going to work. As a small business owner, "when things happen beyond anybody's control, I can't just add a fee to make up for profits that I'm losing. It doesn't work that way." However, the Commission has allowed Columbia to add a line item called the WNA to make up for lost profits when weather is warmer than average. Many consumers are not even aware of this charge on their bill because they are on automatic payment, paperless billing. We are captive customers of the utility with no choice. Why should consumers be penalized for weather beyond their control? "I should not be paying for something that…I am not using and is not delivered to me." Ms. Rothwell has not seen a WNA credit on her bill.

- Daniel Skvarla: Tr. 174-178. Ms. Rothwell is right about the WNA. "We're being charged for something that doesn't exist." It is based on a formula; the Commission should not allow Columbia to charge consumers for usage that does not exist. Nobody can control the weather. Also, the fossil fuel companies are contributing to the warming weather, and now they want us consumers to pay for something they may have caused? The WNA is unfair; Mr. Skvarla opposes it.

- Linda Mosley: Tr. 194-196. Ms. Rothwell and Mr. Skvarla are right and their testimony got to the point. Consumers are not aware and do not know anything about the WNA. She claims she was charged $71.94 for the WNA in March. Her bill was about $48 for gas supply and a few hundred dollars for distribution, including the WNA charge. "I think that's a little ridiculous and overboard." We cannot change the weather, and it is not fair to charge consumers for not spending enough money on gas.

Revenue Normalization Adjustment (RNA)

- Renee Rothwell: Tr. 166. Not aware of the RNA prior to testifying and if she had been aware she "would be absolutely infuriated by it."

- Daniel Skvarla: Tr. 178-180. Mr. Skvarla believes that if he takes intentional steps to reduce his usage and conserve energy, he should see savings on his bill for that. He uses

a Nest thermostat and tries to maintain his furnace. If he is doing his part to conserve energy, then he should reap that reward. He opposes the RNA to charge him more for something that he is trying to conserve. He believes the RNA is unfair and any savings resulting from conservation should be applied back to the consumer and not returned to the Company. He believes the RNA would disincentive conservation.

- Linda Mosley: Tr. 195, 196-197, 200. The RNA is really unfair. "I keep my thermostat down to about 63 [degrees Fahrenheit] most of the winter, and they want to charge me for it? That's ridiculous." If she turned the thermostat lower than 63 degrees, she would have to live very uncomfortably by wearing coats in the house. It is not fair to charge consumers for not spending enough money on gas. If she is going to receive the RNA charge, it would be a disincentive for her to conserve, saying: "I wouldn't conserve energy anymore if it's not going to pay me to do it."

Regulatory Capture

- Phillip Bloch: Tr. 184-185. The Commission is not giving consumers a fair shake. What's happening is regulatory capture. Regulatory capture is an economics concept he studied. "It is what happens when a regulatory agency instituted to protect citizens and the abuses of private companies becomes cooped by the same companies they are supposed to regulate. Now, instead of serving the public interest they serve the interests of the companies. It is a common occurrence, and this is what has happened to the PUC. That is why Columbia Gas consumers are paying such exorbitant rates." However, Mr. Bloch still has hope and believes all people are capable of redemption. The Commission can start to redeem itself in the eyes of the public by turning down this rate increase request.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Roger Colton, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 6, 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 14, 2024

Signature: */s/ Roger Colton*
Roger Colton

Address: Fisher Sheehan & Colton
34 Warwick Road
Belmont, MA 02478

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission Office of Small Business Advocate Office of Consumer Advocate Ronald T. Bernick	: : : : :	Docket Nos.: R-2024-3046519 C-2024-3047905 C-2024-3047675 C-2024-3048339

v.

Columbia Gas of Pennsylvania, Inc.

DIRECT TESTIMONY

OF

Nicholas A. DeMarco

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

Date Served: June 14, 2024

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Introduction

Q. Please state your name and business address.

A. My name is Nicholas Anthony DeMarco. My business address is 555 Walnut Street, Forum Place, 5th Floor, Harrisburg, Pennsylvania 17101. I am currently employed as a Regulatory Analyst by the Pennsylvania Office of Consumer Advocate (OCA).

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the OCA.

Q. Have you previously provided testimony before the Pennsylvania Public Utility Commission?

A. Yes, I have testified as a policy witness in cases in front of the Public Utility Commission. The cases can be found attached to my CV at NAD-1.

Q. Please describe your educational background and qualifications to provide testimony in this case.

A. I have a Master's Degree in Political Science from Lehigh University and a Bachelor of Arts in Political Science, with a concentration in Constitutional Law from Bloomsburg University of Pennsylvania. I also attended Michigan State University's Institute of Public Utilities online rate school program. I have attached my CV as NAD-1.

Q. Have you prepared Exhibits to accompany your testimony?

A. Yes. Attached as NAD-1 is my CV.

Q. What is the purpose of your testimony in this case?

A. I am filing Direct Testimony in response to the application by Columbia Gas of Pennsylvania (Columbia or Company) to increase its base rate for natural gas distribution

service in this proceeding. My testimony will address customer service and consumer protection concerns for the increase in rates for residential customers if Columbia's request is approved. I will also be addressing portions of the Company's policy related to Personal Identification Information (PII).

Q. Please describe the proposal for rate increase filed by Columbia.

A. Currently Columbia is a subsidiary of NiSource, Inc., an Indiana based company, and serves approximately 445,000 residential, commercial, and industrial customers throughout 26 counties in the Commonwealth of Pennsylvania[1]. In this case Columbia is claiming a revenue deficiency of $124.1 million[2] and estimates that a customer who uses 70 therms per month will see a bill increase of $18.76 per month.[3] The Company is requesting a 25-basis point rate of return adjustment for management effectiveness in this proceeding.[4]

Q. What is the connection between your discussion of service quality and performance and the rate increase proposed by Columbia?

A. The topics that I will address directly relate to the efficiency, effectiveness and adequacy of service of Columbia, which the Commission must consider when setting rates under Section 523 of the Public Utility Code. 66 Pa.C.S. § 523.

Q. Please summarize your conclusions and recommendations.

A. I recommend that the Company take the additional steps listed below, which will be addressed in further detail within my testimony.

[1] Columbia Statement No.1 pg. 3-4 ln. 9-6.
[2] Columbia Statement No.1 pg. 7 ln. 5.
[3] Columbia Statement No.1 pg. 7 ln. 19.
[4] Columbia Statement No.1 pg. 30 4-14.

– Address call center performance areas which are degrading.

– Monitor call center performance to ensure a secure and quality transition to a fully remote workforce.

– Implement the changes from their analysis and concerning their investigation into the Company's decreasing UCARE performance and increase in customer complaints and verified infractions.

– Reduce the use and retention of customer Personal Identification Information (PII).

Customer Service

Q. What categories does Columbia's "Quality of Service Report" measure performance statistics?

A. Columbia's Report was filed on January 31, 2024, and it has 5 general categories: call center performance, residential and small commercial billing, meter reading, dispute reporting, and customer satisfaction.

Q. What categories will you provide analysis for in your testimony?

A. In this section of my testimony, I will be analyzing Columbia's call center performance and training. Later in my testimony, I will cover disputes and customer satisfaction regarding customer complaints.

Q. What statistics does Columbia measure for call center performance?

A. Columbia collects data for three separate measures: (1) average busy out rate, (2) call abandonment rate, (3) precent of call answered within 30 seconds.[5]

[5] Columbia Statement No.1 pg.36 ln. 8-11.

Q. What was Columbia's average busy out rate?

A. Columbia asserts that its busy out rate was 0%.[6]

Q. What was Columbia's call abandonment rate?

A. Columbia's call abandonment rate was 6.93%, which according to Mr. Kempic is flat in comparison to 2021's 7% and 2022's 7.46% rate.[7] There was an increase in Q4 of 2023 to 9.73%.[8] However, this is a significant increase from 2019 and 2020 where Columbia's call abandonment rate was only 2% each year.[9]

Q. What percent of calls did Columbia answer within 30 seconds?

A. Columbia answered 72.93% of calls withing 30 seconds.[10] This is a slight decrease from 74% from 2022 and in 2021.[11][12] These are decreases from 2019 (83%) and 2020 (85%).[13]

Q. Did the Company provide testimony on where the Company seeks to improve its call center performance?

A. Mr. Kempic states that Columbia aims to maintain services levels of 80% which Columbia has not met and has an abandonment rate that is still higher compared to other utilities.[14] According to the Commission's 2022 Customer Service Performance Report, in both 2021 and 2022, Columbia had a call abandonment rate of 7%, the third highest compared to other NGDC's in the same time frame.[15] Columbia's average call

[6] Columbia Statement No.1 pg.36 ln. 16.
[7] Columbia Statement No.1 pg.36 ln. 15
[8] Response to OCA-7-001 Attachment B.
[9] PUC 2022 Utility Customer Service Report pg. 8.
[10] Columbia Statement No.1 pg.36 ln. 14.
[11] Response to OCA-7-001 Attachment A.
[12] PUC 2022 Utility Customer Service Report pg. 10.
[13] PUC 2022 Utility Customer Service Report pg. 10.
[14] Columbia Statement No.1 pg.36 ln. 17-21.
[15] Commission Customer Service Performance Report pg. 8 - https://www.puc.pa.gov/media/2566/2022-customer-service-performance-report-final-092623.pdf

abandonment rate was on average lower in 2023, however Q4's rate was 9.73%, a concerning trend away from improvement.[16]

Q. Does the Company offer any solutions to improving its call center performance?

A. Yes. In his testimony, Mr. Kempic states that he had a team created in 2023 to identify what could be done to improve the above metrics.[17] The following actions were implemented in 2023 in an effort to improve the call center's metrics: [18]

- A mentorship program was established;
- A "New Hire Employee Engagement and Recognition Program was established;
- Bilingual CSR Recruitment efforts continue;
- Developed CSR Empathy Training;
- Delivered a series of leadership and professional development training for our front-line leaders to enhance skills, knowledge, and abilities to become more effective leaders; and
- Created Real-Time Analyst positions to manage performance in real-time focused on meeting service levels and average speed of answer metrics.

Q. Do you have any comments?

A. Yes. It is too early to tell whether the changes discussed by Mr. Kempic will succeed and I recommend that the Company continue with them, track their success, and make iterative changes to their processes between now and their next rate filing so these

[16] Response to OCA-7-001 attachment b.
[17] Columbia Statement No.1 pg.36-37 ln.21-3.
[18] Columbia Statement No.1 pg.37-38 ln. 2-13.

processes can be evaluated. The Company should also report on these changes in their next rate case and highlight what was and what was not successful.

Q. Does the Company claim any other ways it is attempting to improve call center performance?

A. Yes. The Company's call center is now 100% remote. The Company claims that this will increase the hiring candidate pool.[19]

Q. Does Columbia have a system to ensure a PA qualified CSR answers PA customer calls?

A. Yes. Columbia has a three-step process:[20]

(1) Once an agent has been certified to handle Pennsylvania calls the agents are skilled within the Genesys Administration inbound call routing application.

(2) Genesys skill-based routing is used to route inbound calls to agents based on defined skills.

(3) Genesys will only route inbound calls to the appropriately skilled agent.

In addition, newly hired agents and existing Columbia agents receive training and assessments to certify they are able to handle Pennsylvania related calls.[21]

Q. Do you have any observations about this process?

A. Yes. The processes proposed above appear to be targeted at ensuring that customers are being served by properly trained customer service representatives. Since the Company's call center is now remote, the Company must ensure that there is no loss or degradation

[19] Columbia Statement No.1 pg.39 ln 4-15.
[20] Response to OCA-7-010.
[21] Response to OCA-7-011 (Attachments A-F confidential).

in performance quality as teams go fully remote and that there are no security risks. The Company should continue to monitor the performance of its call center and adapt to the changing workflow if it begins to see a drop in call center performance.

Q. Please describe how Columbia tracks the quality assurance process conducted by the third-party relating to adherence to Pennsylvania specific customer service, consumer protection, and service quality policies and regulations.

A. According to Columbia's response to OCA-7-009, Columbia uses a third-party contractor for handling Columbia's automated customer payment and calls via IVR. While this third-party "does conduct quality assurance, and checks on their Call Center agents; however, the results of those checks are not shared with Columbia."[22] Columbia has limited management oversight via spot check and check-ins by phone with the contractor's manager to determine if regulatory and contractual expectations were followed.[23]

Also, during the first quarter of 2024 Columbia temporarily used two additional third-party contractors to augment its staff. During this time, the agents were monitored and coached by Columbia management as if they were Columbia employees.[24]

Q. Do you have any comments?

A. Yes. I am concerned that Columbia has limited insight into how its third-party call center staff are performing, and it appears to rely on a summary and check in with the third-party supervisors. Since it is Columbia who is ultimately accountable for its third-party

[22] Response to OCA-7-009.
[23] Response to OCA-7-009.
[24] Response to OCA-15-001.

agents, it is my opinion that Columbia should have a direct line of sight into the performance of agents. Thus, it should adopt a more detailed and comprehensive plan to manage and oversee its third-party contractors to ensure they conduct customer call center business in compliance with applicable Pennsylvania laws and regulations. At the moment, the Company's limited management of its third-party agents places too much deference in the hands of the contractor's manager.

UCARE Report

Q. What is the UCARE Report[25]

A. The UCARE Report is a report and evaluation prepared annually by the Commission's Bureau of Consumer Services (BCS) in accordance with 66 Pa.C.S. § 308.1(a). The report details a utility's compliance with the statutes and regulations concerning residential customer service and billing maters as reflected in the Public Utility Code, 52 Pa. Code and a Utility's Tariff.[26]

Q. What does the UCARE Report Measure?

A. The UCARE report measure Total Complaint Rate, Consumer Complaints, Payment Arrangement Requests, Termination of Service and Reconnection of Service, Compliance.[27]

Q. What are Columbia's UCARE stats

A. Table 1 – Columbia Gas of Pennsylvania UCARE Statistics.[28]

[25] https://www.puc.pa.gov/filing-resources/reports/consumer-activities-report-evaluation/
[26] 2022 Utility Consumer Activities Report and Evaluation pg. 1.
[27] 2022 Utility Consumer Activities Report and Evaluation pg. 39-51.
[28] https://www.puc.pa.gov/filing-resources/reports/consumer-activities-report-evaluation/ - UCARE Report 2022 and 2023 1st-4th quarter

BCS Category	2021[29]	2022	2023
Residential Customer Complaints[30]	122	168	204
Residential Payment Arrangement Requests (PARs)[31]	338	552	604
Inquiries	122	284	362
% Justified Residential Customer Complaints	6	8.1	4
% Justified[14] PARs	4	3.1	4
Response Time to Complaints and PARs (Days)	10.1/5.5	8.1/1.6	6.2/1.5
Verified Infractions[32] (Chapter 56)[33]	3	8	11

Q. What trends are apparent from this historical and most recent data?

A. While Columbia's statistics generally place them in the top rankings statistically among its peers, the data in the UCARE report shows Columbia's compliance with the law. There is generally an obvious decrease in performance outside of PARs.

[29] Used both the 2022 and 2021 UCARE reports and quarterly reports.
[30] The BCS defines a Justified Consumer Complaint as "A consumer complaint where, prior to BCS intervention, the company did not comply with Commission Orders, policies, regulations, reports, Secretarial Letters, tariffs or guidelines when the consumer brought the complaint to the company's attention. The justified consumer complaint rate equals the number of justified consumer complaints for each 1,000 residential customers."
[31] The BCS defines a Justified PAR as, "A Payment Arrangement Request where, prior to BCS intervention, the company did not comply with Commission regulations, reports, Secretarial Letters, tariffs or guidelines. The justified payment arrangement request rate equals the number of justified payment arrangement requests for each 1,000 residential customers."
[32] Response to OCA-7-01 attachment N.
[33] The BCS defines an Infraction as "A misapplication or infringement of a Commission regulation, particularly the standards and billing practices for residential utility service."

Q. Did Columbia perform a root cause analysis to find the cause of the customer complaints since 2021?

A. Columbia claims that they undertook a root cause analysis to find the cause of the complaints dating from 2021. Due to the overall yearly increase in complaints and infractions since 2021, I recommend that Columbia enact changes to their workflow to ensure that the Company reduces or eliminates future infractions. The Company should also report on these changes in their next rate case and highlight what was and what was not successful. If the Company has already enacted changes, the Company should address it in Rebuttal Testimony in this proceeding.

Personal Identification Information (PII)

Q. Has any vendor Columbia uses in its service of Pennsylvania utility customers experienced any cybersecurity attack since the filing of its last base rate case?

A. Yes. In response to OCA-1-028, Columbia stated: "NiSource was notified on December 1, 2022, regarding a cyber attack at Intrado. Intrado is a telecommunications vendor that supports Columbia customer contact center services. The attack did not impact any Columbia customer data and Columbia is not claiming any costs in this rate case related thereto."[34]

Q. Does Columbia ask customers to provide their social security numbers during the process of acquiring utility service or for any other purpose?

A. Yes. In response to OCA-1-030, Columbia stated: "Columbia requests a social security number from new customers who do not have an established credit history with

[34] Response to OCA 1-028.

Columbia in order to perform a credit check with the credit reporting agency. The credit reporting agency requires a social security number to perform the credit check. If a customer refuses to provide a social security number, the Company will request a photo ID via its website, mail or fax."[35]

Q. Does Columbia maintain any record of customers' social security numbers that have been historically used to establish utility service with the Company?

A. Yes. The customer's social security number is retained on the customer's account, however, only the last four digits are visible to most employees.[36]

Q. Do you have any comments?

A. If the sole reason for collecting SSNs from customers is to conduct a credit check, I do not see any reason for Columbia to store the number at all in their system after the need for the information is completed. There is simply no compelling reason to risk disclosure of this information in the event of a data breach. Columbia should cease its practice of retaining SSNs in its system.

Safety Incidents

Q. Has the Company entered into any settlements with the Commission's Bureau of Investigation and Enforcement (I&E) since its last base rate case at Docket No. R-2022-30312111?

A. Yes. In response to OCA-20-001, the Company indicated that it has entered into the following settlements with I&E:

[35] Response to OCA 1-030.
[36] Response to OCA 1-31.

- Rimersburg and Fayetteville Overpressure Events, Docket No. M-2021-3005572, Revised Joint Petition for Approval of Settled filed March 17, 2023;
- North Franklin Incident, Docket No. M-2022-3012079, Revised Joint Petition for Approval of Settlement filed February 27, 2023; and
- Maiden Street Line Damage, Docket No. C-2023-3040925, Joint Petition for Approval of Settlement filed November 30, 2023.

Q. Did Columbia indicate its status of compliance with the settlements?

Q. Yes. In response to OCA-20-001, Columbia stated that it has fulfilled all settlement conditions for M-2021-3005572 and M-2022-3012079 and is in the process of fulfilling the settlement provisions at C-2023-3040925.Did the Commission approve the Revised Settlement at M-2021-3005572?

A. Yes. For the Rimersburg and Fayetteville Overpressure Events, the Commission approved the Revised Settlement by Opinion and Order[37] entered March 17, 2023, at Docket No. M-2021-3005572.

Q. Can you provide a description of the case at M-2021-3005572?

A. Yes. The Commission approved the Revised Joint Petition for Settlement on March 17, 2023, following an informal investigation conducted by I&E regarding overpressurization events on Columbia's Fayetteville and Rimersburg distribution systems in 2018. The investigation indicated over 200 leaks were reported in early 2018, with the majority because of mechanical fitting failure for meter sets. Columbia then developed a plan to

[37] Available at https://www.puc.pa.gov/pcdocs/1797093.pdf.

replace approximately 45,000 feet, or 1/3, of compromised facilities. Columbia was ordered to: (1) pay a civil penalty in the amount of $535,000, not to be passed through as an additional charge to its customers; and (2) take numerous corrective actions including continued installation of monitor regulators.

Q. Did the Commission approve the Revised Settlement at M-2022-3012079?

A. Yes. For the North Franklin Incident, the Commission approved the Revised Settlement by Opinion and Order[38] entered August 3, 2023, at Docket No. M-2022-3012079.

Q. Can you provide a description of the case at M-2022-3012079?

A. For the North Franklin Incident, the Commission approved the Revised Joint Petition for Settlement on August 3, 2023, following a joint evaluation conducted by I&E and the State Fire Marshal to determine the cause of an explosion of 100 Park Lane, which resulted in the bodily injury of 4 people and extensive property damage. Overpressurization of the house piping and appliances caused the explosion, since the Park Lane residence was not equipped with a service regulator at the time of the incremental pressure uprating. The Park Lane residence was found to be incorrectly mapped by Columbia. Columbia was ordered to: (1) pay a civil penalty in the amount of $990,000, whereas Columbia will not seek recovery of any portion of the total civil penalty amount in any future ratemaking proceeding; and (2) take numerous corrective actions including the discontinuation of Columbia's use of incremental mainline uprating for low pressure to elevated pressure and Columbia's updating its mapping tools.

[38] Available at https://www.puc.pa.gov/pcdocs/1794731.pdf.

Q. Did the Commission approve the Settlement at C-2023-3040925?

A. Yes. For the Maiden Street Line Damage, the Commission approved the Settlement by Opinion and Order[39] entered February 14, 2024, at Docket No. C-2023-3040925.

Q. Can you provide a description of the case at C-2023-3040925?

A. Yes. The Commission approved the Joint Petition for Settlement on February 14, 2024, after I&E filed a Complaint in connection with a damaged, unmarked gas line owned and operated by Columbia, struck during excavation activity. Columbia was ordered to pay a $2,500 administrative penalty, not to be passed through as an additional charge to its customers.

Q. What is the total amount Columbia was directed to pay in penalties related to the above cases?

A. Columbia was directed to pay a total of $1,527,500 in administrative penalties related to the above incidents and settlements.

Q. Has Columbia made a ratemaking claim for the $1,527,500 penalties it was directed to pay at the above dockets?

A. Not based on my review thus far, but the OCA is still engaging in discovery with the Company on this topic and such discovery is still ongoing as of the due date of my direct testimony. The Company should address in its rebuttal testimony whether it has made or not made a ratemaking claim to recover the $1,527,500 in administrative penalties that it

[39] Available at https://www.puc.pa.gov/pcdocs/1816567.pdf.

was directed to pay at Docket Nos. M-2021-3005572, M-2022-3012079, and C-2023-3040925.

Q. Does Columbia include ratemaking claims related to the Rimersburg and Fayetteville Overpressure Events at Docket No. M-2021-3005572?

A. In response to OCA Set 20-002, Columbia stated it has incurred costs related to the Rimersburg and Fayetteville Overpressure Events that occurred in 2018, including expenses and capital costs. However, Columbia said that because the events occurred in 2018, it already included these costs in an earlier rate case and said that the OCA did not challenge recovery of such costs in the 2020, 2021, or 2022 rate cases. As a result, Columbia chose not to provide the amounts of the costs included for rate recovery in response to OCA discovery.

Q. Do you have any comments?

A. Yes. The OCA's attorneys will address in briefing any claims or assertions made by Columbia that the OCA cannot challenge any amounts that were removed by Columbia or added to Columbia's rate base. I am informed by counsel that the OCA disagrees with Columbia's position that because the OCA did not raise the issue in the 2020, 2021, or 2022 rate cases that the OCA is somehow precluded in this rate case from challenging the relevant costs included in existing rates or potentially for setting new rates. The 2018 Rimersburg and Fayetteville Overpressure Events were being investigated when the earlier rates cases were filed, and since then, the Commission concluded its investigation and approved the Revised Settlement on March 17, 2023, at Docket No. M-2021-3005572. Now that the Commission's investigation is concluded, it is appropriate to

examine ratemaking treatment related to Columbia's involvement in the overpressurization events. The OCA will continue to conduct discovery, and I reserve the right to identify the amount and category of the costs in my surrebuttal testimony. The Company should address in its rebuttal testimony whether the expenses and capital costs that were previously incurred by the Company related to the events was covered by insurance or shareholder funds or were previously recovered by the Company in rates or being recovered in existing rates and identify the category and amount of such costs. The Company should further address whether any related ongoing recovery (such as depreciation expense) or recurring recovery is being proposed in this rate case to set new rates.

Q. Do you have a tentative recommendation related to such costs?

A. Yes. Tentatively, I am recommending disallowing any ongoing or recurring costs in rate base and expenses from the revenue requirement and potentially seeking refunds for any amounts previously recovered in existing rates. These costs should have been covered by insurance or through shareholder funding. Ratepayers should not be required to fund costs related to property damage or incidents resulting directly from the Company's actions, inactions, or that of its contractors. If the liabilities related to the events were not covered by insurance or through shareholder funding, there is no basis for Columbia to merely pass these costs onto ratepayers. Placing responsibility of covering costs related to violations of safety with the utility properly incents the utility to behave in a manner that complies with its public service obligations for safety.

Q. Does Columbia include ratemaking claims related to the North Franklin Incident at Docket No. M-2022-3012079

A. In response to OCA Set 20-002, Columbia stated it has incurred expenses related to the deductible portion of its insurance policy and that the deductible expense is included in the Company's 5-year average of Injuries and Damages. Columbia stated that amounts owed for damages above the deductible expense were covered by insurance.

Q. Do you have any comments?

A. I recommend disallowance of the $25,000 expense. Ratepayers should not pay a deductible expense because of the Company's actions resulting in the North Franklin Incident.

Q. Does Columbia include ratemaking claims related to the Maiden Street Line Damage at Docket No. C-2023-3040925?

A. In response to OCA Set 20-002, Columbia stated that this incident involved damage to the Company's facilities during a main replacement project in May of 2020 and that subsequent to the event, Columbia filed a rate case in 2021 and its capital expenditures related to Columbia's repair of its facilities would have been included in that case. As a result, Columbia chose not to provide the amounts of the costs included for rate recovery in response to OCA discovery.

Q. Do you have any comments?

A. Yes. For the same reasons explained above for the Rimersburg and Fayetteville Overpressure Events, I am informed by counsel that the OCA disagrees with Columbia's position that because the OCA did not raise the issue in the 2020, 2021, or 2022 rate

cases that the OCA is somehow precluded in this rate case from challenging the relevant costs included in existing rates or potentially for setting new rates. The May 2020 event was being investigated when the earlier rates cases were filed, and since then, the Commission concluded its investigation and approved the Settlement on February 14, 2024, at Docket No. C-2023-3040925. Now that the Commission's investigation is concluded, it is appropriate to examine ratemaking treatment related to Columbia's involvement in the incident. The OCA will continue to conduct discovery, and I reserve the right to identify the amount and category of the costs in my surrebuttal testimony. The Company should address in its rebuttal testimony whether the expenses and capital costs that were previously incurred by the Company related to the incident was covered by insurance or shareholder funds or recovered by the Company in rates and identify the category and amount of such costs. The Company should further address whether any related ongoing recovery (such as depreciation expense) or recurring recovery is being proposed in this rate case.

Q. Do you have a tentative recommendation related to such costs?

A. Yes. I have the same tentative recommendations as for the Rimersburg and Fayetteville Overpressure Events.

Conclusion

Q. Does this conclude your testimony.

A. Yes, at this time.

Qualifications of

Nicholas A. DeMarco

Education:

2021 Master's of Political Science, Lehigh University

2016 B.A. Political Science with concentration in Constitutional Law, Bloomsburg University of Pennsylvania

2016 B.A. Eastern European Languages and Cultures, Russian, Bloomsburg University of Pennsylvania

Relevant Positions:

January 2023 Regulatory Analyst, Pennsylvania Office of Consumer Advocate

Role Description:

I am currently employed by the Pennsylvania Office of Attorney General, Office of Consumer Advocate (OCA) as a Regulatory Analyst. In this position, my responsibilities include reviewing utility company filings with the Pennsylvania Public Utility Commission (Commission) and analyzing the financial, economic, rate of return, and policy issues that are relevant to the filings. Additionally, I am tasked with preparing recommendations for the OCA's involvement in utility filings with the PA PUC, writing testimony and presenting oral testimony on behalf of the OCA. As part of my role, I also assist in the policy matters regarding low-income issues and PJM.

Submitted Testimony:

PAWC's proposed acquisition of the Brentwood Borough wastewater system, at
Docket No. A-2021-3024058

Pennsylvania Public Utility Commission, Office of Consumer Advocate, v. Community Utilities of Pennsylvania, Inc.

Docket Nos. R-2023-3042804 (water), R-2023-3042805 (wastewater), C-2023-3044737 (water), C-2023-3044738 (wastewater)

Pennsylvania Public Utility Commission, Office of Consumer Advocate, v. Veolia Water Pennsylvania, INC
Docket Nos. R-2024-3045192 (Water), R-2024-3045193 (Wastewater)

Pennsylvania Public Utility Commission, Office of Consumer Advocate, v. Duquesne Light Co
Docket No. R-2024-3046523

Relevant Training:

IPU Michigan State University, IPU Accounting and Ratemaking Course 2023

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Nicholas A. DeMarco, hereby state that the facts above set forth in my Direct Testimony, OCA Statement 7, 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 14, 2024

Signature: */s/ Nicholas A. DeMarco*
Nicholas A. DeMarco

Address: Office of Consumer Advocate
555 Walnut Street
Fifth Floor
Harrisburg, PA 17101

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Rebuttal Testimony of

Greg R. Meyer

OCA Statement 2R

On behalf of

Pennsylvania Office of Consumer Advocate

July 11, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11633

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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Rebuttal Testimony of Greg R. Meyer

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Rebuttal Testimony of Greg R. Meyer

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. ARE YOU THE SAME GREG R. MEYER WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE ("OCA")?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony in this proceeding is to address the issues proposed by the Bureau of Investigation and Enforcement ("I&E") witness Christian Yingling.

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. I support the adjustments proposed by Ms. Yingling as it pertains to the effects of vacant employees and the assignment of NiSource Corporate Service Company ("NCSC") compensation costs; specifically stock awards and profit-sharing costs.

III. RESPONSE TO MS. YINGLING

Q. HAVE YOU READ THE DIRECT TESTIMONY OF I&E WITNESS CHRISTIAN YINGLING?

A. Yes, I have. Many of the issues raised by Ms. Yingling have also been discussed by me in my Direct Testimony. The proposed adjustments may not match exactly, but both Ms. Yingling and I agree that the cost of service proposed by Columbia Gas is overstated because of the required increase in these specific expenses.

Q. DO YOU HAVE ANY SPECIFIC AREAS YOU WOULD LIKE TO SUPPORT FROM REVIEWING MS. YINGLING'S DIRECT TESTIMONY THAT YOU DID NOT ADDRESS IN YOUR DIRECT TESTIMONY?

A. Yes. I will be discussing Ms. Yingling's vacant employee adjustment and the NCSC allocated compensation costs.

Q. PLEASE DESCRIBE MS. YINGLING'S VACANT EMPLOYEE ADJUSTMENT.

A. Based on historical information, Ms. Yingling contends that Columbia Gas has not operated at full employment levels for several years. In her analysis, Ms. Yingling developed a three year employee vacancy rate.

Q. DID YOU PROPOSE AN ADJUSTMENT FOR LABOR EXPENSE IN YOUR DIRECT TESTIMONY?

A. Yes, I did. However, I did not address vacant employees. My labor adjustment simply restated the level of payroll expenses for the Fully Projected Future Test Year ("FPFTY") and did not address the level of employees during the FPFTY period.

Q. WHAT IS YOUR POSITION REGARDING VACANT EMPLOYEES?

A. If the Pennsylvania Public Utility Commission ("Commission") accepts Ms. Yingling's employee vacancy adjustment, I support the additional disallowances of incentive compensation, and other employee benefits expense. These areas of labor expenses should also be disallowed if a vacant employee adjustment is adopted by the Commission. It should be noted that acceptance of these labor adjustments should not be interpreted to replace the adjustments I have proposed in my Direct Testimony. Ms. Yingling's vacant employee adjustment is separate and distinct from any adjustment I have proposed in my Direct Testimony.

Q. PLEASE PROVIDE THE RATIONALE FOR YOUR SUPPORT OF THE ADJUSTMENT PROPOSED BY MS. YINGLING REGARDING THE ASSIGNMENT OF NCSC ALLOCATED COMPENSATION COSTS.

A. Ms. Yingling's proposed disallowance of NCSC compensation costs relate to the payment of stock awards and profit-sharing costs. Consistent with my arguments regarding incentive compensation, I believe these costs should be assigned to the shareholders of Columbia Gas. The achievement or granting of these costs are more beneficial to the shareholders than to the customers of Columbia Gas. I, therefore, support the adjustment proposed by Ms. Yingling to disallow these costs.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Greg Meyer, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement 2R, 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 11, 2024

Signature: Greg R Meyer

Greg Meyer

Address: Brubaker Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Rebuttal Testimony of

Christopher C. Walters

OCA Statement 3R

On behalf of

Pennsylvania Office of Consumer Advocate

July 11, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11633

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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Rebuttal Testimony of Christopher C. Walters

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Rebuttal Testimony of Christopher C. Walters

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE ("OCA")?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony in this proceeding is to address the recommendations relating to the overall rate of return ("ROR") offered in the Direct Testimony of Bureau of Investigation & Enforcement ("I&E") witness D.C. Patel.

Specifically, I will address Mr. Patel's recommended return on equity ("ROE") of 9.93% and capital structure including a common equity ratio of 54.4%.

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. My rebuttal testimony will discuss areas of disagreement with Mr. Patel and some of the errors that are present in Mr. Patel's analysis which have ultimately led him to his recommended ROE of 9.93% and common equity ratio of 54.4%. I will demonstrate that Mr. Patel's recommendations are unsupported and, at times, are even contradicted by his own testimony. I conclude that Mr. Patel's recommended ROE and capital structure are excessive and reiterate my recommendations including the Company be awarded an ROE of 9.45% and an equity ratio of 50.0%.

III. RESPONSE TO MR. PATEL

Q. PLEASE SUMMARIZE MR. PATEL'S RECOMMENDATIONS AS THEY RELATE TO THE COMPANY'S OVERALL ROR.

A. Mr. Patel recommends the Company's ROE be set a 9.93% at a common equity ratio of 54.40%.[1] Mr. Patel's ROE recommendation is based on the application of a single constant growth DCF model. He performs a CAPM analysis but does not consider its

[1] I&E Statement No. 2 at page 6.

results in his recommendation. Rather, he uses the CAPM as a comparison to the DCF results.[2] His recommended capital structure including a common equity ratio of 54.40% is the same as the Company's request.

Q. DOES THERE APPEAR TO BE ANY AGREEMENT BETWEEN YOU AND MR. PATEL?

A. Yes. Mr. Patel and I have several overlapping concerns with Mr. Moul's analysis and recommendation. For example, we both take issue with the several upward adjustments recommended by Mr. Moul including the leverage adjustments, the size adjustment, and the premium for management performance. We both take issue with Mr. Moul's application of, and inputs to, his various models. Mr. Patel and I both agree that a capital structure with 50% common equity and 50% debt is reasonable and fairly balances the interests of shareholders and ratepayers. We also agree that a capital structure with too much equity corresponds with lower financial risk.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH MR. PATEL'S ANALYSIS AND RECOMMENDATIONS.

A. My concerns with Mr. Patel's analysis are as follows:

- Similar to Mr. Moul, Mr. Patel's ROE recommendation of 9.93% would be the highest allowed ROE for a natural gas utility in the lower-48 in 2024.
- Mr. Patel's constant growth DCF model is based on excessive growth rates, necessitating the consideration of a multi-stage DCF model.

[2] *Id.* at 18.

- Mr. Patel's recommended common equity ratio of 54.40% is excessive and is contradicted by his own testimony.

- Mr. Patel's ROE recommendation of 9.93% is inconsistent with the reduced financial risk associated with an equity-rich capital structure.

III.A. Mr. Patel's ROE Recommendation Exceeds Relevant Benchmarks

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS YOU WOULD LIKE TO DISCUSS AS IT RELATES TO MR. PATEL'S RECOMMENDED ROE OF 9.93%?

A. Yes. Relative to the authorized ROEs for other natural gas utilities in 2024, Mr. Patel's recommended ROE of 9.93% would be the second highest in the United States, and the highest in the lower-48. While the average authorized ROE in 2024 is 9.93%, there is only one decision that is higher than 9.85% and that is the 11.88% ROE that was authorized to ENSTAR Natural Gas Company in Alaska. The remaining ROE awards in 2024 range from 9.30% to 9.85%.[3] Given the presence of such a significant outlier (11.88%), the median is more representative of the central tendency as it mitigates the impact outliers have. The median allowed ROE in 2024 is 9.70%, or 23 basis points lower than Mr. Patel's recommendation of 9.93%.

[3] S&P Capital IQ.

III.B. Mr. Patel's DCF Model is Based on Excessive Growth Rates,

Q. PLEASE SUMMARIZE MR. PATEL'S DCF MODEL.

A. Mr. Patel performs a constant growth DCF analysis based on spot stock prices as of February 23, 2024 and April 8, 2024, as well as 52-week average prices as of those same two dates.[4] Mr. Patel assumes an average growth rate of 5.95% for his proxy group.[5] The indicated cost of equity for the spot stock price analysis is 10.04%, while the result for his 52-week stock price analysis is 9.81%. The midpoint of these two results is 9.93% and serve as the basis for his recommendation.[6]

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH MR. PATEL'S DCF ANALYSIS.

A. My primary concern with Mr. Patel's DCF analysis is the assumed growth rate of 5.95%. As I discussed in my Direct Testimony, the consensus of research on the subject finds a utility's growth rate cannot exceed the growth rate of the economy in which it provides services in perpetuity, which is the time period assumed by the DCF model.

Q. WHY IS THE GDP GROWTH PROJECTION A REASONABLE PROXY FOR THE MAXIMUM SUSTAINABLE LONG-TERM GROWTH RATE?

A. Utilities cannot indefinitely sustain a growth rate that exceeds the growth rate of the economy in which they sell services. A utilities' earnings and dividend growth are

[4] I&E Exhibit No. 2, Schedule 7.
[5] *Id.*
[6] *Id.*

created by increased utility investment in its rate base. Examples of what can drive such investment are: service area economic growth, system reliability upgrades, or state and federal green energy initiatives. As such, nominal GDP growth is a reasonable upper limit for utility sales growth, rate base growth, and earnings growth in the long-run.

Q. WHAT IS THE PROJECTED LONG-TERM GROWTH RATE FOR THE U.S. ECONOMY?

A. At the time of my analysis in my Direct Testimony, the consensus for long-term GDP growth in the United States was 4.14%, a difference of 181 basis points relative to Mr. Patel's assumed average growth rate of 5.95% for his proxy group.

Q. IS THE APPLICATION OF A MULTI-STAGE DCF MODEL USED IN PRACTICE?

A. Yes. As I explained in my Direct Testimony, the multi-stage DCF model is widely used in practice. For example, the CFA Institute curriculum text states as follows:

> Multistage models are a staple valuation discipline of investment management firms using DCF valuation models.
> A survey of CFA Institute members with job responsibility for equity analysis indicates that, among respondents using a dividend discount model, two-stage and multistage models are used more often than the single-stage model (Stowe, Pinto, and Robinson 2018). Among analysts using a dividend discount model, 55% use a two-stage model, 11% use an H-model (a type of two-stage model), and 50% use a model with more than two stages (Stowe, Pinto, and Robinson 2018).[7]

[7] Chartered Financial Analyst Institute, 2023 CFA Program Level 2 Refresher Reading, Equity Valuation: Discounted Dividend Valuation, at 30. [footnote omitted].

As Stowe *et al*. have revealed, the majority of equity analysts rely on multi-stage models more frequently than single-stage or constant growth models.

Q. WHAT WOULD THE RESULTS OF A MULTI-STAGE DCF ANALYSIS BE BASED ON MR. PATEL'S INPUTS?

A. Given Mr. Patel's proxy group growth rate (5.95%) is very close to my proxy group's growth rate (6.02%), and our constant growth DCF results are relatively close, the results of my multi-stage DCF analysis (8.20% and 8.12%) would be a close approximation. Assuming a multi-stage DCF result of 8.20%, the midpoint of the collective DCF analyses would be 9.07% [(9.93% + 8.20%) / 2]. This result is consistent with the low-end of my recommended range of 9.1%.

III.C. Mr. Patel's Recommended Common Equity Ratio of 54.40% is Excessive

Q. PLEASE SUMMARIZE THE BASIS FOR MR. PATEL'S RECOMMENDED COMMON EQUITY RATIO OF 54.40%.

A. Mr. Patel's recommendation is to adopt the Company's proposed common equity ratio of 54.40%. He seems to support his recommendation by observing that an equity ratio of 54.40% falls within the range of his proxy group's common equity ratios of 34.74% to 59.95%.[8]

[8] I&E Statement No. 2 at page 12.

Q. DO YOU HAVE ANY CONCERNS WITH MR. PATEL'S RECOMMENDED EQUITY RATIO?

A. Yes. Given Mr. Patel simply adopts the Company's proposed common equity ratio, the concerns and arguments against such a high equity ratio that are presented in my Direct Testimony apply here as well. However, I have additional concerns with Mr. Patel's recommendation to adopt the Company's proposed equity ratio of 54.40%.

In his Direct Testimony, Mr. Patel acknowledges that the optimal capital structure for the Company would consist of 50% debt and 50% equity, which is identical to my recommended capital structure. Specifically, Mr. Patel states as follows:

> I believe a capital structure of 50% long-term debt and 50% common equity is optimal when trying to balance the financial integrity of a utility as well as trying to control costs to ratepayers in this proceeding.[9]

Notwithstanding this acknowledgment, Mr. Patel recommends the Company be authorized an equity ratio of 54.40%.

Mr. Patel even observes that his recommended equity ratio is higher than the typical equity ratio of his proxy group companies and is at the high-end of the range of observable common equity ratios for his proxy group. Mr. Patel explains as follows:

> It is worth noting that the Company's equity ratio is well above the five-year average of my proxy group's equity ratios. In fact, six of seven companies including NiSource, Inc. (the parent company) in my proxy group have a capital structure wherein the equity ratio is less than 50% for the most recent five-year average.[10]

Notably, the basis for his support of such a high equity ratio – the fact that 54.40% is within the proxy group's range of 34.74% to 59.95% – also applies to my

[9] *Id.*
[10] *Id.* at page 13.

recommended equity ratio of 50.0%, albeit my recommendation is closer to the central tendency of the proxy group than is his.

Not only does Mr. Patel observe that his recommended equity ratio is significantly higher than the typical equity ratio of his proxy group, he does not make an adjustment to his recommended ROE to account for the relatively lower financial risk that is commensurate with such an equity-rich equity ratio. As I explained in detail above, Mr. Patel's recommended ROE of 9.93% is higher than any allowed ROE for a natural gas utility in the lower-48 states in 2024.

Collectively, Mr. Patel recommends an excessive ROE be authorized even in a scenario where he recommends an equity-rich capital structure. I urge the Commission to give little weight to his recommendations.

Q. DO YOU HAVE ANY CONCLUDING REMARKS?

A. Yes. It is notable that all rate of return witnesses in this proceeding recognize the fundamental fact that a higher equity ratio is consistent with lower financial risk. Allowing an excessive ROE at a relatively less risky capital structure would violate this basic financial principle. I continue to recommend the Commission authorize the Company an ROE of 9.45% with a capital structure that consists of 50% debt and 50% equity. In the event the Commission opts to adopt an equity ratio closer to the recommendations of Mr. Patel and Mr. Moul, an ROE in the lower half of my recommended range (i.e., 9.10% to 9.45%, which has a midpoint of 9.275%) would be necessary to recognize the significantly less relative financial risk.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

501903

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Christopher C. Walters, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement 3R, 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 11, 2024

Signature: _____

Christopher C. Walters

Address: Brubaker Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

OCA Statement No. 5R

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	Docket No. R-2024-3046579
COLUMBIA GAS OF PENNSYLVANIA, INC.	)	

REBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

July 11, 2024

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement No. 5 on June 14, 2024, in this Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company") proceeding.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

The purpose of my rebuttal testimony is to respond to certain aspects of the direct testimony of Bureau of Investigation and Enforcement ("I&E") witness Esyan A. Sakaya, the direct testimony of Office of Small Business Advocate ("OSBA") witness Mark D. Ewen, and the direct testimony of Penn State University ("PSU") witness James L. Crist.

II. I&E WITNESS: ESYAN A. SAKAYA

Q. DOES MR. SAKAYA AGREE WITH THE COMPANY'S PROPOSED ALLOCATION OF ITS REQUESTED REVENUE INCREASE TO THE VARIOUS CUSTOMER CLASSES?

A. Mr. Sakaya does not directly address the Company's proposed allocation of the revenue increase to the various customer classes in his direct testimony, and he does not present an alternative allocation. Therefore, I assume that Mr. Sakaya accepts the revenue allocation proposed by Columbia.

Q. SHOULD COLUMBIA'S PROPOSED ALLOCATION OF THE REVENUE INCREASE BE APPROVED?

A. No. As discussed in greater detail in my direct testimony, the revenue allocation presented by Columbia does not provide adequate movement toward cost-based rates for each customer class and does not adequately account for the significant subsidies provided to certain customers that receive service at less than cost of service rates. Therefore, Columbia's proposed revenue allocation should not be approved by the Commission, and the revenue allocation presented in Table 3, page 12, of my direct testimony should be adopted.

Q. WHAT IS MR. SAKAYA'S PROPOSAL CONCERNING THE RESIDENTIAL CUSTOMER CHARGE IN THIS PROCEEDING?

A. Columbia's current Residential customer charge is $16.75. In this proceeding, Columbia is proposing to increase that charge to $26.00, or by 61.3%. Mr. Sakaya recommends an initial Residential customer charge of $20.46.[1] Mr. Sakaya's proposed Residential customer charge of $20.46 reflects a 22.1% increase in the current charge, which Mr. Sakaya claims is the overall average percentage revenue increase request by Columbia in this proceeding.[2] Mr. Sakaya recommends that if the Commission authorizes an increase in this proceeding which is less than Columbia's requested increase, his proposed Residential customer charge be scaled back proportionately based on the revenue increase that is ultimately approved by the Commission.[3]

[1] I&E Statement No. 3, p. 22, line 3-6.
[2] I&E Statement No. 3, p. 22, line 10-12.
[3] I&E Statement No. 3, p. 23, line 4-9.

Q. DO YOU AGREE WITH MR. SAKAYA'S RESIDENTIAL CUSTOMER CHARGE RECOMMENDATION?

A. No, for several reasons. Based on the comparison presented in Table 4, page 15, of my direct testimony, Mr. Sakaya's Residential customer charge proposal would result in the highest natural gas distribution company ("NGDC") Residential customer charge in the Commonwealth. Columbia's current residential customer charge is already, at current rates, the highest in the Commonwealth. Second, as discussed in the rebuttal testimony of OCA witness Colton, Mr. Sakaya's proposal would have a disproportionate impact on low-income customers. Finally, as explained in my direct testimony, a high fixed monthly customer charge such as the charge proposed by Mr. Sakaya is inconsistent with the Commission's general goal of fostering energy conservation.[4] Therefore, Columbia's current Residential customer charge of $16.75 should be maintained.

III. OSBA WITNESS: MARK D. EWEN

Q. PLEASE SUMMARIZE YOUR ASSESSMENT OF COLUMBIA'S PROPOSED REVENUE ALLOCATION THAT WAS PRESENTED IN YOUR DIRECT TESTIMONY.

A. In my direct testimony I found that Columbia's proposed revenue allocation did not reflect adequate movement toward cost-based rates for each customer class and did not adequately account for the significant subsidies provided to LDS/LGSS and Flex rate customers that receive service at less than cost of service rates.[5] Therefore, I presented an alternative revenue allocation in Table 3, page 12, of my direct testimony.

[4] OCA Statement No. 5, p. 17, line 7-11.
[5] OCA Statement No. 5, p. 11, line 2-6.

Q. DOES MR. EWEN AGREE WITH COLUMBIA'S PROPOSED REVENUE ALLOCATION AND IF NOT, DOES HE PRESENT AN ALTERNATIVE ALLOCATION?

A. Mr. Ewen does not agree with Columbia's proposed revenue allocation, and he presents an alternative allocation utilizing what he refers to as the revenue-cost ratio metric in Table 1Ec-4, page 19, of his direct testimony.

Q. IS MR. EWEN'S PROPOSED ALTERNATIVE REVENUE ALLOCATION REASONABLE AND HOW DOES IT COMPARE TO THE REVENUE ALLOCATION PRESENTED IN TABLE 3 OF YOUR DIRECT TESTIMONY?

A. Mr. Ewen's proposed alternative revenue allocation is reasonable and results in an allocation of the proposed revenue increase which, as shown in Table 1-R, is nearly identical to the revenue allocation I have proposed.

Table 1-R
Comparison of OCA and OSBA Revenue Allocations

	(Millions $)		
Class	**OCA Increase**	**OSBA Increase**	**Difference**
RSS/RDS	$75.28	$75.20	($0.08)
SGSS/DS-1	12.99	13.20	0.21
SGSS/DS-2	15.73	15.62	(0.09)
SDS/LGSS	9.05	8.94	(0.11)
LDS/LGSS	11.09	11.18	0.09
MLDS	0.00	0.00	0.00
FLEX	0.00	0.00	0.00
Total:	**$124.14**	**$124.14**	$0.00

IV. PSU WITNESS: JAMES L. CRIST

Q. HOW MANY COST OF SERVICE STUDIES DID COLUMBIA PRESENT IN THIS PROCEEDING?

A. Columbia presented three cost of service studies in this proceeding, as further discussed in the direct testimony of Kevin L. Johnson in Columbia Statement No. 6, pages 4-5. Columbia presented a cost of service study utilizing the Peak & Average method and a study utilizing the Customer-Demand method. The third study presented by Columbia reflected an average of the Peak & Average and Customer-Demand studies.

Q. HOW DOES COLUMBIA'S CUSTOMER-DEMAND COST OF SERVICE STUDY ALLOCATE DISTRIBUTION MAINS INVESTMENT AND RELATED COSTS TO THE VARIOUS CUSTOMER CLASSES AND HOW DOES THE PEAK & AVERAGE METHOD ALLOCATE THESE COSTS?

A. Columbia's Customer-Demand method allocated distribution mains related costs 45% based on the number of customers and 55% based on peak day demands. The Peak & Average method allocates distribution mains related costs 50% based on annual throughput and 50% based on peak demands.

Q. WHAT COST OF SERVICE STUDY METHOD DID COLUMBIA RELY UPON TO DETERMINE THE DISTRIBUTION OF THE REVENUE INCREASE IT IS REQUESTING IN THIS PROCEEDING?

A. Columbia claims to have relied upon the Peak & Average method to determine the distribution of the revenue increase it is requesting in this proceeding. Columbia used the Peak & Average method because it was approved by the Commission in Columbia's 2020 base rate proceeding (Docket No. R-2020-3018835).

Q. DOES MR. CRIST BELIEVE THAT THE PEAK & AVERAGE METHOD SHOULD BE RELIED UPON IN THIS PROCEEDING BECAUSE IT WAS APPROVED IN COLUMBIA'S 2020 BASE RATE PROCEEDING?

A. No. Mr. Crist contends that in Columbia's 2020 proceeding, the Administrative Law Judge ("ALJ") found in her Recommended Decision that Columbia's Customer-Demand cost of service study would be the preferred method, but the Company's Customer-Demand study contained serious flaws. Therefore, the ALJ adopted the Peak & Average method rather than the Customer-Demand method. In its final Order in the 2020 proceeding, the Commission was not persuaded to reverse the ALJ's Recommended Decision that adopted the Peak & Average method.[6] Mr. Crist claims that the serious flaws in the Company's Customer-Demand study identified by the ALJ in the 2020 proceeding have now been eliminated.[7] Mr. Crist explains that the allocation of distribution mains costs has a significant impact on the results of a cost of service study.[8] Mr. Crist claims that annual throughput, which is used to allocate 50 percent of mains costs under the Peak & Average method, is not used in the design of gas main piping and that the cost causer of gas distribution mains is peak demand.[9] Therefore, Mr. Crist believes that the Customer-Demand study method should be utilized in this proceeding.[10]

[6] PSU Statement No. 1, page 14, lines 13-16.
[7] PSU Statement No. 1, page 14, line 15 - page 15, line 2.
[8] PSU Statement No. 1, page 15, lines 7-11.
[9] PSU Statement No. 1, page 18, lines 11-15.
[10] PSU Statement No. 1, page 18, lines 18-22.

Q. WHAT IS YOUR RESPONSE TO MR. CRIST?

A. First, as just explained, the Company's Customer-Demand cost study allocates distribution mains costs 45 percent based on peak demand and 55 percent based on the number of customers. In the Peak & Average study, distribution mains costs are allocated 50 percent based on peak demand and 50 percent based on annual throughput. Therefore, it is not clear why, if mains are sized based on peak demands as Mr. Crist claims, the Customer-Demand method should be utilized in this case when it results in less of an allocation of mains costs based on peak demand than the Peak & Average method.

Second, in its Order in Columbia's 2020 proceeding, the Commission specifically approved the use of the Peak & Average allocation methodology. This finding was not due to the errors in the Customer-Demand cost study presented by Columbia in its 2020 case (that have now been eliminated). Rather, the Commission's findings in Columbia's 2020 proceeding concerning the use of the Peak & Average method are presented on pages 6 through 7 of my direct testimony. More specifically, in the 2020 proceeding the Commission found:

> …we remain of the opinion that although mains serve customers, it is the throughput that determines the mains investment, not the number of customers served. (Order at 217).

Thus, the errors in the Customer-Demand cost study presented by Columbia in its 2020 proceeding had no influence on the Commission's finding that the Peak & Average method is superior as throughput, and not the number of customers served, determines the Company's distribution mains investment.

Q. DO YOU AGREE WITH MR. CRIST'S CLAIM THAT ANNUAL THROUGHPUT IS NOT A COST CAUSER OF DISTRIBUTION MAINS?

A. No. The Company's distribution mains extension policy provides that with the general exception of mains extensions up to 150-feet for new Residential customers, the net present value ("NPV") of base rate revenues is considered in CPA's mains extension decision-making process. Columbia's base rate revenues are primarily collected on a volumetric basis. This policy is described in Section 8.2 of the Company's tariff. The exception for Residential mains extensions of up to 150 feet was approved in Docket No. R-2015-2468056. Since its adoption, the exception has been applied to approximately 24,000 Residential customers, which reflects less than 6% of current Residential customers. Since Columbia's distribution mains extension provisions have largely been based on annual revenues which are primarily a function of annual throughput, annual throughput is clearly significant cost causation factor for Columbia's distribution mains investment.

Q. MR. CRIST CLAIMS THAT THE PEAK & AVERAGE STUDY ALLOCATES AN AVERAGE OF 13 MILES OF DISTRIBUTION MAINS TO EACH OF THE 80 LDS/LGSS CUSTOMERS AND THAT THIS IS UNREASONABLE?[11] WHAT IS YOUR RESPONSE?

A. As indicated in Columbia's response to data request PSU 3-001, which is included as page 5 in Mr. Crist's Exhibit JLC-2, the Company's plant accounting system does not differentiate plant information, including mains data by rate class. Therefore, the miles of distribution mains required to serve LDS/LGSS customers is unknown. In addition, Mr. Crist's claim is based on Columbia's average cost of distribution mains sized 3-

[11] PSU Statement No. 1, page 19, lines 16-19.

inches and greater in diameter. The response to PSU 3-001 indicates that this average cost is $65.70 per foot. Based on the Company's response to Standard Data Request GASCOS-004, the average cost of a 6-inch main is $73.92, and the average cost of an 8-inch main is $115.45. Therefore, if LDS-LGSS customers are served by a 6-inch or 8-inch main, Mr. Crist has overstated the miles of distribution mains allocated to LDS/LGSS customers.

Q. MR. CRIST CLAIMS THAT FOR THE 10 LARGEST CUSTOMERS IN TERMS OF ANNUAL THROUGHPUT, COLUMBIA WAS ONLY REQUIRED TO EXTEND ITS DISTRIBUTION MAINS BY ONLY .03 TO 1.4 MILES, AND WHEN COMPARED TO THE 13 MILES OF DISTRIBUTION MAINS ALLOCATED TO LDS/LGSS CUSTOMERS UNDER THE PEAK & AVERAGE METHOD, CLEARLY SHOWS THAT THE PEAK & AVERAGE METHOD IS UNREASONABLE.[12] WHAT IS YOUR RESPONSE?

A. First, as just indicated, the miles of distribution mains serving LDS/LGSS customers is unknown, and Mr. Crist's estimate that each LDS/LGSS customer has been assigned 13 miles of distribution mains is likely overstated. However, more importantly, the miles of distribution mains that Columbia was required to extend its facilities to serve an LDS/LGSS customer is not an appropriate basis to determine an allocation of distribution mains to LDS/LGSS customers. The gas supplies delivered to LDS/LGSS customers by Columbia are initially delivered to Columbia by interstate pipelines. Therefore, the miles of distribution mains required to serve an LDS/LGSS customer must take into account the mains that are upstream of the point from which Columbia

[12] PSU Statement No. 1, page 20, lines 17-24.

extended its distribution mains to serve the LDS/LGSS customer. That is, it must also consider the distribution mains required to deliver the LDS/LGSS customer's gas supplies from the interstate pipeline serving the LDS/LGSS customer to the point at which Columbia extended its distribution mains to serve the LDS/LGSS customer. Mr. Crist fails to consider the upstream distribution mains required to serve an LDS/LGSS customer.

Attached to my testimony as Exhibit JDM-1 is a map of the state of Pennsylvania which identifies Columbia's service territories and the interstate pipelines delivering gas to Columbia. While there is no distance scale on the map, to provide some perspective, I would note that Pennsylvania is 180 miles north to south and 310 miles east to west. This map clearly indicates that for most customers, more than 1.4 miles of distribution mains is required to deliver gas from an interstate pipeline to the customer's premises or facility.

Q. MR. CRIST CLAIMS THAT THE CUSTOMER-DEMAND COST OF SERVICE STUDY ALLOCATED AN AVERAGE OF 3.5 MILES OF DISTRIBUTION MAINS TO EACH LDS/LGSS CUSTOMER, AND THAT WHILE MORE THAN THE MAXIMUM 1.4 MILE ASSIGNMENT, IS STILL EXCESSIVE.[13] WHAT IS YOUR RESPONSE?

A. The 1.4 miles reflects the distance Columbia was required to extend its distribution mains to serve an LDS/LGSS customer. As just explained, the distance Columbia extended its distribution mains to serve a customer is not the appropriate basis to allocate distribution mains costs because it ignores the costs associated with the

[13] PSU Statement No.1, page 20, lines 17-24.

distribution mains required to deliver gas supplies from an interstate pipeline to the point from which Columbia extended its facilities to serve the customer.

Q. WHAT HAS MR. CRIST PROPOSED TO REVISE WHAT HE CONTENDS IS AN EXCESSIVE ASSIGNMENT OF DISTRIBUTION MAINS COSTS UNDER THE COMPANY'S CUSTOMER-DEMAND STUDY?

A. Mr. Crist has proposed to assign distribution mains costs to the LDS/LGSS customer class based on the assumption that 1.4 miles of distribution mains were required to connect each of the 80 LDS/LGSS customers to Columbia's distribution system.[14] Under Mr. Crist's proposed allocation, LDS/LGSS customers would be assigned $39,647,336 in distribution mains investment.[15] Mr. Crist proposal claims that his revised allocation of distribution mains investment would result in a cost of service of $15,800,000 for the LDS/LGSS class, compared to present revenues of $27,382,567.[16]

Q. WHAT IS YOUR RESPONSE TO MR. CRIST'S REVISED ALLOCATION OF DISTRIBUTION MAINS INVESTMENT TO THE LDS/LGSS CLASS?

A. Again, it is unreasonable to assign distribution mains costs to the LDS/LGSS class based on the distance Columbia was required to extend its distribution mains from the nearest upstream customer to the LDS/LGSS customer. LDS/LGSS customers should also be assigned a portion of the costs of the distribution mains required to deliver gas from the interstate pipeline serving that portion of Columbia's distribution system serving the LDS/LGSS customer to the upstream location. When Columbia designed its distribution system, it is likely that the gas usage by LDS/LGSS customers were

[14] PSU Statement No. 1, page 21, lines 3-5.
[15] *Id.*
[16] PSU Statement No. 1, page 21, lines 7-10.

considered by Columbia in its decision to build the upstream distribution mains necessary to deliver gas to the LDS/LGSS customers. Because Mr. Crist fails to assign any of these upstream distribution mains costs to the LDS/LGSS class, his proposed allocation should be rejected.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	)	
v.	)	Docket No. R-2024-3046579
COLUMBIA GAS OF PENNSYLVANIA, INC.	)	

EXHIBIT ACCOMPANYING THE

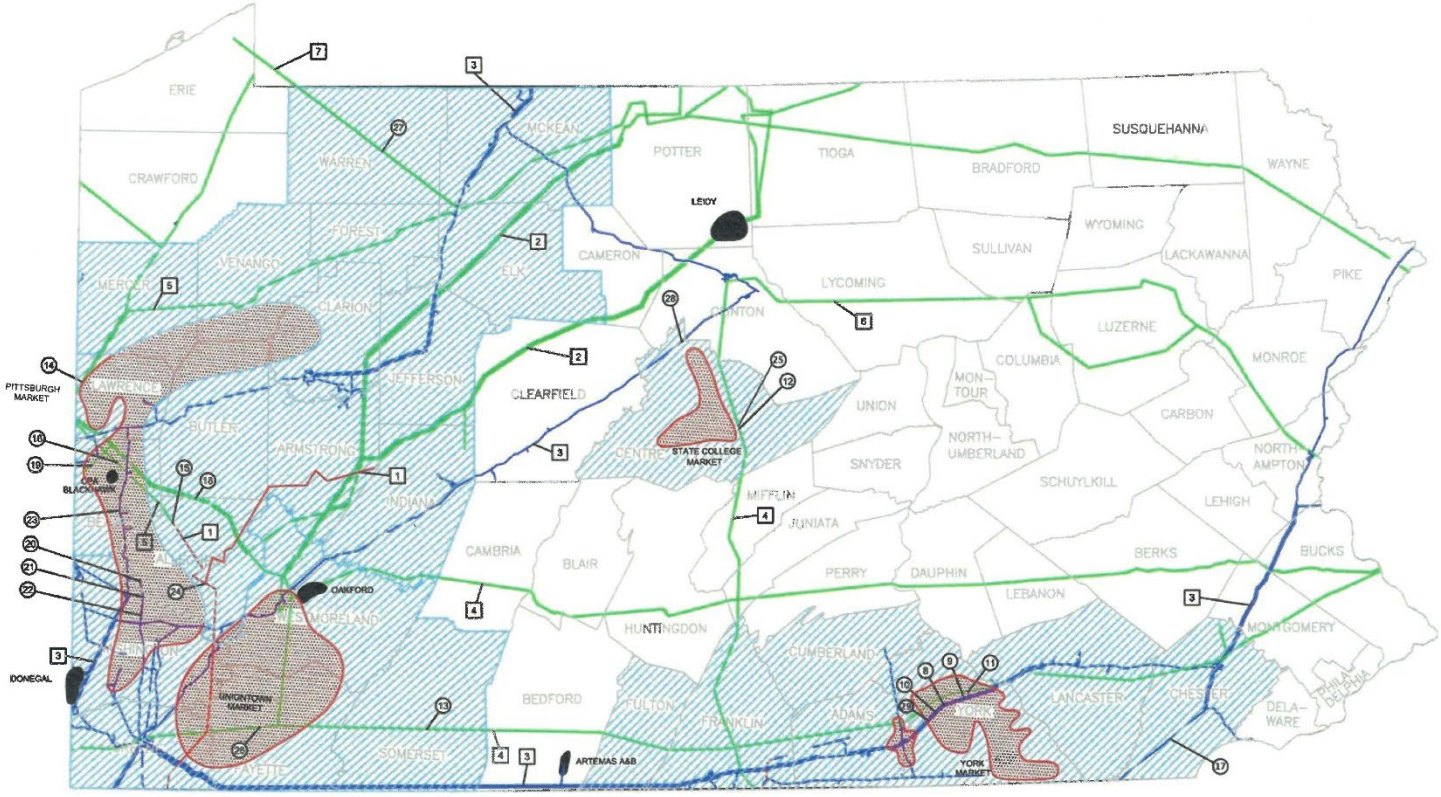
REBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

COLUMBIA GAS OF PENNSYLVANIA, INC.
PIPELINE INTERCONNECTS, SUPPLY POINTS AND STORAGE LOCATIONS



TRANSMISSION PIPELINES

1. Equitrans Gas Transmission (EQ)
2. Eastern Gas Transmission & Storage (EGT&S)
3. Columbia Gas Transmission (TCO)
4. Texas Eastern Transmission (TET)
5. Tennessee Gas Pipeline (TGP)
6. Transcontinental Gas Pipeline (TRANSCO)
7. National Fuel Gas Supply (NFG)

MAJOR INTERCONNECTS SERVING PA

8. (TCO) North York
9. (TCO) Emigsville
10. (TCO) Admire
11. (TET) Emigsville
12. (TET) Pleasant Gap
13. (TET) Rockwood
14. (TGP) New Castle
15. (TGP) Bradford Woods
16. (TGP) Koppel
17. Cleveland Cliffs
18. (EGT&S) Warrendale
19. (EGT&S) Darlington
20. (TCO) McCandless
21. (TCO) Cecil Greentree
22. (TCO) Tannehill
23. (TCO) Ambridge
24. (EQ) Spartan
25. (EGT&S) Pleasant Gap
26. (TET) Uniontown
27. (NFG) Warren
28. (TCO) Snowshoe
29. Pixelle Specialties (Glatfelter)

LEGEND

- CPA Service Areas
- CPA Major Markets
- Storage Fields

Exhibit 10.1

Exhibit JDM-1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v Columbia Gas of Pennsylvania, Inc.	: : : : :	Docket Nos. R-2024-3046519

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Rebuttal Testimony, OCA Statement 5R, are true and correct (or 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 11, 2024

Signature: Jerome D. Mierzwa
Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc. 10480
Little Patuxent Parkway, Suite 300
Columbia, MD 21044-3575

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket Nos.: R-2024-3046519
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

SURREBUTTAL TESTIMONY

OF

DAVID E. DISMUKES, PH.D.

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 1SR

Date Served: July 25, 2024

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. ARE YOU THE SAME DAVID E. DISMUKES WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING ON JUNE 14, 2024?

A. Yes, I am.

Q. WAS THIS TESTIMONY PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. PLEASE SUMMARIZE THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY.

A. The purpose of my Surrebuttal Testimony is to respond to elements of the Rebuttal Testimonies of Mr. Mark Kempic and Mr. Kevin Johnson on behalf of Columbia Gas of Pennsylvania. Specifically, I respond to the Company's statements related to regulatory lag and ratepayer protections regarding the Revenue Normalization Adjustment ("RNA"). I also respond to some of the assertions made by the Company regarding the Weather Normalization Adjustment ("WNA") mechanism.

Q. HAVE YOUR RECOMMENDATIONS CHANGED AS A RESULT OF THE COMPANY'S REBUTTAL TESTIMONY?

A. No. I recommend the Commission reject the Company's RNA proposal. The Company has provided no record evidence showing that this mechanism is needed. Further, the Company has still not proven that there is a financial need for the RNA. Most

revenue decoupling proposals are tied to either new or enhanced energy efficiency efforts. The Company's RNA should be rejected, for among other reasons, since it does not include any meaningful expanded energy efficiency commitments if approved. The failure to directly tie expanded energy efficiency savings opportunities to revenue decoupling adoption shifts the entire performance risk of the RNA away from the Company and onto ratepayers. Lastly, the RNA includes no ratepayer protections, exposing customers to unneeded and potentially unnecessary rate changes for rates that are already higher than regional peers. Overall, the proposed RNA will provide real benefits to NiSource and its shareholders by de-risking its revenue recovery while providing no corresponding benefits for ratepayers.

Q. WHAT ABOUT YOUR RECOMMENDATIONS REGARDING THE WNA?

A. In rebuttal, the Company withdrew its proposal to eliminate the three percent deadband under its pilot WNA in part, due to the evidence I provided in my direct testimony.[1] However, the Company offered considerable new information in rebuttal attempting to show that the WNA has provided ratepayer benefits. I disagree with the Company's assertions about the WNA in its rebuttal and continue to find that, at least to date, it has not provided any demonstrative ratepayer benefits. In fact, given recent information, cumulative net WNA surcharges have increased since the time I filed by direct testimony and are now approximately $62 million.

[1] Statement No. 6-R. Direct Testimony of Kevin L. Johnson, pp. 32-33.

II. REGULATORY LAG

Q. PLEASE DISCUSS MR. KEMPIC'S STATEMENTS REGARDING REGULATORY LAG.

A. The Company disagrees that it is seeking an RNA in order to reduce regulatory lag.[2] It claims that it is seeking to implement the RNA to more closely align its rates with the drivers of its cost to send the appropriate price signal to customers.[3] Mr. Kempic further notes that inflation is not a driver of Columbia's effort to implement an RNA[4] but rather it is the magnitude of the Company's pipeline replacement program and the inflationary pressures on that which are the main driver of the rate increase.[5]

Q. DO YOU AGREE WITH THE COMPANY'S CLAIM THAT IT IS NOT SEEKING TO REDUCE REGULATORY LAG WITH ITS RNA PROPOSAL?

A. No. First, the Company explicitly noted that regulatory lag was important as I cited in my direct testimony.[6] Second, revenue decoupling is commonly recognized as a method for addressing regulatory lag by many regulator commissions and the natural gas industry itself (such as through the publications and representations of the American Gas Association).[7]

---

[2] *See,* Rebuttal Testimony of M. Kempic, Company Statement No. 1-R at 1:17-18.

[3] *Id.* at 2:11-13.

[4] *Id.* at 4:14-15.

[5] *Id.* at 4:17-5:3.

[6] *See*, Direct Testimony of Mark Kempic, Company Statement No. 1 at 9, 14; *see also*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6 at 28-29, 35-36, 38-39, 43-44.

[7] *See,* Ken Costello, *Decision-Making Strategies for Assessing Ratemaking Methods: The Case of Natural Gas,* p. 17 (2007); *see also,* "*Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)*" (September 2007), Grants & Research Department, National Association of Regulatory Utility Commissioners, p. 4.

Q. ARE REVENUE AND COST TRACKERS SUCH AS THE RNA KNOWN TO REDUCE REGULATORY LAG?

A. Yes. Trackers of all types eliminate the positive incentives typically afforded through regulatory lag. It is a basic economic fact that rational utility management has little incentive to enhance efficiencies (operational and capital) if it has no effect on the utility's profits.[8] Regardless of whether the Company is seeking to reduce regulatory lag or not, that *is* the result of their proposal.

Q. DO YOU AGREE WITH THE COMPANY'S STATEMENT THAT INFLATIONARY PRESSURES ARE NOT A DRIVER OF ITS RNA PROPOSAL?

A. No. The Company states that even if the inflationary pressures it faces due to the magnitude of its capital investment did not exist, the RNA still makes sense.[9] Again, the Company has provided no evidence showing that there is any financial need for the RNA.

III. RATEPAYER PROTECTIONS

Q. PLEASE DISCUSS MR. JOHNSON'S STATEMENTS REGARDING RATEPAYER PROTECTIONS FOR THE RNA.

A. The Company argues that the following ratepayer protections will be in place for the RNA: (1) the RNA protects the consumer from over collecting fixed costs through volumetric base rates due solely to rate design;[10] (2) the Company is not able to retain

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

[9] *See,* Rebuttal Testimony of M. Kempic, Company Statement No. 1-R at 5:1-3.

[10] *See,* Rebuttal Testimony of Kevin L. Johnson, Company Statement No. 6-R at 25:8-9.

revenue in excess of the Benchmark Distribution Revenue per Bill ("BDRB");[11] (3) the Company will submit two filings per year for the RNA, which can be reviewed and audited by the Commission.[12]

Q. WOULD THESE RATEPAYER PROTECTIONS BE CONSIDERED SUFFICIENT?

A. No. A filing requirement is not a ratepayer protection. These filing requirements will do nothing to prevent rates from increasing or protect ratepayers in any way excessive rate increases. Additionally, the other two items are not ratepayer protections. They are a part of the design of every decoupling mechanism. The Company has not addressed any of the other proposals I raised in my Direct Testimony on ways ratepayers can be protected that are accepted and recognized by other commissions.[13] Other commissions have approved ratepayer protections such as performance guarantees, a pilot program to first prove the promised ratepayer benefits, and/or a check on over earnings, and the current RNA proposal includes none of these protections.

Q. HAS THE COMMISSION RECENTLY DECIDED A SIMILAR REVENUE DECOUPLING MECHANISM?

A. Yes. In the Commission's July 22, 2024 Opinion and Order entered at Docket No. R-2023-3043189 and R-2023-3043190 in the Pennsylvania-American Water Company

[11] *Id.* at 25:4-5.

[12] *Id.* at 25:6-7

[13] *See,* Direct Testimony of David E. Dismukes, OCA Statement No. 1, DED-8.

base rate case (PAWC Order),[14] the Commission found the following as to PAWC's similar revenue decoupling mechanism (RDM) proposal:

> Upon review, we agree with the ALJs that approval of PAWC's proposed RDM is not in the public interest. First, PAWC did not establish a need for the RDM as an additional revenue stabilization mechanism. Revenue stabilization mechanisms are implemented to remove the risk of non-recovery of the full amount of any permitted revenue requirement. However, PAWC already utilizes frequent base rate cases, the FPFTY, and the DSIC to address revenue shortfalls. Specifically, the impact of the RDM on the frequency of base rate case filings is unknown and may not lessen the need and frequency of base rate cases. Therefore, PAWC has not proven that the RDM is needed.
>
> In addition, we find that the RDM does not benefit customers. In fact, it appears that the RDM will hinder customer conservation efforts and could cause customers who take measures to reduce their water consumption to share some of their bill savings with PAWC. We agree that charging customers an additional charge through the RDM may act as a disincentive from conservation practices by customers because it will diminish the value of any savings achieved from such conservation efforts.
>
> Furthermore, the RDM is not a just and reasonable alternative distribution ratemaking mechanism. As proposed, the RDM would produce guaranteed rate recovery where no guarantee existed in the past and shift the risk of recovery entirely onto customers without any benefit. Without adequate consumer protections, low-income customers will be placed at risk of bearing additional costs from the RDM, and this potential increase in unaffordability would expose these customers to a greater risk of arrears and termination of service. Moreover, the RDM will likely be confusing and difficult to understand for consumers due to its complex design in determining whether the RDM is a credit or charge. This additional surcharge on customer bills, along with the quarterly rate changes that occur under PAWC's DSIC, would only add to that complexity and confusion.
>
> Therefore, we conclude that it is not in the public interest to approve the proposed RDM, which would provide an additional type of revenue stabilization to PAWC at the risk of eroding customers' conservation savings, which is the only way for water customers to affect a reduction to

[14] Available at https://www.puc.pa.gov/pcdocs/1838564.pdf.

> their water bill. With the PAWC's frequency of filing base rate cases, along with its use of the FPFTY and the DSIC, we further find that PAWC has not demonstrated a need for the proposed RDM. For these reasons, as well as the RDM's negative impact on consumer conservation efforts and its resulting confusion, as discussed above, we shall reject PAWC's proposed RDM. Accordingly, we will deny PAWC Exception No. 6.2.

PAWC Order, pp. 307-308. As Mr. Mierzwa states in his surrebuttal, there is no major difference between PAWC's RDM proposal and Columbia Gas' RNA proposal in this proceeding. Accordingly, the Commission's rationale above should be equally instructive as to the RNA proposal in this proceeding.

IV. WNA BENEFIT ASSERTIONS

Q. PLEASE DISCUSS MR. JOHNSON'S STATEMENTS REGARDING THE COMPANY'S WNA.

A. Mr. Johnson states that after a review, the Company acknowledges the approval of the WNA until the time of the final order in its first rate case after May 31, 2016, which was agreed upon in the settlement entered in Docket No. R-2021-3024296, and it withdraws its proposal to eliminate the three percent WNA deadband in this proceeding.[15] Additionally, the Company does not believe the WNA requires further evaluation now that the proposal has been withdrawn and requests that any proposals to end the Company's WNA in this matter be denied.[16]

[15] *See*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6-R at 32:11-14.

[16] *See*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6-R at 33:9-11 and 33:20-21.

Q. DO YOU AGREE WITH THE COMPANY'S POSITION THAT THE WNA IS BENEFICIAL TO RATEPAYERS?

A. No. The Company has provided over 20 pages of rebuttal testimony designed to "show" that the WNA has led to ratepayer benefits. However, the entirety of the rebuttal is nothing more than a restatement of the Company's support of the WNA, there is nothing in this rebuttal that provides any record evidence documenting how the WNA has led to demonstrable ratepayer benefits.

Q. WHAT ARE THE BENEFITS OF THE WNA THAT MR. JOHNSON DISCUSSES IN HIS REBUTTAL TESTIMONY?

A. The only benefit that the Company discusses is "fairness". Mr. Johnson states that fairness is the most important principle of rate design and that the goal is to provide a rate design that provides a reasonable opportunity for a utility to recover the cost of service.[17] Specifically, he states that "in the interest of fairness to both the Company and customers, the WNA eliminates the over or under recovery of cost of service due solely to weather."[18]

Q. DO YOU AGREE WITH THE COMPANY?

A. No. The Company seems to believe that the only test for fairness is if the Company is guaranteed to fully recover its cost of service with no consideration of the WNA's negative impacts on retail ratepayers. Because the WNA severs the link between revenue and sales altogether, the Company faces little to no risk associated with revenue variability (often referred to as "business risk"). Mr. Johnson stated in his own testimony

[17] *See*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6-R at 37:4-9.

[18] *See*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6-R at 43:16-18.

that "the goal is to provide a rate design that provides a reasonable opportunity for a utility to recover the cost of service."[19] The goal is not to provide a guarantee, but rather a reasonable opportunity for utilities to recover their cost of service. Furthermore, the Company did not address any of my concerns about the negative impacts of the WNA on ratepayers.

Q. IS THERE ANY NEW INFORMATION SHOWING THE NEGATIVE IMPACTS OF THE WNA ON RATEPAYERS?

A. Yes. I have included Exhibit DED-SR-1 which is an updated version of an exhibit I filed in my direct testimony with new data provided by the Company's 2023-2024 WNA annual report. My exhibit shows an increase in net WNA revenue from $59.1 million to $61.9 million, or an increase of 4.7 percent. The summary of these reports shows that the WNA provides no benefits to retail ratepayers, and over the last five years, ratepayers have been required to reimburse the Company $66.6 million.

V. SUMMARY OF RECOMMENDATIONS

Q. HAVE YOUR RECOMMENDATIONS CHANGED AS A RESULT OF THE COMPANY'S REBUTTAL TESTIMONY?

A. No. I recommend the Commission reject the Company's RNA proposal. The Company has provided no record evidence showing that this mechanism is needed. Further, the Company has still not proven that there is a financial need for the RNA. Most revenue decoupling proposals are tied to either new or enhanced energy efficiency efforts. The Company's RNA should be rejected, for among other reasons, since it does

[19] *See*, Direct Testimony of Kevin L. Johnson, Company Statement No. 6-R at 37:4-9.

not include any meaningful expanded energy efficiency commitments if approved. The failure to directly tie expanded energy efficiency savings opportunities to revenue decoupling adoption shifts the entire performance risk of the RNA away from the Company and onto ratepayers. Lastly, the RNA includes no ratepayer protections, exposing customers to unneeded and potentially unnecessary rate changes for retail rates that are already higher than regional peers. Overall, the proposed RNA will provide real benefits to NiSource and its shareholders by de-risking its revenue recovery while providing no corresponding benefits for ratepayers.

Q. HAS THE WNA RESULTED IN ANY NET RATEPAYER BENEFITS?

A. No, despite the assertions presented by the Company it offers no documentable evidence that ratepayers have benefited from the WNA. In fact, given recent information, cumulative net WNA surcharges have increased since the time I filed by direct testimony and are now approximately $62 million.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

Table of Exhibits

Title	Exhibit
WNA Annual Report	Exhibit DED-SR-1

WNA Annual Report Summary

Heating Season	Revenue Impact
2013-2014	$ (9,356,200.00)
2014-2015	(10,981,225.00)
2015-2016	11,522,044.00
2016-2017	13,904,913.97
2017-2018	(6,052,269.62)
2018-2019	(3,734,377.25)
2019-2020	4,979,367.40
2020-2021	5,327,157.73
2021-2022	2,530,224.11
2022-2023	17,441,275.00
2023-2024	36,341,357.00
Total	**$ 61,922,267.34**

Source: DR OCA 17-003 & Company WNA Annual Reports

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, David E. Dismukes, 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 25, 2024

Signature: 

David E. Dismukes

Address: Acadian Consulting Group
5800 One Perkins Pl # 5F,
Baton Rouge, LA 70808

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Corrected Surrebuttal Testimony & Exhibit of

Greg R. Meyer

OCA Statement 2SR

On behalf of

Pennsylvania Office of Consumer Advocate

July 25, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11633

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1

INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Greg R. Meyer. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME GREG R. MEYER WHO PREVIOUSLY FILED BOTH DIRECT AND REBUTTAL TESTIMONY IN THIS PROCEEDINGON BEHALF OF PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE ("OCA")?

A Yes, I am.

Q WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A The purpose of my surrebuttal testimony in this proceeding is to address the rebuttal testimony of various Columbia Gas witnesses. My surrebuttal testimony will address the following issues:

- Plant-in-Service;
- Sales Revenues;
- Uncollectibles Expenses;
- Labor Expenses;
- Incentive Compensation;
- Rate Case Expenses;
- Injuries and Damages;
- Corporate Insurance Expense;
- Materials and Supplies;
- Directors and Officers Insurance;
- Depreciation Rate Adjustment; and
- Interest Synchronization.

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

CASE OVERVIEW

Q PLEASE PROVIDE A CASE OVERVIEW AS IT PERTAINS TO COLUMBIA GAS' REQUESTED REVENUE REQUIREMENT.

A Based on BAI's review of the revenue requirement requested by Columbia Gas and the rebuttal testimony filed by Columbia Gas, we believe the revenue increase requested by Columbia Gas — $124.1 million — is significantly overstated. Based on the results of our audit and based on the adjustments we have made after reviewing the Company's rebuttal testimony, we believe Columbia Gas should reduce its current revenue requirement by approximately $6.172 million. That is, Columbia Gas' customers should receive a decrease of $6.172 million to current rates. This is shown in Exhibit GRM-SR-1.

Q HAVE YOU PREPARED A SUMMARY OF THE ADJUSTMENTS THE OCA IS PROPOSING TO COLUMBIA GAS' REVENUE REQUIREMENT.

A Yes. Table GRM-SR-1 below summarizes the adjustments the OCA is proposing to Columbia Gas' revenue requirement in the surrebuttal phase of the case (the adjustments that have been revised based on review of the Company's rebuttal testimony are indicated with an asterisk (*).

TABLE GRM-SR-1

Revenue Requirement Adjustments

Line	Issue	Witness	Total (1)
1	Company Proposed Revenue Deficiency[1]		$ 124.1
	PA OCA Adjustments:		
	Cost of Capital Adjustment:		
2	Return on Equity	Walters	$ 60.1
3	Capital Structure	Walters	$ 12.3
4	Total Cost of Capital Adjustment		$ 72.4
5	Depreciation*	Andrews	$ 41.6
6	North Franklin Incident	DeMarco	$ 0.0
7	Plant-in-Service*	Meyer	$ 4.3
8	Sales Revenues*	Meyer	$ 5.3
9	Uncollectibles Expense	Meyer	$ 1.4
10	Labor	Meyer	$ 1.9
11	Incentive Compensation	Meyer	$ 1.8
12	Rate Case Expense	Meyer	$ 0.4
13	Injuries and Damages	Meyer	$ 0.0
14	Corporate Insurance Expense	Meyer	$ 0.5
15	Materials and Supplies	Meyer	$ 0.1
16	Total PA OCA Adjustments		$ 129.9

Source and Note:
1. Exhibit 102, Schedule 3, Page 5.
2. These adjustments are calculated on a pre-tax rate of return basis and, therefore, any effects of interest synchronization are not included. Please see Exhibit GRM-SR-1 for the detailed revenue requirement calculation.

PLANT-IN-SERVICE

Q. HAVE YOU READ THE VARIOUS COLUMBIA GAS WITNESSES' TESTIMONIES REGARDING THE $41 MILLION ADJUSTMENT YOU MADE TO PLANT-IN-SERVICE?

A. Yes, I have.

Q. SEVERAL WITNESSES CLAIMED YOUR ADJUSTMENT WAS LACKING IN OTHER ASPECTS OF THE RATE BASE, SPECIFICALLY ADJUSTMENTS FOR ACCUMULATED DEPRECIATION AND ACCUMULATED DEFERRED INCOME TAXES ("ADIT"). PLEASE RESPOND.

A. Those witnesses' claims were correct. I have updated the OCA revenue requirement calculation to reflect the impact on Accumulated Depreciation Reserve and ADIT.

Q. PLEASE EXPLAIN THE IMPACT TO THE ACCUMULATED DEPRECIATION RESERVE AND HOW YOU PROPOSED TO CAPTURE THAT IMPACT.

A. A proposal to reduce plant-in-service during the test year should be accompanied by an adjustment to reduce the Accumulated Depreciation Reserve due to the fact that less plant in the future test year is subject to depreciation. In this instance, in my direct testimony, I omitted an adjustment to the Accumulated Depreciation Reserve. To correct this omission, in my surrebuttal, I have applied the new depreciation rates proposed by OCA witness Andrews (utilizing the Average Life Group ("ALG") procedure) to the specific accounts that comprise the $41 million plant disallowance

adjustment that I am proposing in this case. The $41 million reduction to plant-in-service results in a reduction of $1,447,796 to the Accumulated Depreciation Reserve, thus increasing rate base. The calculation for this adjustment can be seen in my revised Exhibit GRM-SR-1.

Q. PLEASE EXPLAIN THE IMPACT TO THE ADIT BALANCE IN RATE BASE AND HOW YOU PROPOSE TO CAPTURE THAT IMPACT.

A. A proposal to reduce plant-in-service during a test year should be accompanied by an adjustment to reduce the ADIT balance because there is less plant subject to accelerated tax depreciation. In this instance, in my direct testimony, I omitted an adjustment to the ADIT balance to account for my proposed $41 million plant adjustment. To correct this omission, in my surrebuttal, I have included an ADIT calculation of $757,174. The calculation for this adjustment can be seen in my revised Exhibit GRM-SR-1.

Q. DOES COLUMBIA GAS AGREE WITH YOUR ADIT CALCULATION?

A. No. Columbia Gas witness Jennifer Harding calculated the impact to the ADIT balance to be a reduction of $1,123,725. I have reviewed that adjustment and believe the ADIT impact proposed by Ms. Harding is overstated. Specifically, Ms. Harding did not recognize any book depreciation from the $41 million plant reduction. Deferred income taxes are created by subtracting tax depreciation from book depreciation and then applying the federal income tax rate of 21%. Ms. Harding's calculation did not incorporate the recognition of book depreciation. My calculated impact to the ADIT is

\$650,838. The calculation for this adjustment can be seen in my revised Exhibit GRM-SR-1.

Q. MANY COLUMBIA GAS WITNESSES CHALLENGED YOUR PLANT ADJUSTMENT OF $41 MILLION BASED ON HISTORIC OBSERVATIONS AND OTHER ARGUMENTS. HAVE THOSE ARGUMENTS PERSUADED YOU TO CHANGE YOUR ADJUSTMENT?

A. Absolutely not. In fact, the updated information I have reviewed would suggest that my adjustment is even more conservative than I originally believed. I will discuss my observations about various Columbia Gas witnesses next.

Q. DID YOU READ COLUMBIA GAS WITNESS SPANOS' REBUTTAL TESTIMONY?

A. Yes. Mr. Spanos states that my analysis shows that capital additions are less than budgeted capital additions four of the last five years. Mr. Spanos then uses this finding to reject my calculation of the $41 million plant adjustment. Mr. Spanos argued that looking at historical information does not support a $41 million plant adjustment since the total historical net plant variance were lower. The historical net plant variance analysis is not appropriate when an actual net plant variance is available.

Q. DID YOU READ COLUMBIA GAS WITNESS JULIE COVERT'S TESTIMONY?

A. Yes. Columbia Gas witness Julie Covert also attempts to persuade the Commission that my adjustment is unfounded on a historical basis by manipulating the data she presents. I want to be very clear, the purpose of the historical analysis I presented was to show that the adjustment I have proposed based on 2024 data is consistent with historic performances by Columbia Gas. This historic performance has been that Columbia Gas over-budgets its net plant additions, thereby increasing its rate base upon which customers' rates are set. Based on that historic trend, I proposed an actual net plant to budget adjustment of $41 million. My adjustment is based on actual data for three months in 2024 and is not based on a historically over-budgeted estimate.

Q. COLUMBIA GAS WITNESS JULIE COVERT GOES INTO MORE DETAILS ABOUT THE HISTORIC BUDGET TO ACTUAL NET PLANT ADDITIONS. PLEASE RESPOND.

A. Ms. Covert discusses how the information I relied on from the prior Columbia Gas rate case was inaccurate and provided an update to that information as reflected in Table JEC-1R.

Q. PLEASE DISCUSS YOUR REVIEW OF TABLE JEC-1R.

A. As I understand it, Table JEC-1R is a table that Ms. Covert provided in her rebuttal testimony in Columbia Gas' last rate case. This table provides historic information about Columbia Gas' historic actual to budget net plant additions. Ms. Covert also

provides a "% Over/Under" column. The % Over/Under column is misleading because the row showing the Average Over/Under percentage is unduly weighted by results from 2022 where only five months of data is included. The approximate 46% estimate in 2022 shows that the Company put in more plant than it projected/budgeted to put in by 46.5% during the first five months of 2022, January through May. The Company weighted these five months of data in 2022 equally with totals from 2016 to 2021 that each include 12 months of data. It is flawed to weight only five months of data equally with 12 months of data when showing annual trends. Furthermore, this analysis is misleading when you refer to Table JEC-2R on the next page of Ms. Covert's rebuttal testimony, where she shows that, for all of 2022, Columbia Gas put in less plant than it projected/budgeted to put in, on a net basis (*i.e.*, over-budgeted net plant additions). In fact, the results of Table JEC-2R confirm that Columbia Gas over-projects/over-budgets net plant additions (*i.e.*, they actually put in less plant than they budgeted to put in, on a net basis) as they have shown this trend for the most recent four out of five years. In summary, the results on Table JEC-1R should be disregarded by the Commission as it portrays a relationship that does not exist and is misleading.

Q. DID YOU READ THE REBUTTAL TESTIMONY OF COLUMBIA GAS WITNESS KEMPIC AS IT RELATES TO THE PLANT DISALLOWANCE YOU HAVE PROPOSED?

A. Yes, I did. Mr. Kempic focuses much of his arguments on how construction work can be slow during certain periods of time and how property restoration work cannot be performed during certain periods of the year. I would expect that Columbia Gas would

reflect these conditions in its budgeting process to provide a more accurate estimation of the work that is to be performed during the year. If the construction budgeting process does not address the conditions described by Mr. Kempic, then the capital budget will not be a good tool to measure Columbia Gas' construction progress for upper management or for projecting plant additions in the FPFTY.

Q. EARLIER IN YOUR TESTIMONY, YOU STATED THAT THE $41 MILLION NET PLANT ADJUSTMENT SHOULD BE CONSIDERED A CONSERVATIVE ADJUSTMENT BASED ON NEW INFORMATION YOU HAVE OBTAINED. PLEASE RESPOND.

A. Columbia Gas provided updated net plant compared to net budget information for the four months ending April 2024,[1] which is attached to my testimony as Exhibit GRM-SR-2. This data shows that Columbia Gas is falling even further behind in actual net plant additions versus budgeted net plant additions. Taking into account another month of actual information reveals that Columbia Gas is now behind in meeting its projected/budgeted plant additions by $68 million, which is an increase of approximately $27 million from my direct testimony. In other words, Columbia Gas has put in less plant than it projected/budgeted to put in, on a net basis (*i.e.*, in under budgeted plant additions) by $68 million. This trend clearly shows that the $41 million adjustment to rate base for the FPFTY I have proposed in my direct testimony is likely conservative and reasonable and should be adopted by the Commission. The actual data does not support the Columbia Gas witnesses' claims that my adjustment is unjustified,

[1]Company Response to OCA Data Request 9-014 Supplemental.

if it had they would have used it in their rebuttal testimony. I would note that I have asked for an update to the actual net plant through the most current month available and will continue to monitor the adjustment I have proposed.

SALES REVENUES

Q. HAVE YOU READ THE REBUTTAL TESTIMONIES OF COLUMBIA GAS WITNESSES MAY BATTIG AND MICHAEL GIRATA AS THEY RELATE TO YOUR PROPOSED SALES REVENUE ADJUSTMENT?

A. Yes, I have. Ms. Battig argues that I used actual usage per customer figures for multiple years instead of weather-normalized usage per customer. Ms. Battig also points out some errors in the calculation of the revenue impact from my proposed adjustment. Mr. Girata limits his discussion of revenues to the use per customer level that I utilized.

Q. PLEASE RESPOND TO THE USAGE PER CUSTOMER LEVELS DISCUSSED BY THE WITNESSES.

A. Mr. Girata provided Table MEG-1 that I have recreated below as Table GRM-SR-2.

TABLE GRM-SR-2

Historical Usage Per Customer (Dth)

Year	Non-Weather Normalized	Weather Normalized
2018	94.45	87.25
2019	86.34	85.08
2020	78.57	83.19
2021	82.5	83.62
2022	83.33	83.02
2023	74.7	81.78
2018-2023 Average without 2020	84.26	84.15
2019-2022 Average without 2020	84.06	83.91

Source:
Rebuttal Testimony of Michael E. Girata Table MEG-1.

This table shows actual usage per customer and weather-normalized usage per customer for the years 2018 to 2023. In addition to those values, I also have included a five-year average calculation for the years 2018 to 2023 excluding 2020, and a three-year average excluding the highest and lowest values in 2018 and 2023 and the year 2020.

Q. WHY DID YOU EXCLUDE THE YEAR 2020?

A. In his testimony, Mr. Girata states "absent 2020 when Covid-19 moratoriums caused customers to change their annual usage patterns."[2] I decided to eliminate the year 2020 from my review based on the statement of Mr. Girata.

[2]Rebuttal Testimony of Michael E. Girata at 2.

Q. PLEASE CONTINUE YOUR DISCUSSION OF TABLE GRM-SR-2.

A. As can be seen from Table GRM-SR-2, the actual results and the weather-normalized results do not show significant variance from each other. The five-year average reveals an actual usage per customer of 84.26 Dth, while the weather-normalized total shows an average usage per customer of 84.15 Dth. Similarly, the three-year average for actual usage per customer shows an actual usage per customer of 84.05 Dth, while the weather-normalized usage per customer was 83.90 Dth.

Q. WHAT USAGE PER CUSTOMER HAS COLUMBIA GAS PROPOSED IN THIS CASE?

A. Columbia Gas is proposing a usage per customer of 82.86 Dth.[3] I would note that this weather-normalized usage per customer has been exceeded every year but one since 2018.

Q. BASED ON THE RESULTS PROVIDED BY COLUMBIA GAS, ARE YOU UPDATING YOUR SALES REVENUE ADJUSTMENT?

A. Yes. I would propose that the revenue adjustment be calculated using a usage per customer of 84.26 Dth instead of the 85.04 Dth as I have incorporated the usage from 2023 in my new calculation. The five-year average is very close to the three-year average eliminating the highest (2018) and lowest (2023) years of usage per customer.

[3]Rebuttal Testimony of Michael E. Girata at 3.

Q. IN HER REBUTTAL TESTIMONY, MS. BATTIG PROVIDES A BREAKDOWN OF THE RESIDENTIAL CLASS CUSTOMERS. DOES YOUR NEW REVENUE CALCULATION REFLECT THOSE DIFFERENT RESIDENTIAL CLASS CUSTOMER BREAKDOWNS?

A. Yes. My revised sales revenue adjustment reflects the customer breakdown supplied by Ms. Battig and also reflects the specific collection of Rider revenues for those classes of customers. Furthermore, all rates have the revenues from Rider USP not included.

Q. WHAT IS THE IMPACT OF YOUR NEW RESIDENTIAL REVENUE ADJUSTMENT?

A. My revised revenue adjustment proposes to increase Columbia Gas' residential revenues at current rates by $5.3 million. This decreases Columbia Gas' needed revenue requirement by $5.3 million.

I would also note that in the rebuttal testimony of Ms. Battig she points out an inconsistency of the value of the residential revenue adjustment in my direct testimony. The references on page 25 of my direct testimony should have reflected $12.2 million consistent with the figure in Table GRM SR-2.

<u>UNCOLLECTIBLE EXPENSES</u>

Q. HAVE YOU READ THE REBUTTAL TESTIMONY OF MS. KOMENDA AS IT ADDRESSES UNCOLLECTIBLE EXPENSE?

A. Yes, I have. Ms. Komenda argues that my uncollectible adjustment does not properly match revenues with the incurrence of uncollectible expense. Ms. Komenda argues that

there is an accepted principle that uncollectible expense varies in relation to billed revenue for residential and small commercial and industrial customers.

Q. PLEASE RESPOND TO THAT ARGUMENT.

A. While I generally agree with Ms. Komenda, I have seen several times where a utility's uncollectible expense does not track with the level of revenues billed to customers. I believe this situation exists with Columbia Gas. I have prepared Table GRM-SR-3 that shows the historic level of uncollectible expense to the level of sales revenues reported in Columbia Gas' annual reports to the Commission.

TABLE GRM-SR-3

Uncollectible Expense vs Sales Revenue

Year	Uncollectible Expense[1]	Sales Revenue
2019	$ 5,920,064	$ 470,359,619
2020	$ 2,882,792	$ 421,175,928
2021	$ 9,432,257	$ 512,686,722
2022	$ 6,703,255	$ 668,096,357
2023	$ 8,776,515	$ 675,159,692

Source:
1. Exhibit No. 1, Schedule 9, Page 1 and Data Response to OCA Set 9 Question 1 Charge Offs Minus Recoveries.

As can be seen from the above table, uncollectible expense is not tracking directly with sales revenues.

Q. HOW WOULD YOU ANTICIPATE MS. KOMENDA TO REPLY TO YOUR ANALYSIS?

A. I would expect Ms. Komenda would say that my analysis is flawed because I have not recognized the time delay of uncollectible write-offs with the collection of sales revenues. Ms. Komenda stated in her rebuttal testimony that net-write-offs lag billed revenues. However, recognizing the regulatory lag for uncollectible will not significantly change these numbers and will still show that the amount of uncollectible expense is not a certainty to tie to sales revenues. There simply is too much variation in the level of uncollectible and sales revenues.

Q. PLEASE SUMMARIZE YOUR POSITION.

A. I continue to support my adjustment to uncollectible expense made in my Direct Testimony. Columbia Gas is requesting the highest level of uncollectible expense dating back to 2019. I have proposed a more reasonable level of expense based on the history of uncollectible expense actually incurred by Columbia Gas.

LABOR EXPENSES

Q. HAVE YOU READ THE REBUTTAL TESTIMONY OF MS. KOMENDA AS IT RELATES TO LABOR EXPENSE?

A. Yes, I have.

Q. HAVE YOU BEEN ABLE TO DETERMINE THE MAJOR DIFFERENCE BETWEEN THE COMPANY'S ANNUALIZATION OF PAYROLL EXPENSES AND YOUR ANNUALIZATION OF PAYROLL EXPENSES?

A. Yes. I believe, from reviewing the rebuttal testimony of Ms. Komenda that Columbia Gas has annualized wage increases based on the 2025 budget. I, however, have annualized payroll expenses using actual payroll data at November 30, 2023.

Q. WHAT IS THE BASIS FOR YOUR ASSERTION REGARDING MS. KOMENDA'S LABOR ANNUALIZATION?

A. In her rebuttal testimony, Ms. Komenda states "The Company's method of determining labor expenses for the FPFTY is to first use the budget for calendar year 2025 and adding an annualization adjustment to reflect a full twelve months of employee labor expenses for the FPFTY."[4]

Q. DOES YOUR ANNUALIZATION METHODOLOGY REFLECT WAGE INCREASE EFFECTIVE IN 2025?

A. Absolutely. My annualization of wages, as I stated previously, takes actual payroll expenses at November 30, 2023 and increases each payroll group for the anticipated wage increases that Columbia Gas identified in its workpapers. My annualization of wage increases does not rely on a budget which by its very nature is a projection and may include additional unidentified wage dollars not specifically addressed by Columbia Gas (additional employees, etc.) My annualization is more accurate, reflects

[4]Rebuttal Testimony of Brittany Komenda at 12.

the current workforce at November 30, 2023, and does not have to rely on budgeted data. My annualization relies on known and measurable labor expense data provided by Columbia Gas and simply increases those known and measurable values for projected payroll increases through 2025 (FPFTY).

Q. SHOULD THE COMMISSION ADOPT THE COMPANY'S LEVEL OF LABOR EXPENSES?

A. No. As I stated previously, my annualized payroll adjustment relies on actual data at November 30, 2023 and increased labor expenses by the same increases provided by Columbia Gas. There is no use of budgeted payroll expenses. My adjustment is more accurate and appropriate for establishing Columbia Gas' cost of service.

INCENTIVE COMPENSATION

Q. HAVE YOU READ THE REBUTTAL TESTIMONY OF COLUMBIA GAS WITNESS KIMBERLY CARTELLA ADDRESSING INCENTIVE COMPENSATION?

A. Yes, I have.

Q. PLEASE SUMMARIZE MS. CARTELLA'S POSITION.

A. Ms. Cartella seeks to include 100% of incentive compensation in customer rates. Ms. Cartella states that "NiSource's total rewards philosophy is to compensate employees and provide benefits that are competitive in comparison to the utility industry, as well

as general industry (non-utility) employers, to attract, and retain and motivate employees."[5]

Q. DO YOU AGREE WITH HER STATEMENT?

A. Yes, I do, and I want to be very clear. I am not proposing to change any aspect of the NiSource compensation plan. I am merely proposing different stakeholders should pay for different portions of that compensation plan; shareholders or customers.

Q. PLEASE DESCRIBE WHAT YOU BELIEVE IS THE MAIN DIFFERENCE BETWEEN YOU AND MS. CARTELLA AS IT RELATES TO THE ADJUSTMENT YOU HAVE PROPOSED.

A. In her rebuttal testimony, Ms. Cartella recognizes that I am allowing 30% of the incentive compensation claimed by the Company.[6] However, Ms. Cartella claims that I have not recognized certain operational metrics that include safety, operational excellence, and net operating earnings per share which is driven by the Company meeting its budget.[7] There is no breakdown or other documentation in her rebuttal testimony showing where I proposed disallowing compensation costs associated with safety. I am not opposed to including compensation for the achievement of safety goals. However, the goal of meeting a net operating earnings per share is exactly what I have classified as a financial metric and the achievement of that metric should be assigned to

[5]Rebuttal Testimony of Kimberly Cartella at 2.
[6]Rebuttal Testimony of Kimberly Cartella at 8.
[7]*Ibid.*

the Columbia Gas shareholders. I believe that is the main difference between my adjustments and the rebuttal testimony of Ms. Cartella.

Again, I would note that Ms. Cartella provided no calculations showing where I argue for disallowing compensation costs related to the achievement of non-financial goals. However, my adjustment of disallowing 70% of incentive compensation is based on the metrics provided in the company response to data request GAS-RR-027. Therefore, I continue to support the adjustment I proposed in my direct testimony.

RATE CASE EXPENSES

Q. HAVE YOU READ THE REBUTTAL TESTIMONY OF BRITTANY KOMENDA THAT ADDRESSES RATE CASE EXPENSE?

A. Yes, I have. Ms. Komenda argues against my adjustment to reduce rate case expenses based on the history of Columbia Gas' over-budgeting rate case expenses for its last three rate cases. However, Ms. Komenda does not refute that in past rate cases, Columbia Gas has consistently over-budgeted rate case expense (Please refer to Table GRM-4 in my direct testimony) by a range of 26% to 50%.

Q. DOES MS. KOMENDA ARGUE THAT THE OVER-BUDGETED AMOUNT IS NOT REFLECTIVE OF THE CURRENT CASE?

A. Yes. Ms. Komenda argues that my 40% over-budgeted rate case expense factor reflects the result of two settled rate cases and only one litigated rate case. First, let me state that in the last two rate cases, Columbia Gas has agreed to settle those rate cases without litigation. That needs to be a factor in determining rate case expense. Second, if you

refer to Table GRM-4 in my direct testimony, you will notice that even in the Columbia Gas' litigated rate case (R-2020-3018835), Columbia Gas over-budgeted rate case expense by 26%. The point is, that regardless of the case process (settled vs. litigated), Columbia Gas over-budgets rate case expense every time.

Q. DO YOU CONTINUE TO SUPPORT YOUR ADJUSTMENT TO REDUCE COLUMBIA GAS RATE CASE EXPENSE BY 40%?

A. Yes, I do. However, if the Commission is persuaded by the arguments of Ms. Komenda, then I would propose that rate case expense be reduced by 26% consistent with the last litigated rate case Columbia Gas was involved in.

INJURIES AND DAMAGES

Q. HAVE YOU READ THE REBUTTAL TESTIMONY OF MS. KOMENDA THAT ADDRESSES INJURIES AND DAMAGES EXPENSE?

A. Yes, I have. Columbia Gas continues to believe that an inflation factor should be applied to the injuries and damage expenses. As I demonstrated in my direct testimony, in Table GRM-9 there is no discernable trend in injuries and damages expense. If these expenses had shown a trend of increasing over a period of time, in a magnitude consistent with inflation, then consideration could be given to an inflation factor. However, as shown on Table GRM-9 of my direct testimony, the level of injuries and damages expense fluctuates over time, thereby suggesting there are likely other factors more responsible for the increase the expense.

Q. DO YOU CONTINUE TO BELIEVE YOUR ADJUSTMENT IS REASONABLE?

A. Yes. I have proposed to include the level of injuries and damages expense incurred for the 12 months ended November 2023 ($367,013). This level of expense is the third highest level experienced by Columbia Gas over the last five years.

I am also aware that regulators many times propose multi-year averages to determine a normalized level of expense. Table GRM-SR-4 below represents multi-year averages of the injuries and damages expense.

TABLE GRM-SR-4

Injuries and Damages

Years	Amount
5 Years (12/18 - 11/23)	$ 347,019
4 Years (12/19 - 11/23)	$ 334,315
2 Years (12/20 - 11/23)	$ 344,709
OCA Proposed	$ 367,013

Source:
1.Company Exhibit No. 4 Schedule No. 2 Page 11.

As can be seen from Table GRM-SR-4, my proposed level of injuries and damages expense is very reasonable, is higher than the normalized expense would be, and should be accepted by both Columbia Gas and the Commission.

CORPORATE INSURANCE EXPENSE

Q. HAVE YOU READ THE REBUTTAL TESTIMONY OF COLUMBIA GAS WITNESS NICHOLAS BLY AS HE DISCUSSES YOUR ADJUSTMENT TO DIRECTORS AND OFFICERS INSURANCE EXPENSE?

A. Yes, I have.

Q. DO YOU STILL SUPPORT YOUR ADJUSTMENT TO DISALLOW THIS INSURANCE EXPENSE FROM COST OF SERVICE?

A. Yes, I do.

Q. PLEASE RESPOND TO THE REBUTTAL TESTIMONY OF MR. BLY.

A. In his rebuttal testimony, Mr. Bly states that the insurance "reduce[s] the risk of exposing the Company and its customers to higher costs due to unforeseen circumstances."[8] Mr. Bly essentially supports my position that this type of insurance provides benefits to the shareholder of Columbia Gas. Yet, Mr. Bly wants the customers of Columbia Gas to pay the insurance premiums. This is hardly a fair compromise for the protection that this insurance provides to shareholders.

Mr. Bly also provides one example of a shareholder that takes issue with the Company's insistence on providing safe and adequate service to the customers to the detriment of shareholders. I have not heard of such a lawsuit being brought against a utility. It is commonly understood that a utility's management has a fiduciary responsibility to maximize the profits for its shareholders while still providing safe and

[8]Rebuttal Testimony of Nicholas Bly at 2.

adequate service. I am unaware of a situation where a Board of Directors or the management of a utility was sued for not maximizing the profits for its shareholders. I would also point out that the risk factors listed by many utilities in their Annual Report to Shareholders have numerous list of risks that a shareholder should be aware of that would affect the profits of the utility.

Finally, Mr. Bly argues that my definition correctly describes the scenarios for coverage of directors and officers insurance which are "shareholder class action, failure to manage, act or disclose, stock value decreases, and regulatory claims."[9] In his testimony, Mr. Bly claims this list is flawed because it does not cover the example he provided as I previously discussed. Mr. Bly did not attempt to argue my list, but simply said it should be expanded to include other situations that I just described. Herein lies the problem, the directors and officers insurance is primarily needed to protect the directors and officers of the utility. Therefore, the cost of that insurance should be paid by the shareholders of Columbia Gas as a protection against the decline in their profits. Columbia Gas' customers should not be required to pay for this insurance premium.

MATERIALS AND SUPPLIES

Q. HAVE YOU READ THE REBUTTAL TESTIMONY OF COLUMBIA GAS WITNESS JULIE COVERT AS IT RELATES TO MATERIALS AND SUPPLIES?

A. Yes, I have. Ms. Covert argues that it is inappropriate to disallow the recovery of materials and supplies based on the premise that a cash working capital study would

[9] *Ibid.*

result in a negative working capital amount from a cash working capital ("CWC") study. Ms. Covert goes on to say that Columbia Gas is not required to file a CWC study, and, therefore, my adjustment should be rejected.

Q. PLEASE RESPOND.

A. I am not here to argue that Columbia Gas has the right to forgo filing a CWC study pursuant to 52 Pa. Code § 53.53. However, Columbia Gas is required to file a rate base that will result in just and reasonable rates. By forgoing filing a CWC study reflecting the fact that Columbia Gas sells it receivables, Columbia Gas is overstating its rate base and that will result in higher customer rates that will not reflect just and reasonable rates.

Q. PLEASE COMMENT ON YOUR EXPERIENCE WITH PERFORMING CWC STUDIES.

A. I have performed or reviewed hundreds of CWC studies in my regulatory career. I can state with certainty that when a utility sells its receivables, the result of a properly conducted CWC study will result in a negative CWC study result. A negative CWC result merely signals that, on the whole, Columbia Gas' customers are paying for service before the time Columbia Gas needs to pay the expenses to provide that service. In other words, Columbia Gas has use of the customer revenues from selling the receivables before it must pay the expenses incurred to provide that service. Selling its receivables significantly shortens the time period Columbia Gas must wait for receipt of those customer revenues.

Q. PLEASE SUMMARIZE YOUR POSITION.

A. I continue to support my position to eliminate the balance for material and supplies until such time as Columbia Gas decides to file a CWC study. I would point out that in the rebuttal testimony of Ms. Covert, she does not dispute that a negative CWC result would occur if Columbia Gas performed a CWC study. If this adjustment is not adopted by the Commission, the rate base for Columbia Gas' determined revenue requirement will be overstated, and Columbia Gas' customers will ultimately pay unjust and unreasonable rates for utility service.

Q. IF THE COMMISSION NEEDS MORE INFORMATION BEFORE ACCEPTING THIS ADJUSTMENT, DO YOU HAVE AN ALTERNATIVE APPROACH?

A. Yes. In its rate case order, the Commission could require Columbia Gas to file a CWC study as part of its next rate case reflecting the sale of its receivables. Then, the Commission would have first-hand knowledge and could make a correct determination of the rate base for Columbia Gas' next rate case.

DEPRECIATION RATE ADJUSTMENT

Q. HAVE YOU READ THE REBUTTAL TESTIMONY OF JULIE COVERT AS IT PERTAINS TO THE DEPRECIATION ADJUSTMENT PROPOSED BY OCA WITNESS BRIAN ANDREWS?

A. Yes, I have. Ms. Covert argues that the OCA failed to account for the impacts to the Accumulated Depreciation Reserve and ADIT for the decrease in depreciation expense

as a result of Mr. Andrews' new proposed depreciation rates. I concur with the arguments provided by Ms. Covert. In our direct testimony, we omitted an adjustment to the Accumulated Depreciation Reserve and ADIT to reflect lower depreciation rates effective in the FPFTY. In surrebuttal, we address and correct those omissions.

Q. PLEASE DISCUSS THOSE IMPACTS.

A. By reducing depreciation rates, depreciation expense during the FPFTY will be lower and, therefore, the Accumulated Depreciation Reserve balance will also be lower. A lower Accumulated Depreciation Reserve balance will result in a higher rate base to apply the rate of return. I have calculated the impact from the lowering of Mr. Andrews' depreciation rates and determined that the Accumulated Depreciation Reserve should be lower by approximately $22 million, thus increasing rate base by $22 million. This total is included in the issue quantification from my revised Exhibit GRM-SR-1 of my surrebuttal testimony.

In the area of ADIT, the Company provided an estimate of the ADIT impact from lower depreciation rates in Schedule JH-10R. That schedule estimates the impact to ADIT to be an increase in the ADIT balance by approximately $9.3 million. This total is also included in the quantification of my revised Exhibit GRM-SR-1 of my surrebuttal testimony.

INTEREST SYCHRONIZATION

Q. DO YOU HAVE ANY COMMENTS ON YOUR INTEREST SYNCHRONIZATION ADJUSTMENT?

A. Yes. My interest synchronization adjustment is merely a byproduct of the rate of return proposed by my colleague Christopher Walters and the rate base adjustments I proposed in this rate case. I cannot recall ever being challenged in attempting to synchronize the level of interest expense the OCA has included in cost of service with the level of rate base proposed by the OCA. Interest synchronization merely recognizes that the interest paid by customers is included in the Company tax return. Interest synchronization guarantees this consistent treatment of interest expense. The Company's interest synchronization refuses to recognize the rate base adjustments and the different cost of debt proposed by the OCA. The Company's arguments in this area are without merit.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

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Columbia Gas of Pennsylvania, Inc.

FPFTY Proposed Revenue Requirement

Line	Description	Reference	Amount (1)
1	Proforma Rate Base at Present Rates	Exhibit No. 1 Page 2	$ 3,461,133,176
2	Return on Rate Base[1]	Exhibit No. 1 Page 13	7.26%
3	Total Requirement[2]	Line 1 x Line 2	$ 251,432,548
4	Net Operating Income at Present Rates	Exhibit No. 1 Page 4	$ 255,909,425
5	Net Required Operating Income	Line 3 - Line 4	$ (4,476,877)
6	Revenue Conversion Factor	Company Exhibit 102, Schedule 3, Page 5	1.37884083
7	Gross Revenue Requirement	Line 5 x Line 6	$ (6,172,901)

Note:

1. See OCA Direct Testimony of Chris Walters for OCA Proposed Capital Structure and Return on Equity Adjustment Details.

2. The difference between Columbia Proposd and OCA Proposed Total Requirement is explained by Chris Walter's Cost of Capital Adjustments as seen on Exhibit No. 1 Page 3.

3. A reference that indicates "No Specific Adjustment Proposed" does not mean acceptance of Columbia's proposed amounts.

Columbia Gas of Pennsylvania

Rate Base Adjustments

Line	Description	Reference	Company Proposed FPFTY[1] (1)	OCA Adjustment (2)	OCA Proposed FPFTY (3) = (1) + (2)
1	Property Plant and Equipment[2]	Exhibit No. 1 Page 3	$ 3,949,617,853	$ (26,860,071)	$ 3,922,757,782
2	Working Capital[3]	Direct Testimony of Greg Meyer	$ 41,193,199	$ (1,094,320)	$ 40,098,879
3	Deferred Income Taxes	No Specific Adjustment Proposed	$ (497,227,686)	$ -	$ (497,227,686)
4	Customer Deposits	No Specific Adjustment Proposed	$ (4,496,884)	$ -	$ (4,496,884)
5	Customer Advances for Construction	No Specific Adjustment Proposed	$ 1,085	$ -	$ 1,085
6	Total Rate Base		$ 3,489,087,567	$ (27,954,391)	$ 3,461,133,176

Source:

1. Company Exhibit 108 Page 3.
2. Plant Adjustment includes plant disallowance and the accumulated depreciaiton and ADIT changes for the plant disallowance and depreciation expense adjustment.
3. Working Capital Adjustment includes adjustment to Materials and Supplies Expense.
4. A reference that indicates "No Specific Adjustment Proposed" does not mean acceptance of Columbia's proposed amounts.

Columbia Gas of Pennsylvania

2024 Budget to Actual Net Plant

Month	Actual[1] Additions	Actual[1] Retirements	Actual[1] Net Plant	Budget[2] Additions	Budget[2] Retirements	Budget[2] Net Plant	Variance Net Plant	Variance %
January	$ 12,453,590	$ 3,908,129	$ 8,545,461	$ 28,067,054	$ 1,967,378	$ 26,099,676	$ (17,554,215)	-67%
February	$ 10,956,610	$ 1,286,883	$ 9,669,727	$ 27,572,429	$ 1,790,831	$ 25,781,598	$ (16,111,871)	-62%
March	$ 18,910,340	$ 3,552,012	$ 15,358,328	$ 33,012,433	$ 9,866,800	$ 23,145,633	$ (7,787,305)	-34%
Total	$ 42,320,539	$ 8,747,024	$ 33,573,516	$ 88,651,916	$ 13,625,009	$ 75,026,907	$ (41,453,391)	-55%

Sources and Notes:

1. Data Response to OCA-9-014 Attachment A.
2. Exhibit No. 108 Schedule No. 1.

Details of Property Plant and Equipment Adjustment on Page 2.

Line	Description	Amount (1)
	Greg Meyer Plant Adjustment	
1	Plant Disallowance	$ (41,453,391)
2	ADIT Adjustment	$ 757,174
3	Accumulated Reserve Adjustment	$ 1,447,796
4	Rate Base Change	$ (39,248,421)
	Brian Andrews Depreciation Expense Adjustment	
5	ADIT Adjustment	$ (8,970,874)
6	Accumulated Reserve Adjustment	$ 21,359,224
7	Rate Base Change	$ 12,388,350
8	Total Rate Base Change	$ (26,860,071)

Columbia Gas of Pennsylvania

Plant Adj. Accumulated Deferred Income Tax Calculation

Line	Account	Jan-24 Net Addition Disallowance	Feb-24 Net Addition Disallowance	Mar-24 Net Addition Disallowance	Total Disallowance	Depreciation Rate	Jan-24 Book Depreciation	Feb-24 Book Depreciation	Mar-24 Book Depreciation	Total Book Depreciation	2024 Tax Rate	2024 Tax	2024 ADIT	2025 Book Depreciation	2025 Tax Rate	2025 Tax	2025 ADIT	Total ADIT
	(1)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	303.30	$ 1,623,198	$ 128,389	$(6,165,851)	$ (4,414,264)		NA		NA	NA		NA	NA	NA		NA	NA	NA
2	303.99	$ (144,682)	$ 23,913	$ (81,289)	$ (202,058)		NA		NA	NA		NA	NA	NA		NA	NA	NA
3	374.20	$ -	$ -	$ 2	$ 2	1.32%	$ -	$ -	$ 0	$ 0	3.750%	$ 0	$ (0)	$ 0	7.219%	$ 0	$ (0)	$ (0)
4	374.40	$ (72,086)	$ 14,895	$ (26,086)	$ (83,277)	1.32%	$ (910)	$ 172	$ (272)	$ (1,010)	3.750%	$ (3,123)	$ 444	$ (1,097)	7.219%	$ (6,012)	$ 1,032	$ 1,476
5	374.50	$ (289)	$ -	$ -	$ (289)	1.02%	$ (3)	$ -	$ -	$ (3)	3.750%	$ (11)	$ 2	$ (3)	7.219%	$ (21)	$ 4	$ 5
6	375.40	$ 46,505	$ 31,287	$ 28,538	$ 106,330	1.46%	$ 652	$ 401	$ 331	$ 1,383	3.750%	$ 3,987	$ (547)	$ 1,556	7.219%	$ 7,676	$ (1,285)	$ (1,832)
7	375.70	$ (98,472)	$ 120,113	$ (3,562)	$ 18,079	2.40%	$ (2,265)	$ 2,522	$ (68)	$ 190	3.750%	$ 678	$ (103)	$ 434	7.219%	$ 1,305	$ (183)	$ (285)
8	375.71	$ (3,339)	$ (3,339)	$ (3,339)	$ (10,017)	2.41%	$ (77)	$ (70)	$ (64)	$ (211)	3.750%	$ (376)	$ 35	$ (241)	7.219%	$ (723)	$ 101	$ 136
9	376.00	$ 9,433,057	$ 10,662,004	$ 7,596,532	$ 27,691,593	1.49%	$ 134,696	$ 139,006	$ 89,607	$ 363,309	3.750%	$ 1,038,435	$ (141,776)	$ 412,605	7.219%	$ 1,999,056	$ (333,155)	$ (474,931)
10	376.30	$ (531,305)	$ (654,471)	$ (801,372)	$ (1,987,148)	3.53%	$ (17,965)	$ (20,205)	$ (22,384)	$ (60,554)	3.750%	$ (74,518)	$ 2,932	$ (70,112)	7.219%	$ (143,452)	$ 15,401	$ 18,334
11	376.80	$ (136,775)	$ -	$ -	$ (136,775)	1.47%	$ (1,923)	$ -	$ -	$ (1,923)	3.750%	$ (5,129)	$ 673	$ (2,007)	7.219%	$ (9,874)	$ 1,652	$ 2,325
12	378.20	$ 3,766,351	$ 3,391,484	$ 4,254,034	$ 11,411,869	2.08%	$ 75,105	$ 61,749	$ 70,077	$ 206,932	3.750%	$ 427,945	$ (46,413)	$ 237,460	7.219%	$ 823,823	$ (123,136)	$ (169,549)
13	378.30	$ -	$ 457	$ -	$ 457	2.08%	$ -	$ 8	$ -	$ 8	3.750%	$ 17	$ (2)	$ 10	7.219%	$ 33	$ (5)	$ (7)
14	380.00	$ 3,399,617	$ 2,159,979	$ 2,872,889	$ 8,432,485	2.02%	$ 65,811	$ 38,178	$ 45,942	$ 149,931	3.750%	$ 316,218	$ (34,920)	$ 170,336	7.219%	$ 608,741	$ (92,065)	$ (126,985)
15	381.00	$ 160,747	$ 12,457	$ (1,552)	$ 171,652	1.92%	$ 2,960	$ 209	$ (24)	$ 3,146	3.750%	$ 6,437	$ (691)	$ 3,298	7.219%	$ 12,392	$ (1,910)	$ (2,601)
16	381.10	$ 16,720	$ 16,705	$ 19,812	$ 53,237	2.16%	$ 346	$ 316	$ 339	$ 1,002	3.750%	$ 1,996	$ (209)	$ 1,151	7.219%	$ 3,843	$ (565)	$ (774)
17	382.00	$ (145,899)	$ 36,473	$ 84,620	$ (24,805)	1.66%	$ (2,327)	$ 531	$ 1,115	$ (681)	3.750%	$ (930)	$ 52	$ (413)	7.219%	$ (1,791)	$ 289	$ 342
18	383.00	$ (22,932)	$ (54,542)	$ 4,636	$ (72,838)	1.77%	$ (389)	$ (844)	$ 65	$ (1,168)	3.750%	$ (2,731)	$ 328	$ (1,289)	7.219%	$ (5,258)	$ 834	$ 1,162
19	384.00	$ 1,814	$ 1,812	$ 2,141	$ 5,767	1.21%	$ 21	$ 19	$ 20	$ 61	3.750%	$ 216	$ (33)	$ 70	7.219%	$ 416	$ (73)	$ (105)
20	385.00	$ 73,085	$ 68,279	$ 72,740	$ 214,105	2.94%	$ 2,059	$ 1,757	$ 1,693	$ 5,509	3.750%	$ 8,029	$ (529)	$ 6,295	7.219%	$ 15,456	$ (1,924)	$ (2,453)
21	385.10	$ 899	$ 392	$ -	$ 1,291	2.94%	$ 25	$ 10	$ -	$ 35	3.750%	$ 48	$ (3)	$ 38	7.219%	$ 93	$ (12)	$ (14)
22	387.45	$ (3,525)	$ (106,467)	$ (280,486)	$ (390,478)	3.92%	$ (133)	$ (3,654)	$ (8,710)	$ (12,497)	3.750%	$ (14,643)	$ 451	$ (15,316)	7.219%	$ (28,189)	$ 2,703	$ 3,154
23	394.30	$ 151,287	$ 145,103	$ 80,609	$ 376,999	3.92%	$ 5,690	$ 4,983	$ 2,504	$ 13,177	3.750%	$ 14,137	$ (202)	$ 14,795	7.219%	$ 27,216	$ (2,608)	$ (2,810)
24	394.31	$ (55,566)	$ -	$ -	$ (55,566)	3.92%	$ (2,090)	$ -	$ -	$ (2,090)	3.750%	$ (2,084)	$ (1)	$ (2,181)	7.219%	$ (4,011)	$ 384	$ 383
25	397.50	$ 117,805	$ 116,948	$ 142,288	$ 377,041	4.46%	$ 5,031	$ 4,560	$ 5,020	$ 14,612	3.750%	$ 14,139	$ 99	$ 16,803	7.219%	$ 27,219	$ (2,187)	$ (2,088)
26	398.00	$ (22,000)	$ -	$ (8,000)	$ (30,000)	6.19%	$ (1,305)	$ -	$ (392)	$ (1,697)	3.750%	$ (1,125)	$ (120)	$ (1,857)	7.219%	$ (2,166)	$ 65	$ (55)
27	Total	$17,554,215	$ 16,111,871	$ 7,787,305	$ 41,453,391		$ 263,012	$ 229,647	$ 184,802	$ 677,461	3.750%	$ 1,727,614	$ (220,532)	$ 770,335	7.219%	$ 3,325,773	$ (536,642)	$ (757,174)
28	Note 1	DR OCA-9-014 Attachment A.	DR OCA-9-014 Attachment A.	DR OCA-9-014 Attachment A.	Line 3 + Line 4 + Line 5	Exhibit BCA-1	Line 3 x Line 7 x 11.5/12	Line 4 x Line 7 x 10.5/12	Line 5 x Line 7 x 9.5/12	Line 8 + Line 9 + Line 10	MACRS Table	Line 6 x Line 12	(Line 11 - Line 13) x 21%	Line 6 x Line 7	MACRS Table	Line 6 x Line 16	(Line 15 - Line 17) x 21%	Line 14 + Line 18
29	Note 2	Exhibit No. 108 Schedule No. 1 Pages 1 to 2.	Exhibit No. 108 Schedule No. 1 Pages 1 to 2.	Exhibit No. 108 Schedule No. 1 Pages 1 to 2.														
30	Accumulated Depreciation									$ 677,461				$ 770,335				

Columbia Gas of Pennsylvania

Statement of Income at Present Rates

Line	Description	Reference	Company Proposed FPFTY at Present Rates[1] (1)	Adjustments Proposed by OCA (2)	OCA Proposed FPFTY at Present Rates (3) = (1) + (2)
1	Total Operating Revenues	Exhibit No. 1 Page 5	$ 786,107,079	$ 5,331,455	$ 791,438,534
2	Total Operating Revenue Deductions[2]	Exhibit No. 1 Pages 6 and 7	$ 539,524,899	$ (49,668,843)	$ 489,856,056
3	Operating Income Before Income Taxes	Line 1 - Line 2	$ 246,582,180	$ 55,000,297	$ 301,582,477
4	Income Taxes	Exhibit No. 1 Page 8	$ 32,834,907	$ 12,959,356	$ 45,794,263
5	Investment Tax Credit	Company Exhibit 107 Page 7a	$ (121,211)	$ -	$ (121,211)
6	Operating Income	Line 3 - Line 4 - Line 5	$ 213,868,484	$ 42,040,941	$ 255,909,425

Sources and Notes:

1. Company Exhibit 102, Schedule 3, Page 3.

2. Includes depreciation expense adjustment as detailed in OCA Direct Testimony of Brian Andrews.

3. A reference that indicates "No Specific Adjustment Proposed" does not mean acceptance of Columbia's proposed amounts.

Columbia Gas of Pennsylvania

Residential Sales Revenue Adjustment

Line	Description	Amount (1)
	Residential Sales Service	
1	Number of Customers[1]	345,713
2	CPA Proposed Usage per Customer[2]	82.86
3	PA OCA Proposed Usage per Customer[3]	84.26
4	PA OCA Adjustment to Usage per Customer	1.40
5	PA OCA Adjustment to Usage	485,381
6	PA OCA Adjustment to Reveue Requirement[4]	$ 4,445,605
	Customer Assistance Plan	
7	Number of Customers[1]	24,718
8	CPA Proposed Usage per Customer[2]	82.86
9	PA OCA Proposed Usage per Customer[3]	84.26
10	PA OCA Adjustment to Usage per Customer	1.40
11	PA OCA Adjustment to Usage	34,704
12	PA OCA Adjustment to Reveue Requirement[4]	$ 316,439
	Residential Distribution Service	
13	Number of Customers[1]	44,335
14	CPA Proposed Usage per Customer[2]	82.86
15	PA OCA Proposed Usage per Customer[3]	84.26
16	PA OCA Adjustment to Usage per Customer	1.40
17	PA OCA Adjustment to Usage	62,246
18	PA OCA Adjustment to Reveue Requirement[4]	$ 569,411
19	Total PA OCA Adjustment to Reveue Requirement	$ 5,331,455

Sources:
1. Rebuttal Testimony of May Battig.
2. Company Exhibit No. 103, Page 8.
3. GRM Exhibit No. 1 Page 5.5
4. Line 13 multipled by restidential rates on Exhibit No. 3, Schedule No. 1.

TABLE GRM-1

Historical Usage Per Customer (Dth)

Year	Non-Weather Normalized	Weather Normalized
2018	94.45	87.25
2019	86.34	85.08
2020	78.57	83.19
2021	82.5	83.62
2022	83.33	83.02
2023	74.7	81.78
2018-2023 Average without 2020	84.26	84.15
2019-2022 Average without 2020	84.06	83.91

Source:
Rebuttal Testimony of Michael E. Girata Table MEG-1.

Columbia Gas of Pennsylvania

Operation and Maintenance Expense Adjustments

Line	Description	Reference	Company Proposed FPFTY[1]	OCA Adjustment	OCA Proposed FPFTY
			(1)	(2)	(3) = (1) + (2)
1	Labor	Direct Testimony of Greg Meyer	$ 38,227,431	$ (1,948,702)	$ 36,278,729
2	Incentive Compensation	Exhibit No. 1 Page 9	$ 2,562,000	$ (1,793,394)	$ 768,606
3	Pension	No Specific Adjustment Proposed	$ -	$ -	$ -
4	Pension Deferral Amortization	No Specific Adjustment Proposed	$ 844,977	$ -	$ 844,977
5	OPEB	No Specific Adjustment Proposed	$ -	$ -	$ -
6	Other Employee Benefits	No Specific Adjustment Proposed	$ 8,527,000	$ -	$ 8,527,000
7	Outside Services	No Specific Adjustment Proposed	$ 19,865,592	$ -	$ 19,865,592
8	Building Leases	No Specific Adjustment Proposed	$ 938,262	$ -	$ 938,262
9	Other Rent and Leases	No Specific Adjustment Proposed	$ 546,000	$ -	$ 546,000
10	Corporate Insurance	Direct Testimony of Greg Meyer	$ 4,961,000	$ (594,530)	$ 4,366,470
11	Injuries and Damages	Direct Testimony of Greg Meyer	$ 398,074	$ (31,061)	$ 367,013
12	Employee Expenses	No Specific Adjustment Proposed	$ 1,563,000	$ -	$ 1,563,000
13	Company Memberships	No Specific Adjustment Proposed	$ 585,692	$ -	$ 585,692
14	Utilities and Fuel Used in Company Operations	No Specific Adjustment Proposed	$ 1,426,083	$ -	$ 1,426,083
15	Advertising	No Specific Adjustment Proposed	$ 610,332	$ -	$ 610,332
16	Fleet & Other Clearing	No Specific Adjustment Proposed	$ 8,847,000	$ -	$ 8,847,000
17	Materials & Supplies	No Specific Adjustment Proposed	$ 6,135,015	$ -	$ 6,135,015
18	Other O&M	No Specific Adjustment Proposed	$ (1,114,000)	$ -	$ (1,114,000)
19	PUC, OCA, OSBA Fees	No Specific Adjustment Proposed	$ 2,550,000	$ -	$ 2,550,000
20	NCSC	No Specific Adjustment Proposed	$ 71,249,563	$ -	$ 71,249,563
21	Operation and Maintenance Expense from Budget		$ 168,723,021	$ (4,367,687)	$ 164,355,334
22	Rate Case Expense	Exhibit No. 1 Page 10	$ 1,008,000	$ (403,200)	$ 604,800
23	Uncollectible Accounts	Exhibit No. 1 Page 11	$ 9,713,182	$ (1,409,173)	$ 8,304,009
24	COVID-19 Amortization	No Specific Adjustment Proposed	$ 708,091	$ -	$ 708,091
25	Total Rider USP	No Specific Adjustment Proposed	$ 37,168,342	$ -	$ 37,168,342
26	Interest on Customer Deposits	No Specific Adjustment Proposed	$ 302,637	$ -	$ 302,637
27	Other Adjustments	No Specific Adjustment Proposed	$ 54,000	$ -	$ 54,000
28	Total Operation and Maintenance Expense		$ 217,677,273	$ (6,180,060)	$ 211,497,213

Source and Note:

1. Company Exhibit 104, Schedule 1, Page 2.

2. A Reference that indicates "No Specific Adjustment Proposed" does not mean acceptance of Columbia's proposed amounts.

Columbia Gas of Pennsylvania

Depreciation Expense Adjustments

Line	Description	Reference	OCA Adjustment (1)
1	Depreciation Expense Adjustment of Brian Andrews	Direct Testimony of Brian Andrews	$ (42,718,447)
2	Depreciation Expense Adjustment from Rate Base Adjustments	Exhibit No. 1 Page 3.5	$ (770,335)
3	Total Other Operating Revenue Deduction Adjustments		$ (43,488,782)

Columbia Gas of Pennsylvania

Interest and Taxes Effect

Tax Rate	27.48%

Line	Adjustment	Revenue Amount (1)	Expense Amount (2)	Difference in Interest Expense[1] (3)	Tax Amount (4)	Operating Income Amount (5)
1	Sales Revenues	$ 4,445,605	$ -		$ 1,221,444	$ 3,224,161
2	Depreciation	$ -	$ (43,488,782)		$ 11,948,679	$ 31,540,103
3	Uncollectibles Expense	$ -	$ (1,409,173)		$ 387,175	$ 1,021,998
4	Labor	$ -	$ (1,948,702)		$ 535,412	$ 1,413,290
5	Incentive Compensation	$ -	$ (1,793,394)		$ 492,741	$ 1,300,654
6	Rate Case Expense	$ -	$ (403,200)		$ 110,780	$ 292,420
7	Injuries and Damages	$ -	$ (31,061)		$ 8,534	$ 22,527
8	Directors and Officers Insurance	$ -	$ (594,530)		$ 163,349	$ 431,181
9	Interest Sync			$ 6,947,173	$ (1,908,758)	
10	Total				$ 12,959,356	

Note:

1. Calculated by taking the OCA proposed rate base multipled by the OCA proposed weighted cost of debt and subtracting the Company proposed interest expense.

Columbia Gas of Pennsylvania

Incentive Compensation Adjustment

Line	Description	Amount (1)
1	Incentive Compensation Paid in 2023 [1]	$ 4,267,188
2	O&M Percentage	51.48%
3	FTY Budget Adjustment (Total Cost)[2]	$ 907,673
4	FPFTY Budget Adjustment (Total Cost)[2]	$ (198,135)
5	Total Incentive Compensation Costs in 2025 (Line 1 + Line 3 + Line 4)	$ 4,976,726
6	Financial Portion of Short-Term	70.00%
7	OCA Proposed Incentive Compensation Costs (Line 5 x Line 6)	$ 1,493,018
8	OCA Proposed Incentive Compensation Expense (Line 7 x Line 2)	$ 768,606
9	Company Proposed Incentive Compensation Expense[2]	$ 2,562,000
10	Adjustment to Revenue Requirement (Line 8 - Line 9)	$ (1,793,394)

Sources:

1. Exhibit 4 Schedule No. 2 Page 4
2. Budgets from Exhibit 104 Schedule No. 1 Pages 3 and 4 divided by Line 2.
3. Company Response to I&E Data Request RE-039-D.

Columbia Gas of Pennsylvania

Rate Case Expense Adjustment

Line	Description	Amount (1)
1	Columbia Proposed Rate Case Expense[1]	$ 1,008,000
2	Average % Over Requested[2]	40.00%
3	OCA Proposed Adjustment to Rate Case Expense	$ (403,200)

Sources:

1. Company Exhibit 104, Schedule 1, Page 2.
2. Table GRM-6 of OCA Direct Testimony of Greg Meyer.

Columbia Gas of Pennsylvania

Uncollectible Expense Adjustment

Line	Description	Amount (1)
1	FPFTY Uncollectible Accounts Expense Bundled[1]	$ 8,506,675
2	FPFTY Uncollectible Accounts Expense Unbundled[1]	$ 1,206,507
3	Total FPFTY Uncollectible Accounts	$ 9,713,182
4	3 Year Average Net Write Offs[2]	$ 8,304,009
5	OPC Adjustment to FPFTY Uncollectible Accounts Expense	$ (1,409,173)

Sources:

1. Exhibit 104, Schedule No. 2, Page 15

2. Average of Three Years of Exhibit No. 1, Schedule 9, Page 1 and Data Response to OCA Set 9 Question 1 Charge Offs Minus Recoveries.

Columbia Gas of Pennsylvania

Pre-Tax Rate of Return

Line	Capital Type	Ratio	Cost Rate	Weighted Cost Rate	Tax Factor[1]	Pre-Tax Rate of Return
1	Long-Term Debt	47.52%	5.07%	2.41%	1	2.41%
2	Short-Term Debt	2.48%	5.25%	0.13%	1	0.13%
3	Common Equity	50.00%	9.45%	4.73%	1.37884083	6.52%
4	Total	100.00%		7.26%		9.05%

Source:
1. Company Exhibit 102, Schedule 3, Page 5.

Columbia Gas of Pennsylvania, Inc.

Cost of Capital & Revenue Requirement Impact at 52% Common Equity

Company Proposed Cost of Capital (Exhibit No. 400, Schedule 5)

	Capital Amount	Capital Ratio	Component Costs	Wtd. Average Costs	Tax Conversion Factor	Pre-Tax Wtd Avg. Cost of Capital
Short-Term Debt	87,624,509	2.48%	5.250%	0.130%		0.130%
Long-Term Debt	1,526,000,000	43.13%	5.070%	2.190%		2.190%
Common Equity	1,924,792,528	54.40%	11.750%	6.390%	1.37884083	8.811%
Total Capital	$3,538,417,037	100.00%		8.710%		11.131%

Company Proposed Weighting, Christopher C. Walters' ROE

	Capital Amount	Capital Ratio	Component Costs	Wtd. Average Costs	Tax Conversion Factor	Pre-Tax Wtd Avg. Cost of Capital
Short-Term Debt	87,624,509	2.48%	5.250%	0.130%		0.130%
Long-Term Debt	1,526,000,000	43.13%	5.070%	2.190%		2.190%
Common Equity	1,924,792,528	54.40%	9.450%	5.140%	1.37884083	7.087%
Total Capital	$3,538,417,037	100.00%		7.460%		9.407%

Christopher C. Walters' Proposed Cost of Capital

	Capital Amount	Capital Ratio	Component Costs	Wtd. Average Costs	Tax Conversion Factor	Pre-Tax Wtd Avg. Cost of Capital
Short-Term Debt	87,624,509	2.48%	5.250%	0.1300%		0.130%
Long-Term Debt	1,681,584,010	47.52%	5.070%	2.4094%		2.409%
Common Equity	1,769,208,519	50.00%	9.450%	4.7250%	1.37884083	6.515%
Total Capital	$3,538,417,037	100.00%		7.264%		9.054%

Company Proposed Rate Base	Exhibit No. 102, Schedule 3	$3,489,087,567
Incremental Change to Cost of Capital Using Mr. Walters' ROE and Company weighting		-1.724%
Impact of Change to Cost of Capital - Change to ROE Only		($60,136,205)
Incremental Change to Cost of Capital Using Mr. Walters' recommended ROE and weighting of 52% common equity		-0.353%
Impact of Change to Cost of Capital - Changing Cap Structure and ROE		($12,308,157)
Total Impact of Changes with 52% common equity - All		($72,444,361)

Note: Pre-Tax Wtd. Average Cost of Capital calculated using Columbia Gas' Gross Revenue Conversion Factor of 1.37884083. See Exhibit No. 102, Schedule 3, Page 5, line 6.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

OFFICE OF CONSUMER ADVOCATE INTERROGATORIES
Set 9

Question No. OCA 9-014-Supplement:

Please provide an updated Exhibit JEC-1 for Gas Plant-in-Service by Gas Plant Account by month for actuals after 12/31/2023 that are available. Please also update this exhibit as the monthly data becomes available.

Supplemental Response:

Please refer to OCA-9-014 Supplemental Attachment A.

Response:

Please refer to OCA-9-014 Attachment A.

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated for Actuals Through April 30, 2024

OCA-9-014 Supplemental
Attachment A
Page 1 of 2

Line No.	Description	Account No. (1)	Plant Beginning Balance 12/31/2023 (2) $	Additions (3) $	Retirements (4) $	Balance as of 1/31/2024 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 2/29/2024 (8)=(5+6+7) $
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	52,579,183	129,691	(1,262,063)	51,446,811	178,988	(54,163)	51,571,636
6	Cloud Software	303.99	7,683,664	116,122	0	7,799,786	12,953	0	7,812,739
7	**Underground Storage Plant**								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	387,525	0	0	387,525	0	0	387,525
16	Compressor Station Equipment	354.00	947,638	0	0	947,638	0	0	947,638
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	**Distribution Plant**								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,034	0	0	3,361,034	0	0	3,361,034
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	8,012,420	78,214	8,781	8,099,415	0	0	8,099,415
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,025	0	289	3,233,314	0	0	3,233,314
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,508,005	8,240	(25,351)	6,490,895	0	(1,918)	6,488,977
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	49,536,882	94,854	0	49,631,736	(123,731)	0	49,508,005
30	Structures, Other Distribution System, Leased	375.71	5,322,270	0	0	5,322,270	0	0	5,322,270
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,666,972,004	8,391,097	(1,228,354)	2,674,134,748	6,216,268	(359,968)	2,679,991,048
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Mains - Bare Steel	376.30	60,365,467	361	(47,801)	60,318,027	0	(13,188)	60,304,839
35	Mains - Cast Iron	376.80	74,139	0	0	74,139	0	0	74,139
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	0	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	143,758,484	71,701	(243,511)	143,586,673	111,493	(17,681)	143,680,485
38	Measuring & Regulating Equipment Local Gas	378.30	406,758	0	0	406,758	0	(457)	406,301
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0	0	(903)	0	0	(903)
41	Services	380.00	815,105,240	2,848,976	(817,567)	817,136,649	3,900,662	(634,351)	820,402,960
42	Meters	381.00	45,848,012	113,492	(179,494)	45,782,010	178,120	(95,918)	45,864,213
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	46,168,212	339,454	(33,732)	46,473,934	184,034	(60,830)	46,597,139
45	House Regulators	383.00	18,025,015	111,886	(5,861)	18,131,040	148,205	(10,647)	18,268,597
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,864,025	715	(4,871)	6,859,869	16,888	(16,300)	6,860,458
48	Industrial M&R Equipment. Large Volume	385.10	995,901	0	(899)	995,002	0	(392)	994,610
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	566,537	0	0	566,537			566,537
53	Other Equipment, Telemetering	387.45	15,104,814	42,960	(39,435)	15,108,340	122,349	(15,882)	15,214,807
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,720,511	0	0	3,720,511	0	0	3,720,511
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	554,184	0	0	554,184	0	0	554,184
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	395,117	0	0	395,117	0	0	395,117
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	20,378,022	0	0	20,378,022	10,380	(5,186)	20,383,215
70	Tools, High Pressure Stopping	394.31	10,847	83,827	(28,261)	66,413	0	0	66,413
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	770,403	0	0	770,403	0	0	770,403
78	Miscellaneous Equipment	398.00	1,027,393	22,000	0	1,049,393	0	0	1,049,393
79	**Total Gas Plant in Service**		**4,053,027,426**	**12,453,590**	**(3,908,129)**	**4,061,572,886**	**10,956,610**	**(1,286,883)**	**4,071,242,613**

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated for Actuals Through April 30, 2024

OCA-9-014 Supplemental
Attachment A
Page 2 of 2

Line No.	Description	Account No. (1)	Plant Beginning Balance 2/29/2024 (2) $	Additions (3) $	Retirements (4) $	Balance as of 3/31/2024 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 4/30/2024 (8)=(5+6+7) $
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	51,571,636	(1,063,155)	(15,052)	50,493,429	1,344,329	(7,617,514)	44,220,244
6	Cloud Software	303.99	7,812,739	23,660	0	7,836,399	(8,214)	0	7,828,185
									0
7	**Underground Storage Plant**								0
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	387,525	0	0	387,525	0	0	387,525
16	Compressor Station Equipment	354.00	947,638	0	0	947,638	0	0	947,638
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
									0
18	**Distribution Plant**								0
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,034	0	(2)	3,361,033	0	0	3,361,033
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	8,099,415	43,677	0	8,143,091	5,377	0	8,148,469
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,314	0	0	3,233,314	0	0	3,233,314
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,488,977	6,316	0	6,495,293	0	(3,618)	6,491,675
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	49,508,005	(56)	0	49,507,949	26,836	0	49,534,785
30	Structures, Other Distribution System, Leased	375.71	5,322,270	0	0	5,322,270	5,991	0	5,328,261
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,679,991,048	14,082,060	(1,971,538)	2,692,101,570	13,132,077	(237,955)	2,704,995,691
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Mains - Bare Steel	376.30	60,304,839	(357)	(43,538)	60,260,943	2	(17,894)	60,243,051
35	Mains - Cast Iron	376.80	74,139	0	0	74,139	0	0	74,139
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	0	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	143,680,485	73,186	(59,019)	143,694,651	3,881,475	(36,121)	147,540,005
38	Measuring & Regulating Equipment Local Gas	378.30	406,301	0	0	406,301	0	0	406,301
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0	0	(903)	0	0	(903)
41	Services	380.00	820,402,960	4,887,236	(1,313,577)	823,976,619	4,396,010	(8,558)	828,364,071
42	Meters	381.00	45,864,213	154,800	(40,979)	45,978,035	310,300	(77,827)	46,210,508
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	46,597,139	165,186	(60,582)	46,701,743	143,035	0	46,844,779
45	House Regulators	383.00	18,268,597	112,670	(19,204)	18,362,063	105,730	0	18,467,793
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,860,458	9,098	0	6,869,556	41,439	(282)	6,910,713
48	Industrial M&R Equipment. Large Volume	385.10	994,610	0	0	994,610	0	(1,032)	993,577
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	566,537	0	0	566,537	0	(439)	566,098
53	Other Equipment, Telemetering	387.45	15,214,807	307,006	(26,521)	15,495,292	5,296	(105,681)	15,394,907
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
									0
56	**General Plant**								0
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,720,511	0	0	3,720,511	0	0	3,720,511
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	554,184	0	0	554,184	0	0	554,184
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	395,117	0	0	395,117	0	0	395,117
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	20,383,215	101,012	(2,000)	20,482,227	312,416	0	20,794,643
70	Tools, High Pressure Stopping	394.31	66,413	0	0	66,413	0	0	66,413
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	770,403	0	0	770,403	0	0	770,403
78	Miscellaneous Equipment	398.00	1,049,393	8,000	0	1,057,393	76,165	0	1,133,558
79	**Total Gas Plant in Service**		**4,071,242,613**	**18,910,340**	**(3,552,012)**	**4,086,600,941**	**23,778,265**	**(8,106,922)**	**4,102,272,284**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Greg Meyer, 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 25, 2024

Signature: 

Greg Meyer

Address: Brubaker Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Surrebuttal Testimony of

Christopher C. Walters

OCA Statement 3SR

On behalf of

Pennsylvania Office of Consumer Advocate

July 25, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11633

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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Surrebuttal Testimony of Christopher C. Walters

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Surrebuttal Testimony of Christopher C. Walters

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Christopher C. Walters. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. ARE YOU THE SAME CHRISTOPHER C. WALTERS WHO PREVIOUSLY FILED DIRECT TESTIMONY ON JUNE 14, 2024 AND REBUTTAL TESTIMONY ON JULY 11, 2024 IN THIS PROCEEDING ON BEHALF OF PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE ("OCA")?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my surrebuttal testimony in this proceeding is respond to the rebuttal testimony of Columbia Gas witness Mr. Paul Moul.

My silence on any particular issue should not be construed as tacit agreement or an endorsement of another party's position.

II. SUMMARY

Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.

A. In my surrebuttal testimony, I respond to the criticisms of my direct testimony offered by Mr. Moul in his rebuttal testimony. In particular, I will address (1) his comments on my recommendation that the Company's equity ratio be set at 50.0% for ratemaking purposes; (2) his comments on my proxy group; (3) his comments on my application of three versions of the DCF model; (4) his comments on my Risk Premium analysis, and; (5) his comments on my CAPM.

Q. HAVE ANY OF THE CRITICISMS OFFERED IN MR. MOUL'S REBUTTAL TESTIMONY CAUSED YOU TO CHANGE YOUR RECOMMENDATIONS?

A. No. I am unpersuaded by the comments offered by Mr. Moul and continue to recommend the Company be authorized an ROE of 9.45% at ratemaking equity ratio of 50.0%. In the event the Commission is unpersuaded to move from the Company's requested equity ratio of 54.4%, and ROE in the lower half of my range would be necessary (i.e. 9.10% to 9.45%, with a midpoint of 9.275%).

III. RESPONSE TO MR. MOUL

III.A Response to Mr. Moul's Criticisms of My Recommended Capital Structure

Q. PLEASE SUMMARIZE MR. MOUL'S CRITICISMS OF YOUR RECOMMENDED EQUITY RATIO.

A. Mr. Moul criticizes my recommendation for proposing a lower hypothetical common equity ratio instead of using Columbia's actual capital structure, which he believes is reasonable and falls within the proxy group's range. He argues that my proposal relies on comparisons to another state regulatory agency without establishing its relevance here. He asserts that Columbia's actual capital structure, with a common equity ratio of 54.40%, is consistent with previous Commission decisions and within the acceptable range, making it unnecessary to deviate from it. Additionally, Mr. Moul points out that my hypothetical debt ratio creates a mismatch with the accepted cost of long-term debt, an inconsistency that I did not address.[1]

Q. PLEASE RESPOND.

A. As an initial matter, I argue that my approach is based on sound financial principles and aligns with the goal of ensuring a fair and reasonable return for the company while protecting ratepayers from excessive costs. The hypothetical common equity ratio I proposed is designed to reflect a more balanced and efficient capital structure, which is consistent with industry standards and regulatory practices. Additionally, my reliance on another regulatory agency's reasoning provides valuable context and insight,

[1] Columbia Gas Statement No. 8-R at 10-11.

supporting a more comprehensive evaluation of Columbia's capital structure. The consistency of Columbia's actual capital structure with previous Commission decisions does not negate the potential benefits of my proposed adjustments, which aim to enhance financial stability and fairness. The perceived mismatch in the cost of long-term debt can be addressed through careful recalibration and consideration of current market conditions, ensuring that my recommendation remains practical and beneficial for all stakeholders. Additionally, Mr. Moul's logic that because the Company's requested equity ratio is within the range of the proxy group's equity ratios also applies to my recommended equity ratio as it too falls within the range of the proxy group.

Finally, Mr. Moul's assertion that my testimony is inconsistent because I do not reflect an increased embedded cost of debt has no merit. Mr. Moul has not established that there would be a ratings downgrade that would increase the Company's cost to borrow. While Mr. Moul takes the position that there is potentially an increase in the cost of debt, he does not reconcile that under the unlikely scenario the Company's cost of debt would increase, it would still be at a much lower cost than the cost of equity at the Company's excessive equity ratio.

Q. IS IT YOUR POSITION THAT THE COMPANY SHOULD BE DOWNGRADED?

A. Absolutely not. The point of my previous statement that under the unlikely scenario the Company's cost of debt would increase, it would still be at a much lower cost than the cost of equity at the Company's excessive equity ratio is simply to illustrate the point that the cost of equity comes at a higher cost to ratepayers. It is higher for two reasons:

(1) the cost of equity is naturally higher than the cost of debt and (2) when reflected in rates, the weighted cost of equity must be grossed up for income taxes. I am not advocating for the Company's ratings to be downgraded, nor do I even believe that is a likely outcome as a result of my recommendations.

III.B Response to Mr. Moul's Criticisms of My Proxy Group

Q. PLEASE SUMMARIZE MR. MOUL'S CRITICISMS OF YOUR PROXY GROUP.

A. Mr. Moul criticizes my exclusion of Chesapeake and NiSource from the proxy group, arguing that these companies fairly reflect the risks of a typical natural gas distribution utility. He points out that the acquisition involving Chesapeake has been completed and financed, and that NiSource's sale of a minority interest in NIPSCO does not affect its suitability. Additionally, Mr. Moul disagrees with my inclusion of six water utility holding companies and Eversource, stating that they are not comparable to Columbia. He argues that water utilities and predominantly electric utilities should not be mixed into the proxy group, as the Commission has no history of including such a mix of utility types in a barometer group.

Q. PLEASE RESPOND.

A. Mr. Moul's criticism overlooks key aspects of my proxy group selection. NiSource's sale of a minority interest in NIPSCO represented approximately 19% of its market capitalization at that time, significantly impacting its investment profile. Similarly, regarding Chesapeake, Mr. Moul has not considered that the transaction fundamentally

altered its investment profile. In fact, Chesapeake has even categorized the transaction as a "transformative acquisition" that more than doubles its natural gas business in Florida.[2] Furthermore, neither Chesapeake nor its subsidiaries are rated by ratings agencies, making them unsuitable for comparison. In terms of including water distribution utilities and a multi-utility like Eversource, these entities share similar risks with gas distribution utilities. Water utilities, like gas utilities, are heavily regulated, capital-intensive, and provide essential services, leading to similar regulatory and operational risks. Eversource, as a multi-utility with water, gas, and electric distribution operations, faces a comparable risk profile due to its diverse utility operations and regulatory environment. This diversity in utility types within my proxy group provides a more comprehensive and balanced representation of the risks and returns relevant to Columbia, supporting a fair and reasonable evaluation. This is particularly important considering the significant consolidation of the gas utility industry over the last decade.

Q. MR. MOUL ARGUES THAT THE COMMISSION RELIED ON HIS PROXY GROUP FOR THEIR QUARTERLY EARNINGS REPORT, AND SHOULD DO SO HERE. HOW DO YOU RESPOND?

A. Over the last several years, there has been significant consolidation in the regulated utility sector through mergers and acquisitions. This is particularly true for the universe of natural gas utility companies. By using an expanded proxy group, analysts can create a more robust and representative sample for estimating the cost of equity for a natural

[2] https://www.chpk.com/chesapeake-utilities-corporation-to-acquire-florida-city-gas/

gas utility like the Company. This approach helps address the challenges posed by industry consolidation while providing a broader, more diverse set of comparable companies. The larger sample size also helps mitigate potential biases and improves the statistical reliability of the estimates, ultimately leading to a more accurate and defensible cost of equity determination.

It is my understanding that the proxy group used in the Commission's quarterly earnings report is not mandated to be used in future rate cases. The proxy group needs to be specific for each base rate case.

Q. ARE YOU AWARE OF OTHER JURISDICTIONS THAT CONSIDER THE USE OF A MIXED GROUP OF UTILITIES IN A PROXY GROUP FOR DETERMINING THE AUTHORIZED ROE?

A. Yes. Several jurisdictions have explored the use of a broader proxy group to determine the ROE. The Illinois Commerce Commission ("ICC"), Massachusetts Department of Public Utilities ("MDPU"), the Florida Public Service Commission ("FPUC"), the Kentucky Public Service Commission ("KYPSC"), and the Iowa Utilities Board ("IUB") have all examined the outcomes of a proxy group that involves natural gas and water utility companies to establish the authorized ROE. For example, in the ICC's final order in the most recent rate case of Illinois's largest private investor-owned water utility, Illinois American Water Company, the Commission relied on a proxy group that included both water and gas utilities. *See* Final Order at 95, 102, *Ill. Am. Water Co.*, ICC Dkt. 22-0210 (Dec. 15, 2022). Further, the MDPU concluded in Docket No. 17-90

that a natural gas utility proxy group was appropriate to demonstrate the investment risk comparability of the proxy group to Aquarion Water Company.[3]

Similarly, in Docket No. 20180006-WS, the FPUC changed the methodology to include a combined proxy group of natural gas and water utilities to calculate the authorized ROE for water and wastewater utilities in Florida.[4] The FPUC had previously used a natural gas-only proxy group but chose to use a combined proxy group to increase the size of the proxy group.

The KYPSC also noted in Case No. 2018-00358 for Kentucky-American Water Company that it has considered ROE results based on a proxy group consisting of both natural gas and water utilities. The KYPSC relied on two proxy groups, a water-only proxy group, and a combined proxy group that included natural gas utilities, to develop the DCF and CAPM models.[5]

Finally, in Docket Nos. RPU-2020-00101, TF-2020-0250, the IUB used analyses based on proxy groups composed of water and natural gas companies.[6]

[3] Massachusetts Department of Public Utilities, Docket No. 17-90, Petition of Aquarion Water Company of Massachusetts, Inc., pursuant to G.L. c. 164, § 94, and G.L. c. 165, § 2, for Approval of a General Rate Increase as set forth in M.D.P.U. No. 3., October 31, 2018, p. 286-287.
[4] Docket No. 20180006-WS, In re. Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f),F.S., Order No. PSC-2018-0327-PAA-WS, at 7.
[5] Case No. 2018-00358, In the matter of: Electronic Application of Kentucky-American Water Company for an Adjustment of Rates, Order, June 27, 2019, at 66.
[6] State of Iowa Department of Commerce Utilities Board, Docket Nos. RPU-2020-00101, TF -2020-0250, June 28, 2021, at 24-25.

III.C Response to Mr. Moul's Criticisms of My DCF Analyses

Q. PLEASE SUMMARIZE MR. MOUL'S CRITICISMS OF YOUR DCF ANALYSES.

A. Mr. Moul criticizes my DCF models for producing unrealistically low returns, particularly highlighting the multi-stage and sustainable growth forms of DCF that result in equity returns between 8.12% to 8.36%, which he believes are insufficient to compensate equity investors for their risk, especially given higher yields on A-rated public utility debt.[7] He points out the inappropriateness of the "multi-step" DCF model used for natural gas utilities and argues that my method for analyzing sustainable growth rates improperly relies on GDP components, which do not reflect the unique growth characteristics of specific companies.[8] Furthermore, Mr. Moul contends that my reliance on GDP growth in the third stage of the multi-stage DCF restricts utility growth to below realistic levels, contradicting the industry's long-term growth prospects supported by infrastructure investments. He also criticizes my use of a 13-week period for measuring dividend yields as too volatile and not reflective of long-term investor sentiment. [9] Mr. Moul asserts that investors value all stocks as a multiple of earnings and alters my DCF to use the 3-5 year price-to-earnings ("P/E") ratio multiple as a terminal cash flow.[10]

Overall, Mr. Moul asserts that my DCF methodologies are fundamentally flawed, as they do not align with the traditional and regulatory expectations of DCF

[7] Columbia Gas Statement No. 8-R at 21.
[8] *Id.* at 21-22.
[9] *Id.* at 22.
[10] *Id.* at 25

application for utilities, leading to results that are not justifiable or reflective of true market conditions.

Q. PLEASE RESPOND.

A. As an initial matter, I am not persuaded by Mr. Moul's personal preference of using a six-month dividend yield and find no reason to alter my approach. As I explain in my direct testimony, I believe a 13-week period fairly balances the need for current reliable data with mitigating potential market aberrations. Nothing Mr. Moul opines on legitimately refutes that approach.

With regard to certain results being "far too low," Mr. Moul misses the mark again. He opines that the results do not provide a sufficient risk premium over the cost of utility debt. Importantly, he provides no evidence in support of what a reasonable risk premium is. Further, Mr. Moul overlooks the fact that these results are well within the range of authorized ROEs for regulated utilities over the last several years. I am aware of approximately 40 authorized ROEs for regulated natural gas, water, and electric utilities that range from 7.36% to 8.91%. My DCF results that Mr. Moul determined to be "far too low" are well within this range.

Mr. Moul's assertion that investors value all stocks as a multiple of earnings is factually incorrect, and unsupported in his testimony. A simple example would be to consider a company that is in a loss per share (negative earnings per share) position. Using Mr. Moul's blanket unsupported statement as truth would mean that investors would expect the market to pay them to own a share of the stock. Mr. Moul's reliance on a 3-5 year P/E multiple as the terminal cash flow to be sustained in perpetuity is

nonsensical. Unlike Mr. Moul, I have provided ample support from financial and academic texts that clearly, and intuitively, explain that no company can grow faster than the economy in which it sells goods and services.

Q. MR. MOUL ARGUES THAT YOU HAVE NOT DEMONSTRATED THAT RETENTION GROWTH DETERMINES INVESTOR EXPECTED RETURN RATES.[11] ARE THERE ANY FINANCIAL TEXTS THAT YOU ARE AWARE THAT SUPPORT THE USE OF A SUSTAINABLE, OR RETENTION GROWTH, FORM OF THE DCF?

A. Yes, there are. For example, using the retention growth methodology is a recognized reasonable method for estimating sustainable dividend growth and should not be ignored.

As noted by the CFA curriculum text:

> We define the sustainable growth rate as the rate of dividend (and earnings) growth that can be sustained for a given level of return on equity, assuming that the capital structure is constant through time and that additional common stock is not issued. The reason for studying this concept is that it can help in estimating the stable growth rate in a Gordon growth model valuation, or the mature growth rate in a multistage DDM in which the Gordon growth formula is used to find the terminal value of the stock.

The expression to calculate the sustainable growth rate is: $g = b$ x ROE[12]

[11] *Id.* at 23.0
[12] See CFA Program Curriculum, 2014, Level II, Volume 4, "Dividend Discount Valuation," at page 264.

Further, *Brigham and Houston* state that, "Companies that retain a high percentage of their earnings rather than paying them out as dividends generate more retained earnings and thus need less external capital."[13]

Q. ARE THERE ANY FINANCIAL TEXTS THAT YOU ARE AWARE THAT SUPPORT THE USE OF GDP GROWTH OR A MULTI-STAGE DCF?

A. Yes, there are. In the long run, earnings growth will be limited by several factors, including, but not limited to, competition and market saturation. Mr. Moul's conclusion that GDP growth is not an upper limit for company and industry growth defies the economic and financial literature of which I am aware. In addition to the texts cited in my direct testimony[14] in support of the premise that GDP is a long-term cap on growth, I would like to refer Mr. Moul to the following excerpts. First, as detailed in the CFA Institute's curriculum:

> For earnings growth to exceed GDP growth, the ratio of corporate profits to GDP must trend upward over time. It should be clear that the share of profits in GDP cannot rise forever. At some point, stagnant labor income would make workers unwilling to work and would also undermine demand, making further profit growth unsustainable. *Thus, in the long run, real earnings growth cannot exceed the growth rate of potential GDP*.[15] (emphasis added)

[13] See *Fundamentals of Financial Management*, Eugene F. Brigham and Joel F. Houston, Eleventh Edition 2007, Thomson South-Western, a Division of Thomson Corporation at page 558.
[14] OCA Statement No. 3 at p. 40.
[15] CFA Program Curriculum, 2014 Level II Vol.1, "Ethical and Professional Standards, Quantitative Methods, and Economics" Reading 15 – Economic Growth and the Investment Decision, pages 608-609.

Additionally, Dr. Roger A. Morin details in his book, *New Regulatory Finance*, as follows:

> It is useful to remember that eventually all company growth rates, especially utility services growth rates, converge to a level consistent with the growth rate of the aggregate economy.
>
> * * *
>
> […] it is quite possible that a company's dividends can grow faster than the general economy for five years, *but it is quite implausible for such growth to continue into perpetuity.*[16] (emphasis added)

Thus, my use of projected GDP growth as an upper limit for company or industry growth is wholly defensible.

Further, as I explained in both my Direct and Rebuttal Testimony, the multi-stage DCF model is widely used in practice. As provided in both testimonies, the CFA Institute curriculum text states as follows:

> Multistage models are a staple valuation discipline of investment management firms using DCF valuation models.
> A survey of CFA Institute members with job responsibility for equity analysis indicates that, among respondents using a dividend discount model, two-stage and multistage models are used more often than the single-stage model (Stowe, Pinto, and Robinson 2018). Among analysts using a dividend discount model, 55% use a two-stage model, 11% use an H-model (a type of two-stage model), and 50% use a model with more than two stages (Stowe, Pinto, and Robinson 2018).[17]

As Stowe *et al*. have revealed, the majority of equity analysts rely on multi-stage models more frequently than single-stage or constant growth models. Mr. Moul seemingly ignores these data in favor of his personal preference or opinion.

[16] Roger A. Morin, New Regulatory Finance, pages 308-309.
[17] Chartered Financial Analyst Institute, 2023 CFA Program Level 2 Refresher Reading, Equity Valuation: Discounted Dividend Valuation, at 30. [footnote omitted].

Finally, Mr. Moul ignores the FERC two-step DCF approach where it calculates a weighted growth rate by applying 80% weighting to the consensus of analyst growth rates and a 20% weighting to projected GDP growth for determining the cost of equity for electric transmission companies.[18]

Again, Mr. Moul has provided no substantive evidence to refute the findings of the academic and practitioner texts cited here and in my direct testimony on the matter. As such, Mr. Moul' concerns should be ignored.

Q. HOW DOES MR. MOUL SUPPORT HIS CRITICISMS OF YOUR DCF ANALYSES IN HIS TESTIMONY?

A. In general, Mr. Moul only offers opinions and personal preferences without supporting evidence. Mr. Moul criticizes my DCF methodologies and the resulting low equity returns, claiming they are unrealistic and inadequately compensate investors for their risk. However, he fails to provide any citations to financial literature, texts, or other documents to substantiate his critiques. His arguments are presented without the backing of empirical evidence or academic research, which undermines the credibility of his criticisms and leaves his assertions largely baseless in the context of established financial analysis practices.

[18] FERC Opinion No. 569-B at para. 80, November 19, 2020.

Q. AT PAGES 28-29 OF HIS REBUTTAL TESTIMONY, MR. MOUL DEFENDS HIS LEVERAGE ADJUSTMENT IN THE DCF MODEL. DO YOU FIND HIS ARGUMENTS PERSUASIVE?

A. No. Mr. Moul's arguments are based on the idea that if a firm's market capitalization is different than its book value capitalization, the risk based on the book value capitalization is higher than the risk of the market capitalization. As I explain in my Direct testimony, utility stocks, on average, have been trading at a market-to-book ratio greater than 1.0x since at least 1986 and was illustrated in Exhibit CCW-9. Over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value. This is an indication that commission-authorized returns on common equity supported a utility's ability to issue additional common stock without diluting existing shares. It further demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders. Notably, in my experience, financial leverage adjustments such as those offered by Mr. Moul are not commonplace in setting the allowed ROE and should be rejected.

III.D Response to Mr. Moul's Criticisms of My CAPM Analyses

Q. PLEASE SUMMARIZE MR. MOUL'S CRITICISMS OF YOUR CAPM ANALYSES.

A. Mr. Moul criticizes my CAPM analysis for several reasons: firstly, for using the undefined "Kroll normalized" market premium, which he deems unrealistic; secondly, for relying on S&P betas that are not adjusted for financial leverage or size, leading to

inaccuracies in risk assessment; and thirdly, for producing CAPM results that significantly understate the cost of equity, with my findings between 8.65% to 8.71% compared to higher values in more standard applications. He suggests that these issues result in an unrealistic and overly conservative estimation of the cost of equity, failing to compensate investors adequately for the risks they assume.[19]

Q. PLEASE RESPOND.

A. As an initial matter, my response to Mr. Moul's argument that my results between 8.65% to 8.71% are too low are already addressed above to a similar argument he made with regard to my DCF results and I will not repeat those arguments here.

In addition, Mr. Moul seems to ignore the significant support from Kroll describing their recommended normalized, or conditional market risk premium, which I provided to him in response to Data Request No. OCA-6. Specifically, Kroll's recommended risk premium is not explicitly based on any particular set of returns, but rather it is a conditional risk premium based on observations of relevant factors including, but not limited to fluctuations in global economic and financial market conditions. Kroll explains its equity risk premium methodology on its Cost of Capital Navigator site as follows:

> There is no single universally accepted methodology for estimating the ERP; consequently, there is wide diversity in practice among academics and financial advisors regarding ERP estimates. In estimating the conditional ERP, valuation analysts cannot simply use the long-term historical ERP, whether as reported or adjusted as we discussed above. A better alternative would be to examine approaches that are sensitive to the current economic conditions.

[19] Columbia Gas Statement No. 8-R at 33-35.

> Kroll employs a multi-faceted analysis to estimate the conditional ERP that takes into account a broad range of economic information and multiple ERP estimation methodologies to arrive at its recommendation.
>
> First, a reasonable range of normal or unconditional ERP is established.
>
> Second, based on current economic conditions, Kroll estimates where in the range the true ERP likely lies (top, bottom, or middle) by examining the current state of the economy (both by examining economic indicators and forecasts, as well as by analyzing the level and trends of stock market indices as forward indicators), in conjunction with the implied equity volatility and corporate spreads as indicators of perceived risk.[20]

I note that since the study period relied on in my analysis, Kroll has subsequently revised its recommended risk premium down from 5.5% to 5.0% as of June 5, 2024. In other words, the base cost of equity has declined.[21]

Mr. Moul's assertion that the Kroll market risk premium does not conform with investor expectations is also misplaced. Kroll is one of the most often cited names in valuation and cost of capital matters, particularly with regard to cost of capital testimony offered in regulated utility proceedings such as this one. His reference to a single estimate of the expected market return from Value Line as of April 2024 does not negate the reasonableness of Kroll's market risk premium. Further, Mr. Moul seemingly ignores the several observations of the expected market return of financial institutions, i.e. industry practitioners and investors, offered in my direct testimony.[22]

[20] Kroll Cost of Capital Navigator.
[21] See: https://www.kroll.com/-/media/kroll-images/pdfs/kroll-lowers-its-recommended-us-equity-risk-premium-effective-june-5-2024.pdf?utm_campaign=na_vas_coc_2406_infographic_update&utm_medium=email&utm_source=Eloqua
[22] See: OCA Statement No. 3 at 56.

Q. MR. MOUL ASSERTS THAT YOUR CAPM UNDERSTATES THE COST OF EQUITY, PARTICULARLY THROUGH INACCURATE ASSESSMENTS OF RISK THROUGH BETA. DO YOU AGREE WITH HIS ASSERTION?

A. No, I do not. As I demonstrate below, there is observable evidence which shows that market risk, as measure by beta, overstates the current market cost of equity if the betas include the unprecedented volatility and market reactions to the onset of the global pandemic in the Spring of 2020. In other words, betas such as Value Line, that rely on five years of prices and volatility are currently overstating the cost of equity.

It is unreasonable to assume that those prices and resulting volatility resemble investor expectations going forward. Prior to the market fallout from the pandemic, utility beta estimates were at several year lows. Subsequent to the period of peak volatility from the pandemic, utility betas have actually declined back toward their normalized levels. This is demonstrated in Table CCW-1-S below. In this table, I present the raw unadjusted beta estimates for the 5-year and 3-year period ending April 26, 2024.

TABLE CCW-1-S

Beta Comparison

Proxy Group	5-Year Beta[1]		3-Year Beta[2]	
	Unadjusted	Adjusted[3]	Unadjusted	Adjusted[3]
Atmos Energy Corporation	0.74	0.85	0.61	0.76
New Jersey Resources Corporation	0.78	0.87	0.56	0.73
Northwest Natural Holding Company	0.61	0.76	0.47	0.67
ONE Gas, Inc.	0.75	0.85	0.51	0.69
Southwest Gas Holdings, Inc.	0.87	0.93	0.50	0.68
Spire Inc.	0.79	0.88	0.49	0.68
Eversource Energy	0.85	0.92	0.54	0.71
American States Water Company	0.47	0.67	0.61	0.76
American Water Works Company, Inc.	0.97	1.00	0.83	0.91
California Water Service Group	0.52	0.70	0.68	0.80
Middlesex Water Company	0.65	0.78	0.64	0.78
SJW Group	0.74	0.85	0.55	0.72
Essential Utilities, Inc.	0.90	0.95	0.75	0.85
Average	0.74	0.85	0.59	0.75
Median	0.75	0.85	0.56	0.73

Source:
[1]S&P Global Market Intelligence, betas for the period 4/26/2019 - 4/26/2024.
[2]S&P Global Market Intelligence, betas for the period 4/26/2021 - 4/26/2024.
[3]Adjusted using Value Line's Blume adjustment methodology: 0.35+(0.67 x Unadjusted Beta)

These data clearly demonstrate that systematic market risk has subsided for regulated utilities after controlling for the impacts of the global pandemic and are largely in line with the long-term beta estimates discussed above with average and median beta estimates of 0.75 and 0.73, respectively.

In addition, the size premia for each decile estimated by Kroll, which Mr. Moul relies upon, are representative of firms that are much more risky than a regulated natural gas utility such as Columbia Gas. For example, the most recent size study published by Kroll is indicated below in Table CCW-2-S.

TABLE CCW-2-S

CRSP Deciles Size Study - Data as of 12/31/2023

Companies Ranked by Market Value of Common Equity

Decile	Low End Breakpoint ($M)	High End Breakpoint ($M)	Size Premium	Beta
Mid Cap (3–5)	3,011.22	14,820.05	0.66%	1.12
Low Cap (6–8)	555.88	3,010.81	1.24%	1.22
Micro Cap (9–10)	1.58	554.52	2.91%	1.34
Breakdown of CRSP Deciles 1 - 10				
1	36,942.98	2,662,326.05	-0.06%	0.92
2	14,910.72	36,391.11	0.46%	**1.04**
3	7,493.61	14,820.05	0.61%	**1.10**
4	4,622.26	7,461.28	0.64%	**1.13**
5	3,011.22	4,621.79	0.95%	**1.16**
6	1,864.29	3,010.81	1.21%	**1.18**
7	1,050.08	1,862.49	1.39%	**1.25**
8	555.88	1,046.04	1.14%	**1.30**
9	213.04	554.52	1.99%	**1.33**
10	1.58	212.64	4.70%	**1.38**
Breakdown of CRSP 10th Decile				
10A	97.46	212.64	3.29%	1.40
10w	153.80	212.64	2.38%	1.37
10x	97.46	153.67	4.43%	1.44
10B	1.58	97.40	7.64%	1.36
10y	57.82	97.40	6.22%	1.41
10z	1.58	57.45	10.73%	1.28

Kroll Cost of Capital Navigator

As shown above, each decile from 2-10 have typical betas that are much higher than that of the proxy group. The Kroll size premia are not based on risk comparable companies to Columbia Gas or the regulated utility industry and should be rejected.

Q. DID MR. MOUL EFFECTIVELY ARGUE THAT YOUR USE OF BETAS FROM S&P GLOBAL MARKET INTELLIGENCE ARE INAPPROPRIATE?

A. No. Mr. Moul takes issue with these betas because they are not adjusted for financial leverage or size. I address the size argument in detail above and will not repeat it here. As far as leverage is concerned, my Vasicek-adjusted betas are already higher than the levered Vasicek-adjusted betas estimated by Kroll in its levered beta study as of March 31, 2024. The results of that study are presented below in Table CCW-3-S.

TABLE CCW-3-S

Industry-level Betas - Data as of 03/31/2024
Levered Beta
Geographic Coverage United States

Industry	Full Information	OLS	Sum	Vasicek Adjusted	Blume Adjusted	Peer Group
GICS 55 - Utilities	0.57	0.56	0.57	0.57	0.72	0.58
GICS 5510 - Utilities	0.58	0.56	0.57	0.57	0.72	0.58
GICS 551010 - Electric Utilities	0.58	0.54	0.62	0.54	0.71	0.58
GICS 55101010 - Electric Utilities	0.58	0.54	0.62	0.54	0.71	0.58
GICS 551020 - Gas Utilities	0.53	N/A	N/A	N/A	N/A	N/A
GICS 55102010 - Gas Utilities	0.54	N/A	N/A	N/A	N/A	N/A
GICS 551030 - Multi-Utilities	N/A	0.55	0.53	0.55	0.72	0.58
GICS 55103010 - Multi-Utilities	N/A	0.55	0.53	0.55	0.72	0.58
GICS 551040 - Water Utilities	0.75	0.54	0.52	0.55	0.72	0.58
GICS 55104010 - Water Utilities	0.74	0.54	0.52	0.55	0.72	0.58

Kroll Cost of Capital Navigator

These data support my estimates of beta and show that the various adjustments for leverage and size overstate the risk for regulated utility companies.

Further, Vasicek-adjusted betas, such as those estimated by S&P, are reasonable estimates to use in a CAPM. As Kroll describes:

> Another technique for adjusting beta estimates is a more sophisticated technique called Vasicek shrinkage. The general idea is that betas with the highest statistical standard errors are the least reliable estimates and are, therefore, adjusted toward the market, peer group, or industry

> average more than are betas with lower standard errors. The Vasicek shrinkage technique is not a "one size fits all" technique like the Blume adjustment, and also offers the flexibility to adjusting to the market, peer group, or industry average. Whether betas tend to move toward market averages or industry averages over time is an issue open to debate, although it seems more intuitive that a company in say, the pharmaceuticals industry, will become more like the average pharmaceutical company over time, rather than look more like the average company in any industry.[23]

Further, in an article titled "An Examination of Blume and Vasicek Betas" published in the journal *The Financial Review,* Martin Lally discusses the merits of both methods of adjusting beta. An observation made by Lally as it relates to the utility industry is as follows:

> "A dramatic example of this is in U.S. electric utilities. A typical such firm has an estimated beta (unadjusted) of around 0.4 (Value Line, 1993). By virtue of being typical, the Vasicek estimate, with prior corresponding to this industry, will also be 0.4. By contrast, Blume adjusts the 0.4 to 0.6 [i.e., 0.33 + 0.67(0.4)]. <u>The result is a dramatic overestimate by Blume</u>, because a singularly relevant fact is ignored, i.e., membership of an industry whose average estimated, and therefore presumably also true, beta is well below one. <u>Given that these firms have output prices that are set so as to recover costs, including the cost of equity, and they have substantial equity investment, then the implications of using Blume betas (i.e., not partitioning into industries) for measuring costs of equity are particularly severe."</u>[24]

Mr. Moul's concerns with the S&P betas are without merit ignore the numerous financial and academics texts in support of Vasicek-adjusted betas and should be ignored.

[23]Kroll Cost of Capital Navigator, "Differences in Estimation of Equity Betas", pages 2-3.
[24]See The Financial Review, Vol. 33 (1998) at pages 183-198, "An Examination of Blume and Vasicek Betas," Martin Lally. (emphasis added)

III.E Response to Mr. Moul's Criticisms of My Risk Premium Analyses

Q. PLEASE SUMMARIZE MR. MOUL'S CRITICISMS OF YOUR RISK PREMIUM ANALYSES.

A. Mr. Moul criticizes my risk premium analysis, highlighting that the results, ranging from 9.63% to 10.14% for a utility with Baa rated credit quality, are unrealistic and conflict with his own analysis that yields a risk premium of 11.50%. He challenges the validity of my use of the Kroll supply-side equity risk premium, arguing that it is much lower than historical data-supported risk premiums and does not adequately adjust to reflect changes in interest rates. Mr. Moul contends that my analysis fails to demonstrate a relationship between the risk premium and the level of interest rates, and lacks grounding in actual, measurable historical returns.[25]

Q. DO YOU HAVE ANY INITIAL COMMENTS ON THIS PORTION OF HIS TESTIMONY?

A. Yes. It is uncertain how Mr. Moul ascertained from my testimony that I argued his equity risk premium analysis was in error because the Kroll supply-side equity risk premium is much lower than the risk premium that he attempted to establish using historical data, making reference to page 34 of Statement No. 8. He makes no reference to my testimony where I made that assertion. I would note that I made no such argument in testimony relating to the Kroll supply-side equity risk premium.

[25] Columbia Gas Statement No. 8-R at 36-37.

Q. MR. MOUL ARGUES THAT YOUR RISK PREMIUM ANALYSIS IS UNSUPPORTED BECAUSE YOU HAVE NOT SHOWN THAT YOUR RISK PREMIUM IS RELATED TO THE LEVEL OF INTEREST RATES. HOW DO YOU RESPOND?

A. I note that I relied on long-term average equity risk premiums in my analysis. For example, I incorporated the 39-year average equity risk premium of 5.63% over long-term Treasury yields. This compares to the 2023 equity risk premium of 5.51%. In a report issued earlier this year, Regulatory Research Associates (a division of S&P Global) discussed the equity risk premium, as measured by the authorized ROE spread over bond yields as follows:

> However, with the uptick in interest rates since 2020, the spread has begun to narrow, falling to around 550 basis points in 2023. With the myriad factors putting upward pressure on customer bills, the spread may continue to narrow as regulators may become more reluctant to raise authorized returns.[26]

As indicated on Exhibit CCW-10, the average Treasury yield in 2023 was 4.09%. Year-to-date, interest rates are higher than they were in 2023. Using Mr. Moul's logic, I should have actually recommended an equity risk premium lower than 5.51% instead of the 5.63% equity risk premium I incorporated in my analysis. If anything, my Risk Premium analysis overstates the cost of equity. I continue to believe my approach to be a reasonable method for estimating the cost of equity.

[26] RRA, Major energy rate case decisions in the US January-December 2023 Quarterly update on decided rate cases, February 6, 2024.

Q. MOVING ON, PLEASE RESPOND TO THE REST OF MR. MOUL'S CRITICISMS OFFERED IN THIS PORTION OF HIS TESTIMONY.

A. Other than stating preference for his Risk Premium analysis that produces a cost of equity estimate of 11.50%, he offers no evidence that actually rebuts my Risk Premium analysis. I would note that the results using my Risk Premium analysis exceed the year-to-date average authorized ROE for natural gas, electric, and even vertically integrated electric utilities. Mr. Moul's assertions are without merit and should be ignored.

III.F Response to Mr. Moul's Insistence that Ratepayers Pay a Management Incentive

Q. PLEASE SUMMARIZE THE TESTIMONY OFFERED BY MR. MOUL, INSISTING THAT COLUMBIA GAS MANAGEMENT IS DESERVING OF A PERFORMANCE PREMIUM IN ITS ROE.

A. Mr. Moul argues that Columbia's management performance should be recognized in determining the return on equity, citing Columbia Witness Kempic's testimonies as evidence of exemplary management.

Q. PLEASE RESPOND.

A. Again, Mr. Moul completely ignores Hope & Bluefield, which require economic and efficient management. In general, determining a fair cost of common equity for a regulated utility has been framed by two hallmark decisions of the U.S. Supreme Court: Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944). In these decisions, the Supreme Court found that just compensation depends on many

circumstances and must be determined by fair and enlightened judgments based on relevant facts. The Court also found that a utility is entitled to such rates as would permit it to earn a return on a property devoted to the convenience of the public that is generally consistent with the same returns available in other investments of corresponding risk. The Court continued that the utility has "no constitutional rights to profits" such as those "realized or anticipated in highly profitable enterprises or speculative ventures,"[27] and defined the ratepayer/investor balance as follows:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[28]

As such, a fair ROR is based on the expectation that the utility costs reflect efficient and economical management, and the return will support its credit standing and access to capital, but the return will not be in excess of this level. Utility rates that are consistent with these standards will be just and reasonable, and compensation to the utility will be fair and support financial integrity and credit-standing, under economic management of the utility.

Hope and Bluefield do not provide for increases in the allowed ROE to reward management for supposed effective management. Neither Mr. Moul nor Mr. Kempic have presented any evidence to support the notion that the Company is entitled to such. Nor have they provided evidence that management has, in fact effectively or efficiently managed Columbia Gas. The fact that Columbia Gas is on its 11th base rate case request

[27] *Bluefield*, 262 U.S. at 692-93.
[28] *Id*. at 693 (emphasis added).

since 2010, even with unique favorable mechanisms such as year-end rate base treatment with a fully projected forecasted test year, could arguably speak to the opposite of effective and efficient management. Mr. Moul and Mr. Kempic ignore the concern for rate affordability in this regard. I urge the Commission to reject the Company's request for an increase to the allowed ROE which would further burden ratepayers while enriching shareholders.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

502507

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Christopher C. Walters, 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 25, 2024

Signature: _____

Christopher C. Walters

Address: Brubaker Associates Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Surrebuttal Testimony & Exhibits of

Brian C. Andrews

OCA Statement 4SR

On behalf of

Pennsylvania Office of Consumer Advocate

July 25, 2024

BRUBAKER & ASSOCIATES, INC.

Project 11633

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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EXHIBIT BCA-SR-1 THROUGH EXHIBIT BCA-SR-2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
Office of Small Business Advocate	)	
Office of Consumer Advocate	)	**R-2024-3046519**
Ronald T. Bernick	)	**C-2024-3047905**
	)	**C-2024-3047675**
v.	)	**C-2024-3048339**
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

Surrebuttal Testimony of Brian C. Andrews

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Andrews. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q ARE YOU THE SAME BRIAN C. ANDREWS WHO PREVIOUSLY FILED DIRECT TESTIMONY IN THIS PROCEEDING ON BEHALF OF THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE ("OCA")?

A Yes, I am.

Q WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A The purpose of my surrebuttal testimony is to reiterate my support and recommendation to use the Average Life Group ("ALG") procedure to calculate depreciation rates by responding to the rebuttal testimonies of Columbia Gas of Pennsylvania's ("Columbia Gas" or "Company") witnesses John Spanos and Mark Kempic. I also update the

OCA's proposed depreciation rates to include the proper level of accumulated depreciation that was provided by Mr. Spanos in his rebuttal testimony, Exhibit No. JJS-R2.

My silence in regard to any issue should not be construed as an endorsement of or acquiescence to any parties' positions raised in their direct or rebuttal testimonies.

SUMMARY OF RECOMMENDATIONS

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. I continue to recommend that the depreciation rates for Columbia Gas be calculated using the ALG procedure. It is the most commonly used depreciation procedure in the country and provides Columbia Gas with full recovery of its investment, while resulting in more reasonable depreciation rates.

2. The precision associated with the Equal Life Group ("ELG") procedure does not exist in real life, nor did Mr. Spanos select survivor curves that best reflect the life of Columbia Gas' assets.

3. Columbia Gas is in a significantly elevated investment environment and has drastically increased its plant in-service over the past 10 years. Columbia Gas is a 139-year old company, yet its gas distribution mains have an average age of just 9.5 years, which accounts for 68% of Columbia Gas' plant in-service.

4. Mr. Spanos shows estimates that the use of the ALG procedure will result in a lower revenue requirement for Columbia Gas through 2034. The ALG procedure would help alleviate the burden of excessive utility bills.

5. The affordability of utility rates is an important factor for credit rating agencies in supporting strong credit standings for utility companies, and the use of ALG depreciation rates will make Columbia Gas' rates more affordable for customers.

6. The depreciation rates for Columbia Gas calculated with the ALG procedure are not low, as Mr. Spanos claims. In Pennsylvania, net salvage is not included in depreciation expense, this is the primary reason the OCA's proposed depreciation rates are lower than the small sample of gas utility depreciation rates that Mr. Spanos provides in his Exhibit No. JJS-R3.

7. I have updated the OCA's proposed depreciation rates to include the level of accumulated depreciation that Mr. Spanos has provided in his Exhibit No. JJS-R2. These depreciation rates are provided in Exhibit BCA-SR-1 and should be approved by the Pennsylvania Public Utility Commission ("Commission").

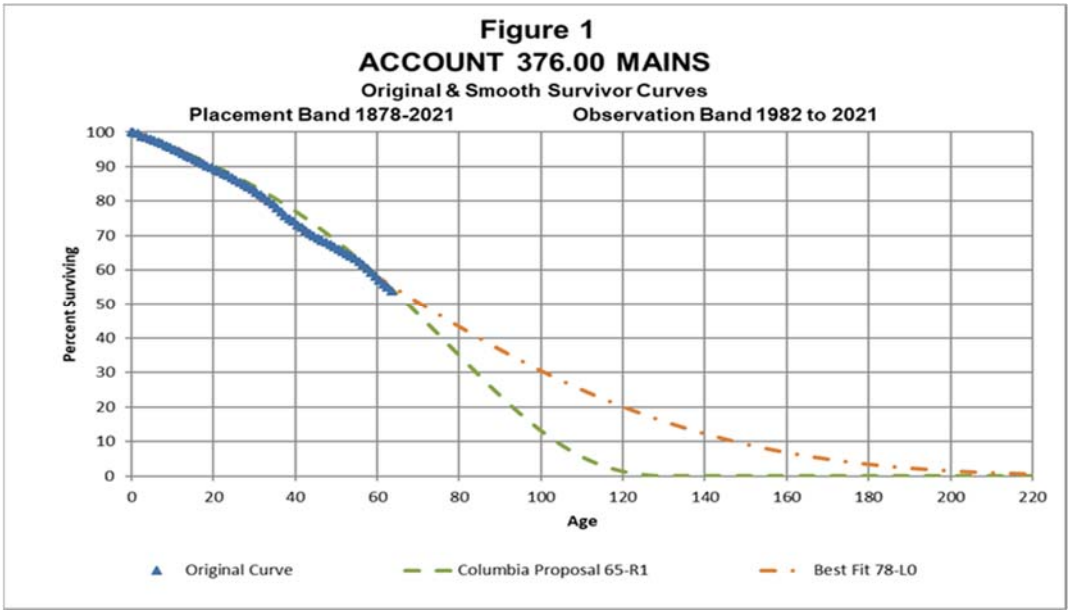
8. The OCA's proposed depreciation rates would reduce Columbia Gas' 2025 depreciation expense by $42.72 million.

RESPONSE TO THE REBUTTAL TESTIMONY OF JOHN J. SPANOS

Q MR. SPANOS PROVIDES CITATIONS TO "DEPRECIATION SYSTEMS" BY WOLF AND FITCH, WHICH REFERS TO THE ELG PROCEDURE AS THE ONLY MATHEMATICALLY CORRECT PROCEDURE, AND THAT ELG IS CONSIDERED TO BETTER MATCH THE CONSUMPTION OF CAPITAL WITH SERVICE PROVIDED THAN THE ALG PROCEDURE.[1] PLEASE RESPOND.

A I do not disagree that Wolf and Fitch have made these statements. While the ELG method may be more precise mathematically, it is not a precision that exists in reality as it is extremely sensitive to the survivor curve that is used to determine the depreciation rates. The depreciation expense is also only accurate if the utility property retires in exactly the manner dictated by the survivor curves used to calculate the ELG rates. This precision does not exist in real life. For example, Mr. Spanos has selected the 65-R1 survivor curve for the Distribution Mains, Account 376. While I do not challenge this proposal, I have conducted a fitting analysis on the significant data points of Columbia Gas' retirement data. In Figure 1, I show that the best-fit of the significant data points is the 78-L0 survivor curve.

[1]Columbia Gas Statement No. 5-R at page 4, lines 5-12.



Q WHAT IS THE SIGNIFICANCE OF THIS FIGURE?

A Figure 1 shows that the best-fitting survivor curve for Columbia Gas' largest account is 78 years, which is 13 years longer than what has been proposed by Mr. Spanos. The 65-R1, proposed by Columbia Gas, indicates service lives ranging from 1 year to 132 years. Thus, under the ELG procedure there would be 132 equal life groups that would be depreciated over their expected service lives. Contrast this with the 78-L0, which indicates service lives ranging from 1 year to 297 years. With this curve, which is supported by Columbia Gas' own data, there would be 297 equal life groups which would be depreciated over their expected service lives. While I am not challenging the service life selection made by Mr. Spanos, the precision that mathematically exists with the ELG procedure can only be achieved if assets retire in the exact manner indicated by the survivor curve. Again, this precision does not exist in reality, which is why the ELG procedure was primarily of academic interest until the 1970s.

Q MR. SPANOS CLAIMS THAT OTHER COMMISSIONS ARE STARTING TO IMPLEMENT THE ELG PROCEDURE. PLEASE RESPOND.

A Mr. Spanos states that the ELG procedure is used in Texas for gas utilities, some jurisdictions in Canada, and for one utility in Colorado.[2] Including Pennsylvania, this is three total states. ALG is by far more commonly used. There are 47 other states that use ALG. As I discussed in my direct testimony, Indiana recently made the switch from ELG to ALG. I have been involved in depreciation cases in 17 other states, plus Washington DC. These jurisdictions all use the ALG procedure. Mr. Spanos states that he has been in 450 cases before approximately 46 regulatory commissions;[3] based on my inspection of his Appendix A, this leaves 43 regulatory commissions that have approved the use of ALG where Mr. Spanos has testified. The ALG procedure is the predominant depreciation procedure in use in the United States and should be approved for Columbia Gas.

[2]Columbia Gas Statement No. 5-R at page 10, lines 12-18.
[3]Columbia Gas Statement No. 5 at page 2, lines 2-4.

Q MR. SPANOS CLAIMS THAT COLUMBIA GAS IS NEITHER IN A "CHANGED LANDSCAPE" NOR IN A "HIGHER THAN AVERAGE INVESTMENT CYCLE"; THEREFORE, THE INDIANA AND KENTUCKY DECISIONS THAT I PROVIDED IN MY DIRECT TESTIMONY THAT SUPPORT THE REJECTION OF ELG AND APPROVAL OF ALG ARE NOT APPLICABLE. PLEASE RESPOND.

A I completely disagree. A changed landscape certainly exists. The affordability of utility rates is of significant concern of regulators, credit agencies, and especially customers themselves. A recent poll by the Commonwealth Foundation found that rising energy costs are a top voter concern, claiming that "Eight in 10 voters say their household energy bills have increased over the past two years, and more than two-thirds (70 percent) say they're concerned about affording their family's energy needs. Rising energy costs (63 percent) top the list as the most prominent environmental issue in Pennsylvania."[4] The high inflationary environment that has existed over the past few years is taking its toll on Pennsylvanians. I would also echo the direct testimony of my colleague Christopher Walters, who stated in his direct testimony, "As outlined by Moody's, S&P and Fitch above, credit analysts are focusing on rate affordability as an important factor needed to support strong credit standing. Customers must be able to afford to pay their utility bills in order for utilities to maintain their financial integrity and strong investment grade credit standing. For this reason, this Commission should carefully assess the reasonableness of cost of service in this proceeding, including an appropriate overall ROR necessitated by a reasonably cost effective balanced

[4] https://www.commonwealthfoundation.org/2024/03/19/pa-voters-energy-costs-2024/.

ratemaking capital structure, and a return on equity that represents fair compensation but also maintains competitive, just and reasonable rates."[5] The switch to ALG depreciation rates will help alleviate energy bill burden for Columbia Gas' customers.

Q HAS MR. SPANOS CONFIRMED THAT ALG DEPRECIATION RATES WOULD REDUCE COLUMBIA GAS' REVENUE REQUIREMENT?

A Yes. Mr. Spanos has conducted an analysis, which he provides in Exhibit No. JJS-R1 and is summarized on Figure 3 on page 16 of his rebuttal testimony. This analysis compares the revenue requirements for the period of 2024-2050 for Columbia Gas under two scenarios, one that assumes ALG depreciation and the other with ELG. This analysis clearly shows that the ALG procedure results in lower revenue requirements through 2034. Ten years of lower utility bills will certainly help with affordability. Utility customers do not plan for future utility bills, they pay and plan for bills on a monthly basis not on decennial basis; most people prefer the next bill to be as low as possible. With the affordability of utility bills of significant concern, the Indiana Utility Regulation Commission ("IURC") decision in the Duke Energy Indiana case is certainly applicable, it states, "the consideration of service affordability in the near term provides sufficient weight to temper our historical preference for ELG."[6] For Columbia Gas it is apparent that affordability of bills is a significant issue as Columbia Gas has proposed to include $9.7 million on uncollectible expense in the Fully Projected Future Test

[5]OCA Statement No. 3 at page 21, lines 3-10.
[6]See Exhibit BCA-2 at page 18.

Year ("FPFTY"), which is nearly $3 million more than the average of uncollectible expense that existed from 2019 through 2023.[7]

Q PLEASE COMMENT ON THE HIGHER THAN AVERAGE INVESTMENT CYCLE.

A I discuss this issue in my direct testimony. As discussed, Columbia Gas has increased plant in-service over six times in a 16-year period and will continue to invest $429 million annually through 2028.[8] This is a substantially high investment cycle. Columbia Gas has been a company since 1885. The oldest assets still in-service are from 1883. The Company has been providing gas service for nearly 140 years. Contrast this to the average age of its distribution mains: just 9.5 years old, which represents 68% of the Company's plant investment.[9] A 140-year-old company with mains that have an average age under 10 years old certainly suggests that Columbia Gas has been in a higher-than-average investment cycle.

Q MR. SPANOS CLAIMS THAT THE OCA'S PROPOSED DEPRECIATION RATES ARE UNREASONABLY LOW DUE TO THE ALG PROCEDURE. PLEASE RESPOND.

A Mr. Spanos has provided a list of 11 unnamed gas utilities in his Exhibit No. JJS-R3, which purports to show an average depreciation rate of 2.66%. From this, he concludes that the composite 1.65% depreciation rate that I have recommended is unreasonably

[7]OCA Statement 2 at page 25, line 11 – page 26, line 1.
[8]OCA Statement 4 at page 21, line 13 – page 22, line 7.
[9]*Id*. at page 23, lines 4-6.

low. I disagree. First, Mr. Spanos has provided no information demonstrating that the unnamed companies are comparable to Columbia Gas. Second, in response to OCA 8-1, we requested Mr. Spanos' database that he maintains for natural gas companies. This file shows the life parameters that Gannet Fleming (Mr. Spanos' firm) has recommended for 85 different gas companies. There is no way to determine if the 11 unnamed companies are representative of the 85 gas utility companies that Gannet Fleming conducts depreciation studies for. Further, Pennsylvania is unique in that net salvage is not included in depreciation expense, but rather recovered through a five-year amortization of actual costs of removal. This drastically reduces depreciation rates. For gas utilities, the net salvage rate for mains can be around -40% to well past -100%. Meaning that for every dollar invested in mains, the utility would recover $1.40 to over $2.00 through depreciation expense. In ALG depreciation, all assets are assumed to have the average life of the group. For Columbia Gas, the mains accounts, which represents 68% of the plant in-service has a life of 65 years. With the ALG procedure, a 65-year life and 0% net salvage would yield a depreciation rate of 1.54%.[10] If net salvage were to be included at an average level of -50%, then the depreciation rate would be 2.31%. Since Columbia Gas does not include net salvage in depreciation, a 1.65% composite depreciation rate is perfectly reasonable.

[10] 1/65 = 1.54%.

Q GIVEN THAT NET SALVAGE IS NOT INCLUDED IN DEPRECIATION RATES IN PENNSYLVANIA, HAVE YOU UPDATED THE EXAMPLE FROM YOUR DIRECT TESTIMONY THAT COMPARES THE ELG AND THE ALG PROCEDURES?

A Yes. I have created an example that will demonstrate the differences between the ALG and ELG procedures, excluding any net salvage costs. It will demonstrate how the rates are calculated under each procedure and will show that the ELG is front-loaded and requires annual updates.

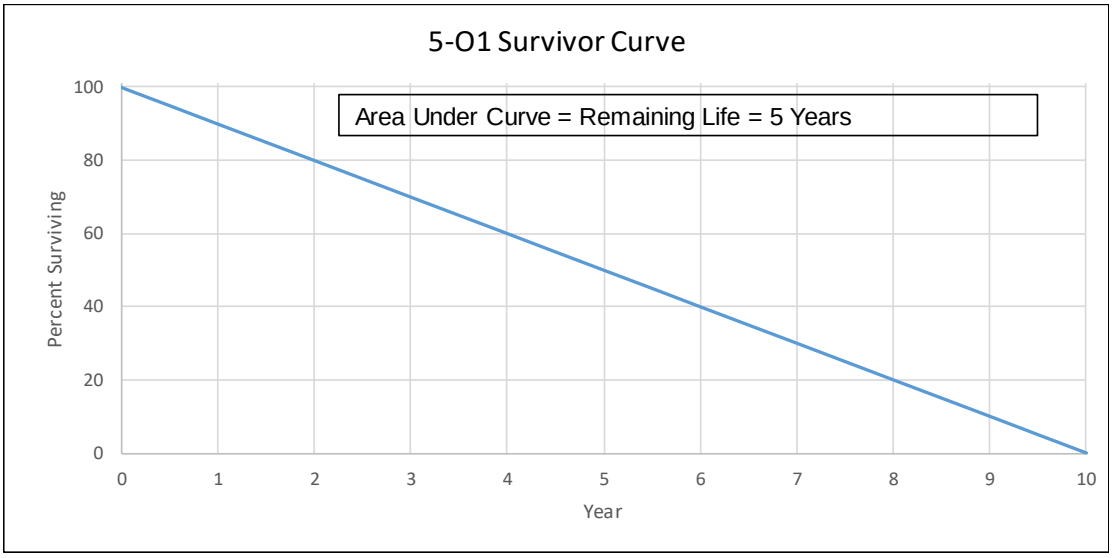
Q WHAT ASSUMPTIONS ARE YOU MAKING IN YOUR EXAMPLE?

A This example assumes that $100,000 of property is placed in-service into an account. It is the first and only property to exist in the account, and it will not be replaced as the initial $100,000 investment retires. The property will retire consistent with the 5-O1 survivor curve and has a 0% net salvage rate. This example will demonstrate how $100,000 will be recovered over the life of the property.

Q PLEASE DESCRIBE THE 5-O1 SURVIVOR CURVE.

A The 5-O1 survivor curve is presented in Figure 2.

FIGURE 2



The 5-O1 survivor curve has a 5-year average service life and assumes that all property is retired by year 10. This survivor curve assumes that 10% retires each year, therefore, in this example, it is assumed that $10,000 retires each year.

Q HOW WOULD THE ALG DEPRECIATION RATE BE CALCULATED FROM THE 5-O1 SURVIVOR CURVE?

A In the ALG procedure, the depreciation rate is calculated by ensuring recovery of the investment less net salvage over the remaining service life of the property. In this example, the net salvage rate is 0%, therefore, 100% of the investment needs to be recovered over the average service life, which in this example is 5 years. 100% divided by 5 years equals 20%. 20% is the depreciation rate that needs to be in place for 10 years to ensure the recovery of the $100,000 investment and $0 for net salvage over the life of the property.

Q HOW WOULD THE ELG DEPRECIATION RATE BE CALCULATED FROM THE 5-O1 SURVIVOR CURVE?

A With the ELG procedure, a different depreciation rate is needed for each year. The 5-O1 survivor curve in this example yields 10 different ELGs. The first group will have a 1-year life, the second group will have a 2-year life, and so on until the last group, which would have a 10-year life. In the first year, the total depreciation rate would allow for recovery of a portion of all 10 of the ELGs. In the second year, the depreciation rate would recover a portion of all of the ELGs except for the 1-year ELG, which according to the survivor curve is retired. The last year's depreciation rate would only provide for the last annual accrual of the 10-year ELG.

Q CAN YOU PROVIDE A COMPARISON OF THE ANNUAL DEPRECIATION EXPENSE IN YOUR EXAMPLE?

A Yes. In Table 1, I provide a comparison of the annual depreciation rates and expense needed to recover the $100,000 investment over its service life assuming it retires according to the 5-O1 survivor curve and has a 0% net salvage rate.

TABLE 1

Comparison of ALG Procedure and ELG Procedure
Recovery of $100,000 Investment with 0% Net Salvage and 5-O1 Survivor Curve

Year	First of Year Surviving Original Cost	ALG Rate	ALG Expense	ELG Rate	ELG Expense	Delta
1	$ 100,000	20.00%	$ 19,000	34.38%	$ 32,665	$13,665
2	90,000	20.00%	17,000	22.74%	19,332	2,332
3	80,000	20.00%	15,000	18.66%	13,998	(1,002)
4	70,000	20.00%	13,000	16.26%	10,570	(2,430)
5	60,000	20.00%	11,000	14.60%	8,030	(2,970)
6	50,000	20.00%	9,000	13.36%	6,010	(2,990)
7	40,000	20.00%	7,000	12.38%	4,332	(2,668)
8	30,000	20.00%	5,000	11.58%	2,896	(2,104)
9	20,000	20.00%	3,000	10.94%	1,641	(1,359)
10	10,000	20.00%	1,000	10.53%	526	(474)
	Total Recovered Investment:		**$ 100,000**		**$ 100,000**	**$ (0)**

Source: BCA WP-2-SR

Q WHAT DOES YOUR EXAMPLE DEMONSTRATE?

A Table 1 above demonstrates how both the ALG and ELG procedures allow for capital recovery of the $100,000 investment over the same 10-year period. The ALG depreciation rate is 20% and held constant through the 10-year period in which this property provides service. The ELG procedure requires a 34.38% depreciation rate in year 1, a 22.74% depreciation rate in year 2, declining until there is a 10.53% depreciation rate in year 10. This example shows how the ELG depreciation rates must be adjusted every year, otherwise significant intergenerational inequities will exist, and more cost will be recovered than is necessary in the first two years. However, in ratemaking, depreciation expense that is included in customer base rates are only updated when the Commission approves new base rates, which means that the year 1 depreciation expense would essentially be utilized as the test year expense until new depreciation rates are approved in a future rate case. In my example above, this would

effectively "lock in" depreciation expense based on a 34.38% depreciation rate until new rates are established in a future rate case.

Q PLEASE EXPAND ON YOUR LAST STATEMENT.

A Utilities typically only update their depreciation expense recovered from customers in the context of a base rate case, which is often not an every year occurrence. When depreciation rates for new assets are proposed using the ELG procedure, the rates put forward for approval would be analogous to the year 1 depreciation rate in this example. Therefore, if the ELG method were approved in a depreciation study, given this example and left in place for 10 years, the effective depreciation rate would be 34.38% every year. To be just to consumers and to produce reasonable rates, ELG depreciation rates should be updated each year and the corresponding depreciation expense adjusted in base rates; however, the ELG depreciation rates are not properly implemented and create intergenerational inequities, significantly overcharging customers in base rates based on the higher depreciation rates in the earlier years. Between rate cases, the depreciation expense component of a utility's revenue requirement remains at the level approved in the rate case, so while Columbia Gas may routinely update its depreciation rates, the depreciation expense provided by customers remains at level approved in the most recent rate case. Table 2 shows an example of improperly implemented ELG depreciation rates. This table shows that if the year 1 ELG rates were left unchanged for the entire 10-year period, the utility would actually recover $71,922, or 72%, more than it is entitled to recover.

TABLE 2

Comparison of ALG Procedure and Improperly Implemented ELG Procedure
Recovery of $100,000 Investment with 0% Net Salvage and 5-O1 Survivor Curve

Year	First of Year Surviving Original Cost	ALG Rate	ALG Expense	ELG Rate	ELG Expense	Delta
1	$ 100,000	20.00%	$ 19,000	34.38%	$ 32,665	$13,665
2	90,000	20.00%	17,000	34.38%	29,227	12,227
3	80,000	20.00%	15,000	34.38%	25,788	10,788
4	70,000	20.00%	13,000	34.38%	22,350	9,350
5	60,000	20.00%	11,000	34.38%	18,911	7,911
6	50,000	20.00%	9,000	34.38%	15,473	6,473
7	40,000	20.00%	7,000	34.38%	12,035	5,035
8	30,000	20.00%	5,000	34.38%	8,596	3,596
9	20,000	20.00%	3,000	34.38%	5,158	2,158
10	10,000	20.00%	1,000	34.38%	1,719	719
	Total Recovered Investment:		**$ 100,000**		**$ 171,922**	**$71,922**

Source: BCA WP-2-SR

Q MR. SPANOS HAS PROVIDED A CORRECTED LEVEL OF ACCUMULATED DEPRECIATION AS OF DECEMBER 31, 2025, ASSUMING ALG DEPRECIATION RATES WERE IN PLACE. HAVE YOU UPDATED THE OCA'S PROPOSED DEPRECIATION RATES TO ACCOUNT FOR THESE CHANGES?

A I have updated the OCA's proposed depreciation rates which uses the ALG procedure and accepts all of Columbia Gas' life parameters. These depreciation rates are provided in Exhibit BCA-SR-1 and should be approved by the Commission. In Exhibit BCA-SR-2, I provide a comparison of OCA's proposed depreciation rates and expense to Columbia Gas. In total, the use of the ALG procedure would reduce Columbia Gas' 2025 depreciation expense by $42.72 million. Table 3 summarizes the reduction by group.

TABLE 3

Depreciation Expense and Rate Comparison
Depreciation Study as of 12/31/2025

Group	Depreciation Expense ($ Millions) Columbia	OCA	Delta Amount	Delta Percent	Depreciation Rate Columbia	OCA	Delta
Underground Storage	$ -	$ -	$ -	0.0%	0.00%	0.00%	0.00%
Distribution	$ 120.39	$ 77.74	$ (42.65)	-35.4%	2.58%	1.66%	(0.92%)
General	$ 1.51	$ 1.44	$ (0.07)	-4.6%	4.23%	4.04%	(0.19%)
Total Depreciable Plant	**$ 121.90**	**$ 79.18**	**$ (42.72)**	**-35.0%**	**2.58%**	**1.68%**	**(0.90%)**

Source: Exhibit BCA-2-SR

Q IF ALG DEPRECIATION RATES ARE ADOPTED TO DETERMINE DEPRECIATION EXPENSE, WILL THE ACCUMULATED DEPRECIATION BALANCE REFLECT THIS CHANGE?

A Yes. Mr. Spanos provided the level of accumulated depreciation that would exist for the 2025 FPFTY if the ALG depreciation rates were in effect during the 2024 future test year. OCA's proposed depreciation rates are based on those corrected levels of accumulated depreciation. If the Commission adopts my recommendation to switch to the ALG procedure to calculate Columbia Gas' depreciation rates and expense going forward, the accumulated depreciation balances will automatically reflect this change on a going forward basis.

RESPONSE TO THE REBUTTAL TESTIMONY OF MARK KEMPIC

Q MR. KEMPIC CLAIMS THAT YOUR $43 MILLION ANNUAL REDUCTION TO DEPRECIATION EXPENSE WOULD FORCE COLUMBIA GAS TO GO TO THE MARKET TO SEEK FUNDING FOR ITS LONG-TERM INFRASTRUCTURE AND IMPROVEMENT PLAN ("LTIIP") AND THAT SLOWING THE PROGRAM WOULD THREATEN SAFETY AND RELIABILITY. PLEASE RESPOND.

A Mr. Kempic has provided no analysis showing that my proposed depreciation expense reduction would increase costs for customers, nor has he demonstrated that safety and reliability would be threatened. As I have discussed earlier, credit agencies significantly consider the affordability of utility rates in the setting of credit ratings. Customers need to be able to pay their bills for Columbia Gas to maintain a strong credit rating. Columbia Gas is 17 years into its LTIIP, surely a sophisticated company like this one would have ensured that the most vulnerable parts of its system were replaced in the first 17 years of a pipeline replacement program. Mr. Kempic has provided no support for his claims, and as such they should not be taken as a reason to reject OCA's proposed depreciation rates.

Q DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A Yes, it does.

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COLUMBIA GAS OF PENNSYLVANIA, INC.

SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

AVERAGE LIFE GROUP PROCEDURE

	DEPRECIABLE GROUP	SURVIVOR CURVE		ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
DEPRECIABLE PLANT									
UNDERGROUND STORAGE PLANT									
350.20	RIGHTS OF WAY	100-SQ	*	1,932.08	1,932	0	0	0.00	1.0
351.00	COMPRESSOR STATION STRUCTURES	65-R3	*	3,294,840.04	3,295,911	(1,071)	0	-	-
	WELLS								
352.01	CONSTRUCTION	100-SQ	*	1,126,771.92	1,126,772	(0)	0	-	-
352.02	EQUIPMENT	55-S2.5	*	1,072,969.89	1,072,970	(0)	0	-	-
	TOTAL ACCOUNT 352			2,199,741.81	2,199,742	(0)	0		
352.10	STORAGE LEASEHOLDS AND RIGHTS	100-SQ	*	206,940.78	206,941	(0)	0	0.00	-
353.00	LINES	60-R3	*	387,525.49	387,525	1	1	0.00	1.0
354.00	COMPRESSOR STATION EQUIPMENT	60-R2.5	*	947,637.58	947,638	(0)	0	-	-
355.00	MEASURING AND REGULATING EQUIPMENT	42-R1.5	*	104,476.92	104,477	(0)	0	-	-
	TOTAL UNDERGROUND STORAGE PLANT			**7,143,094.70**	**7,144,166**	**(1,071)**	**1**	**-**	
DISTRIBUTION PLANT									
	LAND AND LAND RIGHTS								
374.40	LAND RIGHTS	75-R2.5		8,549,393.47	1,164,440	7,384,953	112,621	1.32	65.6
374.50	RIGHTS OF WAY	80-S4		3,233,024.97	1,930,180	1,302,845	32,895	1.02	39.6
	TOTAL ACCOUNT 374			11,782,418.44	3,094,620	8,687,799	145,516	1.24	
	STRUCTURES AND IMPROVEMENTS								
375.34	MEASURING AND REGULATING	60-R0.5		7,659,844.06	1,619,357	6,040,487	112,095	1.46	53.9
375.60	INDUSTRIAL MEASURING AND REGULATING	55-R1		86,083.56	77,105	8,979	380	0.44	23.6
375.70	OTHER DISTRIBUTION SYSTEMS								
375.71	DISTRIBUTION SYSTEM STRUCTURES	90-R1.5	*	46,319,692.09	8,180,736	38,138,956	1,115,132	2.41	34.2
375.72	OTHER BUILDIINGS	38-S1.5		4,369,715.64	1,203,921	3,165,795	103,444	2.37	30.6
	TOTAL ACCOUNT 375.70			50,689,407.73	9,384,657	41,304,751	1,218,576	2.40	33.9
375.80	COMMUNICATION	45-R3		16,515.16	9,609	6,906	306	1.85	22.6
	TOTAL ACCOUNT 375			58,451,850.51	11,090,728	47,361,123	1,331,357	2.28	
376.00	MAINS								
376.30	BARE STEEL	65-R1	*	36,412,665.62	24,849,958	11,562,708	1,284,741	3.53	9.0
376.45	OTHER	65-R1		3,180,891,582.61	427,604,251	2,753,287,331	46,671,637	1.47	59.0
	TOTAL ACCOUNT 376			3,217,304,248.23	452,454,209	2,764,850,039	47,956,378	1.49	
378.00	MEASURING AND REGULATING EQUIPMENT - GENERAL	45-R0.5		238,738,145.80	29,351,644	209,386,502	4,967,708	2.08	42.1
379.10	MEASURING AND REGULATING EQUIPMENT - CITY GATE	35-S2		119,158.02	48,652	70,506	8,253	6.93	8.5

COLUMBIA GAS OF PENNSYLVANIA, INC.

SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

AVERAGE LIFE GROUP PROCEDURE

	DEPRECIABLE GROUP		SURVIVOR CURVE		ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)		(2)		(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
380.00	SERVICES									
380.30	BARE STEEL		45-R0.5	*	347,355.93	244,225	103,131	16,126	4.64	6.4
380.45	OTHER		45-R0.5		971,342,738.31	194,373,673	776,969,065	19,598,730	2.02	39.6
	TOTAL ACCOUNT 380				971,690,094.24	194,617,898	777,072,196	19,614,855	2.02	
381.00	METERS		44-S1		48,663,361.81	19,815,661	28,847,701	934,987	1.92	30.9
381.10	METERS - AMR		20-S2.5		25,165,054.68	20,511,638	4,653,417	544,091	2.16	8.6
382.00	METER INSTALLATIONS		55-R3		50,934,022.06	17,114,065	33,819,957	847,522	1.66	39.9
383.00	HOUSE REGULATORS		50-S2		20,531,392.36	6,100,489	14,430,903	363,276	1.77	39.7
384.00	HOUSE REGULATOR INSTALLATIONS		40-S4		3,538,803.18	2,978,739	560,064	42,757	1.21	13.1
385.00	INDUSTRIAL MEASURING AND REGULATING EQUIPMENT - OTHER THAN METERS		30-R0.5		9,883,926.00	2,995,425	6,888,501	290,600	2.94	23.7
	OTHER EQUIPMENT									
387.00	GENERAL		32-R1		136,698.14	89,275	47,423	2,510	1.84	18.9
387.40	COMMUNICATION EQUIPMENT		25-R1.5		16,050,396.45	3,978,127	12,072,269	629,571	3.92	19.2
387.50	GPS EQUIPMENT		10-S3		2,201,371.95	2,097,596	103,776	58,987	2.68	1.8
	TOTAL ACCOUNT 387				18,388,466.54	6,164,998	12,223,468	691,068	3.76	
	TOTAL DISTRIBUTION PLANT				**4,675,190,941.87**	**766,338,766**	**3,908,852,176**	**77,738,368**	**1.66**	
GENERAL PLANT										
390.10	STRUCTURES AND IMPROVEMENTS - COMMUNICATION		45-R2		49,821.42	49,821	0	0	0.00	17.6
	OFFICE FURNITURE AND EQUIPMENT									
391.10	FURNITURE		20-SQ		3,674,992.31	1,419,280	2,255,712	178,855	4.87	12.6
391.11	EQUIPMENT		15-SQ		91,303.67	70,925	20,379	5,032	5.51	4.0
391.12	INFORMATION SYSTEMS		5-SQ		126,594.17	125,325	1,269	846	0.67	1.5
	TOTAL ACCOUNT 391				3,892,890.15	1,615,530	2,277,360	184,733	4.75	
392.00	TRANSPORTATION EQUIPMENT - TRAILERS		13-L4		25,616.89	24,006	1,611	579	2.26	2.8
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		25-SQ		25,303,257.61	8,510,197	16,793,061	992,996	3.92	16.9
394.12	CNG FACILITIES		12-S1.5		18,450.18	18,097	353	0	-	-
	TOTAL ACCOUNT 394				25,321,707.79	8,528,294	16,793,414	992,996	3.92	

COLUMBIA GAS OF PENNSYLVANIA, INC.

SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

AVERAGE LIFE GROUP PROCEDURE

	DEPRECIABLE GROUP	SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2025	BOOK DEPRECIATION RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
395.00	LABORATORY EQUIPMENT	20-SQ	264,921.24	135,121	129,800	14,123	5.33	9.2
396.00	POWER OPERATED EQUIPMENT	13-L2.5	948,698.04	977,116	(28,418)	0	-	-
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	21-R2	4,290,323.34	599,444	3,690,879	191,206	4.46	19.3
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	990,093.14	680,455	309,638	61,290	6.19	5.1
	TOTAL GENERAL PLANT		**35,784,072.01**	**12,609,787**	**23,174,284**	**1,444,927**	**4.04**	
	SUBTOTAL DEPRECIABLE PLANT		**4,718,118,108.58**	**786,092,719**	**3,932,025,389**	**79,183,296**	**1.68**	
AMORTIZABLE PLANT								
303.00	MISCELLANEOUS INTANGIBLE PLANT		70,950,449.03	33,056,275	37,894,174	10,867,210 **		
303.60	MISCELLANEOUS INTANGIBLE PLANT - CLOUD		16,163,961.41	6,518,572	9,645,389	2,766,653 **		
362.10	ENVIRONMENTAL REMEDIATION		0.00	(81,773)				
375.71	STRUCTURES AND IMPROVEMENTS - LEASED		6,386,139.82	3,513,383	2,872,757	471,457 **		
	SUBTOTAL AMORTIZABLE PLANT		**93,500,550.26**	**43,006,457**	**50,412,320**	**14,105,320**		
NONDEPRECIABLE PLANT			**3,533,175.06**	**235,418**				
	TOTAL GAS PLANT		**4,815,151,833.90**	**829,334,594**	**3,982,437,710**	**93,288,616**		

* Indicates the use of an interim survivor curve and retirement date.
** Accrual rate based on individual asset amortization.

COLUMBIA GAS OF PENNSYLVANIA, INC.

COMPARISON OF COLUMBIA AND OCA DEPRECIATION MODELS
RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

	DEPRECIABLE GROUP	SURVIVOR CURVE		ORIGINAL COST AS OF DECEMBER 31, 2025	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL AMOUNT	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL RATE	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL AMOUNT	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL RATE	DELTA CALCULATED ANNUAL ACCRUAL AMOUNT	DELTA CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)		(3)	(4)	(5)=(4)/(3)	(6)	(7)=(6)/(3)	(8) = (6) - (4)	(9) = (7) - (5)
DEPRECIABLE PLANT										
UNDERGROUND STORAGE PLANT										
350.20	RIGHTS OF WAY	100-SQ	*	1,932.08	0	-	0	0.00	0	0.00
351.00	COMPRESSOR STATION STRUCTURES	65-R3	*	3,294,840.04	0	-	0	-	0	-
	WELLS									
352.01	CONSTRUCTION	100-SQ	*	1,126,771.92	0	-	0	-	0	-
352.02	EQUIPMENT	55-S2.5	*	1,072,969.89	0	-	0	-	0	-
	TOTAL ACCOUNT 352			2,199,741.81	0		0		0	
352.10	STORAGE LEASEHOLDS AND RIGHTS	100-SQ	*	206,940.78	0	0.00	0	0.00	0	0.00
353.00	LINES	60-R3	*	387,525.49	0	-	1	0.00	1	0.00
354.00	COMPRESSOR STATION EQUIPMENT	60-R2.5	*	947,637.58	0	-	0	-	0	-
355.00	MEASURING AND REGULATING EQUIPMENT	42-R1.5	*	104,476.92	0	-	0	-	0	-
	TOTAL UNDERGROUND STORAGE PLANT			**7,143,094.70**	**0**	**-**	**1**	**-**	**1**	**-**
DISTRIBUTION PLANT										
	LAND AND LAND RIGHTS									
374.40	LAND RIGHTS	75-R2.5		8,549,393.47	137,864	1.61	112,621	1.32	(25,243)	(0.29)
374.50	RIGHTS OF WAY	80-S4		3,233,024.97	34,545	1.07	32,895	1.02	(1,650)	(0.05)
	TOTAL ACCOUNT 374			11,782,418.44	172,409	1.46	145,516	1.24	(26,893)	(0.22)
	STRUCTURES AND IMPROVEMENTS									
375.34	MEASURING AND REGULATING	60-R0.5		7,659,844.06	186,200	2.43	112,095	1.46	(74,105)	(0.97)
375.60	INDUSTRIAL MEASURING AND REGULATING	55-R1		86,083.56	459	0.53	380	0.44	(79)	(0.09)
375.70	OTHER DISTRIBUTION SYSTEMS									
375.71	DISTRIBUTION SYSTEM STRUCTURES	90-R1.5	*	46,319,692.09	1,220,146	2.63	1,115,132	2.41	(105,014)	(0.22)
375.72	OTHER BUILDIINGS	38-S1.5		4,369,715.64	125,903	2.88	103,444	2.37	(22,459)	(0.51)
	TOTAL ACCOUNT 375.70			50,689,407.73	1,346,049	2.66	1,218,576	2.40	(127,473)	(0.26)
375.80	COMMUNICATION	45-R3		16,515.16	339	2.05	306	1.85	(33)	(0.20)
	TOTAL ACCOUNT 375			58,451,850.51	1,533,047	2.62	1,331,357	2.28	(201,690)	(0.34)
376.00	MAINS									
376.30	BARE STEEL	65-R1	*	36,412,665.62	1,154,594	3.17	1,284,741	3.53	130,147	0.36
376.45	OTHER	65-R1		3,180,891,582.61	72,418,288	2.28	46,671,637	1.47	(25,746,651)	(0.81)
	TOTAL ACCOUNT 376			3,217,304,248.23	73,572,882	2.29	47,956,378	1.49	(25,616,504)	(0.80)
378.00	MEASURING AND REGULATING EQUIPMENT - GENERAL	45-R0.5		238,738,145.80	8,811,177	3.69	4,967,708	2.08	(3,843,469)	(1.61)
379.10	MEASURING AND REGULATING EQUIPMENT - CITY GATE	35-S2		119,158.02	8,870	7.44	8,253	6.93	(617)	(0.51)

COLUMBIA GAS OF PENNSYLVANIA, INC.

COMPARISON OF COLUMBIA AND OCA DEPRECIATION MODELS
RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

	DEPRECIABLE GROUP	SURVIVOR CURVE		ORIGINAL COST AS OF DECEMBER 31, 2025	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL AMOUNT	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL RATE	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL AMOUNT	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL RATE	DELTA CALCULATED ANNUAL ACCRUAL AMOUNT	DELTA CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)		(3)	(4)	(5)=(4)/(3)	(6)	(7)=(6)/(3)	(8) = (6) - (4)	(9) = (7) - (5)
380.00	SERVICES									
380.30	BARE STEEL	45-R0.5	*	347,355.93	14,195	4.09	16,126	4.64	1,931	0.55
380.45	OTHER	45-R0.5		971,342,738.31	31,759,310	3.27	19,598,730	2.02	(12,160,580)	(1.25)
	TOTAL ACCOUNT 380			971,690,094.24	31,773,505	3.27	19,614,855	2.02	(12,158,650)	(1.25)
381.00	METERS	44-S1		48,663,361.81	1,169,284	2.40	934,987	1.92	(234,297)	(0.48)
381.10	METERS - AMR	20-S2.5		25,165,054.68	597,484	2.37	544,091	2.16	(53,393)	(0.21)
382.00	METER INSTALLATIONS	55-R3		50,934,022.06	971,345	1.91	847,522	1.66	(123,823)	(0.25)
383.00	HOUSE REGULATORS	50-S2		20,531,392.36	419,579	2.04	363,276	1.77	(56,303)	(0.27)
384.00	HOUSE REGULATOR INSTALLATIONS	40-S4		3,538,803.18	45,532	1.29	42,757	1.21	(2,775)	(0.08)
385.00	INDUSTRIAL MEASURING AND REGULATING EQUIPMENT - OTHER THAN METERS	30-R0.5		9,883,926.00	469,848	4.75	290,600	2.94	(179,248)	(1.81)
	OTHER EQUIPMENT									
387.00	GENERAL	32-R1		136,698.14	3,672	2.69	2,510	1.84	(1,162)	(0.85)
387.40	COMMUNICATION EQUIPMENT	25-R1.5		16,050,396.45	785,293	4.89	629,571	3.92	(155,722)	(0.97)
387.50	GPS EQUIPMENT	10-S3		2,201,371.95	53,631	2.44	58,987	2.68	5,356	0.24
	TOTAL ACCOUNT 387			18,388,466.54	842,596	4.58	691,068	3.76	(151,528)	(0.82)
	TOTAL DISTRIBUTION PLANT			**4,675,190,941.87**	**120,387,558**	**2.58**	**77,738,368**	**1.66**	**(42,649,190)**	**(0.92)**
GENERAL PLANT										
390.10	STRUCTURES AND IMPROVEMENTS - COMMUNICATION	45-R2		49,821.42	0	-	0	0.00	0	0.00
	OFFICE FURNITURE AND EQUIPMENT									
391.10	FURNITURE	20-SQ		3,674,992.31	178,856	4.87	178,855	4.87	(1)	(0.00)
391.11	EQUIPMENT	15-SQ		91,303.67	5,679	6.22	5,032	5.51	(647)	(0.71)
391.12	INFORMATION SYSTEMS	5-SQ		126,594.17	846	0.67	846	0.67	0	(0.00)
	TOTAL ACCOUNT 391			3,892,890.15	185,381	4.76	184,733	4.75	(648)	(0.01)
392.00	TRANSPORTATION EQUIPMENT - TRAILERS	13-L4		25,616.89	638	2.49	579	2.26	(59)	(0.23)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ		25,303,257.61	994,416	3.93	992,996	3.92	(1,420)	(0.01)
394.12	CNG FACILITIES	12-S1.5		18,450.18	0	-	0	-	0	-
	TOTAL ACCOUNT 394			25,321,707.79	994,416	3.93	992,996	3.92	(1,420)	(0.01)

COLUMBIA GAS OF PENNSYLVANIA, INC.

COMPARISON OF COLUMBIA AND OCA DEPRECIATION MODELS
RELATED TO GAS PLANT AS OF DECEMBER 31, 2025

	DEPRECIABLE GROUP	SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2025	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL AMOUNT	COLUMBIA MODEL[1] CALCULATED ANNUAL ACCRUAL RATE	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL AMOUNT	OCA MODEL[2] CALCULATED ANNUAL ACCRUAL RATE	DELTA CALCULATED ANNUAL ACCRUAL AMOUNT	DELTA CALCULATED ANNUAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)=(4)/(3)	(6)	(7)=(6)/(3)	(8) = (6) - (4)	(9) = (7) - (5)
395.00	LABORATORY EQUIPMENT	20-SQ	264,921.24	14,122	5.33	14,123	5.33	1	0.00
396.00	POWER OPERATED EQUIPMENT	13-L2.5	948,698.04	0	-	0	-	0	-
397.50	COMMUNICATION EQUIPMENT - TELEMETERING	21-R2	4,290,323.34	258,267	6.02	191,206	4.46	(67,061)	(1.56)
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	990,093.14	61,361	6.20	61,290	6.19	(71)	(0.01)
	TOTAL GENERAL PLANT		**35,784,072.01**	**1,514,185**	**4.23**	**1,444,927**	**4.04**	**(69,258)**	**(0.19)**
	SUBTOTAL DEPRECIABLE PLANT		**4,718,118,108.58**	**121,901,743**	**2.58**	**79,183,296**	**1.68**	**(42,718,447)**	**(0.90)**
AMORTIZABLE PLANT									
303.00	MISCELLANEOUS INTANGIBLE PLANT		70,950,449.03	10,867,210 **		10,867,210 **		0 **	
303.60	MISCELLANEOUS INTANGIBLE PLANT - CLOUD		16,163,961.41	2,766,653 **		2,766,653 **		0 **	
362.10	ENVIRONMENTAL REMEDIATION								
375.71	STRUCTURES AND IMPROVEMENTS - LEASED		6,386,139.82	471,457 **		471,457 **		0 **	
	SUBTOTAL AMORTIZABLE PLANT		**93,500,550.26**	**14,105,320**		**14,105,320**		**0**	
NONDEPRECIABLE PLANT			**3,533,175.06**						
	TOTAL GAS PLANT		**4,815,151,833.90**	**136,007,063**		**93,288,616**		**(42,718,447)**	

* Indicates the use of an interim survivor curve and retirement date.
** Accrual rate based on individual asset amortization.

Sources:
[1] Exhibit No. 105, pages 7 - 9
[2] Exhibit BCA-1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Brian C. Andrews, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 4SR, 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 25, 2024

Signature: _____

Brian C. Andrews

Address: Brubaker & Associates, Inc.
16690 Swingley Ridge Road, Suite 140
Chesterfield, MO 63017

OCA Statement No. 5SR

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2024-3046519
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

SURREBUTTAL TESTIMONY OF

JEROME D. MIERZWA

ON BEHALF OF THE

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

PUBLIC (REDACTED) VERSON

July 25, 2024

EXETER
ASSOCIATES, INC.
10480 Little Patuxent Parkway, Suite 300
Columbia, Maryland 21044

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jerome D. Mierzwa. I am a Principal and the President of Exeter Associates, Inc. ("Exeter"). My business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044. Exeter specializes in providing public utility-related consulting services.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY IN THIS PROCEEDING?

A. Yes. My direct testimony was submitted as OCA Statement No. 5 on June 14, 2024, and my rebuttal testimony was submitted as OCA Statement No. 5R on July 11, 2024.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. The purpose of my Surrebuttal Testimony is to respond to the rebuttal testimony of Kevin L. Johnson and Mark Kempic presented on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company"), Mark D. Ewen presented on behalf of the Office of Small Business Advocate ("OSBA"), and James L. Crist presented on behalf of Pennsylvania State University ("PSU").

II. COLUMBIA GAS OF PENNSYLVANIA, INC. WITNESS: KEVIN L. JOHNSON

Q. ON PAGES 9 AND 10 OF COLUMBIA STATEMENT NO. 6-R, MR. JOHNSON CONTENDS THAT THE 2.0 TIMES THE SYSTEM AVERAGE INCREASE YOU AND OSBA WITNESS MR. EWEN HAVE ASSIGNED TO THE LDS/LGSS CLASS IS IN EXCESS OF THE UPPER BOUND FOR RATE GRADUALISM. WHAT IS YOUR RESPONSE?

A. As I explained in my direct testimony, there is no hard and fast rule with respect to applying the concept of gradualism, and typically an increase of 1.5 to 2.0 times the

system average increase is considered consistent with the concept of gradualism. Mr. Ewen agrees that a 2.0 times the system average increase for the LDS/LGSS class is appropriate.[1] Under Columbia's proposed revenue allocation and the Peak & Average allocated cost of service study ("ACOSS") supported by Mr. Johnson, the relative rate of return ("RROR") of the LDS/LGSS class is 0.41. A ROR of 1.0 indicates that a rate class is providing revenues equal to its indicated cost of service. Given that the LDS/LGSS rate class would be providing a return which is significantly lower than the indicated cost of service under Columbia's proposed revenue allocation of a 1.5 times system average increase, I believe the 2.0 times system average increase is appropriate for the LDS/LGSS rate class in order to develop an overall revenue allocation that is more reasonable in this proceeding. Based on Columbia's revenue requirement claim in this proceeding, a 2.0 times the system average increase would only increase the RROR of the LDS/LGSS class to 0.55.[2]

Q. IN YOUR DIRECT TESTIMONY YOU INDICATED THAT UNCOLLECTIBLE EXPENSE IS NOT A DIRECT CUSTOMER COST AND, THEREFORE, SHOULD NOT BE INCLUDED IN THE CALCULATION OF A CUSTOMER CHARGE.[3] DOES MR. JOHNSON AGREE WITH YOUR POSITION?

A. No. Mr. Johnson claims that my recommendation would result in assigning 100% of uncollectible costs to volumetric base rates for recovery and this eventually creates an intra-class subsidy to lower use customers.[4] He contends that because the customer charge is a portion of the customers' bills that become uncollectible, those who pay the customer charge should help pay for the uncollectible accounts the charge generates

[1] OSBA Statement No. 1, page 18, lines 5-10.
[2] OSBA Statement No. 5, page 13, Table 3.
[3] OSA Statement No. 5, page 16, lines 7-12.
[4] Columbia Statement No. 6-R, page 12, lines 14-16.

and, therefore, the uncollectible expenses should be included in the customer charge calculation.[5]

Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON'S CLAIM CONCERNING THE INCLUSION OF UNCOLLECTIBLE EXPENSES IN THE CALCULATION OF A CUSTOMER CHARGE?

A. As indicated in my direct testimony, only those costs which change directly, both with the addition or subtraction of a customer, should be included in the calculation of a customer charge.[6] Uncollectible expense does not directly change with the addition or subtraction of a customer and, therefore, should not be included in the calculation of a customer charge. A charge that does not change with the addition or subtraction of a customer should not be characterized as a direct customer cost.

Q. AT PAGE 16 OF YOUR DIRECT TESTIMONY, YOU STATE COLUMBIA'S "MONTHLY RESIDENTIAL CUSTOMER CHARGE IS ALREADY THE HIGHEST IN THE COMMONWEALTH AND THE PROPOSED CHARGES IS INCONSISTENT WITH THE COMMISSION'S GOAL OF ENCOURAGING ENERGY CONSERVATION. THEREFORE, I RECOMMEND THAT THE EXISTING $16.75 MONTHLY CHARGE BE MAINTAINED." WHAT IS MR. JOHNSON'S RESPONSE TO THIS RECOMMENDATION?

A. Mr. Johnson does not dispute my claim that Columbia's current monthly Residential charge is already the highest in the Commonwealth, but he contends that Columbia's Residential customer charge should not be determined by the cost of service of other local distribution companies ("LDCs") in Pennsylvania.[7]

[5] Columbia Statement No. 6-R, page 12, lines 16-19.
[6] OCA Statement No. 5, page 16, lines 7-11.
[7] Columbia St. No. 6-R, page 13, lines 4-7.

Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON?

A. Columbia is proposing to increase its current monthly Residential customer charge from $16.75 to $26.00. The additional proposed increase would further increase the difference between Columbia's Residential customer charge and those of the other major Pennsylvania LDCs. With the strains on household budgets attributable to the economic conditions caused by inflation, increasing fixed charges limits the benefits Residential customers can realize from engaging in conservation actions and their ability to address budgetary strains. Promotion of energy conservation has been a longstanding energy policy of the Commonwealth. To promote the Commonwealth's policy goals to encourage conservation and provide the Residential customers of Pennsylvania's largest LDCs comparable opportunities to control their heating bills, Columbia's current monthly Residential customer charge should not be increased.

Q. COLUMBIA HAS PROPOSED A "REVENUE NORMALIZATION ADJUSTMENT" ("RNA") MECHANISM. ON PAGE 18 THROUGH 24 OF YOUR DIRECT TESTIMONY, YOU ADDRESS THE 14 FACTORS FOR CONSIDERATION IDENTIFIED IN THE COMMISSION'S STATEMENT OF POLICY ON ALTERNATIVE RATEMAKING IN RESPONDING TO THE COMPANY'S PROPOSED RNA. HOW DOES MR. JOHNSON RESPOND?

A. Mr. Johnson notes that of the 14 factors, I agreed in principle with Columbia on four considerations.[8] He then comments on those considerations where I differed from Columbia. Below, I identify each consideration in which I continue to differ as well as

[8] Columbia St. No. 6-R, page 18, lines 18-19.

Columbia's initial response, my initial response, Mr. Johnson's comments, and my response to Mr. Johnson's comments.

Consideration 1:	Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.
	COLUMBIA: Columbia's proposed RNA is designed to recover the residential base revenues needed to satisfy the cost of service requirements determined in this proceeding while negating over or under recovery of costs.
	OCA: The Company's response does not indicate how the mechanism aligns revenues with cost causation as to fixed and variable costs. The RNA provides for the recovery of fixed costs on a volumetric basis; therefore, it does not align utility revenues with cost causation principles as to both fixed and variable costs.

Mr. Johnson claims that the RNA is designed to recover/pass back the under/over amount charged by the variable base rates for the recovery of those fixed and variable costs caused by the change in usage per customer.[9] He therefore claims that the RNA more closely aligns actual revenues to costs.[10]

In response to Mr. Johnson, under the RNA, all Residential customers will be assessed the same "Benchmark Distribution Revenue per Bill," or BDRB, regardless of whether a customer's usage contributed to an under- or over-recovery. That is, if an overall under-recovery for the Residential class occurs, all customers will be assessed the same BDRB, including those customers whose usage increased and resulted in an over-recovery of costs. Under these circumstances, the RNA does not align actual

[9] Columbia St. No. 6-R, page 19, lines 21-24.
[10] Columbia St. No. 6-R, page 19, lines 24-25.

revenues to costs and has the potential to produce unduly discriminatory rates among Residential customers.

Consideration 3:	Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.
	COLUMBIA: Columbia's RNA benchmark includes the anticipated volumetric base rate revenue derived from the fully projected test year consumption.
	OCA: The RNA "true-up" mechanism creates the anomaly where customers see rates increase when they reduce consumption and rate decreases when they increase consumption.

Mr. Johnson claims that the RNA mechanism and the Company's rate design do reflect the customer's anticipated consumption levels as provided in the fully projected future test year.[11] However, Mr. Johnson does not address the anomaly caused by the RNA that I note in my direct testimony where in customers see rate increases when they reduce consumption and rate decreases when they increase consumption.

Consideration 4:	Please explain how the ratemaking mechanism and rate design limit or eliminate inter-class and intra-class cost shifting.
	COLUMBIA: Columbia's RNA minimizes inter-class cost subsidization by limiting the amount of cost recovery for the residential class to the revenue benchmark established in this case. Residential intra-class cost subsidization is reduced through Columbia's proposal of a higher customer charge for the residential class.
	OCA: The RNA is only applicable to the Residential class and, therefore, does not affect interclass cost shifting. The Company's higher Residential customer

[11] Columbia St. No. 6-R, page 20, lines 10-12.

charge proposal, which should be rejected, is unrelated to the RNA. OCA Witness Roger Colton explains that with respect to interclass cost shifting, the RDM could shift revenue within the Residential class from customers that are financially able to invest in energy efficiency and conservation measuring to low-income customers who are not financially able to make those same investments.

Mr. Johnson claims that the Company's proposed higher Residential customer charge is related to the RNA in that it reduces the amount of revenue subject to recovery through the RNA for all customers, including low-income customers.[12]

I agree with Mr. Johnson that the higher customer charge proposal reduces the amount of revenue subject to recovery through the RNA; however, customer charge revenues are excluded from the RNA. A higher customer charge combined with a class-wide BDRP has the potential to result in highly diverging Residential rates that do not reflect individuals' usage of the distribution system.

Consideration 5: Please explain how the RNA limits or eliminates disincentives for the promotion of efficiency programs.

COLUMBIA: Reduced throughput will not lead to revenue and earnings erosion due to under-recovery because the link between level of throughput and base revenue recoveries is broken with the implementation of the RNA.

OCA: The Company has not demonstrated that the lack of an RNA has been a major obstacle for the promotion of its voluntary energy efficiency & conservation (EE&C) activities. The Company has been able to implement methods to improve consumer efficiency without an RNA. Moreover, there has been a long-term trend of per-customer declining gas consumption (i.e. improved natural gas efficiency use) without an RNA.

[12] Id., lines 33-36.

> Columbia has not proposed any new energy efficiency programs in this proceeding. The RNA disincentives customers to engage in energy efficiency programs because less of a customer's total bill would be subject to reduction through energy conservation. Under the RNA, the residential consumer would be required to pay the benchmark revenue level per customer regardless of the customer's efforts to increase energy efficiency. The RNA provides a disincentive to consumers to work towards more efficient energy usage by minimizing or eliminating all together bill savings related to consumption savings and in no way promotes efficiency programs.

Mr. Johnson claims that the Company's RNA does not affect customers' ability to pursue energy efficiency measure, and the Company will continue to promote the use of energy efficiency measure to its customers through the Company's Energy Efficiency programs via Columbia's website, social media, emails, newsletters, bill inserts, and Google ads.[13] However, Mr. Johnson does not disagree that less of a customers' total bill would be subject to reduction through energy conservation. As pointed out by OCA witness Colton, the fact that the RNA will lessen the bill reduction impact of energy conservation also has an acute impact on low-income customers who may seek to reduce their bills through reduced consumption or efficiency.

Additionally, in the Commission's July 22, 2024 Opinion and Order entered at Docket No. R-2023-3043189, R-2023-3043190 in the Pennsylvania-American Water Company ("PAWC") base rate case ("PAWC Order"),[14] the Commission found the following as to PAWC's similar revenue decoupling mechanism ("RDM") proposal:

> In addition, we find that the RDM does not benefit customers. In fact, it appears that the RDM will hinder customer conservation efforts and could cause customers who take measures to reduce their water consumption to share some of their bill savings with PAWC. We agree that charging customers an

[13] Columbia St. No. 6R, page 21, lines 17-21.
[14] Available at https://www.puc.pa.gov/pcdocs/1838564.pdf.

> additional charge through the RDM may act as a disincentive from conservation practices by customers because it will diminish the value of any savings achieved from such conservation efforts… Therefore, we conclude that it is not in the public interest to approve the proposed RDM, which would provide an additional type of revenue stabilization to PAWC at the risk of eroding customers' conservation savings, which is the only way for water customers to affect a reduction to their water bill.

PAWC Order at 307. The Commission found that the negative impact on consumer conservation efforts along with various other factors warranted rejection of PAWC's RDM proposal. PAWC Order at 308. Given that there is no major difference between the RDM proposed by PAWC and the RNA proposed by Columbia in terms of the impact on customer conservation efforts, the Commission's rationale should apply equally here as well given that the only way for gas customers affect a reduction in their gas bill is to conserve their usage of gas.

Consideration 6: Please explain how the RNA impacts customer incentives to employ efficiency measures and distributed energy resources.

COLUMBIA: Customers will continue to have an incentive to pursue energy efficiency measures since approximately 30% of an average residential bill is still subject to volumetric usage not related to base rate revenue recovery.

OCA: The RNA reduces the incentive for Residential customers to pursue energy efficiency programs. Base rate revenue savings that would ordinarily be achieved through usage reductions will be offset by higher usage charges under the RNA.

More specifically, the proposed RNA could provide a disincentive to ratepayers to undertake energy conservation efforts because they would be required to pay for gas they did not use. Revenue savings to individual customers that would ordinarily be achieved through usage reductions would be offset by surcharges to all customers under the RNA. Hence, if customers save money on their monthly gas bill due to efficient consumption, customers will be forced to share their bill savings with the utility. Moreover, with

the high and apparently never-ending rate increases that Columbia Gas has implemented and will apparently continue to seek, customers are already incented to conserve gas without a new RNA surcharge.

Mr. Johnson claims that when an individual Residential customer decides to reduce their usage, the customer pays less to the Company through their volumetric charge.[15] He explains the shortfall in base revenue from the customer will be made up by the entire Residential class, not just the customer that chose to conserve, implying that the incentive to conserve would still exist under the RNA. Mr. Johnson fails to recognize that the shortfall in base revenue would also be recovered from the customer that chose to conserve, reducing the inventive for the customer to conserve by pursuing energy efficiency programs.

Additionally, I incorporate my response in Consideration 5 above regarding the Commission's PAWC Order finding that the proposed RDM would have a negative impact on customer conservation efforts.

Consideration 7: Please explain how the RNA impacts low-income customers and support consumer assistance programs.

COLUMBIA: Columbia's proposed RNA only applies to non-CAP customers.

OCA: The RNA will not impact CAP customers. However, as OCA witness Colton points out, not all low-income customers are enrolled in CAP and for those customers not enrolled in CAP, the RNA will be applied to their bills and have the same effect of being a disincentive to energy efficiency as non-low-income customers. Additionally, OCA witness Colton addresses how the RNA could affirmatively harm non-CAP, low-income customers that do not have the financial means to pursue investments in energy efficiency and conservation measures.

[15] Columbia St. No. 6R, page 22, lines 11-13.

Mr. Johnson disagrees that the RNA will have the same effect of being a disincentive to energy efficiency.[16] Please see my response to Consideration 6 regarding energy efficiency. In addition, by virtue of the fact that they have limited income, low-income customers may be less able to actually take measures to reduce their bills through conservation. Under the RNA, they would then have to pay additional costs because of conservation efforts enacted by other non-low-income households, which would likely have adverse impact on utility bill affordability.

Additionally, in the Commission's PAWC Order,[17] the Commission found the following as to PAWC's similar RDM proposal:

> Without adequate consumer protections, low-income customers will be placed at risk of bearing additional costs from the RDM, and this potential increase in unaffordability would expose these customers to a greater risk of arrears and termination of service.

PAWC Order at 307. Given that there is no major difference between the RDM proposed by PAWC and the RNA proposed by Columbia in terms of the impact on low-income customers, the Commission's rationale should apply equally here as well.

Consideration 8	Please explain how the RNA impacts customer rate stability principles.
	COLUMBIA: Columbia's proposed RNA enables the recovery of costs established in this case and, therefore, mitigates the potential under or over recovery of costs that could require a material rate adjustment in the future.
	OCA: Under the current regulatory standard in Pennsylvania, base rate cost under and over recoveries are currently not tracked and are not eligible for recovery in future base rate proceedings. The RNA will not change this standard.

[16] Columbia St. No.6-R, page 22, lines 33-35.
[17] Available at https://www.puc.pa.gov/pcdocs/1838564.pdf.

> The proposed RNA would add another surcharge to customers' bills and the Company has not shown how it would reduce the frequency of Columbia Gas base rate filings. Thus, it does not appear that a new RNA surcharge would improve rate stability. In contrast, under traditional cost-of-serve ratemaking, if a utility experiences sales reductions and under-recovery, it cannot simply achieve the same result as an RNA true-up by filing another base rate case with adjusted sales forecasts. When a utility files a general rate increase, all relevant information is reviewed to determine just and reasonable rates, not just sales forecasts. Traditional ratemaking produces rate stability.

Mr. Johnson claims that absent the RNA, when the billing determinants used in a rate case to design rates are different from the usage per customer currently experienced, the Company's only option is to file a base rate case.[18] In response, I would note that in the last 17 years, Columbia has filed 12 base rate cases. Mr. Johnson has not claimed that the RNA will reduce the frequency of Columbia's rate case filings.

In the Commission's PAWC Order, the Commission found the following with regard to the PAWC's proposed RDM:

> [W]e agree with the ALJs that approval of PAWC's proposed RDM is not in the public interest. First, PAWC did not establish a need for the RDM as an additional revenue stabilization mechanism. Revenue stabilization mechanisms are implemented to remove the risk of non-recovery of the full amount of any permitted revenue requirement. However, PAWC already utilizes frequent base rate cases, the FPFTY, and the DSIC to address revenue shortfalls. ***Specifically, the impact of the RDM on the frequency of base rate case filings is unknown and may not lessen the need and frequency of base rate cases***. Therefore, PAWC has not proven that the RDM is needed.

PAWC Order at 307 (emphasis added). Given that there is no major difference between the RDM proposed by PAWC and the RNA proposed by Columbia , the Commission's rationale should apply equally here as well.

[18] Columbia St. No. 6-R at 47.

Consideration 9	Please explain how weather impacts utility revenue under the RNA.
	COLUMBIA: The RNA as proposed will capture base revenue differences net of weather as the benchmark is based upon normal weather and the actual revenue will include billed WNA adjustments.
	OCA: Weather will not impact utility revenue under the RNA.

Mr. Johnson claims that to the extent WNA does not address weather impact within the 3% band and to the extent it impacts weather outside the months the WNA is in effect, weather may impact the RNA. Given this further explanation , I agree with Mr. Johnson.

Consideration 12	Please explain whether the RNA includes appropriate consumer protections.
	COLUMBIA: The RNA as proposed establishes a Benchmark Distribution Revenue per Bill ("BDRB") residential customer. Rider RNA will refund any amount over the established benchmark, and collect any amount below the benchmark. By design, the Company cannot retain revenue in excess of the BDRB, which protects the customer from being over-charged. Columbia will submit two filings per year for the RNA mechanism, which can be reviewed and audited by the Commission, similar to the process for the Company's PGC and Rider USP filings.
	OCA: The RNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony and the testimony of OCA witness Colton and OCA witness Dismukes.

In responding to this consideration, Mr. Johnson references the testimony of Mr. Colton and Mr. Dismukes, and I will let them respond directly to Mr. Johnson. Nevertheless, in my direct testimony, I gave several examples as to why the RNA does

not include appropriate consumer protections.[19] More specifically, I indicated that the RNA:

- Could increase earnings beyond those that the Company would ordinarily be entitled;
- Unreasonably applies to customers whose usage is relatively constant over time;
- Embodies a take-or-pay pricing policy;
- The RNA removes the risk of non-recovery of the full amount of any permitted revenue requirement, and as such, the RNA would produce guaranteed rate recovery where no guarantee existed in the past and shift the risk of recovery entirely onto consumers without any benefit; and
- Inappropriately adjusts rates without considering other changes in total revenues and costs.

In the Commission's PAWC Order, the Commission found the following with regard to the PAWC's proposed RDM: "As proposed, the RDM would produce guaranteed rate recovery where no guarantee existed in the past and shift the risk of recovery entirely onto customers without any benefit." PAWC Order at 308. Given that there is no major difference between the RDM proposed by PAWC and the RNA proposed by Columbia Gas, the Commission's rationale should apply equally here as well.

Consideration 13	Please explain whether the RNA is understandable to customers.
	<u>COLUMBIA</u>: Columbia's RNA is not a unique concept to the regulated utility industry and similar versions have been implemented successfully in other jurisdictions in which Columbia operates. Columbia is also providing an RNA tariff that clearly shows the detail how the mechanism works.

[19] OCA St. 3 at 22.

OCA: Columbia has not provided any evidence that the RNA will be understandable to customers.

Mr. Johnson claims that Columbia's affiliates in other states have successfully billed an RNA to Residential customers in Virginia since 2010 and in Maryland since 2013, and it is Columbia's understanding that these billings have been done with minimal inquiries.[20] Mr. Johnson claims that experience shows that customers do not have difficulty understanding the RNA concept.[21] However, in the PAWC Order, the Commission found the following with regard to PAWC's proposed RDM: "Moreover, the RDM will likely be confusing and difficult to understand for consumers due to its complex design in determining whether the RDM is a credit or charge." The Commission found that the resulting confusion along with a myriad of other factors warranted rejection of PAWC's proposal.

Moreover, in response to Mr. Johnson, a lack of billing inquiries in other states with different regulatory schemes and billing practices has no bearing on whether the RNA is understandable to customers under the factors laid out by the Pennsylvania Commission. To understand their future bills, Pennsylvania customers would have to know the BDRB assigned to Residential customers as a result of the base rate case and know the underlying mathematical formula behind the RNA. Instead of being billed a fixed customer charge and a volumetric charge based on usage, Columbia is inserting additional mechanisms into the utility bill that further complicates efforts to calculate future bills based on usage.

[20] Columbia St. No. 6-R, page 25, lines 22-24.
[21] Columbia St. No. 6-R, page 25, lines 25-26.

Q. MR. JOHNSON NOTES THAT IN YOUR DIRECT TESTIMONY YOU STATE "A NEW CUSTOMER IS LIKELY TO HAVE PURCHASED A MORE ENERGY-EFFICIENT GAS APPLIANCE THAN AN AVERAGE EXISTING CUSTOMER, AND WOULD HAVE LOWER USAGE THAN AN AVERAGE CUSTOMER, ALL ELSE BEING EQUAL. THIS WOULD INCREASE COLUMBIA'S EARNINGS BEYOND WHAT THEY WOULD HAVE BEEN WITHOUT RIDER RNA BECAUSE COLUMBIA'S MARGINS WOULD BE BASED ON AVERAGE RESIDENTIAL CUSTOMER MARGINS."[22] WHAT IS HIS RESPONSE TO THOSE STATEMENTS?

A. Mr. Johnson claims that my statements are not accurate.[23] He contends that although new homes are more energy efficient than existing homes, they are also, on average, larger, and therefore use more gas than existing homes.[24] He presents an analysis which he contends shows that the forecasted usage of newly constructed homes is higher than the usage of existing homes.[25]

Q. WHAT IS YOUR RESPONSE?

A. Mr. Johnson's claims that a new home would use more gas than an existing home is based on usage projections developed by the Company and is inconsistent with the findings of a study conducted by the National Association of Home Builders ("NAHB"). A special study conducted by the NAHB found that:

> Newer homes are larger, but over the long run the effects of increased efficiency more than offsets the extra square footage.[26]

[22] Columbia St. No. 6-R, page 25, line 27 - page 26, line 5.
[23] Columbia St. No. 6-R, page 26, lines 6-7.
[24] Columbia St. No. 6-R, page 26, lines 8-13.
[25] Columbia St. No. 6-R, page 26, lines 14-22.
[26] nahbclassic.org/generic/aspx?section10=734GenericContentID=23790&print=true.

Q. ON PAGE 27 OF COLUMBIA STATEMENT NO. 6-R, MR. JOHNSON DISAGREES WITH YOUR CLAIM IN YOUR DIRECT TESTIMONY THAT THE COMPANY'S PROPOSED RNA SHOULD NOT BE ASSESSED TO CUSTOMERS WITH CONSTANT USAGE. WHAT IS YOUR RESPONSE?

A. Under the RNA, a BDRB would be established for Residential customers through a base rate case proceeding. The RNA would collect or refund any variation in total Residential revenues that differed from the BDRB and that are not due to differences between actual and normal weather. Therefore, it would be unreasonable to apply the RNA to those Residential customers whose usage is relatively constant over time.

Q. ON PAGES 27 AND 28 OF HIS REBUTTAL TESTIMONY, MR. JOHNSON ALSO DISAGREES WITH YOU THAT THE RNA IS EQUAL TO A "TAKE-OR-PAY" ARRANGEMENT. WHAT IS YOUR RESPONSE?

A. Under the proposed RNA, consumers would pay for distribution service they do and do not receive when revenues fall short of projections. No matter how much distribution service is actually purchased by Columbia's Residential customers, ultimately, under the proposed RNA, those customers would pay for the presumed level of service whether they take delivery or not. This is how take-or-pay arrangements are structured. That is, a take-or-pay arrangement requires the purchasing party to pay for a commodity even if the purchasing party does not accept delivery of the commodity that is subject to the arrangement.

Q. ON PAGES 25 AND 26 OF YOUR DIRECT TESTIMONY YOU STATE, "THE PROPOSED RIDER RNA OPERATES TO CHANGE RATES, AUTOMATICALLY, BETWEEN RATE CASES, SIMPLY AS A FUNCTION OF RESIDENTIAL DISTRIBUTION REVENUES BEING DIFFERENT FROM BENCHMARK REVENUES DUE TO FACTORS OTHER THAN WEATHER. THERE IS NO REVIEW OF COLUMBIA'S COSTS, OR THE VOLUMES AND ATTENDANT REVENUES FROM OTHER CUSTOMER CLASSES THAT ARE NOT INCLUDED UNDER RIDER RNA." DOES MR. JOHNSON AGREE?

A. No. Mr. Johnson claims that I allege that if Residential usage per customer were to fall over time, while SGSS1/DS-1 deliveries increased, Columbia's Residential rates would be increased under the RNA with no recognition of the increased SGSS1/DS-1 distribution revenues.[27] He claims that this statement is flawed because I assume that higher SGSS1/DS-1 usage is not associated with higher costs and it is possible that the higher usage could result in incremental costs.[28]

Q. WHAT IS YOUR RESPONSE?

A. If the decline in Residential usage was offset by an increase in SGSS1/DS-1 usage so that overall usage remained the same, I believe it likely that Columbia's costs would remain the same. The RNA does not provide for the review of revenues from other classes and would not recognize the increase in SGSS1/DS-1 revenues that Columbia would experience.

[27] Columbia Statement No. 6-R, page 29, lines 3-6.
[28] Columbia Statement No. 6-R, page 29, lines 6-12.

Q. MR. JOHNSON DISAGREES WITH YOUR ASSERTION THAT COLUMBIA'S CURRENT SYSTEM OF RATES AND CHARGES ALREADY PROVIDES FOR REVENUE STABILITY. [29] WHAT IS YOUR RESPONSE?

A. Mr. Johnson claims that the Company's Purchased Gas Adjustment ("PGA") mechanism does not provide for revenue stability.[30] This claim is misplaced. My testimony was referring to base rate revenue stability. The PGA mechanism provides for dollar-for-dollar recovery of Columbia's purchased gas costs which eliminates the impact of purchase gas costs on base rate revenue. In addition, Mr. Johnson claims that the Company's quarterly Distribution System Improvement Charge ("DSIC") is capped at 5 percent and, therefore, limits its usefulness.[31] I would note that since April 2018 – a period of more than 6 years -- Columbia's DSIC has only reached the 5 percent cap in **one quarter** and, therefore, Columbia has not fully maximized the benefits of utilizing its DSIC. Mr. Johnson has not demonstrated that Columbia's current system of rates and charges do not provide sufficient revenue stability.

[29] Columbia Statement No. 6-R, page 29, lines 13-20.
[30] Columbia Statement No. 6-R, page 29, lines 20 - page 30, line 1.
[31] Columbia Statement No. 6-R, page 30, lines 7-9.

Q. ON PAGE 26 OF YOUR DIRECT TESTIMONY, YOU STATE "THE COMPANY PROPOSED A SIMILAR RIDER RNA IN ITS LAST BASE RATE CASE. IN THAT PROCEEDING THE ALJ DETERMINED THAT THE COMPANY FAILED TO PROVE THAT THE RNA WOULD RESULT IN RATES THAT WERE JUST AND REASONABLE, IN THE PUBLIC INTEREST, AND THE COMPANY DID NOT DEMONSTRATE THAT ITS CURRENT RATES AND SYSTEMS OF REVENUE STREAMS FAILED TO PROVIDED REVENUE STABILITY. (ORDER AT 264-265)." WHAT WAS MR. JOHNSON'S RESPONSE?

A. Mr. Johnson claims that because no exceptions to the ALJ's Recommended Decision were filed, full arguments were not presented to the Commission in the last case.[32]

Q. WHAT IS YOUR RESPONSE?

A. In Columbia's last base rate proceeding, the Commission's Order found that the ALJ's recommendation was supported by ample evidence and was just and reasonable. (Order at 265). Therefore, based on the Commission's Order, it appears that all relevant factors were considered by the Commission.

Q. IN YOUR DIRECT TESTIMONY, YOU INDICATED THAT COLUMBIA'S WEATHER NORMALIZATION ADJUSTMENT (WNA") SHOULD BE EVALUATED IN THIS PROCEEDING EVEN THOUGH THE SETTLEMENT APPROVING THE WNA PROVIDED THAT THE WNA WOULD REMAIN IN EFFECT AT LEAST UNTIL MAY 31, 2026.[33] WHAT WAS THE BASIS FOR THAT POSITION?

A. The current version of Columbia's WNA was most recently approved in Columbia's 2021 base rate proceeding in Docket No. R-2021-3024296 which was resolved by

[32] Columbia St. No. 6-R, page 30, lines 17-19.
[33] OCA Statement No. 5, page 31, lines 5-22.

settlement ("2021 Settlement"). In its Order approving the settlement entered December 16, 2021, the Commission approved provision 33 of Section III of the settlement which provided that "Columbia's proposal to continue its Pilot Weather Normalization Adjustment ("WNA") mechanism until a final order is entered in the Company's first rate case filed after May 31, 2026 is approved." (Opinion and Order, pages 15-16). The 2021 Settlement was referring to the pilot WNA mechanism with a 3% deadband, as was approved in Columbia's 2018 base rate proceeding pursuant to settlement at Docket No. R-2018-2647577. Hence, in the 2021 proceeding, the Commission approved the parties' agreement to continue the pilot WNA with a 3% deadband until a final order was entered in the Company's first rate case filed after May 31, 2026.

In its initial application in this proceeding, Columbia proposed to eliminate the 3% HDD deadband included in its current WNA. Therefore, Columbia proposed to modify the WNA approved by the Commission in Docket No. R-2021-3024296. Counsel informed me that since Columbia proposed to modify the provisions of the WNA approved in the 2021 Settlement, whether the WNA should continue in effect requires evaluation in this proceeding.

Q. IN HIS REBUTTAL TESTIMONY, MR. JOHNSON NOTES THAT COLUMBIA IS WITHDRAWING ITS PROPOSAL TO ELIMINATE THE 3% WNA DEADBAND IN THIS PROCEEDING.[34] DOES THAT MEAN THAT DUE TO THE SETTLEMENT APPROVED IN DOCKET NO. R-2021-3024296 THE WNA SHOULD NOT BE EVALUATED IN THIS PROCEEDING?

A. No. Even though Mr. Johnson asserts that Columbia has withdrawn its proposal to modify the WNA approved in the 2021 Settlement, Mr. Johnson presents over 20 pages of rebuttal testimony asserting why the WNA is just and reasonable. Given the record being developed on the justness and reasonableness of the WNA, Counsel informs me that the OCA must address the 20 pages of Mr. Johnson's rebuttal testimony in the OCA's surrebuttal testimony. Counsel for the OCA believes Columbia's withdrawal of its proposal to modify the WNA does not undo the evidence the OCA is required to investigate and submit because of Columbia's initial proposal or that has been developed in the record in this case. In addition, the 2021 Settlement does not insulate the WNA from being reviewed given the record that has now been developed due to Columbia's initial proposal. The 2021 Settlement was approved by a final order, and the Commission has the authority to modify its prior orders in setting just and reasonable rates.

[34] Columbia Statement No. 6-R, page 32, lines 11-14.

Q. BEFORE ADDRESSING MR. JOHNSON'S REBUTTAL TESTIMONY ON THE WNA, ARE THERE ANY UPDATES YOU WOULD LIKE TO PROVIDE TO THE INFORMATION INITIALLY PRESENTED IN YOUR DIRECT TESTIMONY.

A. Yes. Table 5 presented on page 32 of my direct testimony identified the revenue impact of the WNA on customers for the past five years based on the response to OCA-17-3. Since the filing of my direct testimony, Columbia filed its WNA report for the 2023-2024 heating season with the Commission. I am updating Table 5 to reflect Columbia's filed WNA report. As shown in Table 5-Revised, the detrimental impact of the WNA on customers over the last 5 years has been nearly $66.6 million.

Table 5.
Revenue Impact of WNA on Customers

Heating Season	Charge
2019/2020	$4,979,367
2020/2021	5,327,158
2021/2022	2,530,224
2022/2023	17,441,275
2023/2024	36,341,357
Total:	**$66,619,381**

Q. WHAT DOES MR. JOHNSON CLAIM IS THE MOST IMPORTANT PRINCIPLE OF RATE DESIGN?

A. Mr. Johnson claims the most important principle of rate design is fairness.[35] He notes that the American Gas Association ("AGA") *Gas Rate Fundamental* book states at page 154, "Most people believe that a rate based on the cost of providing service is fair".[36]

Q. IN YOUR DIRECT TESTIMONY YOU INDICATE THAT DURING THE PERIOD OCTOBER 2013 THROUGH APRIL 2024, THE WNA HAD A NET DETRIMENTAL IMPACT OF $59.1 ON RESIDENTIAL CUSTOMERS.[37] WHAT IS MR. JOHNSON'S RESPONSE?

A. On page 41, lines 1-6 of his rebuttal testimony, Mr. Johnson claims that if temperatures were predictable in advance and rates had been designed consistent with actual temperatures, the net revenue differential would not have existed. Furthermore, if temperatures had been colder than normal throughout this period of time, as occurred during a portion of the ten years I referenced, there would have been no net collection from customers, but instead a net return of revenues to customers.

Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON'S CLAIM ON PAGE 41?

A. Unfortunately, weather and temperatures are not predictable in advance. It is generally recognized that regulation should emulate a competitive market outcome.[38] The demand and use of many products sold in the competitive markets are dependent on weather and temperature. The purpose of rate regulation of natural monopoly utilities

[35] Columbia Statement No. 6-R, page 37, lines 3-4.
[36] Columbia Statement No. 6-R, page 37, lines 5-6.
[37] Mierzwa direct, at 32: 7-8.
[38] Bonbright, James C. *Principles of Public Utility Rates*, Columbia University Press: New York, 1961, page 107; and Kahn, Alfred E. *The Economics of Regulation: Principles and Institutions*. Vol. I, John Wiley and Sons: New York, 1970, page 17.

is to serve as a proxy for competitive market pricing and to prevent monopolistic unjust and unreasonable pricing from occurring. In the competitive markets, customers are charged for and pay for products based on the quantity of a product purchased. Customers are not charged for a product based on how much of a product they were expected to have purchased if actual weather and temperatures matched the historic projections. Assessing customer charges based on the quantity of a product that the seller expected a customer to have purchased based on actual weather or temperatures does not occur in the competitive markets. Therefore, assessing customers a WNA to reflect expected consumptions levels based on actual weather and temperatures is inconsistent with competitive markets, and the WNA should be eliminated. I would note that no non-gas distribution utilities operating in Pennsylvania have been authorized to adopt rate adjustment mechanisms similar to Columbia's WNA. And this is meaningful, because absent a statewide approach where customers can equally benefit from a WNA to receive credits under electric rates due to trend in warming weather, simply allowing gas utilities to charge WNA only harms customers without a benefit in electric rates to balance the scales. Again, as shown in Table 5-Revised, the detrimental impact of the WNA on customers over the last 5 years has been nearly $66.6 million.

Q. ON PAGE 32, LINES 8-11, OF YOUR DIRECT TESTIMONY YOU CLAIM THAT THE DETRIMENTAL IMPACT OF THE WNA IS LIKELY TO CONTINUE. WHAT IS MR. JOHNSON'S RESPONSE?

A. The detrimental impact of the WNA occurs when weather is warmer-than-normal because customers are charged for consuming less-than-expected volumes of gas. He claims that no one knows whether warmer-than-normal weather will continue and

claims that I have offered no support for my statement that the detrimental impact of the WNA will continue.[39]

Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON'S CLAIM THAT NO ONE KNOWS WHETHER WARMER-THAN-NORMAL WEATHER WILL CONTINUE AND YOU HAVE PRESENTED NO EVIDENCE THAT THE DETRIMENTAL IMPACT WILL CONTINUE?

A. Given that as shown on Table 5-Revised the WNA has had a detrimental impact on Residential customers for the last five years, it can reasonably be expected that the detrimental impact will continue. Additionally, Exhibit DED-1 as updated in the Surrebuttal Testimony of David E. Dismukes, shows a $62 million cumulative detrimental impact between the 2013-2014 heating season, when WNA started, and the most recent 2023-2024 heating season report, or a period of 11 heating seasons. Given this, it can reasonably be expected that the detrimental impact will continue.

Q. ON PAGES 32 THROUGH 33 OF YOUR DIRECT TESTIMONY, YOU TESTIFY "THAT AUTOMATIC RATE ADJUSTMENTS SUCH AS THE WNA SHOULD BE AVOIDED BECAUSE THEY WEAKEN TRADITIONAL REGULATORY PRINCIPLES AND UNREASONABLY SHIFT RISK TO CUSTOMERS. TO JUSTIFY MAINTAINING THE WNA, COLUMBIA SHOULD BE REQUIRED TO DEMONSTRATE THAT IT IS NECESSARY TO AVOID SIGNIFICANT FINANCIAL DAMAGE." DOES MR. JOHNSON AGREE WITH YOUR POSITION?

A. No, and Mr. Johnson presents no evidence demonstrating that Columbia would experience significant financial damage if the WNA were not maintained.

[39] Johnson rebuttal at 42: 4-5.

Q. ON PAGE 33 OF YOUR DIRECT TESTIMONY, YOU STATE THAT "SIMILAR TO THE PROPOSED RNA, THE WNA INAPPROPRIATELY ADJUSTS RATES WITHOUT CONSIDERING OTHER CHANGES IN TOTAL REVENUES AND COSTS. THE WNA CHANGES RATES, AUTOMATICALLY, BETWEEN RATE CASES, SIMPLY DUE TO THE IMPACT OF WEATHER ON RESIDENTIAL DISTRIBUTION REVENUES. THERE IS NO REVIEW OF COLUMBIA'S COSTS, OR THE VOLUMES AND ATTENDANT REVENUES FROM RESIDENTIAL CUSTOMERS AND OTHER CUSTOMER CLASSES." DOES MR. JOHNSON AGREE WITH YOUR STATEMENTS?

A. No. Mr. Johnson claims on page 41 of his rebuttal that the WNA is a mechanism that corrects a fundamental issue in volumetric base rate design. Because no one knows what the weather will be when a customer is billed in the future when rates go in effect, the Company uses estimated volumes that reflect usage at normal temperatures based on the most recent 20-year average to determine the residential volumetric base rate. Mr. Johnson claims that in the interest of fairness to both the Company and customers, the entire purpose of the WNA is to compensate for this issue in rate design. The WNA mitigates the impact of the recovery overage or shortfall of the residential volumetric base rate design caused solely by the unpredictability of weather.

Mr. Johnson claims that the purpose of the WNA is not to reopen the cost of service as I suggest, as cost of service changes can only be considered in a rate case. The WNA is a rate design mechanism that is approved by the Commission at the time of rate design to compensate for the unknown denominator of the Residential volumetric charge so that the base revenue charged to the customer is not impacted by weather.

Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON?

A. Mr. Johnson is correct that the purpose of the WNA is to adjust revenues to reflect differences in customer usage that occur because of actual temperatures being different that the temperatures utilized to project the usage upon which rates were designed. However, other factors affect Columbia' revenues and these factors are not considered under the WNA. It is unreasonable to collect additional revenues from customers under a WNA due to warmer-than-normal temperatures when other factors may have increased the revenues received by Columbia to levels that exceed those reflected in base rates.

Q. ON PAGE 33 OF YOUR DIRECT TESTIMONY, YOU STATE THAT "THE WNA EMBODIES A TAKE-OR-PAY PRICING POLICY. UNDER THE WNA, RESIDENTIAL CUSTOMERS PAY FOR DISTRIBUTION THEY ACTUALLY RECEIVE, AND MAY PAY FOR DISTRIBUTION SERVICE THEY DO NOT RECEIVE, DESPITE THE CUSTOMER HAVING NO IMMEDIATE ALTERNATIVES TO COLUMBIA'S DISTRIBUTION SERVICE." DOES MR. JOHNSON AGREE WITH THESE STATEMENTS?

A. No. Mr. Johnson claims that the WNA has no take-or-pay clauses and is not akin to a take-or-pay contract. The cost to serve Residential customers has already been determined in a rate case and the WNA is simply a mechanism to recover the costs that the Commission has already established as being incurred by the Company to provide the distribution service the residential class requires. He claims that the WNA in no way requires the Residential class to pay for more than the established cost of service in the last rate case, and that the WNA is a balanced, customer-specific mechanism designed to address the impossibility to accurately project future temperatures.

Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON?

A. Under the WNA, Residential customers are required to pay for a specified minimal level of service. When Residential customers purchase less than their minimal level of service, they are required to pay for the minimal level of service. Such a payment requirement is how a take-or-pay contract is defined.

Q. ON PAGES 34 THROUGH 37 OF YOUR DIRECT TESTIMONY, YOU LIST THE 14 FACTORS FOR CONSIDERATION IDENTIFIED IN THE COMMISSION'S STATEMENT OF POLICY ON ALTERNATIVE RATEMAKING AND IDENTIFY THE RELEVANT EFFECT OF THE WNA ON EACH RATE CONSIDERATION. DOES MR. JOHNSON RESPOND TO EACH CONSIDERATION?

A. Yes. Mr. Johnson responds to each consideration. Identified below are 14 factors for consideration, my initial response, Mr. Johnson's response to my initial response, and my response to Mr. Johnson.

Consideration 1: Please explain how the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.

OCA: The WNA represents a clear misalignment between revenue and cost causation because it bills customers based on hypothetical usage, and not based on actual cost-based usage. The WNA provides for the recovery of fixed costs on a volumetric basis. Therefore, it does not align utility revenues with cost causation principles as to both fixed and variable costs.

COLUMBIA: The Company disagrees with Mr. Mierzwa. The WNA adjusts the customer's actual usage to determine the customer's weather normalized usage in order to apply the usage to the Residential volumetric base rate. The Residential volumetric base rate was established using cost causation principles to determine the Residential Cost of Service. However, the rate was established by dividing actual cost of service by weather normalized usage. It is because the

Residential volumetric base rate established in the last rate case was based on weather normalized usage that the WNA is necessary to recover or pass-back revenue generated by the volumetric base rate due solely to weather.

Additionally, because of settlement agreements, unfortunately there has been no increase to the Residential customer charge in each of the Company's last seven rate cases, thereby forcing the entire increase in fixed costs to be recovered through the Residential volumetric rate. As a result, the Company recovers a significant portion of fixed costs through the Residential volumetric rate. These costs also do not vary due to changes in temperatures. Because of this, the Company requires the WNA mechanism that is designed to recover or pass-back the over or under recovery of fixed costs billed by the Residential volumetric base rate because of an inherent flaw in the design of the Residential volumetric base rate solely caused by weather.

In the interest of fairness to both the Company and the customer, the WNA compensates for this flaw in rate design. The WNA mitigates the impact of the recovery overage or shortfall of the Residential volumetric base rate design caused solely by weather. The customer essentially pays the same amount that they would have paid had the original rate design used the same weather that occurred in the month the customer is billed.

OCA RESPONSE: As previously discussed, under the WNA, Residential customers charges based on how much gas they should have utilized, not on how much gas they actually utilized. This is inconsistent with how charges are assessed in the competitive markets. Regulation should emulate competitive markets.

Consideration 2: Please explain how the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.

OCA: The proposed WNA is unrelated to capacity utilization since the determining metric for the charge is weather not utilization.

COLUMBIA: The Company agrees.

Consideration 3: Please explain whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.

OCA: 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.

COLUMBIA: The WNA does reflect customers' anticipated consumption levels, by adjusting to normal levels used for designing base rates. The Company believes, due to its inability to predict weather, it can only anticipate demand based on normal weather and design rates accordingly. However, because the Company does know the weather and customer's usage at time of billing, the WNA mechanism adjusts the revenue generated by the Residential volumetric base rate by way of the WNA to mitigate the effects of weather on the rate design.

OCA RESPONSE: See the response to OCA Consideration 1.

Consideration 4: How the ratemaking mechanism and rate design limit or eliminate interclass and intra-class cost shifting.

OCA: The WNA is only applicable to the Residential class and, therefore, does not affect traditional interclass cost shifting.

COLUMBIA: The Company agrees.

Consideration 5: Please explain how the WNA limits or eliminates disincentives for the promotion of efficiency programs.

OCA: The WNA disincentives energy efficiency programs because it imposes a disconnect between cost-savings for customers that participate in energy efficiency programs. The disincentive exists in that by relying upon temperature variances to impose a WNA regardless of reduced usage that may otherwise result from participation in an energy efficiency program, the WNA inserts an artificial variable that would mitigate at least some cost savings contingent on the weather. In addition, the Company has not demonstrated that the lack of a WNA would be a major obstacle for the promotion of its voluntary energy efficiency and conservation activities.

COLUMBIA: The Company's WNA only addresses variations due to weather and does not affect customers' ability to pursue energy efficiency measures, as demonstrated above. Further, the Company will continue to promote the use of energy efficiency measures to its customers.

OCA RESPONSE: The Company has not demonstrated that the lack of a WNA would be a major obstacle for the promotion of its voluntary energy efficiency and conservation activities.

Consideration 6: Please explain how the WNA impacts customer incentives to employ efficiency measures and distributed energy resources.

OCA: The WNA could provide a disincentive to employ energy efficiency measures for customers whose energy efficiency initiative takes place during periods of warmer than normal weather. This is because a portion of a customer's bill savings would be returned to the Company because the efficiency actions occurred when weather was warmer-than-normal. As such, the customer may perceive the WNA as a disincentive for deploying more energy efficiency measures.

COLUMBIA: As stated above, with the WNA, a customer has a greater incentive for energy efficiency than without it, because when weather is warmer than normal, the customer receives greater energy savings on both the residential volumetric rate billing as well as the WNA billing.

However, the Company's customers will continue to be incentivized to use energy efficiency measures because a reduction in the customer's usage will continue to reduce their overall bill.

OCA RESPONSE: The OCA agrees. .

Consideration 7: Please explain how the WNA impacts low-income customers and supports consumer assistance programs.

OCA: The impact of the WNA on Residential low-income customers would be the same as the impact on Residential non low-income customers. The WNA does not support customer assistance programs.

COLUMBIA: The Company agrees with Mr. Mierzwa. However, it is important to note under the Company's WNA mechanism, customers enrolled in CAP see lower bill

variability for distribution costs during colder than normal billing cycles. Similarly, customers who are currently enrolled to pay their bills based on a percentage of their household income see little to no impact to their bills under the WNA mechanism.

OCA RESPONSE: The Company agrees with the OCA's initial comments.

Consideration 8: Please explain how the WNA impacts customer rate stability principles.

OCA: Under the current regulatory standard in Pennsylvania, base rate cost under and over recoveries are currently not tracked and are not eligible for recovery in future base rate proceedings. The WNA will not change this standard. The proposed WNA would add another surcharge to customers' bills and the Company has not shown how it would reduce the frequency of Columbia Gas base rate filings. Thus, it does not appear that the WNA surcharge would improve rate stability. In contrast, under traditional cost-of-service ratemaking, if a utility experiences sales reductions and under-recovery, it cannot simply achieve the same result as a WNA by filing another base rate case with adjusted sales forecasts. When a utility files a general rate increase, all relevant information is reviewed to determine just and reasonable rates, not just sales forecasts. Traditional ratemaking produces rate stability. In addition, the WNA decreases customer rate stability because it obscures price signals for customers by disassociating their monthly bill from their actual usage. As a result, a customer is less likely to be able to predict what their bill would be at the end of the month based off usage.

COLUMBIA: The American Gas Association *Gas Rate Fundamentals* book (Pages 152 – 156) states "The goal of stability recognizes historical relationships among customers in terms of the proportion of system costs each customer group bears. Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are called for in the context of a single rate case, Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operation are minimized." The Company's WNA ensures stability in that the customer will pay for the costs assigned to the residential volumetric base rate in the most recent rate case and the customer will not pay more or less than that amount solely because the actual weather for the month the customer is billed

is different than the weather used to determine the rate design of the residential volumetric base rate. Further, the WNA has been on customers' bills for over 10 years, and thus will not add another charge to the bill.

OCA RESPONSE: See the OCA's response to Consideration 1.

Consideration 9: Please explain how the weather impacts utility revenue under the WNA.

OCA: Weather will directly impact utility revenue under the WNA.

COLUMBIA: The Company's WNA adjusts a customer's bill due to variations from normal weather during the heating season months (October through May). The WNA only applies to the Company's residential customers. The WNA only mitigates the revenue effect of weather on the original rate design of the Residential Volumetric base rate. The WNA does not guarantee 100% recovery of its cost of service.

OCA RESPONSE: See the OCA's response to Consideration 1.

Consideration 10: Please explain how the WNA impacts the frequency of rate case filings and affects regulatory lag.

OCA: Columbia files a rate case nearly every year. This is unlikely to change and a WNA does not prevent the Company from seeking additional rate increases. The WNA does not affect future revenue requirements and does not recover fixed costs that are incurred after a rate case that are over and above those approved by the Commission. Therefore, if future rate cases are driven by future investment needs or higher expenses and associated cost recovery, the WNA would not reduce the need for such cases.

COLUMBIA: The WNA does not impact the Company's rate case frequency or have an effect on regulatory lag.

OCA RESPONSE: The Company agrees that the WNA does not impact the frequency of rate case filings or the effect of regulatory lag.

Consideration 11: Please explain if the WNA interacts 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 (relating to standards for restructuring of electric industry) or system improvement charges Pa. C.S. § 1353 (relating to distribution system improvement charge).

OCA: The WNA will not interact with other revenue sources.

COLUMBIA: The Company's WNA only applies to distribution related charges recovering the base distribution revenue requirement from residential customers subject to the WNA during October through May of each year. WNA amounts will be subject to STAS and DSIC riders.

OCA RESPONSE: The OCA agrees with the Company's response.

Consideration 12: Please explain whether the WNA includes appropriate consumer protections.

OCA: The WNA does not include appropriate consumer protections and should be rejected for the reasons subsequently discussed in my testimony and the testimony of OCA witness Colton and OCA witness Dismukes.

COLUMBIA: The Company's WNA mechanism adjusts bills to reflect the revenues that would be recovered under normal weather, on a per-customer basis, because that is how the residential volumetric base rate is designed.

OCA RESPONSE: See the OCA's response to Consideration 1.

Consideration 13: Please explain whether the WNA is understandable to customers.

OCA: Columbia has not provided any evidence that the WNA is understandable to customers.

COLUMBIA: The Company has been billing the WNA since October 2013. In fact, as stated above, the Company has billed Residential customers 31,954,946 times in the months that the WNA has been in effect and yet has received no measurable complaints. Unfortunately, as with any billing rate, there are customers who may not completely understand the reason for

the WNA charge or refund. However, the fact that WNAs are in effect in many states today, including Pennsylvania, is a testament to its effectiveness and acceptability.

OCA RESPONSE: While the Company claims that there have been no measurable complaints, this is contrary to the record from the public input hearing. Transcript at 156, 172-173, 174-175, For example, a Columbia customer provided the following testimony into the record: "When I asked other people how they feel about this charge, no one even knows it's there because people do not take the time to look at their bill. They feel so helpless. They feel like we have no choice. It's our utility. We just have to keep paying. And I'm just wondering if the PUC ever realized that this was going to happen. It's not my fault that the weather is normal than - warmer than average, yet I'm penalized and charged for something that I did not use and was not delivered to my home. That just seems totally unbelievable." Transcript at 156.

Consideration 14: Please explain how the WNA will support improvements in utility reliability.

OCA: The WNA does not provide an incentive to increase the safety and reliability of Columbia's system.

COLUMBIA: The WNA mitigates the impact of weather in the recovery of the Commission-approved cost of service established in rate cases. In rate cases, there are costs to continue to enhance the safety and reliability of the Company's system. The WNA helps ensure that cost recovery is not impacted by warmer or colder than normal weather.

OCA RESPONSE: The Company has not claimed the WNA will increase system improvements designed to increase system reliability.

Q. MR. JOHNSON NOTES THAT ON PAGE 30 OF YOUR DIRECT TESTIMONY, YOU STATE WITH RESPECT TO THE MUNICIPAL LEVELIZATION CHARGE ("MLC") THAT: "THE ADDITIONAL PAVING AND RESTORATION COSTS INCURRED TO SERVE CUSTOMERS IN THE CITY OF PITTSBURGH AND BOROUGH OF PERRYOPOLIS ARE REFLECTED IN THE RATES PROPOSED BY COLUMBIA IN THIS PROCEEDING FOR ALL CUSTOMERS SERVED BY COLUMBIA" AND THAT "IT IS UNREASONABLE TO IMPOSE A CHARGE ON 22,604 CUSTOMERS FOR ADDITIONAL COSTS INCURRED TO SERVE THOSE CUSTOMERS AND THEN CREDIT THE ADDITIONAL CHARGES TO 2,116 CUSTOMERS WHEN THE ADDITIONAL CITY OF PITTSBURGH AND BOROUGH OF PERRYOPOLIS PAVING AND RESTORATION COSTS HAVE BEEN REFLECTED IN THE RATES OF ALL COLUMBIA CUSTOMERS. THE MLC SHOULD BE REJECTED." WHAT WAS MR. JOHNSON'S RESPONSE?

A. Mr. Johnson agrees that paving and restoration costs are included in the Company's cost of service. He believes the MLC is a fair and revenue-neutral mechanism.[40] He claims that the MLC ensures that customers in municipalities causing higher costs by requiring milling and overlay standards which far exceed PennDOT standards receive a charge and that customers in municipalities with minimal milling and overlay requirements that cost far less than PennDOT standards receive a credit.[41]

[40] Columbia Statement No. 6-R, page 54, lines 27-28.
[41] Id., page 54, line 28 - page 55, line 2.

Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON'S CLAIMS CONCERNING THE MLC?

A. The MLC is not a fair mechanism. As I explained in my direct testimony, the MLC recognizes a less than 1% difference in the cost of serving customers in different municipalities and ignores cost differences which may exist for the remaining 99% of the cost of service.[42] In addition, only the 2,116 customers in New Sewickley Township and Roscoe Borough would receive the MLC credit when the additional paving and restoration costs incurred in other municipalities would be socialized and reflected in the base rates of all Columbia customers.[43] This is not fair and it is unreasonable.

Q. ON PAGE 55 OF HIS REBUTTAL TESTIMONY, MR. JOHNSON STATES THAT IN YOUR DIRECT TESTIMONY YOU FOUND THAT THE MLC SHOULD NOT BE APPROVED SINCE THE MLC DOES NOT RECOGNIZE DIFFERENCES IN THE COSTS ASSOCIATED WITH SERVING DIFFERENT CUSTOMER CLASSES. WHAT WAS MR. JOHNSON'S RESPONSE TO YOUR FINDING?

A. Since MLC costs are distribution mains related costs, Mr. Johnson presents a table (Table KLJ-5R) showing the MLC for each customer class based on "Allocation Factor 13 – Mains Account 376" from the Company's Peak and ACOSS. However, he does not support an MLC based on this allocation because he believes MLC costs are not directly associated with the customer class receiving the charge.[44]

[42] OCA Statement No. 5, page 29, lines 11-14.
[43] Id., page 30, lines 3-12.
[44] Columbia Statement No. 6-R, page 55, line 16 – page 56, line 3.

Q. WHAT IS YOUR RESPONSE TO MR. JOHNSON?

A. Although it is my recommendation that the MLC not be approved, if it is approved, I recommend that the MLC be based on the allocations presented in Table KLJ-5R since MLC costs are distribution mains related costs.

III. COLUMBIA GAS OF PENNSYLVANIA, INC. WITNESS: MARK KEMPIC

Q. ON PAGE 10 OF HIS REBUTTAL TESTIMONY, MR. KEMPIC CONTENDS THE PROPOSED MLC WILL PROVIDE THE COMMISSION, THE STATUTORY INTERVENORS, AND COLUMBIA WITH VALUABLE INFORMATION CONCERNING THE IMPACT OF COMMUNICATING THE COST OF RESTORATION TO CUSTOMERS, AND CAN HELP SPUR MUNICIPALITIES TO ACCEPT REASONABLE PENNDOT PERMITTING AND RESTORATION STANDARDS WHEN CUSTOMERS LIVING IN THOSE MUNICIPALITIES ARE MADE AWARE OF THE FINANCIAL IMPACT OF THOSE MUNICIPAL ORDINANCES ARE HAVING ON THEIR GAS UTILITY BILLS. WHAT IS YOUR RESPONSE?

A. The "fairness" of a utility rate generally means that the rate bears a reasonable relationship to the utility's cost of serving the customer without exceeding the value of service to the customer. James C. Bonbright et al., *Principles of Public Utility Rates*, at 82-92 (1st ed. 1988). The Company is trying to solve the problem of certain municipalities charging unjustifiable high fees related to utility restoration work. While the problem that Columbia is trying to solve may be a legitimate one, and one that the OCA supports solving in the interest of keeping rates just and reasonable for ratepayers, the Company's solution of the MLC is illegitimate. As I have explained,

the MLC violates the cost causation principle (because the customers did not cause these higher costs) and is fundamentally unfair to consumers to whom the MLC will apply. The Company's goal in wanting to make consumers aware of the financial impact related to these fees appears to be to drive political activity at a grassroots level to change how a municipality implements fees. However, this effort to make societal/political change through ratemaking is not a demonstration with substantial evidence that the MLC will have such a desired effect or that it is even appropriate. The OCA would be supportive of legitimate solutions to the problem on a statewide basis including statutory improvements and statewide PennDOT standards; however, these are policy solutions that involve the utilities, statutory advocates, and the Commission to work together outside of the context of a litigated rate case to develop and seek to implement.

Q. WHAT IS MR. KEMPIC'S RESPONSE TO THE FINDING IN YOUR DIRECT TESTIMONY THAT THE MLC ONLY REPRESENTS LESS THAN 1% OF THE COST OF SERVING CUSTOMERS?[45]

A. Mr. Kempic claims that the proposed MLC is not intended to address all differences in costs between municipalities; it is intended to address one major cost category that is uniquely driving increases in rates to customers across all municipalities: i.e., those municipalities that demand restoration which far exceeds PennDOT standards.[46] He claims that in 2022 and 2023, the Company was forced to spend nearly $1.3 million of its capital program to pave above and beyond the standards that are perfectly fine for every state highway in Pennsylvania.[47]

[45] OCA Statement No. 5, page 29, lines 11-14.
[46] Columbia Statement No. 6-R, page 10, line 19 – page 11, line 3.
[47] Columbia Statement No. 6-R, page 11, line 14-21.

Q. WHAT IS YOUR RESPONSE TO MR. KEMPIC?

A. Under the proposed MLC, customers in the City of Pittsburgh and Borough of Perryopolis would be charged an MLC of $0.70 per month and customers in New Sewickley Township and Roscoe Borough would receive a monthly credit of $7.44. As demonstrated in my direct testimony, the average feet of distribution mains installed by Columbia to serve a customer in the City of Pittsburgh is much lower than the average feet of distribution mains installed by Columbia to serve a customer in New Sewickley Township.[48] However, under the MLC, City of Pittsburgh customers would be assessed higher charges than New Sewickley Township customers, and the MLC fails to account for the lower costs of the distribution mains serving the City of Pittsburgh.

Q. MR. KEMPIC CLAIMS THAT THERE ARE NO CUSTOMER CLASS COSTS DIFFERENCES IN THE PERMITTING OR RESTORATION COSTS TO BE RECOVERED THROUGH THE MLC AND, THEREFORE, THE SAME MLC SHOULD APPLY TO ALL CUSTOMER CLASSES.[49] DO YOU AGREE?

A. Although it is my recommendation that the MLC not be approved, as indicated previously in responding to Mr. Johnson, MLC costs are distribution mains related costs, and if approved, the MLC should be based on the distribution mains allocations presented in Table KLJ-5R.

[48] OCA Statement No. 5, page 29, lines 14-21.
[49] Columbia Statement No. 1-R, page 13, line 15 – page 14, line 4.

IV. OSBA WITNESS: MARK D. EWEN

Q. IN YOUR DIRECT TESTIMONY, YOU PRESENTED AN ALTERNATIVE TO COLUMBIA'S PROPOSED CUSTOMER CLASS REVENUE ALLOCATION AND MR. EWEN ALSO PRESENTED AN ALTERNATIVE. HOW DID THE ALTERNATIVE YOU PRESENTED COMPARE TO THE ALTERNATIVE PRESENTED BY MR. EWEN?

A. As shown on Table 1-R, page 4, of my Rebuttal Testimony, and Table 1Ec-1R page 4 of Mr. Ewen's rebuttal testimony, the Revenue Allocations presented by Mr. Ewen and I are essentially identical.

Q. SINCE THE REVENUE ALLOCATIONS ARE ESSENTIALLY IDENTICAL, DOES MR. EWEN AGREE WITH OR ACCEPT YOUR ALTERNATIVE?

A. Based on his rebuttal testimony, it is not clear whether Mr. Ewen agrees with or accepts my revenue allocation. While Mr. Ewen notes that the revenue allocations each of us has proposed are consistent,[50] Mr. Ewen appears to criticize my revenue allocation because it assigns the smallest class percentage increase to the Residential class.[51] Mr. Ewen also claims that my proposed revenue allocation is inequitable because it shifts cost from the Residential class to the remaining smaller classes which are normally small business customers.[52]

Q. WHAT IS YOUR RESPONSE TO MR. EWEN'S CRITICISMS OF YOUR PROPOSED REVENUE ALLOCATION?

A. Mr. Ewen's criticisms of my alternative revenue allocation when compared to his proposed alternative are without merit. As shown on Table IEc-1R, the increase

[50] OSBA Statement No. 1-R, page 5, line 3-5.
[51] OSBA Statement No. 1-R, page 5, line 11-13.
[52] OSBA Statement No. 1-R, page 6, line 4-6.

assigned to the Residential class under my alternative is actually higher than the increase assigned to the Residential class under Mr. Ewen's alternative. In addition, the increases assigned to the remaining smaller classes (SGS1, SGS2 and SDS/LGSS) are essentially identical, with $37.76 million being assigned to the smaller classes under Mr. Ewen's alternative and $37.77 million being assigned under my alternative.

V. PENNSYLVANIA STATE UNIVERSITY
WITNESS: JAMES L. CRIST

Q. MR. CRIST CLAIMS YOUR PROPOSAL TO INCREASE THE RATES OF LDS/LGSS CUSTOMERS IS "UNCONSCIONABLE."[53] WHAT IS YOUR RESPONSE?

A. As indicated in Table 3 of my direct testimony, at present rates, LDS/LGSS revenues are significantly below the indicated cost of service with a relative rate of return ("ROR") of 0.34. An ROR of 1.0 would indicate that revenues are fully recovering the indicated cost of service. Based on the result of the ACOSS method approved by the Commission in the Company's 2020 base rate case, I have proposed an increase of 2.0 times the system average increase for the LGSS class which is consistent with the principle of gradualism. Even with this increase, rates for the LDS/LGSS class would still be significantly under-recovering the indicated cost of service with a ROR of 0.55. In this context, I disagree with Mr. Crist's assessment that my allocation is "unconscionable."

[53] Statement No. 1-R, page 6, line 21 – page 7, line 2.

Q. MR. CRIST CLAIMS HE HAS RECEIVED MORE COMPREHENSIVE DATA FROM THE COMPANY SINCE FILING HIS DIRECT TESTIMONY REGARDING THE MILES OF GAS DISTRIBUTION MAINS SERVING THE LDS/LGSS CLASS. WHAT DATA DID MR. CRIST RECEIVE AND WHAT DOES HE CLAIM THE DATA SHOWS?

A. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** should be assigned to LDS/LGSS in the ACOSS.

Q. DO YOU AGREE WITH MR. CRIST THAT ONLY **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** OF GAS MAINS ARE REQUIRED TO SERVE LDS/LGSS CUSTOMERS?

A. No. As explained in my rebuttal testimony, the miles of distribution mains that Columbia was required to extend its facilities to serve an LDS/LGSS customer is not an appropriate basis to determine an allocation of distribution mains to LDS/LGSS customers. The gas supplies delivered to LDS/LGSS customers by Columbia are initially delivered to Columbia by interstate pipelines. Therefore, the miles of

[redacted]

distribution mains required to serve an LDS/LGSS customer must take into account the mains that are upstream of the point from which Columbia extended its distribution mains to serve the LDS/LGSS customer. That is, it must also consider the distribution mains required to deliver the LDS/LGSS customer's gas supplies from the interstate pipeline serving the LDS/LGSS customer to the point at which Columbia extended its distribution mains to serve the LDS/LGSS customer. Mr. Crist fails to consider the upstream distribution mains required to serve an LDS/LGSS customer.[59]

Q. MR. CRIST CLAIMS THAT COLUMBIA'S CUSTOMER-DEMAND ACOSS IS BASED ON ACTUAL COST CAUSATION BECAUSE IT APPROPRIATELY ASSIGNS MAINS EXPENSES BASED ON BOTH THE NUMBER OF CUSTOMERS SERVED AND PEAK DEMAND.[60] WHAT IS YOUR RESPONSE TO MR. CRIST'S CLAIM?

A. As explained in my Rebuttal Testimony, in its Order in Columbia's last litigated proceeding, the Commission specifically approved the use of the Peak & Average allocation methodology. This finding was not due to the errors in the Customer-Demand ACOSS presented by Columbia in its last litigated case that have now been eliminated. Rather, the Commission's findings in Columbia's last litigated proceeding concerning the use of the Peak & Average method were presented on pages 6 through 7 of my direct testimony, there specifically in the litigated 2020 proceeding the Commission found:

> …we remain of the opinion that although mains serve customers, it is the throughput that determines the mains investment, not the number of customers served. (Order at 217).

[59] OCA Statement No. 5-R, page 9, line 17 – page 10, line 6.
[60] PSU Statement No. 1-R, page 13, line 22 – page 14, line 2.

Thus, the elimination of the errors in the Customer-Demand ACOSS presented by Columbia in its last litigated case had no influence on the Commission's finding that the Peak & Average method is superior as throughput, and not the number of customers, determines the Company's mains investment.

Q. HAS THIS COMMISSION PREVIOUSLY ADDRESSED THE ALLOCATION OF DISTRIBUTION MAINS COSTS BASED ON THE NUMBER OF CUSTOMERS IN OTHER PROCEEDINGS?

A. Yes. In Philadelphia Gas Works, Docket No. R-00061931, 2007 PA. PUC LEXIS 46 (2007), the Commission found that mains allocations based on the number of customers was not acceptable.

Q. MR. CRIST CLAIMS THAT THE MARYLAND PUBLIC SERVICE COMMISSION ("MPSC") APPROVED IN A BALTIMORE GAS AND ELECTRIC COMPANY PROCEEDING AN ACOSS METHOD WHICH ALLOCATES MAINS INVESTMENT BASED ON NON-COINCIDENT PEAK DEMANDS.[61] WHAT IS YOUR RESPONSE?

A. In Washington Gas Light Company ("WGL"), Case No. 9322, the MDPSC found "…that the CCOSS and accompanying demand study were sufficient for purposes of rate design and that the Proposed Order fairly assigned costs to each customer class, including non-residential customer classes." (Order No. 86013, Issued November 22, 2013). In that proceeding WGL's cost of service study utilized the Peak & Average approach to the allocation of distribution mains. In WGL's base rate proceeding in Case No. 9481, the cost-of-service study presented by WGL again used the Peak & Average method to allocate distribution mains, and WGL's cost of service study was accepted by the MDPSC (Order No. 88944, Issued December 11, 2018). In WGL's

[61] PSU St. No. 1-R at 13.

base rate proceeding in Case No. 9605, the cost-of-service study filed by WGL also utilized the Peak & Average method. That proceeding was resolved by settlement.

Q. MR. CRIST CITES PROCEEDINGS IN OTHER JURISDICTIONS IN WHICH COMMISSIONS HAVE ADOPTED CUSTOMER-DEMAND ACOSSs. ARE YOU AWARE OF PROCEEDINGS IN WHICH COMMISSIONS HAVE ADOPTED PEAK AND AVERAGE ACOSSs?

A. Yes. The Indiana Utility Regulatory Commission ("IURC") has strongly endorsed the use of the Peak & Average methodology. See In re Citizens Gas & Coke Utility, IURC Case No. 42767 (Oct. 19, 2006). The IURC found that the Peak & Average method was the "equitable and realistic" method for allocating distribution mains costs, and provided the following analysis:

> Based upon the record evidence, this Commission concludes that the OUCC's cost-of-service study is most reflective of cost causation and possesses a high degree of objectivity upon which the Commission may place reliance in establishing the rates and charges in this proceeding.
>
> While we do not doubt that distribution mains must be constructed with peak demand in mind, distribution mains do not only serve customers on peak demand days. Therefore, a measure of the costs of distribution mains must be allocated to customers based on their usage that takes place on non-peak days. For example, a customer that does not take service at all on the peak demand day-and therefore contributes nothing to peak demand requirements of distribution mains-but receives service through distribution mains at other times should be responsible for some portion of distribution main costs.
>
> The OUCC's approach is much more equitable and realistic. Rather than allocating distribution main costs exclusively based on either peak demand day or average annual consumption, the OUCC used a

> compromise approach that allocated these costs based on both. Under the OUCC's cost-of-service study, 80% of distribution main costs are allocated based on average demand. (Public's Ex. No. 6 at 13.) In this way, the OUCC's approach allocates part of distribution main costs to customers who receive service through distribution mains throughout the year but who may not receive much or any service on the peak demand day.
>
> For the reasons set forth above, we find the OUCC's cost-of-service study most accurately reflects the manner in which distribution main costs are actually incurred. See, In Re Citizens Gas & Coke Utility, IURC Cause No. 39066, at 31 (Nov. 1, 1999). We therefore adopt the OUCC's cost-of-service study to implement the rates increase approved in this Cause.
>
> [In re Citizens Gas & Coke Utility, IURC Cause No. 42767, at 74-75 (Oct. 19, 2006)]

The Illinois Commerce Commission ("ICC") has also accepted the Peak & Average method for allocating transmission and distribution costs in the natural gas industry. The ICC explained the reasoning behind utilizing a Peak & Average methodology in their decision as follows:

> Generally, [Central Illinois Public Service Company or CIPS] and [Union Electric Company or UE] gas transmission and distribution facilities exist because there is a daily need for such facilities. Regardless of when CIPS and UE experience their respective peak and the level of the peak, customers depend on the continued operation of the Ameren gas transmission and distribution systems to meet their daily needs. On the day that the peak does occur. Ameren's own Mr. Carls testifies that CIPS' and UE's respective systems are built to accommodate the system peak without regard to each class' peak. In light of the nature in which the transmission and distribution systems are used and because of the relatively declining cost of increasing capacity, peak demand is not the appropriate emphasis in allocating demand costs…As the Commission

> concluded in Docket 94-0040, a utility can not justify its transmission and distribution investment on demands for a single day. The allocation method that properly weights peak demand is the [Average & Peak or A&P] method, the same method that the Commission adopted in CIPS' and UE's last gas rate cases. The A&P method properly emphasizes the average component to reflect the role of year-round demands in shaping transmission and distribution investments.
>
> [Central Ill. Pub. Service Co. Proposed General Increase in Natural Gas Rates, et al., 2003 Ill. PUC Lexis 824, 231-232 (2003)]

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission v Columbia Gas of Pennsylvania, Inc.	: : : : :	Docket Nos. R-2024-3046519

VERIFICATION

I, Jerome D. Mierzwa, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 5SR, are true and correct (or 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 25, 2024

Signature: 
Jerome D. Mierzwa

Consultant Address: Exeter Associates, Inc. 10480
Little Patuxent Parkway, Suite 300
Columbia, MD 21044-3575

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3046519
	:	
Columbia Gas of Pennsylvania, Inc.	:	

Surrebuttal Testimony of Roger Colton
on behalf of the
Office of Consumer Advocate
OCA Statement 6SR

Date Served: July 25, 2024

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Roger Colton. My address is 34 Warwick Road, Belmont, MA 02478.

Q. ARE YOU THE SAME ROGER COLTON WHO PREVIOUSLY PREPARED DIRECT TESTIMONY FOR THE OFFICE OF CONSUMER ADVOCATE IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY TODAY?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimony Mark Kempic, Kevin Johnson, Ribeka Danhires, and Deborah Davis as they respond to my Direct Testimony.

Part 1. Response to Mark Kempic.

Q. WHAT IS YOUR FIRST RESPONSE TO MR. KEMPIC's REBUTTAL TESTIMONY REGARDING DISCONNECT NOTICES?

A. Mr. Kempic argues in his Rebuttal Testimony that the mismatch between the number of disconnect notices and the actual number of disconnections is not evidence of poor Company management of its collection process. He argues, for example, that sometimes Columbia stops collections if a customer asks for a payment plan, asks for a medical certificate, or applies for LIHEAP. What he does not acknowledge is that while that may happen on occasion, it does not happen sufficiently often to explain the substantial disparity between the number of disconnect notices and the actual number of disconnections. Moreover, Mr. Kempic argues that "in some cases," customers pay every other month but receive a disconnect notice monthly. He does not quantify how

frequently this "some cases" is. It is not, however, likely to be a sufficient number of cases to explain the substantial disparity.

Q. DOES THE DATA SUPPORT MR. KEMPIC'S ASSERTIONS?

A. No. Columbia provided the number of accounts in arrears by the age of arrears. If what Mr. Kempic suggests actually occurs, it would be seen in the month-to-month variation in numbers of accounts in arrears. That variation simply does not occur. (OCA-II-31). Similarly, Mr. Kempic argues that Columbia "sends out termination notices beginning in February for an April 1 termination date or later so a customer can apply for CRISIS. That customer could get two notices before April 1 with no additional action."[1] Again, however, he provides no numbers. Remember, the difference between the number of notices issued and the number of actual disconnections was nearly 250,000 (268,830 notices vs. 19,522 disconnections). The highest number of notices Columbia issued in the February/March time period of 2022-2023 or 2023-2024 was 24,809 (March 2022). The numbers of notices issued by Columbia in the months referenced by Mr. Kempic simply do not support his assertion.

Q. DOES YOUR DIRECT TESTIMONY CONTRADICT MR. KEMPIC'S ASSERTION THAT DISCONNECT NOTICES MOTIVATE CUSTOMERS?

A. Yes. Mr. Kempic's conclusory assertion does not respond to my Direct Testimony. He asserts that "all of these efforts, which are designed to motivate customers to pay or take action, inflate the termination to disconnect ratio. One could suggest that the disconnect notices are working as intended and customers are acting to stop the termination, which is

[1] Columbia St. 1-R, at 14.

the desired outcome."[2] As I demonstrate in my Direct Testimony, however, and as was found by the federal court considering Columbia's over-noticing of shutoffs in Ohio, that assertion is factually incorrect. By over-noticing disconnections, Columbia does not "motivate customers to pay or take action." It instead teaches customers that they can ignore the notice without consequence. The over-noticing of shutoffs impedes rather than facilitates or motivates collections.

Q. PLEASE RESPOND TO MR. KEMPIC'S REBUTTAL TESTIMONY REGARDING THE COLUMBIA CAP PAYMENT RATE.

A. Mr. Kempic asserts that the reason Columbia has a lower CAP Payment Rate is because the CAP Payment Rate tracks only the portion of a CAP bill paid by the CAP participant. He asserts that bills paid by LIHEAP are not considered to be bills paid by the CAP participant. Given Columbia's relatively low CAP bills, he asserts, LIHEAP will pay a higher portion of that bill, leaving less to be paid by the CAP participants themselves. Mr. Kempic makes this summary assertion without providing any data to demonstrate its accuracy. Mr. Kempic's assertion would, however, only be true if LIHEAP covered a substantial portion of CAP bills, something Mr. Kempic does not attempt to demonstrate. Again, however, Columbia's data simply does not support Mr. Kempic's argument.

Q. WHY DOES THE DATA NOT SUPPORT MR. KEMPIC'S ARGUMENT?

A. According to Columbia, while it had $18,529,098 in CAP bills in 2023, the *total* LIHEAP received was only $3,927,102.[3] Not all of those LIHEAP dollars would have been received by CAP participants or applied to CAP bills. Moreover, the Columbia data

[2] Id., at 15.

[3] OCA_II-01, Attachment E.

shows that while Columbia issued 298,833 CAP bills in 2023, the *total* number of LIHEAP participants reached only 9,749.[4] In contrast, the total number of complete and timely payments made by the CAP participants themselves reached 139,352.[5] The number of LIHEAP grants received by *all* Company customers, and the dollar value of those grants, simply do not support the assertion that Mr. Kempic advances in summary fashion.

Q. WHAT IS THE FINAL RESPONSE YOU MAKE TO MR. KEMPIC'S REBUTTAL TESTIMONY?

A. Mr. Kempic asserts that the percentage of Columbia's estimated low-income customers enrolled into CAP is not a good metric by which to measure the Company's performance. First, he asserts that the number of estimated customers I use is wrong, because it is based on Census data at a county level that is shared by two gas companies. Moreover, he asserts that the Census data does not consider "the use of other fuel types."[6] On the first Columbia point, the Company reports that it reviews census data annually of where its low–income customers reside by county. It also analyzes data provided by the Pennsylvania Department of Education that identifies where low–income household students attend school. Columbia submits that these sources provide a framework for where to prioritize outreach activities.

[4] Id.

[5] Id.

[6] Columbia St. 1-R< at 14.

Q. ARE THERE FLAWS IN MR. KEMPIC'S ANALYSIS?

A. Yes. Mr. Kempic does not acknowledge that I used the official estimates of low-income customers produced by Penn State University for the Commission. He does not explain any specific flaws in how Penn State develops those numbers. It is, however, important to note that the estimate is not simply of the total number of low-income households in Columbia service territory, which estimate might include customers of another gas utility or households using other fuels. It is, instead, an estimate of the number of Columbia customers who are low-income. If Columbia objects to that calculation by Penn State, the appropriate remedy is to direct those objections to Penn State and the Commission, not to refuse to rely upon the numbers prepared for the Commission and published in Commission reports.

Finally, I note that in explaining its CAP education and outreach to the Commission in the 2019 generic investigation of affordability, Columbia told the Commission that it "reviews census data annually of where its low–income customers reside by county."[7] Given Columbia's prior use of county-specific Census data in Commission proceedings, Mr. Kempic's objection to that use in his Rebuttal Testimony rings somewhat hollow.

Part 2. Response to Ribeka Danhires.

Q. PLEASE RESPOND TO THE REBUTTAL TESTIMONY OF COLUMBIA WITNESS RIBEKA DANHIRES.

A. In response to my Direct Testimony, Columbia witness Danhires proposes to modify Columbia's tariff regarding cash security deposits to read: "A Customer or Applicant that

[7] Final Order, at 57.

self-declares or provides income documentation that household income is at or below 150% of poverty or less shall not be asked to provide a cash deposit."[8]

Q. DOES THIS PROPOSED MODIFICATION ADDRESS THE CONCERNS YOU RAISE IN YOUR DIRECT TESTIMONY?

A. This proposed modification partially, but not entirely, addresses the concerns raised in my Direct Testimony. This proposed modification, while welcome, continues to only look forward. It codifies the regulatory requirement that eligible customer "shall not be asked to provide a cash deposit." As I note in my Direct Testimony, however, the regulatory requirement is broader. Eligible customers should be exempt from Columbia holding deposits. Not only may they not be "asked to provide" a deposit, but any low-income customer identified in the fashion proposed by Columbia should have their deposits refunded.[9] The Commission directed Columbia to

> refund security deposits, with applicable interest, collected from customers who are income–eligible for CAP. Columbia may apply the security deposit to the account balance only with the customer's informed consent. As part of obtaining this informed consent, Columbia must explain to the customer how applying the security deposit to the account balance would impact the customer's monthly bill. Columbia is directed to include this provision in its Revised 2024 USECP.[10]

[8] Columbia St. 12-R, at 1.

[9] The Commission clearly recognizes these statutory and regulatory obligations. In its Both the statute and Commission regulations prohibit requiring a cash deposit for public utility service from customers who are confirmed to be eligible for a CAP. . .Commission regulations also state that a public utility must "refund a deposit, along with any applicable interest, within 60 days upon determining that the customer or applicant from whom a deposit was collected is not subject to a deposit…." Order, Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2024-2028 Submitted in Compliance with 52 Pa.Code §62.4, Order, at 30-31. (internal citations omitted).

[10] Id.

As I discuss further below in response to the Rebuttal Testimony of Deborah Davis, Columbia filed a motion for the Commission to reconsider this decision. On July 11, 2024, the Commission affirmed its original decision.[11]

In addition to expanding the tariff language to incorporate an exemption from any cash security deposit, Columbia should further adopt the other three remedies I recommended in my Direct Testimony:

- That Columbia Gas refund any cash security deposit to a customer who is currently categorized as "Confirmed Low-Income."
- That Columbia include in its tariff the April 2024 order of the PUC, directing that Columbia may apply an existing security deposit to the account balance only with the customer's informed consent. As part of obtaining this informed consent, Columbia must explain to the customer how applying the security deposit to the account balance would impact the customer's monthly bill.
- That Columbia Gas provide a report to its Universal Service Advisory Committee every six months for three years, or until the final decision in its next base rate case, whichever is longer, of the number of low-income customers who have had deposits waived, as well as the number of low-income customers who have had deposits refunded.

Part 3. Response to Kevin Johnson.

Q. WHAT ASPECT OF THE REBUTTAL TESTIMONY OF MR. JOHNSON DO YOU WISH TO RESPOND?

A. Mr. Johnson responds to my objection to the increased customer charge by posing a hypothetical replacement of a furnace as the means by which low-income customers would reduce their energy consumption. He argues that replacing a furnace would result in a monthly savings of only $1.62 and that "it is unlikely that $1.62 per month savings

[11] Columbia Gas of Pennsylvania, Inc. Universal Service and Energy Conservation Plan for 2024–2028 Submitted in Compliance with 52 Pa. Code § 62.4, Docket No. M-2023-3039487, Order, at 8 (July 11, 20240.

would motivate a customer to purchase a new furnace. . ."[12] His testimony is a complete red herring. His testimony about the impact of the increased customer charge on whether a low-income customer would purchase a new furnace completely ignores my testimony about how, and why, low-income customers are not in the market to make substantial investments in energy efficiency in any event. As I note, not only do low-income customers lack the financial resources to make a major purchase such as a furnace (customer charge or not aside), low-income customers in Columbia's service territory also largely tend to be tenants, who would lack the decision making authority on whether to replace a furnace in their home.[13]

The problem which Mr. Johnson does *not* address are the other steps that low-income customers have been documented to take, such as closing parts of their home; reducing heating temperatures (even if to unsafe or unhealthy levels); or substituting the use of ovens or stoves to heat limited areas of their homes rather than using their heating systems to heat the entire home.[14] As the customer charge increases, these more dramatic, and harmful, responses to unaffordability are impeded as customers see that they have a larger and larger portion of their bill that is irreducible because it is in the form of a fixed monthly charge.

[12] Columbia St. 6-R, at 15.

[13] OCA St. 6, at 82 – 83.

[14] OCA St. 6, at 75.

Q. WHAT IS THE A SECOND ASPECT OF MR. JOHNSON'S TESTIMONY TO WHICH YOU WISH TO RESPOND?

A. The same observation I make above is applicable to Mr. Johnson's discussion of low-income energy efficiency investments as they may be affected by the Company's Revenue Normalization Adjustment (RNA). To the extent that usage reduction is impeded, it is not merely low-income investment in energy efficiency, which is not likely to occur in any event, but it is the more harmful usage reduction efforts that would be impeded.

In addition, however, what Mr. Johnson did *not* directly address is the fact that the customers who do (and will) invest in energy efficiency, thus creating a revenue reduction that will be passed on to ratepayer not making such investments, are non-low-income customers. It is the low-income customer population that gets left behind and who, accordingly, will pay the increased rates generated by the RNA. That result is unavoidable given the inability of low-income customers to invest in energy efficiency measures.

Mr. Johnson responds to that simply by noting that Columbia offers its CAP program, and the RNA does not apply to CAP participants. He does not respond to the undeniable observation that not only are not "all" low-income customers CAP participants, but also that, in fact, the percentage of low-income customers enrolled in CAP is unreasonably small. While Mr. Johnson seeks to equate "low-income" with "CAP," that effort should be rejected. Low-income customers not protected by CAP, which is quite large as I describe in my Direct Testimony.

Finally, Mr. Johnson does not even attempt to respond to how and why the need for the RNA breaks down, particularly as applied to low-income customers. As I noted in my Direct Testimony, the RNA mismatches two data sets. The RNA is based on *billed* revenues. But the loss of revenue to the Company from any investment in energy efficiency should not be based on *billings* before energy efficiency. The lost revenue, if any, should instead consider the impact on what the Company actually collects. To the extent that the RNA is based on billings, it is collecting lost revenue once through base rates, and collecting those same dollars through the RNA.

The proposed RNA should be denied. It represents a direct cash transfer from those who can invest in energy efficiency (non-low-income customers) to those who cannot (low-income customers).

Part 4. Response to Columbia Witness Deborah Davis.

Q. PLEASE EXPLAIN THE PURPOSE OF THIS SECTION OF YOUR SURREBUTTAL TESTIMONY.

A. In this section of my Surrebuttal Testimony, I respond to the Rebuttal Testimony of Columbia Gas witness Deborah Davis. Ms. Davis responds to my recommended changes to Columbia tariffs and practices which are necessary to bring Columbia into compliance with Commission statutes and regulations.

Q. WHAT IS THE FIRST ASPECT OF MS. DAVIS' REBUTTAL WHICH YOU WISH TO RESPOND?

A. Ms. Davis argues that the Company need not comply with the Commission's definition of a "confirmed low-income customer" because the Commission defines other terms

differently in its regulations.[15] She does not dispute that the Commission has specifically defined what it means by the term "confirmed low-income residential account." Nor does she dispute that Columbia's use of the term "confirmed low-income residential account" differs from how the Commission defines that term. She relies on various Commission definitions of "household income" to justify Columbia's divergence from the definition of "confirmed low-income residential account." Ms. Davis asserts that the Company may require a customer to report its actual dollars of household income to be identified as a "confirmed low-income residential account." Not even her use of other definitions, however, supports her position. The Commission regulation she cites with respect to being exempt from cash security deposits, for example, states that "a customer is confirmed to be eligible for a customer assistance program by the public utility when the customer provides income documents *or other information*. . ."[16] The emphasized language demonstrates that a customer need not reveal to the Company the household's actual dollars of income. A customer participating in Food Stamps, for example, is "low-income" whether that customer's household income is $5,000 or $15,000.

The question is *not* whether Columbia should consider "total household income rather than relying on a single income source" as suggested by Ms. Davis.[17] No-one, including myself, has suggested that the Company must rely on "a single income source." The question is only whether it is reasonable, or appropriate, for the Company to insist that a

[15] Columbia Gas St. 18-R, at 2.

[16] Columbia Gas St. 18-R, at 2 (emphasis added).

[17] Id., at 3.

customer must reveal actual dollars of income when the Commission's regulations provide that they do not.

Ms. Davis inappropriately seeks to equate enrollment in CAP with identification of a customer as a "confirmed low-income residential account."[18] The question of what is required to enroll in CAP is, of course, an entirely different question. It is not a question that I raised. Whether or not a customer must document their actual income to participate in CAP, providing such documentation of actual income is not necessary to be identified as a "confirmed low-income residential account."

Ms. Davis next states that when a Columbia customer contacts the Company for any "relevant reason," "the Company obtains financial information that includes household composition and total monthly income."[19] In addition to the receipt of LIHEAP, this "financial information that includes household composition and total monthly income" is beyond the scope of information which the Commission's definition of "confirmed low-income residential account" allows. The Commission's regulations explicitly allow a customer to self-certify their "income source" to establish their "confirmed low-income" status. Whether or not Columbia ***agrees*** with that regulation is irrelevant. The Company is bound to comply with the regulation. The Company's refusal to have a tariff provision that simply reflects the Commission's own regulation should be rejected.

Finally, Ms. Davis asserts that adopting a tariff provision which complies with the Commission definition of "Confirmed Low-Income Residential Account" would

[18] Id., at 3.

[19] Id., at 3.

"infringe on the process" initiated by Columbia to "improve low-income customer count accuracy."[20] This argument has no merit. Determining whether the Company complies with Commission regulations is not assigned to any particular proceeding. And, it is no more within the purview of the Company's Universal Service Advisory Committee, than it is within the purview of the Company standing alone, to decide not to comply with the Commission's regulations.

Q. PLEASE EXPLAIN THE SECOND ASPECT OF MS. DAVIS' REBUTTAL TESTIMONY TO WHICH YOU RESPOND.

A. Ms. Davis argues that the Company should not commit to affording any Confirmed Low-Income Customer the protections provided by tariff or regulation to any customer or applicant with household income at or below 150% of Federal Poverty Level. Adopting such protections, Ms. Davis would say, would "force" a customer to "join CAP, a payment plan, or a budget." She offers absolutely no explanation of how that assertion has any basis to it. Ensuring that Confirmed Low-Income customers are afforded the protections provided by regulation of tariff does not force any customer to do anything. It simply allows customers to take advantage, should they choose to do so, of the protections which the Commission has provided. Protections include, but are not necessarily limited to, protection from winter shutoffs, longer payment arrangements, exemption from prepayment meters, possible waiver of late payment charges, extended payment of reconnection fees and amount of arrears required to be paid in order to be reconnected.

[20] Id., at 4.

Ms. Davis then reargues that allowing a household to be identified as a "Confirmed Low-Income Residential account" without providing their actual dollars of income "may include customers with higher incomes by allowing customers to verify income without providing total household income."[21] If Columbia genuinely believes this to be a problem, however, the appropriate remedy is for the Company to ask the Commission to amend its regulations. As it stands, the Commission's regulation *explicitly* allows customers to provide information on their "source of income" as one way to establish their status as a Confirmed Low-Income residential account. If Columbia believes that to be a bad regulation, its remedy is to ask the Commission to change it, not to choose to ignore it.

Finally, Ms. Davis argues that allowing a customer to establish their Confirmed Low-Income status by asserting their participation in a low-income program –remember, the Commission regulation explicitly allows a customer to provide information on their "source of income"—may "include customers with higher incomes by allowing customers to verify income without providing total household income."[22] The *only* example she uses, and she raises it without documentation or citation, is her assertion that an Supplemental Security Income (SSI) recipient that an individual receiving SSI recipient "could also be receiving a pension that is considered reportable income."[23] There are two flaws with this argument. On the one hand, even if accurate, it is illogical and extreme to refuse to accept any program simply because *one* different program may

[21] Id., at 5.

[22] Id., at 5.

[23] Id., at 3.

have that flaw. To refuse to accept programs such as the Supplemental Nutrition Assistance Program (SNAP, or Food Stamps), Medicaid, Temporary Aid to Needy Families (TANF), or Free school lunches, all of which unquestionably have maximum income eligibility at or below 150% of FPL, because SSI "could" have some source of additional income for a one-person household is not reasonable (particularly when the Commission's regulation explicitly allows a customer to establish their Confirmed Low-Income status by reference to their "source of income"). On the other hand, Ms. Davis's characterization of SSI is in error. The Social Security Administration (SSA) describes SSI as follows:

> **Income and resource limit.** If an individual's income or resources go above the limit, he or she may not qualify for SSI assistance. The countable income limits for individuals and couples are equal to their respective Federal benefit rates (FBR) and generally increase annually according to changes in the cost of living. For 2019, *the FBR is $771 a month for individuals and $1,157 a month for couples.* [24]

There is no income exclusion for "a pension" as asserted by Ms. Davis. According to the Social Security Administration, effective January 1, 2024 the Federal benefit rate (FBR) is $943 for an individual and $1,415 for a couple. An FBR of $943 for an individual is $11,316. In contrast, 150% of FPL for a one-person household in 2024 is $22,590 (100% FPL x 1.5 = $22,590).

[24] Social Security Administration. 2019 Annual Report on the Supplemental Security Income Program (emphasis added) available at https://www.ssa.gov/OACT/ssir/SSI19/III_ProgramDescription.html#:~:text=As%20a%20means%2Dtested%20program,or%20her%20need%20for%20assistance.

Q. PLEASE RESPOND TO MS. DAVIS' REBUTTAL TESTIMONY THAT NOT ALL LOW-INCOME CUSTOMERS WILL CHOOSE TO ENROLL IN CAP.

A. Ms. Davis asserts that my testimony assumes that "all customers will join CAP if they are made aware of the program. . ."[25] I made no such assumption, and made no such assertion in my testimony. Ms. Davis did not include a page citation to my testimony when she states that I made such an assertion. Nonetheless, Ms. Davis disagrees with the proposition that "Columbia's Universal Service Programs are not entirely successful in helping low-income customers maintain gas service."[26] She asserts that "it is the Company's experience that once a customer learns they are safe from disconnection for nonpayment, the immediate crisis is resolved, and the motivation to take further action for a long-term solution diminishes." She states further that "it is the Company's experience that many customers view entering a payment arrangement and preventing a disconnection as successful."[27]

Q. DOES MS. DAVIS ADDRESS YOUR DIRECT TESTIMONY REGARDING DISCONNECTIONS OF CONFIRMED LOW-INCOME CUSTOMERS?

A. No. While she talks about entering into payment plans and *preventing* disconnections, Ms. Davis does *not* address the facts presented in my Direct Testimony that from May 2021 through the end of that year, Columbia disconnected 5,475 Confirmed Low-Income customers, while in 2022, 6,124 Confirmed Low-Income accounts experienced a service disconnection. In 2023, Columbia disconnected 5,974 Confirmed Low-Income

[25] Columbia St. 18-R, at 6.

[26] Id., at 5.

[27] Id., at 6.

customers.[28] Remember, these figures are limited to the customers that Columbia knows to be low-income through their narrow (and unlawful) interpretation of who represents a "Confirmed Low-Income customer."

Q. DOES MS. DAVIS ADDRESS THE DATA IN YOUR DIRECT TESTIMONY REGARING LOW-INCOME CUSTOMERS WHO DEFAULT ON PAYMENT ARRANGEMENTS?

A. No. While Ms. Davis generically and summarily refers to low-income customers who enter into payment arrangements to prevent the disconnection of service, she ignores the data on low-income customers who ***default*** on those payment arrangements. She did not respond to the data presented in my Direct Testimony, as reported to the Bureau of Consumer Services (BCS) by Columbia Gas, that the number of "payment-troubled" Confirmed Low-Income customers in 2023, alone, ranged from 5,050 in January 2023 to 9,339 in December 2023.[29] While in 2023, Columbia Gas averaged 7,335 Confirmed Low-Income customers with arrears on arrangement, it average 7,442 Confirmed Low-Income customers per month who had defaulted on their arrangement one or more times in the past 12 months.[30]

[28] OCA St. 6, at 42.

[29] According to BCS, "A payment troubled customer is a customer who has failed to maintain one or more payment arrangements in a 1-year period." BCS 2022 Report (2022), at 11, citing 52 Pa. Code § 54.72 or § 62.2 .

[30] OC-II-01 (Attachment E).

Q. PLEASE RESPOND TO MS. DAVIS' DISCUSSION OF THE NEED FOR PERSONAL CONTACT TO OFFER THE CAP PROGRAM PRIOR TO A SERVICE DISCONNECTION FOR NONPAYMENT.

A. Ms. Davis opposes making personal contact with customers known to be low-income to offer them an opportunity to enroll in CAP and gain arrearage forgiveness prior to the disconnection of service. She asserts that making such personal contact would interpose "unnecessary delay."[31]

It is difficult to justify a refusal to provide personal notice to Confirmed Low-Income customers prior to the disconnection of service on the grounds that it would impose "unnecessary delay." As I reported in my Direct Testimony, Columbia's data to BCS indicates that the average arrears for a Confirmed Low-Income customer was $1,034 in 2021 and $955 in 2022.[32] Indeed, from March 2021 through February 2024, on average, 86.4% of Columbia's Confirmed Low-Income accounts in arrears were in arrears 90 or more days,[33] while an average of 94.4% of the dollars of confirmed low-income accounts in arrears were 90 days old or older.[34] Any minor delay associated with providing personal notice to Confirmed Low-Income customers who are in imminent danger of losing their service to a disconnection for nonpayment will not appreciably add to what, in the absence of the personal notice, would be a time-sensitive collection activity.

[31] Columbia St. 7, at 7.

[32] OCA St. 6, at 84.

[33] OCA-II-31.

[34] OCA-II-33.

Ms. Davis finally asserts that "a limited number of confirmed low-income customers would be facing disconnection without having heard of the CAP program."[35] She offers no data in support of that assertion. Her statement is based on her further assertion that "they would have had to ignore all notices up to that point and chosen not to call the Company." She asserts that "the Company follows all required notices during its collection process, and this additional step would only serve to add another delay."[36] The "notices" to which she refers, however, do not specifically call-out CAP, along with the associated arrearage forgiveness, as an alternative to the disconnection of service for nonpayment. The personal notice I recommend, developed in collaboration with the Company's Universal Service Advisory Committee, would provide a targeted outreach initiative to a particularly vulnerable population.

It is difficult to understand how, or why, Columbia believes it is more reasonable to disconnect service to nearly 17,600 customers it ***knows*** to be low-income (5,475 in 2021; 6,124 in 2022; 5,974 in 2023) rather than providing personal notice of a program that, by statute, is ***supposed*** to be designed to "help low-income customers maintain natural gas. . .service."

[35] Id.

[36] Id., at 7, 8.

Q. PLEASE RESPOND TO MS. DAVIS' REBUTTAL TESTIMONY REGARDING THE DEMAND FOR DEPOSITS FROM LOW-INCOME CUSTOMERS.

A. Ms. Davis testifies that "current Company policies. . .do not match the Company's current tariff language. . ."[37] She then references proposed tariff changes as set forth in the Rebuttal Testimony of Company witness Danhires. I address those proposed changes in my response to Witness Danhires in my Surrebuttal Testimony above.

Q. PLEASE RESPOND TO MS. DAVIS' REBUTTAL TESTIMONY REGARDING THE REFUND OF DEPOSITS.

A. In my Direct Testimony, I noted that the Commission recently held in a Columbia Gas proceeding that in refunding deposits to Confirmed Low-Income customers, the Columbia Gas practice of applying those deposits as credits against arrears rather than providing a cash refund did not comply with Commission regulations. I urged that Columbia Gas incorporate the Commission holding into its tariff language regarding the refund of deposits.

Ms. Davis replies that the Commission has granted the Company's Motion for Reconsideration of that April 2024 decision. She stated that the Commission has not yet provided a decision on that Motion for Reconsideration and argued that "The Company does not agree that any changes should be made until that Petition is decided."[38]

Since Ms. Davis' Rebuttal Testimony, however. the Commission decided the issue of the Company's Motion for Reconsideration. The Commission held:

[37] Columbia St. 18-R, at 12.

[38] Id., at 12.

> We deny Columbia's request to apply security deposits collected from CAP-eligible customers to customer bills without express consent instead of refunding them. We direct Columbia to suspend collection activity and provide retroactive CAP benefits (i.e., CAP credits and arrearage forgiveness) to customers determined eligible for CAP whose enrollment is delayed due to a security deposit refund.[39]

As the Commission upheld its original decision, Columbia should incorporate the language into the tariff.

Q. PLEASE RESPOND TO MS. DAVIS' REBUTTAL TESTIMONY REGARDING WHAT SHOWING A CUSTOMER MUST MAKE IN ORDER TO BE EXEMPT FROM CASH SECURITY DEPOSITS.

A. Ms. Davis argues that my testimony regarding what customers must show the Company in order to be entitled to an exemption from posting cash security deposits is the same issue as how to define a "Confirmed Low-Income residential account."[40] The issue regarding exemptions from being required to post a cash security deposit are different. The regulatory language does not revolve around anyone's definition of "Confirmed Low-Income customer account." Ms. Davis should not be allowed to conflate the two issues.

The Commission regulation regarding when a customer is to be exempt from posting a cash security deposit is unambiguous. The PUC's regulations provide that a customer is exempt from a cash security deposit "when *the customer provides income documents or other information* that he or she is eligible for state benefits based upon household

[39] Order on Reconsideration, Docket No. M-2023-3039487, at 8 (July 11, 2024).

[40] Columbia St. 18-R, at 14.

income eligibility requirements that are consistent with those of the public utility's customer assistance program."[41] (emphasis added). As I note in my Direct Testimony, Columbia's current tariff and practices (which would be continued under the proposed modification contained in Witness Danhires' Rebuttal Testimony), the Columbia current practices and practices conflict with this regulation in at least the following respects:

- First, the language in the current Tariff is more restrictive than it needs to be. Rather than needing to have information "confirmed" in some way, the regulation provides that a deposit exemption can be based upon information which "the customer provides." I agree that the Company's proposed tariff modification included in Witness Danhires' Rebuttal Testimony allows "self-declaration" and addresses this concern.

- Second, the current tariff inappropriately requires that a customer be confirmed to be eligible for Columbia's CAP. I agree that the Company's proposed tariff modification included in Witness Danhires' Rebuttal Testimony removes this restriction, and allows for a deposit exemption for customers with income at or below 150% of Federal Poverty Level irrespective of CAP certification.

- Third, in order to be confirmed to be eligible for CAP, the current tariff requires that a customer must provide specific household income and household composition data. That requirement goes beyond the PUC's regulation, which allows the customer to provide "income documents *or other information*" (emphasis added). The Company's proposed modified tariff does not address this lack of compliance. Indeed, Ms. Davis explains why Columbia disagrees with the regulation and thus chooses not to comply with it. This shortcoming of the Company's response was discussed in detail above.

- Finally, the Tariff provides only that customers "shall not be *asked to provide* a cash deposit." (emphasis added). The PUC's tariff, however, is not exclusively forward-looking. If a customer has previously provided a cash security deposit, and is found to be meet the requirements of the regulation, that customer is entitled to a refund of their deposit. Ms. Davis testifies, however, that

[41] 56 Pa. Code § 56.41(4).

"Beginning in June 2023, the company has proactively reviewed and refunded the security deposits of confirmed low-income customers on a monthly basis."[42] This monthly review addresses the concern about the absence of any reference to the right to receive such reviews in the tariff. These monthly reviews, however, should be expanded to incorporate not merely "confirmed low-income customers," but should include all customers who would be entitled to an exemption from any deposit request with which to begin.

Q. PLEASE EXPLAIN YOUR RESPONSE TO THE LAST ISSUE ADDRESSED BY MS. DAVIS' REBUTTAL TESTIMONY.

A. Ms. Davis opposes having the Company include in its tariff a recognition that it is bound not merely by "general industry practices" in applying any credit scoring methodology it utilizes, but it is bound, also, by the federal Equal Credit Opportunity Act (ECOA). As I documented in my Direct Testimony, "general industry practices" in the utility industry do not necessarily comply with the ECOA in particular. Considerations of whether a consumer is employed and, if so, for how long, may have the effect of discriminating against consumers who lack employment because they receive public assistance (one of the protected classes under ECOA). Any consideration of whether a consumer is a homeowner, as well as about whether a consumer is banked or unbanked, has a high probability of having racially disparate impacts. Consistency with "general industry practices," which is all that the PUC regulations reference, does not incorporate compliance with the federal consumer credit law which also binds Columbia Gas. The protections against discrimination based on ECOA-identified protected classes should be incorporated into the Columbia tariff. It is difficult to understand *why* Columbia opposes

[42] Id., at 13.

agreeing with the proposition that it is required to avoid discrimination based on the ECOA federally-protected classes.

Q. ARE THERE ASPECTS OF YOUR DIRECT TESTIMONY WHICH MS. DAVIS DID NOT OPPOSE?

A. Yes. Ms. Davis testified that the Company is willing to "consider" the following:

- Providing a written stand-alone written plain English notice of the right to enroll in CAP when a security deposit is waived.
- Providing provided a written, stand-alone, plain English notice **to customers** at or below 150% of the FPL when negotiating a payment arrangement.
- Providing a written stand-alone plain English notice to Confirmed Low-Income customers achieving a minimum arrears of $300.
- Providing a written stand-alone plain English notice to customers who have had service disconnected for nonpayment, and who remain disconnected at the time of the Company's Cold Weather Survey ("CWS") undertaken for the PUC.

In addition, Ms. Davis testified that the Company was "willing to consider" the ability and cost associated with using speech analytics for this purpose in a future proceeding.

Q. WHAT IS YOUR RESPONSE TO THIS REBUTTAL TESTIMONY?

A. Expressing a "willingness to consider" each of the stated initiatives is not a particularly strong commitment. I recommend that the Commission accept this "willingness to consider" but go further to direct that the Company initiate, on a pilot basis, each of the stated outreach initiatives within 90 days after a final order in this proceeding. The pilots should be developed in collaboration with Columbia's USAC. The results of the pilots,

along with a future recommendation, should, after being shared with the USAC, be presented to the Commission no later than the Company's next USECP review or base rate proceeding, whichever comes first.

Moreover, expressing a willingness "to consider" the future use of speech analytics "in a future proceeding" is not a strong commitment. The Commission should build on this "willingness to consider" to direct the Company to present a pilot program involving the use of speech analytics no later than the Company's next USECP review or base rate proceeding, whichever comes first. It should be remembered that this is not a big step on the part of Columbia Gas. It said in response to discovery that it "is *currently investigating* speech analytics tools for the inbound calls from customers, but presently does not incorporate these tools in its business model." (OCA-3-21 025) (emphasis added).

Q. DOES THIS COMPLETE YOUR SURREBUTTAL TESTIMONY?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Roger Colton, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 6SR, 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 25, 2024

Signature: _____

Roger Colton

Address: Fisher Sheehan & Colton
34 Warwick Road
Belmont, MA 02478

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:		
Office of Small Business Advocate	:	Docket Nos.:	R-2024-3046519
Office of Consumer Advocate	:		C-2024-3047905
Ronald T. Bernick	:		C-2024-3047675
	:		C-2024-3048339

v.

Columbia Gas of Pennsylvania, Inc.

SURREBUTTAL TESTIMONY

OF

Nicholas A. DeMarco

On behalf of the

PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

OCA Statement 7SR

Date Served: July 25, 2024

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Introduction

Q. Mr. DeMarco, did you previously provide testimony in this proceeding on behalf of the Office of Consumer Advocate?

A. Yes. My direct testimony was submitted as OCA Statement 7. I am a Regulatory Analyst for the Office of Consumer Advocate. My Testimony covered customer service and protection concerns, company's policy related to PII, and several safety incidents.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony will be to address the rebuttal testimony presented by Company Witness George Dice (Columbia Statement 17-R) who addresses Columbia's customer service issues that I addressed in my direct testimony. Additionally, I will address the rebuttal testimony of Company Witness Mark Kempic (Columbia Statement 1-R) and Brittany Komenda (Columbia Statement 4-R), regarding the Company's cost recovery due to multiple safety incidents which lead to the damage of private property, company property, or both in the following cases Rimersburg/Fayetteville Over Pressurization Event (M-2021-3005572), North Franklin Incident (M-2022-3012079), Maiden Street Line Damage (C-2023-3040925).

Summary

Q. Please provide an overview of your surrebuttal testimony.

A. First, I will respond to Company witness Dice and the remaining issues related to customer service call center performance, Company oversight of third-party vendors, Company retention of customer social security numbers, and Columbia's UCARE statistics.[1]

Second, I respond to the rebuttal testimony of Company witness Kempic regarding the Company's expenses related to the safety incidents introduced in my direct testimony.

- Rimersburg/Fayetteville Over Pressurization Event (M-2021-3005572)
- North Franklin Incident (M-2022-3012079)
- Maiden Street Line Damage (C-2023-3040925)

Q. What customer service issues remain to be addressed?

A. I will address the following customer service issues that remain to be adequately addressed by the Company:

- Columbia's call center performance
- Columbia's oversight of third-party vendors
- Columbia's storage of customer social security numbers
- Columbia's UCARE statistics

[1] UCARE stands for the Utility Consumer Activities Report and Evaluation data published by the PUC quarterly and with a report published annually. *See*: https://www.puc.pa.gov/filing-resources/reports/consumer-activities-report-evaluation/

Q. What issues remain to be addressed regarding the Company's cost recovery regarding the safety incidents?

A. Yes. As a matter of policy, the OCA believes insurance deductibles and replacements that occurred as a result of over-pressure incidents should not be recoverable in rates in order to properly encourage utilities to provide safe, adequate, and reasonable service and facilities. However, case by case specific commentary will be discussed below.

Customer Service

Q. Did Mr. Dice address your concerns regarding Columbia's customer service performance trends?

A. Yes. In my direct I stated my concern for the downward performance trends since 2019 related to Columbia's abandonment rate and calls answered within 30 seconds. Mr. Dice disagrees with my analysis that it is yet too soon to determine if the internal team created by Columbia to assess its call center performance has been effective in increasing the call center performance. Mr. Dice provides Columbia's call center performance statistics for the year to date for 2024.[2]

Q. Do you have any remaining concerns?

A. Yes. While there may have been some marginal improvements in some areas since the team's inception in 2023 the team has only been in existence for around a year. It takes more than one year of data to determine a trend. Columbia should show long-term improvement and the ability to maintain increased performance. Additionally, the Commission should not grant performance management adjustments based on projected statistics as suggested in Mr. Dice's testimony[3] and instead base its decision on the multi-

[2] Columbia Statement No. 17-R pg. 2-3 ln. 15-16
[3] Columbia Statement No. 17-R pg. 3 ln. 12-16

year analysis presented in my direct testimony.[4] Ultimately, the service offered by Columbia is to be expected of a utility company and should not warrant a performance management adjustment.

Q. Did Mr. Dice address your concern regarding Columbia's oversight of third-party contractors?

A. Yes. Mr. Dice states that Columbia is not currently retaining third-party contractors[5] and that Columbia did not have direct oversight of quality assurance checks of their previous third-party contractor that they employed.[6] Mr. Dice states that in the future:

> "If Columbia uses a third-party vendor for call center staff augmentation or for other call center related services in the future, a detailed and comprehensive plan would be included within the contract terms to manage and oversee the vendor's performance and compliance with applicable laws and regulations."[7]

Q. Does Mr. Dice address your concerns regarding the storage of customer social security numbers?

A. Partially. While Columbia must comply with the Federal Trade Commission's Red Flag Rule, I continue to question whether keeping customer SNN on file for the identification of bad debt or for debt collections is a sufficient enough reason to store and risk this customer information being subject to inadvertent disclosure. Cyber-attacks are rising. While the attack on NiSource communications vendor that supports Columbia's contact services did not impact any customer data, storing such data increases customer's risk of having their Personal Identification Information stolen when the Company can request

[4] OCA St. 7 pg. 3-5 ln. 18-2
[5] Columbia Statement No. 17-R pg. 4 ln. 12-15
[6] Response to OCA-7-009.
[7] Columbia Statement No. 17-R pg. 4-5 ln. 16-2

photo ID when a customer refuses to provide an SSN.[8]

Q. Does Mr. Dice address your concerns regarding Columbia's UCARE stats and complaints?

A. Partially. Mr. Dice discussed the steps the Company has taken since it conducted its Root Cause Analysis (RCA).[9] However, even with the steps the Company has taken, as shown in my direct testimony there has been a trend of decreased performance outside of PARs.

BCS Category	2021[10]	2022	2023
Residential Customer Complaints[11]	122	168	204
Residential Payment Arrangement Requests (PARs)[12]	338	552	604
Inquiries	122	284	362
% Justified Residential Customer Complaints	6	8.1	4
% Justified[14] PARs	4	3.1	4
Response Time to Complaints and PARs (Days)	10.1/5.5	8.1/1.6	6.2/1.5
Verified Infractions[13] (Chapter 56)[14]	3	8	11

[8] Response to OCA 1-030.
[9] Columbia Statement No. 17-R pg. 5-6 ln. 16-15
[10] Used both the 2022 and 2021 UCARE reports and quarterly reports.
[11] The BCS defines a Justified Consumer Complaint as "A consumer complaint where, prior to BCS intervention, the company did not comply with Commission Orders, policies, regulations, reports, Secretarial Letters, tariffs or guidelines when the consumer brought the complaint to the company's attention. The justified consumer complaint rate equals the number of justified consumer complaints for each 1,000 residential customers."
[12] The BCS defines a Justified PAR as, "A Payment Arrangement Request where, prior to BCS intervention, the company did not comply with Commission regulations, reports, Secretarial Letters, tariffs or guidelines. The justified payment arrangement request rate equals the number of justified payment arrangement requests for each 1,000 residential customers."
[13] Response to OCA-7-01 attachment N.
[14] The BCS defines an Infraction as "A misapplication or infringement of a Commission regulation, particularly the standards and billing practices for residential utility service."

Q. Do you have any remaining concerns?

A. While the Company may have begun to take steps to show it is addressing its growing customer complaint problem, the Company should continue to track and readjust their practices to reverse the current trend.

Q. Please summarize your conclusion regarding customer service.

A. In conclusion, I believe that the customer service offered by Columbia is at a level that a customer should expect to receive and does not warrant a management performance adder.

Safety Incidents

Q. Did Mr. Kempic address your concern regarding the Company making a ratemaking claim for any related to the aforementioned cases civil penalties?

A. Yes. The Company is not making a claim for the $1,527,500 in civil penalties accrued by the Company. He states that the settlement agreement approved by the Commission specifically prohibits recovery of those penalties.[15]

Q. Did Mr. Kempic address your concerns as to whether the expenses and capital costs that were previously incurred by the Company related to the events were covered by insurance or shareholder funds?

A. Mr. Kempic refers to OCA Set 20-002 as Exhibit MK-1-R-2, denoting that there are two basic costs generally associated with incidents, including: third party claims, and O&M and capital costs associated with the repair of infrastructure, if any is needed.[16]

According to Mr. Kempic, only the North Franklin Incident (M-2022-3012079) involved claims by third parties. For third-party costs, Columbia is responsible for the

[15] Columbia Statement No. 1-R pg. 15 ln. 8-15
[16] Columbia Statement No. 1-R pg. 15-16 ln. 16-3

deductible portion of its insurance policy in the amount of $25,000. Any amount over the deductible is paid and/or reimbursed by insurance carriers. Columbia has traditionally included any deductible expenses in the company's 5-year average of Injuries and Damages (I&D) which has historically been included in the Company's expense claim for the cost of doing business.[17]

Q. How does Company witness Komeda address the $25,000 insurance deductible related to the North Franklin Incident (M-2022-3012079)?

A. Company witness Komenda disagrees with my recommendation that the $25,000 deductible related to the North Franklin Incident should be disallowed for two reasons. The first reason Ms. Komenda presents is that if my recommended adjustments were accepted, Columbia's I&D would only see a decrease of $5,000 because Columbia uses a five-year average, instead of the $25,000 proposed. Secondly, if OCA witness Meyer's proposed adjustments are accepted to I&D to the HTY expense, or if I&E witness Yingling's three-year average is accepted, the $25,000 deductible would not be included in the revenue requirement and no adjustment would be necessary.[18]

Q. Do you have any comments?

A. Yes. While the reasons for adopting Mr. Meyer's adjustments stand apart from my testimony and are fully supported in Mr. Meyer's direct testimony, my direct testimony provides additional support for the Commission to adopt Mr. Meyer's adjustment to I&D. Should the Commission not adopt Mr. Meyer's fully supported adjustment to I&D, it should, at the very least, adjust the Company's five-year average by eliminating this payment, thereby reducing its I&D by the $5,000 noted above.

[17] Columbia Statement No. 1-R pg. 16 ln. 4-12
[18] Columbia Statement No. 7-R pg. 8-9 ln. 3-2

Q. What safety incidents involved O&M and capital costs?

A. According to Mr. Kempic the following safety incidents involved O&M and capital costs:

- Maiden Street Line Damage: Involved damage to existing Company facilities. Mr. Kempic cites to Columbia's responses to OCA Set 24-004 and OCA 20-002(a) to indicate the Company's costs to repair the Maiden Street line damage were charged to O&M and that, as such, the costs were not included in the FPFTY in Columbia's 2021 rate case or any other case.[19]
- Rimersburg portion of Over Pressurization Incident: Mr. Kempic states that the cost to replace the main that was involved in the Rimersburg overpressurization incident were not related to the overpressurization because the replacement of those facilities had been planned for operational purposes. The revised settlement agreement noted that the section of pipeline in Rimersburg that was overpressurized and that was taken out of service and replaced was not due to the overpressure event but, rather, due to the age and condition of the facilities.[20]
- Fayetteville portion of Over Pressurization Incident: According to Mr. Kempic the compromised facilities related to the overpressurization incident had not been scheduled as of the date of the event, due to the vintage and material type the facilities they would have eventually been replaced as part of Columbia's Long Term Infrastructure Improvement Plan even if they overpressurization event had not occurred.[21] The revised settlement agreement noted that Columbia replaced

[19] Columbia Statement No. 1-R pg. 16-17 ln. 16-2
[20] Columbia Statement No. 1-R pg. 17-18 ln. 3-4
[21] Columbia Statement No. 1-R pg. 18 ln. 4-12

approximately 45,000 feet of compromised facilities related to the Fayetteville overpressure event. Any O&M costs associated with the replacement of the Fayetteville facilities would not have been included in the Company's claim for O&M recovery as part of any fully projected future test year. The capital costs associated with the replacement was $5,842,294 and were included in the Company's rate base in 2018.[22]

Q. Do you have any comments regarding the Maiden Street Incident?

A. The Company estimated the initial cost of the project to be $6.3 million. In discovery the Company stated that the Company incurred $16,872 in O&M as a result of the incident that had not been included in the proposed rate increase.[23] I&E's inspection found that the main was not added to the Company's mapping system. I&E issued the Company a non-compliance letter for violations of Federal and State pipeline safety laws and regulations. In the end the Company agreed to additional training and paid a civil penalty.[24] Given Mr. Kempic's testimony that the Company's costs to repair the Maiden Street line damage were charged to O&M and that, as such, the costs were not included in the FPFTY in Columbia's 2021 rate case or any other case, I have no further comments at this time.

Q. Do you have any concerns regarding the Rimersburg Incident?

A. According to the Commission's Order, I&E found that the Rimersburg Incident occurred due to the age and condition of the facilities.[25] Given these stipulated facts between the Company and I&E in resolving the settlement, and the Commission's order accepting this

[22] OCA 24-003-part b
[23] OCA 25-002
[24] C-2023-3040925
[25] M-2021-3005572 Order Aug. 24, 2023

resolution, I have no further comments regarding the recovery of costs related to replacement of facilities related to this incident.

Q. Do you have concerns regarding the Fayetteville Incident?

A. Yes. As a matter of policy, the OCA believes replacements that occurred as a result of overpressurization incidents should not be recoverable in rates in order to properly encourage utilities to provide safe, adequate, and reasonable service and facilities. In its order the Commission determined that the damage caused to the Fayetteville system resulted from the overpressurization incident but appears to have accepted "the parties"[26] assertion that Columbia would nevertheless be permitted to recover these damages in rates. Given these stipulated facts between the Company and I&E in resolving the settlement, and the Commission's order accepting this resolution, I have no further comments regarding the recovery of costs related to replacement of facilities related to this incident.

Conclusion

Q. Please summarize your recommendations.

- The Company should continue to work to address the downward performance trends seen in Columbia's abandonment rate and calls answered within 30 seconds since 2019. It is yet too early to tell if the "team" started by the Company to improve call center performance will show long-term improvements or stability.
- The Company should eliminate the storage of customer SSN as the Company has shown it has other ways of identifying customers.

[26] M-2021-3005572 Order Aug. 24, 2023, pg. 29

- The Company has begun to take steps to show it is addressing its growing customer complaint problem, the Company should continue to track and readjust their practices to reverse the current trend.
- The Commission should, at the very least, adjust the Company's five-year average by eliminating the insurance deductible payment, thereby reducing its I&D by $5,000.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	Docket No.: R-2024-3046519
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Nicholas A. DeMarco, hereby state that the facts above set forth in my Surrebuttal Testimony, OCA Statement 7SR, 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 25, 2024

Signature: */s/Nicholas A. DeMarco*
Nicholas A. DeMarco

Address: Office of Consumer Advocate
555 Walnut Street
Fifth Floor
Harrisburg, PA 17101

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	**Docket Number: R-2024-3046519**
	:	
v.	**:**	
	:	
Columbia Gas of Pennsylvania, Inc.		

TESTIMONY AND EXHIBITS
OF THE
OFFICE OF SMALL BUSINESS ADVOCATE
TO BE ADMITTED INTO THE EVIDENTIARY RECORD

The Office of Small Business Advocate ("OSBA") intends to admit the attached testimony and exhibits as evidence into the evidentiary record at the Evidentiary Hearings scheduled on July 31, 2024, August 1, 2024, and August 2, 2024, in the above-captioned proceeding:

- Direct Testimony of Mark D. Ewen, labelled OSBA Statement No. 1 and associated Exhibits IEc-1 and IEc-2 with Verification
- Rebuttal Testimony of Mark D. Ewen, labelled OSBA Statement No. 1-R and associated Exhibit IEc-R1 with Verification
- Surrebuttal Testimony of Mark D. Ewen, labelled OSBA Statement No. 1-S and associated Exhibit IEc-S1 with Verification

Date: July 29, 2024

COMMONWEALTH OF PENNSYLVANIA

June 13, 2024

The Honorable Jeffrey A. Watson
Administrative Law Judge
Pennsylvania Public Utility Commission
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas Company / Docket No. R-2024-3046519

Dear Judge Watson:

Enclosed for filing please find the Direct Testimony of Mark D. Ewen, labelled OSBA Statement No. 1 and associated Exhibits IEc-1 and IEc-2, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

Copies will be served on all known parties in this proceeding, as indicated on the attached Certificate of Service.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Attorney
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: PA PUC, Secretary, Rosemary Chiavetta (Cover Letter and Certificate of Service Only)
Mark D. Ewen
Parties of Record

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2024-3046519**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Direct Testimony and Exhibits of

MARK D. EWEN

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Context
Cost Allocation
Revenue Allocation
Rate Design
Rate Decoupling/RNA/WNA

Date Served: June 13, 2024

Date Submitted for the Record: _____

DIRECT TESTIMONY OF MARK D. EWEN

1. Introduction and Context

Q. Mr. Ewen, please state your name and briefly describe your qualifications.

A. My name is Mark D. Ewen. I am a Principal and President of Industrial Economics, Incorporated ("IEc"), a consultancy of 165 professionals headquartered at 2067 Massachusetts Avenue, Cambridge, MA 02140. My consulting practice focuses on regulatory and environmental economics, expert case management and economic damages estimation in a variety of litigation contexts, and financial analysis. I obtained a B.A degree in Economics and Political Science from the University of North Dakota, and a Master of Public Policy degree from the University of Michigan. I have participated and provided testimony in a variety of proceedings before the PA Public Utilities Commission, including electric and gas base rates cases, 1307(f) purchased gas cost filings, energy efficiency and conservation cases, merger and acquisition cases, and default service provider ("DSP") petitions. My résumé and a listing of the expert testimony that I have filed in various litigation and utility regulatory proceedings are attached in Exhibit IEc-1.

Q. Please describe your assignment in this matter.

A. I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). The OSBA requested that I review the Company's filing in this proceeding to evaluate whether the rates proposed for small business customers are consistent with sound economics and regulatory principles. My analysis focuses primarily on issues of cost allocation, revenue allocation and rate design. If I have not addressed a particular issue, it cannot be inferred that I agree with Columbia's proposal for that topic.

Q. Please provide some background regarding the Company's filing, in the context of recent base rates proceedings.

A. Since 2008, Columbia has submitted twelve base rates filings. Prior to 2008, Columbia had not filed a base rates case since 1995. This steady flow of rate cases has been primarily driven by the Company's mains and services replacement program, undertaken over the past sixteen years. A summary of the base rates filing amounts and settlement rate increases is shown in Table IEc-1 below.

Table IEc-1 Recent Columbia Base Rate Increase Cases				
Docket No.	**Test Year Ending**	**Proposed Increase ($mm)**	**Award Amount ($mm)**	**Award Percent**
R-2008-2011621	Sep-2008	$58.9	$41.5	71%
R-2009-2149262	Sep-2010	$32.3	$12.0	37%
R-2010-2215623	Sep-2011	$37.8	$17.0	45%
R-2012-2321748	Jun-2014	$77.3	$55.3	72%
R-2014-2406274	Dec-2015	$54.1	$32.5	60%
R-2015-2468056	Dec-2016	$46.2	$28.0	61%
R-2016-2529660	Dec-2017	$55.3	$35.0	63%
R-2018-2647577	Dec-2019	$46.8	$26.0	56%
R-2020-3017206	Dec-2021	$100.4	$63.5	63%
R-2021-3024296	Dec-2022	$98.3	$58.5	60%
R-2022-3031211	Dec-2023	$82.2	$44.5	54%
Total		**$689.6**	**$413.8**	**60%**
R-2024-3046519	Dec-2024	$124.1	--	--

As is apparent in the table, the Company's cost requirements have accelerated, with relatively large increases being proposed in each of the past four rate cases. Columbia has justified these accelerating costs and aggressive pipe replacement efforts in part on customer affordability grounds, noting: "It makes sense to do it now before the pipe fails, and since gas prices remain relatively low in Pennsylvania. Therefore, in addition to reducing risk by replacing this pipe now, the customer's total gas bill will continue to be affordable."[1] Given natural gas prices have been volatile in recent years, this assertion is tenuous at best.[2] I respectfully disagree with Columbia that accelerating pipeline replacements on the basis of current commodity prices represents a reasonable strategy.

[1] Columbia Statement No. 1 at 16.

[2] https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.settlements.html last reviewed 11 June 2024.

With its proposed increase, Columbia now has the dubious distinction of having the highest residential and small commercial base rates among large natural gas distribution companies ("NGDCs") in the Commonwealth.

Q. Is there an end in sight for these regular large base rate increases?

A. Based on what is currently proposed in Columbia's Age and Condition Program, it does not appear so. Over the next four years, it has budgeted for over $1.2 billion in expenditures for mains, services, and measurement and regulation stations alone.[3]

The cost for this enormous physical replacement requirement is compounded by the rapidly increasing cost per mile to replace mains. Between 2008 and 2023, the cost to replace a foot of pipe has increased from $81.25 to $289.00, a more than tripling of the cost.[4]

Q. Will the Company be able to fully recover its allowed rate of return on this massive capital spend over the longer term?

A. I do not know. We all recognize that there are growing societal and political concerns regarding the burning of fossil fuels, and there is concomitant increasing pressure for electrification, not only in transportation but in home heating. For the past fifteen years, the Company's declining distribution cost competitiveness has been rescued by the hydraulic fracturing boom and the resulting decline in natural gas commodity prices. At a minimum, commodity price volatility is likely to increase. If Columbia's distribution rates continue to grow at the historical rate, heating alternatives like heat pumps and mini-splits will become more economically attractive to customers. In addition, the potential remains for increased regulation of CO_2 emissions for both gas consumers and gas producers, both of which could further increase the cost of gas.

Q. What are the implications of these trends for the current rate proceeding?

A. Given the apparent lack of a long-term competitive analysis of its distribution business, I do not believe that the Company has demonstrated that its overall capital spending plan is prudent. While I cannot comment on the legal issues, I believe the Commission should

[3] Columbia Statement No. 7 at 3.

[4] Columbia Statement No. 7 at 13.

advise Columbia that future capital expenditures have not been shown to be part of a demonstrably prudent long term investment plan, and that they can be subjected to *ex post* prudence reviews should they become stranded. At a minimum, I believe the Commission should require Columbia to demonstrate that it has a long-term viable business as part of its next LTIIP filing.

Q. Do you have any preliminary general comments regarding cost allocation and rate design in this proceeding?

A. I do. In the Company's base rates proceeding at Docket No. R-2020-3017206, the Commission approved the use of a "peak-and-average" ("P&A") method for mains cost allocation. Also in that proceeding, the Commission accepted the Company's position with respect to negotiated rate revenues from its "flex" rate customers.[5] For the current proceeding, these decisions have three significant impacts.

First, the costs allocated to the regular rate larger industrial customers in the Rate LDS class are roughly double the revenues currently recovered from that class, a shortfall of more than $30 million.[6] Moving rates reasonably into line with allocated cost for this class cannot be achieved in a single proceeding, and thus much of this shortfall must be borne by other classes. Moreover, this class can reasonably expect significant rate increases on top of the system average base rate increases for the foreseeable future.

Second, the costs allocated to negotiated "flex" rate customers are more than thirteen times higher than the revenues generated by these customers, under the negotiated rate agreements that were generally approved by the Commission in the 2022 base rates case. This results in a shortfall of $38 million, none of which can be recovered from the flex rate customers due to the negotiated contract rates. This shortfall must therefore be reassigned to the other rate classes, including the regular rate LDS customers.

[5] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2020-3017206, Order Entered February 19, 2021, pages 211-218 and 240-241.

[6] These values are based on the Company's P&A cost allocation study (Exhibit 111 Schedule 2), and do not reflect any provision for the LDS class to contribute to the shortfall from flex rate customers. See IEc WP1.

Third, because no mains costs are classified as customer-related, the customer portion of allocated costs is materially lower than that presented in previous cost evaluations. This change reduces the potential for cost-based customer charge increases, particularly for non-residential rate classes.

2. Review of Columbia's Non-Residential Rate Classes

Q. Before getting into the details of your analysis, please summarize the rate classes under which businesses take service from Columbia.

A. Columbia's tariff has a number of schedules under which non-residential customers take service. These tariff schedules are generally distinguished by size of customer (as measured by annual throughput) and type of service. Service types include the following:

- Sales service, in which customers procure both gas supplies and distribution service from Columbia;
- Retail transportation "Choice" service, in which smaller customers can purchase gas supply from NGSs and purchase both bundled load balancing services and distribution services from Columbia;
- Transportation service, in which larger non-residential customers purchase gas supplies from NGSs, purchase load balancing services as needed from Columbia and/or their NGSs, and purchase distribution service from Columbia.

For cost allocation purposes, Columbia aggregates these disparate rate classes into rate class groups.

In total, the non-residential rate classes represent about 55 percent of Columbia's total throughput in the test year. Customer size varies widely, ranging from small businesses that consume less than 10 Dth per year to very large industrial customers with more than 1,000,000 Dth per year.

The following are the non-residential rate class groups specified by Columbia for its cost allocation analysis. Because the Company's abbreviations for the rate class groups are somewhat contradictory, I include descriptive names for these groups.

SGSS/SCD/SGDS ("Small General" or "SGS"): This group consists of three tariff schedules: Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD"), and Small General Distribution Service ("SGDS"). To reflect the range of costs associated with serving these diverse classes, Columbia has adopted differentiated customer and commodity charges for customers in this group of classes, split between customers with annual consumption above and below 644 Dth. Maximum annual throughput for this class is 6,440 Dth/year. Consistent with recent past practice, the Company separates these two groups for both cost allocation and rate design purposes. I refer to the customers with annual consumption below 644 Dth as "SGS1," and the larger customers as "SGS2."

Within these two rate class groups, SGSS is sales service, SCD is retail "Choice" transportation service and SGDS is regular transportation service.

In the SGS1 group, about 77 percent of the load is to sales customers, implying a shopping rate of 23 percent, nearly double the residential shopping rate of 12 percent. The average SGS1 customer size is about 179 Dth per year, which is a little more than twice the size of the average residential customer. Overall, this class represents about 13 percent of the Company's non-residential throughput.

In the SGS2 group, about 59 percent of the load relates to sales customers, with the majority of SGS2 shopping customers using traditional transportation service. The average SGS2 customer size is 1,637 Dth/year, which is about 9 times the size of the average SGS1 customer. Overall, this class represents 24 percent of the Company's non-residential throughput.

SDS/LGSS ("Medium General"): This rate class group includes both sales and transportation service customers, taking service under Rate Schedules LGSS (sales service) and Small Distribution Service ("SDS") (transportation service). Columbia's "Small" designation for the transportation customers in this tariff category is misleading, as the

minimum throughput is 6,440 Dth per year, matching the *maximum* size requirement for the Small General customers. The maximum annual throughput for this class is 54,000 Dth per year, with an average annual customer throughput of about 15,878 Dth. This rate class group (excluding the flex rate customers) represents about 18 percent of non-residential throughput.

LDS/LGSS ("Large General"): This class includes the larger sales customers in the LGSS class along with the transportation service customers taking service under Rate Schedule Large Distribution Service ("LDS"). Minimum throughput is 54,000 Dth per year, matching the Medium General Service upper limit. A significant share of the volume for this rate class is included in the "Flex" rate class category for cost allocation, revenue allocation and rate design purposes.

MDS ("Mainline"): Customers in this rate class group take service under Rate Schedule Main Line Distribution Service ("MDS").[7] To be eligible for this service, customers must have annual throughput over 27,400 Dth, *and* be directly connected to an interstate pipeline (Class I), *or* have a minimum annual demand of 214,600 Dth *and* be located within two miles of an interstate pipeline interconnection (Class II). Because these customers require very little in the way of distribution facilities, and because Columbia reports that they are credible "bypass" threats, Columbia uses different cost allocation and rate design methods for this rate class group.

Consistent with recent practice, the Company does not treat large general sales service ("LGSS") customers as a separate rate class for cost allocation purposes, and it includes those customers with transportation customers of comparable size. Sales customers taking service under Rate LGSS are free to switch to the comparable transportation service schedule, and, generally, vice versa. Thus, it is reasonable that the distribution rates for all customers of a similar size be the same, to avoid distorting the decision to shop. Since the distribution rates are the same, there is no need to separately allocate costs. Moreover, the

[7] Columbia's tariff includes a Main Line Sales Service schedule, but no customers currently take service under that schedule.

total load associated with Rate LGSS is relatively small, since most large customers directly procure natural gas supplies.

Finally, the tariffs for the Company's larger rate classes allow for discounted, negotiated "flex" rates, for customers who have the potential to economically use an alternative fuel or to bypass the distribution system to interstate pipelines or local supply. Rates for these customers are therefore set based on market conditions rather than utility cost to serve. To allow the Company to set regular tariff rates based on allocated cost, the customers who currently have flexed rates are segregated into a separate class for cost allocation purposes.

3. Flex Rate Customers

Q. Please summarize the economic and regulatory issues surrounding Columbia's "flex rate" customers.

A. In general, utility tariff charges are set based on allocated cost of service and other rate design criteria, and these tariff charges apply to all customers within the rate class. However, under certain conditions, it can be beneficial to all parties to allow the utility to negotiate rate discounts from the regular tariff rates to retain customers who have lower-cost competitive options. These options include alternative fuel, pipeline bypass, and in the case of western Pennsylvania, "gas-on-gas competition" from other natural gas distribution companies ("NGDCs").[8] The specific criteria where negotiated discounts are in the interests of all ratepayers are:

- Negotiated rates exceed the incremental cost of providing service to the customer. Thus, for example, if Columbia needs to upgrade its distribution system to continue to provide service to a flex rate customer, the negotiated rates must be sufficient to justify that expenditure.

[8] NGDCs do not "compete" for customers in overlapping service territories on the basis of cost or service. They have historically "competed" on the basis of which NGDC can offer the largest rate discount to those customers who have options and pass the cost for those discounts on to captive customers who do not have options.

- In the case of alternative fuel competition, negotiated tariff rates plus the cost of gas should be set at or near the full delivered cost of the alternative fuel plus the customer's costs of conversion.

- In the case of pipeline bypass, negotiated tariff rates are justified only if there is a credible engineering plan for how the customer could physically bypass the NGDC. If that criterion is met, the negotiated tariff rate plus the cost of gas should be set at or near the customer's full cost for bypassing the NGDC and taking service directly from the pipeline. This cost necessarily includes obtaining the necessary permits to allow for such bypass.

- In the case of NGDC "competition," the Commission has determined that where customers are served in overlapping NGDC service territories, the minimum flex rate that can be charged is the lowest regular tariff rate of the NGDCs serving the customer's location.[9]

Q. How does the Company ensure that flex rates are competitive and appropriately priced?

A. The Company is obligated to update a competitive alternative analysis for any customer that has not had its alternative fuel source verified for a period of ten years. This decennial review requirement was implemented under Commission order for Docket No. R-2020-3017206. It is unclear whether this requirement is sufficient.

Q. Given your concern about having robust competitive analyses, do you have a recommendation?

A. Yes. I recommend that the Company conduct the competitive alternatives analysis for each flex rate customer every two years.

[9] *Opinion and Order,* Pennsylvania Public Utility Commission, Docket Nos. P-2011-2277868 and I-2012-2320323, Order Entered May 4, 2017, page 52. To my knowledge, there has not been a firm resolution as to how the lowest applicable tariff rate should be defined. See *Opinion and Order,* Pennsylvania Public Utility Commission, Docket Nos. P-2011-2277868 and I-2012-2320323, Order Entered June 13, 2019.

Q. What are the implications of the flex rates for the Company's revenue requirement in this proceeding?

A. Based on my cost allocation analysis, the costs allocated to flex rate customers are about $30 million higher than current negotiated rate revenues.[10] This shortfall must be recovered from the other rate classes.

4. Cost Allocation

Q. What is the purpose of a utility's allocated cost of service study ("ACOSS")?

A. The primary criterion for setting regulated utility rates is the cost incurred by the utility for providing the service.[11] To assign costs to specific customers, utilities aggregate customers into rate classes, within which the customers have similar load sizes, seasonal consumption, peak demand patterns, and other characteristics. An ACOSS is an analytical tool with which the utility's total cost (or "revenue requirement") is allocated among each of the rate classes. These allocated costs are then used as a key input in determining the total revenues that the utility plans to recover from each rate class through tariff rates.

In using the results from an ACOSS to develop class revenue requirements, utilities and regulatory authorities usually have a longer-term goal of moving the revenue recovered from each class as close as possible to the costs allocated to that class. That is, in each proceeding, regulators try to move class revenues more into line with cost-based rates. Thus, rate classes whose revenues substantially exceed allocated costs are assigned either relatively low rate increases or rate decreases. Rate classes whose revenues are well below allocated costs are assigned larger rate increases than those classes whose revenues are only slightly below allocated costs.

In addition to class revenue requirement issues, an ACOSS can provide useful cost information regarding the specific nature of utility tariff charges. In particular, an ACOSS

[10] See IEc WP1.

[11] The Commonwealth Court affirmed this basic principle, referring to cost of service as the "polestar" criterion. Lloyd v. Pennsylvania Public Utility Commission, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

provides a cost basis for the relative magnitude of the various individual tariff charges, including the customer charge, demand charges, and commodity charges.

Q. How does an ACOSS assign costs to the various rate classes?

A. The underlying principle of an ACOSS is that costs are assigned to the rate classes that *cause* the utility to incur those costs. This principle of cost causation is both equitable and economically efficient. It is equitable because costs are borne by those customers who cause them. It is economically efficient because the price signal for consumption from a particular rate class is reasonably consistent with the cost incurred by the utility to provide the service. In that way, the consumer receives the correct price signal for determining whether to purchase more or less of the utility service. In effect, the consumer balances the value received from the purchase of that service against the utility's cost of providing the service.

Q. What is the Company's approach to cost allocation in this proceeding?

A. With its filing, the Company presented three detailed cost allocation studies, in Exhibit 111 Schedules 1, 2 and 3. The Company's cost allocation analysis is supported by Witness Kevin L. Johnson, Columbia Statement No. 6.

Q. Why does the Company present three different cost allocation studies?

A. The Company has consistently submitted two alternative ACOSS models in its base rates filings stretching back to at least 2008, with a third version that is an average of the two. The models differ only in how mains plant costs are classified and allocated.

The "CD" model classifies and allocates mains costs using a "minimum system" method, in which costs are segregated into a "customer component" and a "demand component." The customer component of costs is derived based on the cost of installing the minimum size pipe throughout the current distribution system, and those costs are allocated based on number of customers. The minimum system construct is designed to reflect the economies of scale of serving and interconnecting larger customers. The remaining costs are deemed to be demand-related, meaning that the costs are causally related to customer's maximum rate of system usage. Demand-related costs are allocated based on a measure of class peak demand (usually "design day" demand for NGDCs), to reflect the fact that each main must

be sized to be able to meet the peak demands of downstream customers under extreme weather conditions.

The Company's "P&A" model allocates all mains costs based on a 50/50 weighting of average demand and design day peak demand.[12] Advocates for this method argue that there are no scale economies to attaching and serving larger customers, and that a portion of mains costs are causally related to annual throughput.

The Company's "AVG" model is a simple average of these two methods. It should be recognized that the Company's two methods produce enormously divergent results.

As I indicated earlier, mains costs allocated to the MDS class are not affected by these alternative allocation methods. MDS customers are either attached directly to the interstate pipeline system or are in close physical proximity. The cost for the mains used to supply these customers are directly assigned to that class, and thus are the same in all ACOSS model simulations.

The Company indicates that it generally relies on the P&A ACOSS for revenue allocation and rate design in this proceeding, although the Company appears to believe that the results of the CD ACOSS have some relevance.[13]

Q. What approach do you take for cost allocation in this proceeding?

A. While I disagree with the Commission's findings regarding mains cost allocation in the 2020 base rates case, I rely generally on the method employed by the Company in its P&A ACOSS for reasons of Commission precedent with respect to Columbia. The issue at hand is to incorporate the implications of that decision into rates as quickly as is practicable, subject to the constraints of rate gradualism.

[12] From a cost allocation perspective, "average demand" is arithmetically equivalent to annual throughput.

[13] Columbia Statement No. 6 at 18.

As a practical matter, I reviewed the results of the Company's P&A and CD ACOSS. Because the Company's method generally appears to be consistent with that used in the last case, I did not conduct an exhaustive review of all aspects of the cost allocation studies.

The enormous revenue shortfall from the flex rate class makes revenue-cost comparisons difficult. To address that issue, I apportion the flex rate shortfall among the various other rate classes as part of my cost allocation analysis.

Q. Please discuss your treatment of the flex rate shortfall.

A. As I discussed earlier, the subsidies provided to the flex rate customer group at current rates dwarf that class's current revenues and represent by far the largest revenue shortfall of any rate class group. Flex customer revenues amount only to about $3.1 million, whereas costs allocated to that customer group are $41.3 million at proposed rates.

However, as I explained earlier, the Company claims that the current rate revenues represent the maximum amount that can be earned from these customers. Thus, the $38 million shortfall from this class must be recovered from the other rate classes. To provide useful cost allocation results for revenue allocation, I redistribute this shortfall to the other rate classes based on allocated cost, for both current and proposed rates.

Q. What are the implications of your alternative ACOSS analysis?

A. Table IEc-2 shows class revenue to cost ratios at current rates under the Company's approach and IEc's alternatives. The Residential class is modestly over-recovering costs, the Small and Medium general service classes are within one percentage point of cost over- or under-recovery, and the Large General Service class substantially under-recovers allocated cost.[14] Thus, to move revenues fully into line with costs for that class, a very large rate increase would be necessary.

[14] As I indicated earlier, the MDS class consists of large customers located in close proximity to interstate pipelines, and mains costs are directly assigned to these customers. These customers have historically provided a cross-subsidy to the other classes, generally because rate decreases have not been applied to reduce rates to allocated costs. The Company proposes to continue this practice in this proceeding, by assigning a zero increase to the class.

Table IEc-2 Comparison of ACOSS Results Revenue-Cost Ratios: Current Rates		
	Columbia P&A ACOSS	**Columbia P&A ACOSS with IEc Flex Adj.**
Residential	109.4%	104.6%
SGS1	104.8%	99.4%
SGS2	104.8%	99.0%
Med Gen'l (SDS/LGSS)	107.9%	101.9%
Lg Gen'l (LDS/LGSS)	62.5%	59.0%
MDS	1749.9%	100.0%
Flex	9.5%	100.0%
Total	100.0%	100.0%
Source: IEc WP1		

5. Revenue Allocation

Q. What is revenue allocation?

A. Revenue allocation is the assignment of the dollar net increase or decrease to each of the Company's rate classes in a base rates proceeding. In contrast, *rate design* determines how the allocated revenue is recovered from individual ratepayers within each class. From a cost recovery standpoint, revenue allocation addresses *inter-class* cross-subsidization issues, while rate design addresses *intra-class* cross-subsidization issues.

Q. What are the primary economic and regulatory criteria for revenue allocation?

A. In general, allocated cost is the primary criterion used by regulators in the revenue allocation process. Most utilities and regulators adopt a policy in a base rates proceeding of attempting to move revenues more into line with allocated costs by varying the magnitude of the rate increases for the individual classes. However, regulators also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue allocation process are:

- the *gradualism* principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customers are avoided; and

- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand. [15]

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. With this proposal, the ACOSS can be simulated at both present and proposed rates to evaluate the magnitude of "progress" that has been made toward the policy of achieving cost-based rates.

Q. Please summarize the process used by Columbia for its proposed revenue allocation in this proceeding.

A. Witness Johnson reviews the Company's considerations at pages 16-21 of Statement No. 6. In short, the Company's criteria appear to be that the revenue allocation produce rates that are just and reasonable, not unduly discriminatory, and which move each class cost recovery closer to "parity." Cost recovery is evaluated using the indexed rate of return metric at current and proposed rates, with the goal of moving each class's value closer to unity.[16] Witness Johnson also cites to the principle of "rate gradualism," and sets a limit that no rate increases be more than 1.5 times the system average. Finally, Witness Johnson indicates that only minimal increases can apply to the flex rate customers, because rates for those customers are set based on competitive circumstances rather than cost of service.

The proposed system average base rate increase is 20.3 percent. Armed with its criteria, the Company proposes to set the rate increases for the MDS and Flex classes near zero, at 22.2

[15] See, for example, Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. The criteria in this text apply to the overall development of a utility rate structure. The criteria that I discuss in this testimony are those that apply to the revenue allocation portion of the process, which is only one aspect of the overall development of utility rates.

[16] The Company refers to the metric as the "unitized rate of return." It is also called the "relative rate of return" metric.

percent for the SDS1, SDS2, and LDS classes, 22.1 percent for the SDS classes; and 19.9 percent for the Residential class.

Q. Please comment on the Company's use of the indexed rate of return metric for evaluating progress toward cost-based rates.

A. The indexed rate of return metric is derived as the ratio of the class rate of return on rate base to the systemwide average return on rate base. Thus, for example, if a rate class is earning 2 percent on rate base at current rates and the system average is 5 percent, the indexed rate of return metric is 2.0/5.0 = 0.4. The metric (correctly) indicates that this class is under-recovering costs.

Unfortunately, the indexed rate of return is not a reliable measure of progress toward cost-based rates when it is evaluated at current and proposed rates. The indexed rate of return metric can, in some circumstances, imply that a particular revenue allocation proposal will result in progress toward cost-based rates when in fact revenues are moving farther away from allocated costs. Moreover, even when the indexed rate of return correctly indicates that progress is occurring, it will overstate the relative magnitude of that progress. My reasoning for this conclusion is detailed in Appendix A to this testimony.

I also recognize that the Commission has recently supported the use of the dollar subsidy metric for evaluating progress toward cost-based rates, where the dollar difference between a class's revenues and allocated costs is compared at current and proposed rates.[17] This metric is also evaluated in Appendix A. As shown, this metric is not as flawed as the indexed rate of return metric, in that it will not mistakenly report progress when there is none. However, this method can potentially imply that no progress toward cost-based rates is occurring for a revenue allocation proposal when in fact some modest progress is achieved.

For this proceeding, I relied on the revenue-cost ("R-C") ratio metric. The "R-C" metric represents (unsurprisingly) the ratio of class revenues to class allocated costs, and thus implicitly recognizes the subsidy as a percentage of the class revenue requirement. As

[17] *Pennsylvania Public Utility Commission v. City of Bethlehem -- Water Department*, Docket No. R-2020-3020256, Order entered April 15, 2021, at 36.

detailed in Appendix A, this method relies entirely on the full test year cost claim as a measure of cost to avoid the distortions associated with excluding some return on capital costs in its evaluation of current revenue-cost performance. As shown in Appendix A, this method does not suffer from the common biases of the other metrics.

Q. How does the Company's revenue allocation proposal stack up using the revenue-cost ratio metric?

A. Table IEc-3 below provides a summary of my evaluation of the Company's revenue allocation proposal. I evaluate the Company's proposal using the Company's P&A ACOSS, modified only to reallocate the Flex class shortfall. I conclude that the Company's revenue allocation proposal makes little progress for most classes in aligning rates with costs from the P&A ACOSS. Rate increases for the Residential class result in no reduction in the subsidy provided by that class, and in fact makes the subsidies modestly higher. The Company's proposal for the SGS1, SGS2 and SDS classes serve to maintain a revenue-cost ratio near unity, but this leaves a larger responsibility for the LDS shortfall with the Residential class. For the LDS customers, despite the very low revenue-cost ratio in the P&A ACOSS, the Company's proposal will make no progress at all toward cost-based rates.

Table IEc-3
Summary of Columbia Revenue Allocation Proposal

	Increase $mm	Increase %	R/C Current*	R/C Proposed*	"Progress"
Residential	$86.31	19.9%	104.6%	105.0%	-8.4%
SGS1	$ 11.24	22.2%	99.4%	99.6%	32.5%
SGS2	$ 12.39	22.2%	99.0%	98.1%	-82.4%
Med Gen'l (SDS/LGSS)	$ 8.13	22.1%	101.9%	100.9%	50.6%
Lg Gen'l (LDS/LGSS)	$ 6.06	22.2%	59.0%	58.5%	-1.2%
MDS	--	0.0%	100.0%	100.0%	0.0%
Flex	$ 0.00	0.0%	NM	NM	NM
Total	**$124.1**	**20.3%**	**100.0%**	**100.0%**	**--**

* With flex rate adjustment

Flex rate cost performance is not meaningful because the shortfall is reallocated to other rate classes. Columbia's filed ACOSS implies a shortfall of $38 million under proposed rates.

Source: IEc WP1

Q. What is your alternative revenue allocation proposal?

A. I developed an alternative revenue allocation proposal that relies on my alternative ACOSS that allows for a larger rate increase for the LDS/LGSS class to reflect the enormous revenue-cost difference under current rates.

Note that a common rule of thumb for rate gradualism is to limit the increase for any particular rate class to no more than 1.5 or 2.0 times system average. Under normal conditions, the 1.5 times parameter will not unduly constrain the ability of the regulator to move rates substantially more into line with allocated cost. However, due to its extremely low revenue-cost ratio, I assign the LDS/LGSS class an increase at the upper end of the range, or 2.0 times system average. This adjustment produces some modest progress toward cost-based rates, with the revenue-cost ratio moving from 59.0% under current rates to 67.5% under proposed rates. Finally, I accept the Company's proposal for the MDS and Flex rate classes for *de minimis* rate increases.

The results of my alternative revenue allocation proposal are summarized in Table IEc-4 below. As shown, my proposal results in more progress toward cost-based rates than the proposal put forward by the Company for the Residential and LDS classes, although the progress remains relatively modest even with the relaxed constraints on increases for the larger customer classes. Note that the increases to the SGS1, SGS2 and SDS classes result in revenues exceeding allocated costs, as these classes are burdened with a contribution to the shortfall from the LDS class.

Table IEc-4 Summary of IEc Alternative Revenue Allocation Proposal					
	Increase $mm	**Increase %**	**R/C Current***	**R/C Proposed***	**"Progress"**
Residential	$75.20	17.3%	104.6%	102.8%	40.2%
SGS1	$13.20	26.0%	99.4%	102.8%	564.8%
SGS2	$15.62	27.9%	99.0%	102.8%	367.2%
Med Gen'l (SDS/LGSS)	$8.94	24.3%	101.9%	102.8%	-44.2%
Lg Gen's (LDS/LGSS)	$11.18	41.0%	59.0%	67.5%	20.7%
MDS	--	0.0%	100.0%	100.0%	0.0%
Flex	$ 0.00	0.0%	NM	NM	NM
Total	**$124.1**	**20.3%**	**100.0%**	**100.0%**	**--**
Flex rate cost performance is not meaningful because $38 million shortfall is reallocated to other rate classes. Source: IEc WP1					

6. Rate Design Issues

Q. Please describe the tariff structure for the SGSS, SCD and SGDS rate classes.

A. Base rate tariff charges for these three classes currently consist of a bifurcated monthly customer charge and a bifurcated commodity charge, both split between customers with annual consumption above and below 644 Dth. Within each size category, SGSS and SCD customers pay the same commodity charge, while SGDS customers pay a slightly lower commodity charge reflecting the fact that the Company does not incur gas storage working capital costs for regular transportation customers. The basic distribution rate tariff structure is shown in Table IEc-6 below.

In addition, the SGSS sales customers are subject to PGC, GPC, MFC and Rider CC charges. Rate SCD Choice and Rate SGDS transportation customers are subject to certain PGC charges (related to load balancing), and the Rider CC charge.

Q. How does Columbia propose to implement its rate increase for these classes?

A. Columbia's proposed increases for the base rates components of Small General Service classes are shown in Table IEc-5 below. The Company has essentially proposed to assign class-average increases to both the customer charge and the commodity charge for each class. In effect, the Company proposes no change to rate design for these classes. Witness Johnson further justifies the customer charge component by citing the range of minimum customer costs yielded by the P&A method under two scenarios where mains costs are included or excluded in the calculation.

Table IEc-5
Columbia Proposed Small General Service Base Rate Design

	Current Rate	Proposed Rate	Percent Increase
Rates SGSS and SCD			
Customer Charge < 644Dth/year	$29.92	$36.55	22.2%
>644 Dth/year	$57.00	$69.63	22.2%
Commodity Charge <644 Dth/year	$6.9747	$8.5194	22.1%
>644 Dth/year	$5.9489	$7.2574	22.0%
Rate SGDS			
Customer Charge < 644Dth/year	$29.92	$36.55	22.2%
>644 Dth/year	$57.00	$69.63	22.2%
Commodity Charge <644 Dth/year	$6.8756	$8.4262	22.6%
>644 Dth/year	$5.8497	$7.1644	22.5%

Q. What approach do you recommend for setting customer charges for these classes?

A. For small and medium general service classes, I generally advocate setting the customer charge at or modestly below the customer-related costs for the smaller customers within each class, subject to rate gradualism constraints. In addition, the P&A method is the primary guide for cost allocation for this submission. As such, the customer cost component as tabulated by the Company in its P&A study excluding mains should be the primary basis for setting the customer charge.

By the Company's calculations, the Rate SGS1 customer cost is $31.68 with the full rate increase. I therefore recommend that the lower volume customer charge be set no higher than that level, which would represent only a relatively modest increase above $29.92. For SGS2, the Company calculates a cost of $59.53, which should also serve as the upper bound for the larger volume customer charge for these classes. This, too, would represent a relatively modest increase over the current $57.00 charge.

6. <u>Rate Decoupling/Revenue Normalization Adjustment</u>

Q. Do you have any comments on any other aspects of Columbia's filing?

A. Yes. Columbia's filing includes a proposal for the implementation of a Revenue Normalization Adjustment ("RNA") mechanism for residential customers except those who participate in the Consumer Assistance Program ("CAP"). A similar proposal was included in its prior base rates case.

Q. What is the RNA mechanism?

A. Columbia's proposed RNA mechanism is a form of a rate "decoupling," that utilities use to "weaken" or "break" the link between revenues and customer gas consumption. Decoupling mechanisms allow utilities to adjust rates and/or implement charges and credits to customer bills to ensure the utility receives a pre-established, benchmark level of revenue.

Q. What is the apparent allure of RNA and other decoupling mechanisms and what are the drawbacks?

A. From the utility's perspective, an RNA mechanism such as the one Columbia proposes theoretically provides the utility with financial certainty against changes to gas consumption that would otherwise cause variability in the utility's revenue. Tying billing to revenue benchmarks removes the effect of variabilities in consumption levels outside of the utility's control. In short, the RNA mechanism reduces utility risk. Certain types of rate decoupling mechanisms may potentially reduce the frequency of rate cases, where revenues targets are adjusted annually by formula rather than by rate case. However, in this case, Columbia's proposed RNA mechanism effectively adjusts the rate for the non-CAP residential class on a period-by-period and year-by-year basis outside of the framework of rate case filings. Residential customers will consistently have their rates adjusted to account for revenue

shortfalls or surpluses without the transparency and due diligence that accompany rate cases.[18] Further, because the RNA mechanism would only apply to the residential class, future rate cases would still be required at the same frequency as before to capture cost and revenue allocation adjustments beyond the residential class.

From the customers' perspective, decoupling mechanisms may lower the barrier to energy efficiency programs by insulating utilities from their accompanying decrease in consumption. Decoupling mechanisms also potentially allow customers to recover payments in excess of the utility revenue benchmarks following periods of higher-than-expected consumption. Of course, the latter benefit flows in both directions, because decoupling permits utilities to issue charges to recoup missed revenue below benchmarks following periods of lower-than-expected consumption.

Decoupling mechanisms come with several other drawbacks for customers. The decoupling adjustment may be complicated and difficult for customers to understand and evaluate. Decoupling shifts financial risks associated with gas consumption variability from the utility, which experienced those risks as fluctuating revenue, to the customer, who will now assume those risks in the form of rate adjustments to normalize revenue. Finally, decoupling disincentivizes the utility from investing resources into reliability because the utility's revenues are no longer tied to its deliveries.

Q. Why are you addressing this proposal when it applies only to the residential class?

A. If approved for the residential class, the Company will almost certainly rely on the precedent to support extending the mechanism to other rate classes, particularly the small commercial classes.

Q. Please summarize the Company's proposed Revenue Normalization Adjustment mechanism.

A. Under the proposed RNA mechanism, Columbia would establish a benchmark distribution revenue per non-CAP residential customer bill ("BDRB") for peak (October through March,

[18] While the revenue reconciliation will be subject to a Commission proceeding, such additional proceedings will simply add to the already significant oversight burden placed upon Commission staff and intervenor groups.

"BDRBp") and non-peak (April through September, "BDRBo") periods.[19] In its filings, Columbia calculates its BDRBp (i.e., the total revenue per non-CAP residential bill that Columbia expects to receive for a given six-month period from October through March) to be $805.03 and its BDRBo (i.e., the total revenue per bill that Columbia expects to receive from April through September) to be $340.82. Columbia would compare the BDRB for a given peak or off-peak period and compare it with Columbia's actual distribution revenue per non-CAP residential customer bill in that period. The Company would then take the difference between the BDRB and ADRB, multiply the difference by the total number of bills for that period, and divide the total surplus or shortfall in revenue versus expected benchmark revenue by the number of therms forecast to be distributed in the *following* peak or off-peak period.

The shortfall or surplus per forecast therm is the RNA and would be applied to non-CAP residential customers' bills as a per therm charge or credit in the forecast period. Through these charges or credits, Columbia would collect from or return to the non-CAP residential customers the shortfall or surplus, respectively, its revenues experienced in the previous peak or off-peak period. RNA charges and credits on customers' bills would include interest at the commercial prime rate. Conceptually, Columbia applies interest because the charges and credits reflect revenue the Company *should* (for charges) or *should not* (for credits) have received in the previous period.

Effectively, the RNA would change the rates that non-CAP residential customers pay on a period-by-period and year-by-year basis, based on whether Columbia experienced a revenue shortfall or surplus from the class in the previous peak or off-peak period.

Q. You indicate that the RNA would provide revenue stability for Columbia through a guaranteed recovery of revenue per customer. Is the RNA similar to Columbia's weather normalization adjustment ("WNA") mechanism that is currently in place for providing bill stability for ratepayers?

[19] The RNA proposal is discussed in Columbia Statement No. 6 beginning at p. 35.

A. No, it is not. The WNA and RNA mechanisms have two substantial differences. First, the WNA is a "real time" mechanism, in that the weather effects of a particular month are reflected in the bill to the customer for that month. Thus, in an unusually cold month, the customer is billed at an average effective rate that is lower than normal. This mechanism provides some real-time bill stability for customers. (Customers, of course, must continue to fully absorb weather risk in their purchased gas costs.) In contrast, the RNA is a longer-term reconciliation mechanism, in which revenue variances in one season are deferred for recovery to the next season. This deferral provides revenue stability for the utility because the deferred amount is recognized as a regulatory asset/liability. However, the deferral provides no bill stabilization benefit to ratepayers, and may in fact increase variability from year to year.

Second, adjusting current distribution bills for weather variability arguably provides revenue/bill stability to both utility and ratepayer. Since weather variability is absorbed in the WNA, one of the largest causes for revenue variances that will be absorbed in the RNA will be overall economic conditions. For these variances, the RNA will compound the economic risk to ratepayers, while substantially reducing the risk to shareholders. This would be particularly problematic for small business customers, were the RNA to be expanded to non-residential customers. For example, during an economic downturn, small businesses face reduced demand for their products and services, and thus lower revenues and less ability to reinvest in their businesses. Columbia's proposed RNA would compound the negative impact of the economic downturn by an after-the-fact tax on those small businesses, all in the name of eliminating economic risk to Columbia's shareholders.

Q. Has Columbia accounted for customer drawbacks of decoupling in its implementation of its proposed RNA mechanism?

A. No. Under its proposed RNA mechanism, Columbia stands to benefit from whatever increased financial certainty the mechanism will provide and the ability to adjust residential rates outside of rate cases without establishing corresponding and equal benefits to residential customers. Further, the RNA shifts the risk of variable gas consumption from the Company to the customer without any reduction in the Company's rate of return to

compensate residential customers for the benefits that will accrue to Columbia. For these reasons and related discussion above, the Commission should reject this proposal.

Q. What does Columbia propose with respect to its Weather Normalization Adjustment ("WNA")?

A. It is proposing to eliminate the three percent "deadband" applicable under the current weather adjustment program.

Q. Do you agree with this proposal?

A. The deadband slightly reduces the effectiveness of stabilizing *bills* from weather effects, but yields effective *rates* that are more stable. This tradeoff is reasonably balanced under the three percent metric. Given this consideration, my recommendation to reject the RNA proposal, and for purposes of program consistency and continuity, I recommend that the Commission retain the current three percent deadband.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

MEASURES OF PROGRESS TOWARD COST BASED RATES

PENNSYLVANIA UTILITY COST AND REVENUE ALLOCATION

Introduction

The Pennsylvania Commonwealth Court held that cost of service is "the polestar" criterion for assigning a utility rate increase among the various rate classes.[20] Parties to Pennsylvania base rates proceedings generally agree that this criterion implies that the revenues for each class at the rates approved by the Commission should be closer to allocated costs than the rates in place when the rate case is filed. Thus, parties to the proceeding will typically compare some metric for cost recovery under "proposed rates" with that same metric for cost recovery under "current rates." This comparison can show (a) *whether* the proposed rates result in class revenues that are closer to allocated costs, and (b) *how much* progress the proposed rates make toward moving class revenues toward allocated costs.

While different metrics are used for this analysis, the most common metric in Pennsylvania is the "indexed rate of return" metric (also called the "relative rate of return" or "unitized rate of return" metric). This appendix demonstrates why the indexed rate of return is not a reliable metric for identifying whether proposed rates are closer to allocate costs than current rates, and that even where the indexed rate of return correctly implies that there is progress toward cost-based rates, it is not a reliable indicator of the amount of progress that is achieved.[21] This appendix also compares the indexed rate of return to three other metrics for evaluating progress toward cost-based rates, namely the dollar subsidy, the rate of return differential, and revenue-cost ratio metrics.

[20] Lloyd v. Pennsylvania Public Utility Commission, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

[21] This problem with the indexed rate of return metric was identified in OSBA-sponsored testimony at least as early as 1994. This critique has been presented in expert testimony many times since. No credible rebuttal to these basic conclusions has been submitted, but the widespread use of this flawed metric continues.

The Structure of the Cost Allocation Study

The indexed rate of return metric is derived from the method that is most often used for utility cost allocation in Pennsylvania. When a utility or regulator develops a revenue requirement for a test year, it simply sums all of the individual cost items for that year, including operating and maintenance ("O&M"), administrative and general ("A&G"), depreciation, taxes other than income, income taxes and allowed return on rate base. Thus, the objective of a cost allocation study should be to simply allocate each of these cost elements to the various rate classes. Because the allowed return and associated income tax are derived from rate base, the cost allocation study allocates all net plant and other rate base items to the various rate classes, and the return and income taxes can then be allocated in proportion to rate base.

Cost allocation studies in Pennsylvania, however, are most often conducted on a class rate of return basis. That is, the cost allocation study calculates a class rate of return by taking revenues, deducting the allocated O&M, A&G, depreciation and taxes other than income, to produce a pre-tax class net income. Income taxes are then most often allocated based on the calculated pre-tax class income, and a net income by class value is derived by difference. The allocated pre-tax and net income figures are thus not a cost of capital, but represent the implied return provided by each class under the revenues (current or proposed) used in the cost allocation study. These net income values are then divided by the allocated rate base, to produce percentage class rates of return.[22] Thus, with this approach to cost allocation, there is a desire by utilities and regulators to develop a metric for evaluating progress toward cost-based rates that is based on the class rates of return produced by the cost allocation study.

Defining Progress Toward Cost-Based Rates

It is not necessarily obvious what it means to "move rates more into line with allocated cost" between current and proposed rates. At the simplest level, one could argue that if the current rate revenues for a particular class are below the allocated cost for that class at the full proposed

[22] Some Pennsylvania utilities also calculate cost of service using a "levelized rate of return" method, in which return and income tax costs are allocated such that each class produces the system average rate of return. This approach is arithmetically equivalent to allocating return and income tax costs in proportion to rate base, as described above.

revenue requirement, any increase in rates will move that class's revenues closer to allocated cost. However, the objective of this exercise is to measure the progress toward cost-based rates for each rate class compared to that for all of the other classes. Thus, a revenue allocation proposal must be evaluated for its impact on all of the rate classes.

Also at the simplest level, of course, a proposed revenue allocation will by definition move rates more into line with allocated cost if each class's revenues are moved exactly to the full proposed allocated cost of service. Or, equivalently, rates are exactly cost-based when each class's revenues are set such that the class produces the system average rate of return. Therefore, there is no question that moving a class exactly to an indexed rate of return of unity (1.0) is necessarily consistent with making rates more cost-based.

In many base rate proceedings, however, moving rates fully into line with allocated costs cannot be achieved due to consideration of other rate design factors, most notably "rate gradualism," which serves to limit the increase for any particular class of customers in any rate proceeding, and has the aim of gradually moving rates into line with allocated cost.

Thus, in terms of determining whether a particular rate proposal moves rates into line with allocated cost, this appendix takes the position that there is progress toward cost-based rates if the proposed relative rate increases across the various classes, when followed for a number of base rates proceedings (in which there is no change in the relative cost structure), will eventually result in cost-based rates. Thus, for any particular metric, it is important to consider not only the difference between the metric and current rates and proposed rates in one base rates case, but also what that metric will imply going into the next base rates case.

As shown further in the numerical example below, this standard for defining progress implies that for classes with revenues below allocated cost at current rates (or, equivalently, with a class rate of return below system average), progress can only be achieved by assigning that class a rate increase above the system average increase. This, of course, is just plain common sense. If a class is under-recovering costs, it should be assigned an above average increase. As shown below, however, the indexed rate of return metric fails at common sense.

The Numerical Example

This appendix takes the approach of defining a specific numerical example, and showing the implications of various different metrics on different rate increase scenario. The calculations associated with this example are also provided in MS Excel electronic format (IEc WP2), and parties are able to simulate alternative examples to evaluate the rigor of this analysis.

The example attached to this appendix shows the arithmetic impacts of a single two-class utility example under four different rate increase proposals. Each page shows the implications of a different revenue-cost metric, namely the indexed rate of return, dollar subsidy, differential rate of return, the revenue-cost ratio and the normalized revenue-cost ratio.

The example involves two rate classes, A and B, in which each generates the same revenue at current rates, but in which Class A has a moderately higher cost to serve. The four rate increase scenarios are (I) an across-the-board increase in which both classes get the same percentage increase, (II) a scenario with a moderately higher percentage increase for Class B, and (III) a slightly higher percentage increase for Class A, and (IV) a moderately higher percentage increase for Class B.

The common-sense answer is that the across-the-board scenario (I) should show no progress toward cost-based rates, Scenario II should indicate that revenues are moving farther away from costs, and Scenarios III and IV should show that revenues are moving slightly and modestly closer to allocated costs. The discussion of each metric below highlights where the metric produces results that are at odds with these expectations.

To evaluate the question as to whether there is consistent progress toward cost-based rates, the metrics are evaluated at both proposed rates in the "current" base rates proceeding, and for what the values would imply going into the next base rates case after a uniform increase in costs.

The Indexed Rate of Return Metric

The indexed rate of return metric is measured as the class rate of return divided by the system average rate of return, at current and proposed rates. If revenues are fully in line with allocated costs, the class indexed rate of return is unity (1.0). Thus, if a class has an indexed rate

of return at present rates that is higher than system average, it is deemed to be over-recovering costs, and conversely, where the indexed rate of is below unity, the class is under-recovering allocated costs.

As a standalone measure for relative cost performance, there is nothing wrong with the indexed rate of return metric – for any particular system average rate of return scenario, the farther a class's indexed rate of return is from unity, the farther it is from allocated costs.

Moreover, since an indexed rate of return of unity represents cost-based rates, it is conceptually appealing to conclude that if the indexed rate of return moves closer to unity, there is progress toward cost-based rates. Moreover, it is similarly appealing to conclude that progress toward cost-based rates could be measured by how much closer the index gets toward unity between current and proposed rates. Unfortunately, this intuitive approach fails in the actual arithmetic.

Utilities have used this argument for decades in Pennsylvania. While it is not clear why alternative methods have not been adopted, it may be that the metric is attractive to both utilities and regulators in that it tends to show significant progress toward cost-based rates when in fact there is little such progress. This then allows utilities to claim that they are following the cost standard without having to make politically unpopular decisions regarding differentiating rate increases among the various rate classes.

When applied in an actual example, the indexed rate of return fails even the simplest test. In the example shown, the current rates class rates of return are 2.50% and 5.71% for Classes A and B respectively, producing indexed rates of return of 0.625 and 1.429 relative to the system average return of 4.00%. When a 30% increase is applied to both classes, the system average rate of return rises to 8.00%, and the class returns rise to 6.25% and 10.00% respectively, yielding indexed rates of return of 0.781 and 1.250.

Thus, despite the fact that both classes get the same percentage increase and common sense says that there should be no progress toward cost-based rates, the indexed rate of return metric not only implies that there is progress, but that there is significant progress. The Class A indexed rate

of return moves from 0.625 to 0.781, which appears to imply that the class has moved 42 percent of the way to cost-based rates.[23]

The fallacy of this logic is shown in the implications for the next rate case. When costs increase, the system average rate of return falls back to its lower level and the indexed rate of return metrics all shift farther away from unity. Thus, as shown, an across-the-board increase in the current rate case followed by an across-the-board cost increase for the next case will demonstrate that, in fact, there is no progress toward cost-based rates and the indexed rates of return are right back where they started.

The other revenue increase scenarios show similar problems with the indexed rate of return metric. In Scenario II, despite a smaller percentage increase for the higher-cost Class A, the indexed rate of return again implies that there is progress toward cost-based rates, which is obviously nonsense. This is again demonstrated by the implications for the next base rates case, which understandably show that rates are farther out of line than they were going into the current rate case. It is simply unreasonable to believe that assigning larger percentage increases to the rate class that is already over-recovering costs will somehow reduce inter-class subsidies. And yet that is the implication of the indexed rate of return metric.

In Scenarios III and IV, the indexed rate of return does produce the correct directional answer, namely that rates are moving more into line with allocated cost. But the indexed rate of return metric implies that both scenarios result in enormous progress toward cost-based rates, when in fact there is relatively little progress, particularly in Scenario III. As shown in the example, despite a small differential in the rate increases, the indexed rate of return implies that revenues have moved 50 percent of the way toward allocated cost. Realistically, however, as shown in the implications for the next base rates case, the actual progress is much lower.

Thus, the indexed rate of return metric is a wholly unreliable guide for evaluating progress toward cost-based rates in a utility rate proceeding, because it (a) may show progress toward cost-

[23] "Progress" is measured by how much the metric has moved divided by how far it needs to move to become fully cost-based. Thus, in the residential class example, the index moves from 0.625 to 0.781, a difference of 0.156, compared to moving fully to cost-based rates, which would require the index to move from 0.625 to 1.000, a difference of 0.375. Progress is measured as 0.156/0.375, or 42 percent.

based rates when in fact revenues are moving farther away from costs, and (b) will overstate the magnitude of progress toward cost-based rates when progress is occurring.

The Dollar Subsidy Method

While the indexed rate of return metric is the most common approach used by Pennsylvania utilities, the Commission has also supported the use of the dollar subsidy metric. In an order involving the City of Bethlehem – Water Department, the Commission concluded:

> "As noted by the OSBA, the proper yardstick for measuring the degree of movement toward cost of service is the change in the absolute level of class subsidies at present and proposed rates."[24]

In the dollar subsidy method, the total cost to provide service is calculated using the method described above, in which each component to cost, including return and income taxes, is allocated to each cost. The difference between current rate revenues and the allocated cost is the dollar subsidy.[25]

In allocating the return and income tax costs under the "current rates" evaluation, the values used represent only the return that the utility would achieve and the income taxes that it would incur if it were assigned no rate increase. These values therefore do not represent the utility cost of capital, but simply residual values of what is left from current rate revenues after O&M, A&G, depreciation and other taxes are deducted.

When the dollar subsidy metric is applied to the four alternative revenue allocation proposals in the attached example, it implies the following:

- For the across-the-board increase, the dollar subsidy metric indicates that the dollar value of the revenue-cost difference increases under proposed rates, implying that rates

[24] *Pennsylvania Public Utility Commission v. City of Bethlehem -- Water Department*, Docket No. R-2020-3020256, Order entered April 15, 2021, at 36.

[25] This appendix uses the term "subsidy" as the difference between revenues and fully allocated cost in a utility cost allocation study. Theoretical economics generally defines subsidy based on incremental cost concepts, rather than fully allocated cost.

are moving farther away from costs. In dollar terms, that conclusion is correct, although in percentage terms the subsidies remain the same.

- When a larger increase is assigned to Class B, the dollar subsidy metric indicates correctly that rates are moving farther away from allocated cost, and that the problem will be worse with the next base rates proceeding.

- When a modestly larger increase is assigned to Class A, the dollar subsidy metric implies that there is no progress toward cost-based rates in the current rate proceeding, and that the situation will be worse in the next base rates case. In effect, even though the slightly higher rate increase for Class A will (eventually) lead to cost-based rates, the dollar subsidy method implies that there is no progress.

- When a materially larger increase is assigned to Class A, the dollar subsidy metric correctly indicates that there is progress toward cost-based rates.

Thus, overall, the dollar subsidy metric will tend to slightly understate progress toward cost-based rates, but the distortion is far smaller (and in the opposite direction) of that of the indexed rate of return metric.

The Differential Rate of Return

The differential rate of return metric is similar to the indexed rate of return metric, in that both approaches calculate class rates of return and current and proposed rates, and compares each class's return to the system average. However, where the indexed rate of calculates the *ratio* of class to average return, the differential rate of return calculates the *difference* between class and average rates of return. In the indexed rate of return, cost-based rates are achieved with an indexed rate of return of unity (1.0); for the differential rate of return, cost-based rates are achieved with a differential rate of return of zero.

When applied to the four revenue allocation scenarios in the example, the differential rate of return produces results that are nearly the same as the dollar subsidy method. That is, the differential rate of return calculation will slightly understate progress toward cost-based rates, but the results are much less distorted than those from the indexed rate of return metric.

Revenue-Cost Ratio

The revenue cost ratio is similar to the dollar subsidy metric, except rather than taking the difference between revenues and allocated costs, it takes the ratio of revenues to allocated cost. Like the indexed rate of return, cost-based rates are achieved at a revenue-cost ratio of unity (1.0 or 100 percent).

Unlike the indexed rate of return metric, however, the revenue-cost ratio generally does not distort the implications of a revenue allocation proposal. As shown in the example, in all four revenue allocation proposals, the revenue-cost ratio correctly indicates when there is progress toward cost-based rates and when there is not.

The only downside to this unadjusted revenue-cost ratio approach is that the progress toward cost-based rates in the current case is not the same as that going into the next base rates case. This results because the mix of operating costs allocated to each class is different from the mix of rate base costs. This minor distortion is addressed in the final metric below.

Normalized Revenue-Cost Ratio

The normalized revenue-cost ratio makes a technical correction to the revenue-cost ratio metric to reduce the distortion associated with using a non-cost parameter, namely the residual return and income tax costs, as a measure of cost at current rates. This metric uses fully allocated costs including the utility's allowed return on capital as the cost metric at both current and proposed rates. In this metric, however, the revenues at current rates are "normalized" by applying the system average rate increase to each class. Thus, in this metric, the current rates revenue-cost ratio is the revenues that would be earned from each class if an across-the-board rate increase were applied divided by the fully allocated class revenue requirement. This is then compared to the revenue-cost ratio that results from the actual proposed revenue allocation.

As shown in the attached example, this metric correctly shows the progress toward cost-based rates in each of the scenarios, and it also correctly predicts what each class's revenue-cost performance will be going into the next base rates case if there is no change in the underlying cost structure.

Summary

The indexed rate of return is a metric that has intuitive appeal, in that cost-based rates are achieved when the index is at unity (1.0), and that it would seem therefore that moving the index closer to 1.0 would represent progress toward cost-based rates.

Alas, it is not that simple. As shown in the examples attached, and as evidenced in hundreds of utility rate proceedings in Pennsylvania, the indexed rate of return is not a reliable metric for gauging progress toward cost-based rates for any particular revenue allocation proposal. It may give a directionally correct answer, and it may not. And even when it does correctly show progress, it implies that there is much more progress toward cost-based rates than actually exists.

Of the five metrics evaluated in this review, the indexed rate of return is the only metric to fail the test and imply that there is progress toward cost-based rates when there is none, and even when rates are moving substantially away from allocated cost.

All the other metrics evaluated in this review are superior to the indexed rate of return approach. The dollar subsidy and differential rate of return have a modest disadvantage in that they may imply that there is no progress toward cost-based rates when in fact some small progress is occurring. This is a relatively modest disadvantage since the distortion is much smaller than that in the indexed rate of return, and moreso because it will encourage Pennsylvania utilities and regulators to adopt revenue allocation proposals that are more aggressive in moving revenues into line with allocated cost, consistent with the legal standard that cost of service be the polestar criterion.

Overall, however, the revenue-cost metric, particularly the normalized revenue-cost metric, does not suffer from the distortions of any of the other methods, and is the most reliable of the methods on offer.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

MARK D. EWEN

IEc

MARK D. EWEN **PRINCIPAL AND PRESIDENT**

Overview

Mr. Ewen has a strong background in applied economics, empirical methodologies, and financial analysis. As a Principal at Industrial Economics, Incorporated (IEc), he focuses on expert case management and economic damages estimation in a variety of litigation contexts, regulatory and environmental economics, and financial analysis. Within his areas of expertise, Mr. Ewen has been qualified as an expert witness before judicial and regulatory bodies (see schedule of testimony and appearances). He has also served as a Managing Director of the firm.

Education

Master of Public Policy, University of Michigan

Bachelor of Arts, summa cum laude in Economics and Political Science, University of North Dakota

Project Experience

Examples of his project work include the following:

Mr. Ewen has participated in various proceedings concerning energy markets and regulated utilities. These efforts, which focus on issues related to cost allocation and rate design, include working on behalf of industry and consumer intervenor groups in rate-making cases before the public utility commissions in Pennsylvania and Alberta, Canada, and the U.S. Postal Rate Commission. For example, for the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**, he has provided consulting and analytic support relating to electricity and natural gas tariff design, revenue requirements, and other regulatory initiatives concerning electrical and natural gas distribution utilities. For the **RHODE ISLAND ATTORNEY GENERAL,** Mr. Ewen conducted a due diligence review of PPL's proposed acquisition of Narragansett Electric Company and its potential impacts on the state's ratepayers.

For the **NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA) AND DEPARTMENT OF PUBLIC SERVICE (DPS)**, Mr. Ewen provided expert services assessing the economic impacts to municipal governments of extended electricity outages related to Tropical Storm Isaias. As part of this work, he constructed a model to estimate various costs of incremental staffing requirements for over 500 localities, including excess overtime, surge time (i.e., bringing on extra staff for outage response coordination and logistics), and idle time (e.g., crews waiting extended periods for downed lines to be de-energized). The review also included consideration of other direct costs, including, among others: effects to water systems; delivery of bottled water; operation of generators; and other constraints on the provision of essential governmental services. The litigation was settled to the satisfaction of the involved parties.

For the **NYSERDA AND NEW YORK DPS,** Mr. Ewen directed the development of a Generic Environmental Impact Statement (GEIS), pursuant to the requirement of the State Environmental Quality Review Act (SEQRA) that assessed the environmental and economic impacts of the "Reforming the Energy Vision" and "Clean Energy

Fund" initiatives within the state. He also directed the preparation of a Supplemental EIS to assess the environmental and economic impacts of the newly proposed Clean Energy Standard (CES). The CES is being developed to support the state's goal of supplying 50 percent of electricity demand with renewable generation resources by the year 2030. More recently, he directed the development of a model to assess the financial viability of various waste-to-energy technologies, and related social welfare benefits. This model uses detailed capital budgeting scenarios for specific facilities to generate forecast scenarios.

For the **U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF OCEAN ENERGY MANAGEMENT (BOEM)**, directing an assessment of the Bureau's approach to calculating and presenting the operating fee included in offshore wind leases under BOEM's jurisdiction. As part of this engagement, IEc provided a number of recommendations for simplifying the implementation of the operating fee formula and identified available data sources and approaches to estimating individual components of the fee formula. The review also addressed the structure and levels of fees associated with operations of renewable wind energy projects in the U.S. and worldwide. More recently, IEc has been supporting the development of Standard Operating Procedures for the fee calculation and lease management process. The overall goal is to provide information resources and a methodological approach that will allow lessees to derive accurate data for fee equation variables efficiently and consistently, and for BOEM to present the fee calculation clearly in the lease.

For **NYSERDA,** conducting a market analysis examining the potential economic development opportunities that could accrue in New York from hydrogen playing a role in achieving components of its Climate Leadership and Community Protection Act.

For the **U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF OCEAN ENERGY MANAGEMENT**, managed the development of a model to assess the economic and fiscal impacts of offshore oil and gas activity in the Gulf of Mexico and other BOEM OCS regions. This model, the Lifecycle Impacts Model (LCIM), assesses the economic and fiscal impacts associated with a specific lease or group of leases, over the time horizon of the lease(s). IEc's framework for the model was to build a capital budgeting forecasting tool for lease development, yielding estimates of industry expenditures, OCS revenues, industry profits, and employment impacts for a single lease or a set of leases. A key component of model development was to dynamically simulate the complex and unique timing parameters of lease development, incorporating the influence of critical exogenous factors like market prices and lease geology.

For the **U.S. COAST GUARD, NATIONAL POLLUTION FUNDS CENTER**, Mr. Ewen provides ongoing support to the NPFC in adjudicating damages claims resulting from oil spills. These claims include damages for business interruption, lost profits, property damage or value diminution, increased costs, and lost wages or employment, among other categories. Cases have also included damages for contract delays to construction projects and shipping demurrage. Industry sectors that Mr. Ewen has evaluated include: *electricity generation (nuclear and coal); railroads; cruise ships; oil ship transport; lodging and tourism; food and beverage; gambling; fisheries; marinas; real estate development, oil and gas development; and oil refining.*

Mr. Ewen's analytic work includes expert financial analysis and economic damages estimation in the context of general litigation and environmental enforcement actions. These efforts include assessing damages in breach of contract, nuisance, and cost recovery actions, and assessing the financial capabilities and economic benefit of noncompliance of firms accused of environmental violations. Clients in this area of his practice include the **U.S. DEPARTMENT OF JUSTICE**, **U.S. COAST GUARD**, **U.S. ENVIRONMENTAL PROTECTION AGENCY, STATES,** and private parties.

Testimony and Appearances

Mr. Ewen has provided testimony or appeared in the following cases and regulatory proceedings.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning the Default Service Plan for PECO Energy Company (Docket No. P-2024-3046008, April/May 2024).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for National Fuel Gas Distribution Corporation (Docket No R-2024-3045177, March 2024).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning the Default Service Plan for Pike County Light and Power Company (Docket No. P-2023-3039927, July 2023).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning cost allocation, revenue allocation, and rate design in the base rates case for Columbia Gas of Pennsylvania (Docket No. R-2022-3031211, June 2022).

On behalf of Attorney General of the State of Rhode Island, submitted testimony before the Rhode Island Division of Public Utilities and Carriers concerning due diligence and related reviews of PPL Corporation's proposed acquisition of Narragansett Electric Company from National Grid USA (Docket No. D-21-09, November 2021).

Expert report and deposition testimony concerning economic damages and related financial matters, *Seaplane Adventures, LLC, vs. County of Marin, California*; expert report filed September 2021, deposition testimony given September 2021.

Expert reports and deposition testimony on bankruptcy reorganization plan feasibility and related financial matters, *in re: First Energy Solutions Corp., et al., Debtors, Case No. 18-50757*; expert reports filed July 2019, deposition testimony given August 9, 2019.

Expert declaration concerning economic damages and related financial matters, *in re: Outer Banks Power Outage Litigation, all actions, No. 4:17-CV-141-D*, March 2018.

Expert report and deposition testimony on Economic Damages in *State of Alaska v. Williams Alaska Petroleum, Inc., et al*., *Case No. 4FA-14-01544 CI;* expert report filed December 2016, deposition testimony given February 15, 2017.

Expert reports and deposition testimony on Economic Benefit in *Sierra Club v. Energy Future Holdings Corp. et al.*, *Case No. 5:10-cv-156 (E.D. Tex.)* and *Sierra Club v. Energy Future Holdings Corp. et al.*, *Case No. 6:12-cv-108 (W.D. Tex.)*; expert reports filed in June and July 2013, deposition testimony given August 2013. Trial testimony given in Case No. *6:12-cv-108 (W.D. Tex.) in March 2014*.

Expert testimony on ability-to-pay provided, in the matter of Mercury Vapor Processing Technologies, Inc., et al. (No. RCRA-05-2010-0015), July 2011.

Expert Declaration in a patent case concerning economic and financial matters in the context of environmental credits valuation -- In re Patent Application of: Jeff Andrilenas et al., Application No.: 12/328,219, For: VALUING ENVIRONMENTAL CREDITS, submitted June 2011.

Export report and deposition testimony on financial matters in Evansville Greenway and Remediation Trust v. Southern Indiana Gas and Electric Company, Inc., et al. (03:07-cv-0066-SEB-WGH); expert report filed July 2009, deposition testimony given January 2010.

Expert testimony on ability-to-pay provided, in the matter of Robert J. Heser, Andrew J. Heser, and Heser Farms (No. CWA-05-2006-0002), May 2007.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning tariff design issues for Columbia Gas of Pennsylvania (Docket No. R-00049783, May 2005).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning cost allocation, revenue assignment, and rate design for Pennsylvania Power and Light (Docket No. R-00049255, August 2004).

Expert report on economic damages in United States v. Southern California Edison No. CIV. F-01-5167 OWW DLB (E.D. Cal)., July 2004; deposition testimony provided September 2004.

Expert testimony on ability-to-pay provided in U.S. v. Peter Thorson, Managed Investments, Inc., Construction Management, Inc., and Gerke Excavating, Inc. (No. 03-C-0074), May 2004.

Expert testimony on ability-to-pay provided in U.S. v. Paul A. Heinrich and Charles Vogel Enterprises, Inc. (No. 03-C-0075-S), October 2003.

Expert testimony on ability-to-pay provided in the matter of Dearborn Refining Company (No. RCRA-05-2001-0019), February 2003.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for PFG Gas and Northern Penn Gas (Docket No. R-00027389, July 2002).

Expert report and testimony on economic damages in Carol Marmo et al. v. IBP, Inc.; expert report filed March 2002, deposition testimony given June 2002, September 2004, and testimony at trial given February 2005.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for National Fuel Gas Distribution Corporation (Docket No. R-00016789, March 2002).

On behalf of the Office of the Consumer Advocate, providing testimony before the United States Postal Rate Commission regarding cost allocation of city carrier street time costs. Docket No. R2000-1, July 11, 2000.

Expert report and declaration on ability-to-pay in re Indspec Chemical Corporation and Associated Thermal Services, Inc., and related testimony in U.S. EPA administrative court on February 24, 1998 (No. CAA-III-086).

Expert report on ability-to-pay in re Harrisburg Hospital and First Capital Insulation, Inc. and related testimony in U.S. EPA administrative court on October 8, 1997 (No. CAA-III-076).

2024

EXHIBIT IEc-2

IEc ELECTRONIC WORKPAPERS

IEc WP1: Cost and Revenue Allocation**
IEc WP2: Metrics for Progress Toward Cost-Based Rates**

The above-referenced workpapers will be served electronically only, as they are in excel format; and will be served in a subsequent follow-up email to all parties, following service of OSBA's Direct Testimony

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2024-3046519**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits IEc-1 and IEc-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 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: June 13, 2024

Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	**:**	**Docket No. R-2024-3046519**
	:	**C-2024-3047905**
v.	**:**	
Columbia Gas of Pennsylvania, Inc.	**:**	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Jeffrey A. Watson
Administrative Law Judge
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DATE: June 13, 2024

/s/ Steven C. Gray
Steven C. Gray
Senior Attorney
Assistant Small Business Advocate
Attorney I.D. No. 77538

COMMONWEALTH OF PENNSYLVANIA

July 11, 2024

The Honorable Jeffrey A. Watson
Administrative Law Judge
Pennsylvania Public Utility Commission
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas Company / Docket No. R-2024-3046519

Dear Judge Watson:

Enclosed please find the Rebuttal Testimony of Mark D. Ewen, labelled **OSBA Statement No. 1-R with associated Exhibit IEc-R1,** on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

Copies will be served on all known parties in this proceeding, as indicated on the attached Certificate of Service.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Attorney
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: PA PUC, Secretary, Rosemary Chiavetta (Cover Letter and Certificate of Service Only)
Mark D. Ewen
Parties of Record

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2024-3046519**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Rebuttal Testimony and Exhibit of

MARK D. EWEN

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: July 11, 2024

Date Submitted for the Record: _____

REBUTTAL TESTIMONY OF MARK D. EWEN

1. Introduction and Context

Q. Mr. Ewen, please state your names and briefly describe your qualifications.

A. My name is Mark D. Ewen. I submitted direct testimony and associated exhibits on behalf of the Pennsylvania Office of Small Business Advocate earlier in these proceedings and my qualifications were presented therein.

Q. What is the purpose of this rebuttal testimony?

A. This rebuttal testimony responds to the revenue allocation recommendations of Mr. Jerome D. Mierzwa representing the Pennsylvania Office of Consumer Advocate ("OCA"), Mr. Esyan A. Sakaya representing the Commission's Bureau of Investigation and Enforcement ("I&E"), and Mr. James L. Crist, P.E., representing the Pennsylvania State University ("Penn State").

2. Cost Allocation

Q. What are the positions of the various parties regarding the appropriate cost allocation method for this proceeding?

A. As I explained in direct testimony, the Company offered three allocated cost of service studies ("ACOSSs"), consistent with past practice. These three simulations of the ACOSS model differ only in how mains costs are allocated. They include a customer-demand ("CD") approach, and 50/50 peak-and-average ("P&A") approach, and an average of the two ("AVG"). The Company indicates that it relies primarily on the P&A approach, based upon prior Commission precedent.

Mr. Sakaya and Mr. Mierzwa both rely on the Company's P&A ACOSS as the cost basis for revenue allocation and rate design.

Mr. Crist opines that the cost allocation of the revenue requirement yielded by the CD approach is most consistent with cost causation principles. His conclusion primarily is based on the reasoning that gas mains costs are incurred to attach customers to the system and are sized to meet peak demand. Furthermore, Mr. Crist contends the P&A COSS favors the

residential class and that the CD was the cost allocation methodology favored prior to Columbia's 2020 base rate case.

Q. What is your position regarding the appropriate cost allocation method for this proceeding?

A. As a theoretical matter, I agree with Mr. Crist that economies of scale exist for serving larger customers. For reasons of Commission precedent, however, I rely on the P&A ACOSS as the cost basis for revenue allocation and rate design. Because the Company's method generally appears to be consistent with that used in the last case, I did not conduct an exhaustive review of all aspects of the cost allocation studies.

While I agree with the use of the P&A ACOSS method, the enormous shortfall in the flex rate class makes revenue-cost comparisons difficult. Firstly, the costs provided to the flex rate customer group at current rates dwarf that class's current revenues, generating a shortfall of approximately $30 million – by far the largest revenue shortfall of any rate class group. This disparity essentially offers a subsidy to the flex rate customer class. Since the Company claims the current rate revenues represent the maximum amount that can be earned from these customers due to competition from other NGDCs, this subsidy must be shouldered by the other rate classes. In my direct testimony, I offer an alternative method of redistributing the flex rate class revenue shortfall among the other classes based on allocated costs for both current and proposed rates.

3. <u>Revenue Allocation</u>

Q. What are the positions of the various parties with respect to revenue allocation in this proceeding?

A. As noted in my direct testimony, the Company's proposed revenue allocation yields no material progress toward cost-based rates for the Residential, SGS2 and LGS/LGSS classes. In addition, because the revenue-cost ratio for the LDS/LGSS class is so low, an increase of even 2.0 times the system average results in comparatively shallow progress toward cost-based rates. The only classes to exhibit even moderate progress toward cost-based rates under the Company's proposal are the Medium General (SDS/LGSS) class (with an increase well above system average) and the SGS1 class. My analysis of this proposal indicated that

the Company's inability to make material progress toward cost-based rates primarily lies with the gradualism constraints for the LDS/LGSS rate class.

I developed an alternative revenue allocation proposal that (a) relies on my modified ACOSS noted previously, (b) is more aggressive in attempting to move rates into line with allocated cost for Residential class and Small Commercial classes, and (c) allows for a larger rate increase for the LDS/LGSS class to reflect the enormous revenue-cost difference under current rates.

Mr. Mierzwa offers an alternative revenue allocation proposal, which is directionally consistent with my proposal and also employs a revenue increase that is 2.0 times system average for the LDS/LGSS class.

Mr. Sakaya appears to not contest the Company's revenue allocation at the full revenue requirement.

For purposes of revenue allocation, Mr. Crist opines that the Commission should rely on the CD ACOSS methodology and suggests several adjustments to this methodology in his testimony. He does not provide an explicit revenue allocation proposal for all classes, but indicates that the LDS/LGSS class's contribution to total revenue should be cut from $27,382,567 to $15,800,000, a 58 percent decrease. Mr. Crist admits such a reduction would be shouldered by the other rate classes, although the explicit allocation is left uncertain.

Table IEc-1R summarizes the revenue allocation proposals for the Company, OSBA, and OCA. As the table shows, both the OSBA and OCA proposals engender greater progress toward cost-based rates and are quite consistent. The residential class receives a lower than system-average increase, the negotiated rate classes receive no increase, and the LDS/LGSS class increase is set at a maximum of 2.0 times the system average. This leaves the small and medium commercial classes to shoulder above system-average increases.

Table IEc-1R Summary of Revenue Increase Allocation Proposals						
	Columbia		OSBA		OCA	
	($mm)	%	($mm)	%	($mm)	%
Residential	$ 86.31	19.9%	$ 75.20	17.3%	$ 75.28	17.3%
SGS1	$ 11.24	22.2%	$ 13.20	26.0%	$ 12.99	25.6%
SGS2	$ 12.39	22.2%	$ 15.62	27.9%	$ 15.73	28.1%
Med Gen'l (SDS/LGSS)	$ 8.13	22.1%	$ 8.94	24.3%	$ 9.05	24.6%
Lg Gen'l (LDS/LGSS)	$ 6.06	22.2%	$ 11.18	41.0%	$ 11.09	40.7%
MDS	$ -	0.0%	$ -	0.0%	$ -	0.0%
Flex	$ 0.00	0.0%	$ 0.00	0.0%	$ 0.00	0.0%
Total	$ 124.1	20.3%	$ 124.1	20.3%	$ 124.1	20.3%
Note: Source: IEc WP1-R						

Q. Please address Mr. Mierzwa's proposal.

A. Table IEc-2R summarizes the impact of Mr. Mierzwa's proposal, using my cost allocation analysis inclusive of the reallocation of the flex rate customer shortfall.[1] For the reasons explained in my direct testimony, I use the revenue-cost ("R-C") ratio and each class's revenue increase relative to the system average as the metrics for evaluating the reasonableness of the proposals. In addition, because it often serves as a rate gradualism constraint, I report the ratio of the class percentage increase to the system average increase.

[1] To allow for accurate reconciliation of this review to Mr. Mierzwa's analysis, I do adjust our calculation of current rate revenues and the proposed revenue requirement by not subtracting certain miscellaneous revenues from the total.

Table IEc-2R
Analysis of OCA Proposed Revenue Allocation

	Revenue-Cost Ratio			Class Increase (%)	Class to System Average Ratio
	Current	Proposed	Progress		
Residential	105.4%	102.8%	48.9%	17.3%	0.85
SGS1	98.1%	102.4%	228.0%	25.6%	1.26
SGS2	96.7%	102.9%	187.4%	28.1%	1.38
Med Gen'l (SDS/LGSS)	99.5%	103.0%	669.8%	24.6%	1.21
Lg Gen'l (LDS/LGSS)	57.6%	67.3%	23.0%	40.7%	2.00
MDS	120.3%	100.0%	100.0%	0.0%	0.00
Flex	NM	NM	NM	0.0%	0.00
Total	100.0%	100.0%	--	20.3%	1.00

Flex rate cost performance is not meaningful because the $38 million shortfall is reallocated to other rate classes.

Source: IEc WP1-R

As shown in the table, Mr. Mierzwa's proposal has the following implications:

- The Residential class receives a slight decrease in its revenue-to-cost ratio, bringing it more in line with its respective costs. Notably, Mr. Mierzwa allocates to the Residential class both the smallest class increase (as a percentage) and smallest Class to System Average Ratio of any class.

- All small and commercial classes experience increases beyond parity with their cost-based revenue. Each of the SGS1, SGS2, and SDS/LGSS classes' subsidies fully reverse, providing a subsidy to the LDS/LGSS, MDS and Flex rate classes. In my experience before the Commission, it would be unprecedented for this type of revenue allocation to be proposed if it were the Residential class facing this effect. The consistency of my proposal with that of Mr. Mierzwa illustrates the OSBA's commitment to economically sound revenue allocation approaches, even in light of the extreme cross subsidies flowing to the LDS/LGSS, MDS, and Flex rate classes.

- Though the proposed increase for the LDS/LGSS classes meets the industry's maximally acceptable limit of 2.0 times the system average, it yields by far the least progress toward cost-based rates. It is inequitable that the four rate classes already

providing subsidies to the MDS and Flex rate classes – Residential, SGS1, SGS2, and SDS/LGSS – must too bear the burden of the industrial class's inability to achieve a parity with cost-based rates.

Based upon these findings, I conclude that Mr. Mierzwa makes an effort to reduce the subsidy reaped from the Residential class. Still, it is inequitable to shift this burden on the remainder of the smaller classes, namely small business customers.

4. Revenue Normalization Adjustment

Q. What are the positions of the various parties with respect to the Company's proposed Revenue Normalization Agreement?

A. The parties concur that the Company's proposed Revenue Normalization Adjustment *should not* be approved by the Commission. I, Mr. Mierzwa, Mr. Sakaya, and Mr. Crist propose arguments against the Company's case for an RNA, primarily that the company has not made a sufficient case that renders the RNA requisite for revenue stabilization.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-R1

IEc ELECTRONIC WORKPAPERS

IEc WP1-R**

**** The above referenced Workpapers, "IEc WP1-R", will be served electronically only, as it is available in excel format only and will be served simultaneous to Rebuttal Testimony****

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2024-3046519**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Rebuttal Testimony labelled OSBA Statement No. 1-R and associated Exhibit IEc-R1 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 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 11, 2024

Mark Ewen

Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility	**:**	**Docket No. R-2024-3046519**
Commission	**:**	**C-2024-3047905**
v.	**:**	
Columbia Gas of Pennsylvania, Inc.	**:**	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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DATE: July 11, 2024

/s/ Steven C. Gray

Steven C. Gray
Senior Attorney
Assistant Small Business Advocate
Attorney I.D. No. 77538

COMMONWEALTH OF PENNSYLVANIA

July 25, 2024

The Honorable Jeffrey A. Watson
Administrative Law Judge
Pennsylvania Public Utility Commission
301 Fifth Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas Company / Docket No. R-2024-3046519

Dear Judge Watson:

Enclosed please find the Surrebuttal Testimony of Mark D. Ewen, labelled **OSBA Statement No. 1-S with associated Exhibit IEc-S1,** on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

Copies will be served on all known parties in this proceeding, as indicated on the attached Certificate of Service.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Attorney
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: PA PUC, Secretary, Rosemary Chiavetta (Cover Letter and Certificate of Service Only)
Mark D. Ewen
Parties of Record

OSBA Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2024-3046519**
	:	
Columbia Gas of Pennsylvania, Inc.	:	
	:	

Surrebuttal Testimony and Exhibit of

MARK D. EWEN

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Revenue Allocation
Rate Design

Date Served: July 25, 2024

Date Submitted for the Record: _____

SURREBUTTAL TESTIMONY OF MARK D. EWEN

1. Introduction and Context

Q. Mr. Ewen, please state your names and briefly describe your qualifications.

A. My name is Mark D. Ewen. I submitted direct testimony, rebuttal testimony and associated exhibits on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA") earlier in this proceeding and my qualifications were presented therein.

Q. What is the purpose of this surrebuttal testimony?

A. This surrebuttal testimony responds to the rebuttal testimony of Pennsylvania Office of Consumer Advocate ("OCA") witness Jerome D. Mierzwa, and Columbia Gas of Pennsylvania ("Columbia" or "the Company") witness Kevin L. Johnson on matters of revenue allocation and rate design.

2. Revenue Allocation

Q. What is Witness Mierzwa's response to your direct testimony regarding revenue allocation?

A. In his rebuttal, Witness Mierzwa recognized my use of the revenue-cost ratio metric in my direct testimony and states my proposed revenue allocation is "reasonable and results in an allocation of the proposed revenue increase which… is nearly identical to the revenue allocation I have proposed."[1]

Q. Do you agree with Witness Mierzwa?

A. Yes. Consistent with my approach, witness Mierzwa proportionately reallocated the immense shortfall realized by the flex rate class to other classes. In doing so, he assigned an increase to the LDS/LGSS rate class at 2.0 times the average system increase, as did I. Our independent conclusions that a 2.0 times average system increase in the LDS/LGSS class's allocation corroborates that the class is far underperforming other classes in progress towards cost-based rates, and that a larger revenue assignment to the LDS/LGSS class is both fair and equitable.

[1] OCA Statement No. 5R, at 4.

Q. What is Witness Johnson's response to your direct testimony regarding revenue allocation?

A. Witness Johnson does not contest my recommendations that the shortfall from the flex rate customers be allocated among the various rate classes or that the revenue-cost metric serves as an accurate guide for achieving cost-based rates. His objection to my testimony is in the use of an allocated revenue requirement of 2.0 times the average system increase. Mr. Johnson cites to a limit of 1.5 times the system average increase as the maximum allowed under the principles of rate gradualism as applied by the Commission in the Company's 2020 base rate case. As such, he disagrees with my proposed revenue allocation.

Q. Do you agree with Witness Johnson?

A. I do not. I agree that regulators often apply a "rule-of-thumb" for a maximum rate increase, and that a 1.5 to 2.0 times system average increase limits may be applied. I also agree that the Commission's decision in Columbia's 2020 base rate case adopted the OCA-proposed revenue allocation, which set a maximum increase at 1.5 times the system average increase. However, I observe that at the time the Commission acknowledged that there are no hard-and-fast rules for rate gradualism in the decision in the Company's 2020 base rates case.

Specifically, the Commission indicated:

> The record indicates that although there are no definitive rules for determining what kind of rate increase would violate the principle of gradualism, limiting the maximum average rate increase for any particular class to 1.5 to 2.0 times the system average increase is one common metric that has been used by experts in the Commonwealth. OSBA St. 1 at 28.[2]

In addition, in that decision, the Commission approved a revenue allocation implying a 36 percent increase for medium and large general service customers, and the Commission recognized that even with that large an increase, rates for larger customers would still lie well below allocated cost.

[2] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2020-3018835, Order Entered February 19, 2021, at 233.

In suggesting the Commission consider a higher rate increase for the large industrial class in this case, I observed that, even with this increase, rates for the Large General Service class will still lie far below allocated cost. The important fact is that the Commission adopted a cost allocation methodology in Columbia's 2020 base rate case – the Peak & Average COSS Method – that has a significant negative impact on large, high load factor customers. This decision implies that the rates paid by Large General Service customers have been far below allocated cost for years and probably decades. In order to move rates into line with allocated cost in a reasonable time frame, and to reflect the historical inequities, I concluded that it is reasonable to apply the upper limits for rate gradualism.

In addition, I observed that on a per-Dth basis the proposed increases for the Large General Service Costs are relatively modest. Table IEc-1S below shows the magnitude of the proposed rate increase for each rate class on a per-Dth basis, both for my proposal and the Company's filed position. As shown, my proposal, while higher in percentage terms, results in a rate increase for Large General Service customers that is far lower than that of the residential and small general service customers. In particular, I note that the proposed rate increase for small business customers in the SGS1 class is more than double my recommended increase for the Large General Service class, when evaluated on a per-Dth basis.

Table IEc-1S
Summary of Revenue Allocation Proposals
Rate Increase in $ per Dth

	Columbia Filed	**IEc Direct**
Residential	$2.53	$2.21
SGS1	$2.00	$2.35
SGS2	$1.41	$1.77
Med Gen'l (SDS/LDSS)	$1.09	$1.20
Lg Gen's (LDS/LGSS)	$0.53	$0.98
MDS	$0.00	$0.00
Flex	$0.00	$0.00
Total	$1.51	$1.51
Source: 2024 IEc WPS1		

3. Rate Design

Q. Please respond to Witness Johnson's argument that the average customer-related cost for a class should serve as a minimum for the customer charge rather than the maximum.

A. As I understand Mr. Johnson's logic, the Company is arguing that there is some incremental fixed cost to attach the customer to the system that is not proportional to either customer demand or customer throughput. As a conceptual matter for cost allocation, I agree. However, the Commission has consistently rejected that logic for NGDC cost allocation over many years, and did so again in recent Columbia base rate cases. Having established the principle that all mains cost to interconnect the customer to the distribution system are causally related to peak demand and annual throughput, and that mains costs are not causally related to customer count, it would be inequitable for the Commission to allow Columbia to disproportionately recover those costs from smaller customers within the class. Intra-class equity is best achieved when rates reflect the same principles used for cost allocation.

It is possible that Witness Johnson is arguing that the costs that are classified as "demand-related" in the ACOSS are "fixed costs," and that these costs are better recovered in a fixed customer charge. I respectfully disagree with that line of reasoning. Costs that are classified as demand-related in the Company's ACOSS will, over the longer term, vary with customer peak demands. Since it is probably not cost effective to recover these costs with a demand charge for smaller customers, the question is whether the customer charge or the volumetric charge is a better proxy for demand charge. Using a customer charge would imply that customers have the same level of peak demand regardless of annual consumption, a nonsensical hypothesis. Using the commodity charge to recover demand-related costs implies that peak demands rise in proportion to annual consumption, an assumption that is much more reasonable. Thus, recovering costs that are classified as demand-related with a commodity charge is much more consistent with cost causation than using a customer charge.

I therefore retain my recommendation that the customer charges for small and medium service customers be set no higher than that justified by the costs classified as customer-related in the Commission-approved ACOSS methodology.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-S1

IEc ELECTRONIC WORKPAPERS

IEc WP1-S – Revenue Allocation Explanatory Details**

**** The above referenced electronic Workpapers, "IEc WP1-S", will be served electronically only, as it is available in excel format only and will be served simultaneous to the OSBA's Surrebuttal Testimony****

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2024-3046519**
	:	
Columbia Gas of Pennsylvania, Inc.	:	
	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Surrebuttal Testimony labelled OSBA Statement No. 1-S and associated Exhibit IEc-S1 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 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 25, 2024

Mark Ewen

Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	**Docket No. R-2024-3046519** **C-2024-3047905**
v.	:	
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless otherwise noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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DATE: July 25, 2024

/s/ Steven C. Gray
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Attorney I.D. No. 77538

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3046519
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

PSU Statement No. 1

DIRECT TESTIMONY OF JAMES L. CRIST, P.E.

ON BEHALF OF
THE PENNSYLVANIA STATE UNIVERSITY

Dated: June 14, 2024

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc., a consulting firm focused on regulatory and market issues. My business address is 4226 Yarmouth Drive, Suite 101, Allison Park, Pennsylvania 15101. I am presenting testimony on behalf of The Pennsylvania State University ("Penn State" or "PSU").

Q. DO YOU HAVE ANY QUALIFICATIONS OR OTHER SPECIALIZED KNOWLEDGE THAT WOULD ASSIST THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("COMMISSION") IN ITS DELIBERATIONS IN THIS CASE?

A. Yes. I have a B.S. in Chemical Engineering from Carnegie Mellon University and an M.B.A. from the University of Pittsburgh. Additionally, I am a Registered Professional Engineer in the Commonwealth of Pennsylvania. I have attached a copy of my CV and Regulatory Experience as Exhibit JLC-1.

Q. BRIEFLY DESCRIBE YOUR RELEVANT BUSINESS QUALIFICATIONS.

A. I have run a consulting practice for the past 28 years focused on regulated and deregulated energy company strategy, market strategy, and regulatory issues. During 2004 and 2005, I undertook a consulting assignment as the Vice President of Consumer Markets for ACN Energy ("ACN"). ACN is a gas and electric marketer that is active in eight states. Prior to my consulting practice, I worked at three major energy companies for a total of 19 years.

Most recently, I was Vice President of Marketing for Equitable Resources. In that function I was responsible for the development of the company's deregulated business strategy.

Prior to that, I was Vice President of Marketing for Citizens Utilities, responsible for gas, electric, water and wastewater marketing activities in several service territories within the United States. The gas and electric utility operations were in Vermont, Louisiana, Arizona, Colorado, and Hawaii. Under my direction, Citizens initiated commercial and industrial transportation and supply services at its gas operation in Arizona. I also directed significant gas supply contracting activities with large industrial and commercial customers in Citizens' gas operation in Louisiana.

Before that, during 1988 through 1994, I was the Marketing Director at the Peoples Natural Gas Company where I was actively involved in many gas transportation programs as the company relaxed transportation requirements so that customers would have supply choices.

In summary, I have considerable experience in several states involving residential, commercial, and industrial customer energy procurement, regulatory issues and industry restructuring programs.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION?

A. Yes, I have appeared before the Commission in numerous gas and electric regulatory proceedings. I have been involved in the previous base rate cases of Columbia Gas of Pennsylvania, Inc. ("Columbia," "CPA," or the "Company") filed in 2008, 2009, 2010, 2012, 2014, 2015, 2016, 2018, 2020, 2021, 2022 and in its 2017 and 2019 purchased gas cost cases.

Additionally, I provided testimony on a variety of issues relating to energy procurement, industry restructuring, and demand response before regulatory Commissions in Arizona, Maryland, New Mexico, Illinois, Kentucky, Tennessee, Ohio, Wyoming and the U.S. Virgin Islands.

I. ISSUES

Q. WHAT ARE THE ISSUES YOU WILL DISCUSS IN THIS TESTIMONY?

A. In my direct testimony, I will first address Columbia's base rate increase requests over the past several years. I will then address Columbia's Cost of Service Study ("COSS") and recommendations. I will then address a service issue that PSU experienced with one of its accounts.

Q. WHAT ARE YOUR RECOMMENDATIONS IN THIS TESTIMONY?

With respect to the Company's COSS, as in the past, the Company conducted two COSS, a Customer-Demand COSS and a Peak & Average COSS. The Company also produced an Average COSS, which averages the results from the Company's two COSS. The process Columbia used is not reflective of cost causation and the recommendations made should not be accepted. Rather, as I will discuss below, the Commission should utilize the Company's Customer-Demand COSS to guide revenue allocation in this proceeding and further modify the Company's Customer-Demand COSS by assigning a more reasonable level of mains investment to the LDS/LGSS class.

As to the service issue, I will present evidence regarding how Columbia transferred natural gas service at one of PSU's properties to an unauthorized, unverified third party

without PSU's knowledge. This resulted in service being shut off at the premises without PSU's knowledge due to the third party's failure to pay. I recommend that the Company revise its existing procedures so that existing customers are alerted when a person initiates a request to start, stop, or transfer gas service to a service property with an active gas account at the time of the request and at least forty-eight (48) hours prior to the change taking effect. Such notice should be sent both by mail to the service property, and billing address if different, and by e-mail if Columbia has the existing customer's email address.

The Company should also create a process where customers may opt-in to a higher level of account security, incorporating (a) two-factor authentication and (b) limitations on changes that can be made through the Company's website, which will help prevent third parties from accessing a customer's account information online. Two-factor authentication would involve knowing a secure password, followed by entering a number texted to a smartphone before a customer is allowed to access their account online. Such procedures are common today for a wide range of services such as on-line shopping, banking, and email access. The Company should also allow the customer to opt-in to a feature whereby certain changes, such as account transfers, can only be made by speaking directly to an employee of Columbia Gas after the employee has verified the that the caller is authorized to make changes on behalf of the customer.

II. PENN STATE SERVICE

Q. WOULD YOU BRIEFLY DESCRIBE PENN STATE'S SERVICE FROM COLUMBIA?

A. Yes. Penn State is a major sales and distribution service customer of Columbia at Penn State's University Park campus and at its Beaver, Fayette, Mont Alto, and York campuses as well as the Biglerville Ag Extension Farm within the Commonwealth. In 2023, Penn State received approximately 2.4 million Dth through distribution service from Columbia. At the University Park campus, PSU takes service from two primary accounts. The two campus steam plants, including combustion turbine-generators with heat recovery steam generators, are serviced from three meters representing about 91% of the campus load and make up one account. A variety of campus buildings that are served from about 50 meters, representing about 9% of the campus load, make up the other account.

Q. WHAT PIPELINES DELIVER GAS TO THE COLUMBIA DISTRIBUTION SYSTEM THAT SERVES THE UNIVERSITY PARK CAMPUS OF PENN STATE?

A. The State College area and other areas of Centre County receive gas that flows into the Columbia distribution system through two Points of Delivery ("PODs") from interstate pipelines. About eight miles east of State College are two interstate pipelines, Eastern Gas Transmission and Storage ("EGTS") and Texas Eastern ("TETCO"). PSU contracts for the majority of its gas supply deliveries to the University Park campus through alternative suppliers and has done so in this configuration since 2014.

III. COLUMBIA'S REQUEST OF $124.1 MILLION

Q. WHEN DID COLUMBIA LAST INCREASE ITS BASE RATES?

A. The Final Order in Columbia's most recent base rate case (Docket R-2022-3031211) was entered on December 8, 2022. The Company was awarded an increase of $44.5 million. It had requested $82.2 million. Columbia has increased its base rates frequently during the past sixteen years as shown in this table, which indicates the amount it filed for and the amount granted in each case.

Table 1: Columbia Rate filings

Docket No.	Test Year Ending	Proposed Increase ($Millions)	Ordered ($Millions)	% of Request
R-2008-2011621	Sep-08	$58.9	$41.7	70.8%
R-2009-2149262	Sep-10	$32.3	$12.0	37.2%
R-2010-2215623	Sep-11	$37.8	$17.0	45.0%
R-2012-2321748	Jun-14	$77.3	$55.2	71.4%
R-2014-2406274	Dec-15	$54.1	$32.5	60.1%
R-2015-2469665	Dec-16	$46.0	$27.1	58.9%
R-2016-2529660	Dec-17	$55.3	$35.0	63.3%
R-2018-2647577	Dec-19	$46.9	$26.0	55.4%
R-2020-3018835	Nov-20	$100.4	$63.5	63.1%
R-2021-3024296	Dec-22	$98.3	$58.5	59.5%
R-2022-3031211	Dec-23	$82.2	$44.5	54.1%

Prior to the filing in 2008, Columbia had not filed a base rate case since 1995. Now the Company seeks an increase of $124.1 million in the instant proceeding.

Q. HOW DOES THIS COMPARE TO THE RATE OF ECONOMIC INFLATION?

A. Columbia's recent rate increase was fully effective in January 2023. The $124.1 million request represents a base rate revenue increase of 20.69%.[1] Although the news media have

[1] Exhibit 103, Schedule No. 8, Page 1 of 9, Line 38

discussed the inflation rate frequently and referred to inflation in recent years as higher than historic, the recent Bureau of Labor Statistics data show the 2023 inflation rate, as measured by the Consumer Price Index ("CPI"), was 4.1%.

Mr. Kempic, Columbia's President and Chief Operating Officer, claims in his direct testimony that the average customer's bill is lower now than it was twenty years ago when adjusted for inflation:

> "However, even with this increase, the average customer's bill will be 24% less than the average customer's bill was 20 years ago after you adjust for inflation. While you cannot put a price on the improvements in safety and reliability which 1 we have brought about by our investments over the last 15 years, it is good to know that we have made those 3 improvements and kept the customer's cost reasonable and less than inflation."

Columbia Statement No. 1, 7:19-8:3. This statement is entirely misleading for he combines two costs, the cost of distribution service and the cost of natural gas commodity. Natural gas commodity prices are volatile and have declined substantially over the period Mr. Kempic uses to present his comparison. In other words, he is using the decline of natural gas commodity cost to offset the large increase in distribution costs. Columbia, however, does not control the cost of natural gas commodity. Columbia should not be allowed to increase its distribution rates simply because the global energy markets have declined over the recent 15-year period.

Rather, when viewed from the perspective of base rates only, Columbia's rate increases are steadily outpacing inflation. For example, as discussed above, last year's inflation rate as measured by the CPI was 4.1%. The recent rolling 12-month inflation rate is approximately 3.1%. The Federal Reserve strives to achieve a 2% inflation rate. Here, Columbia is requesting a 20.69% increase in total base rate revenues, even though

Columbia recently received a substantial base rate revenue increase at the end of 2022. This substantially outpaces recent economic inflation.

IV. COST OF SERVICE STUDY

Q. WHAT IS A COST OF SERVICE STUDY?

A. A Cost of Service Study ("COSS") examines costs incurred by the utility and allocates those costs into distinct customer classes. To produce an accurate COSS it is necessary to possess quality accounting data detailing utility expenses and be able to determine assignment of expenses to customer classes. Expenses must be examined in detail to determine what customer or class of customers created the need for the utility to make the expenditure. This identification of expense responsibility is known as cost causation.

In Columbia's 2020 rate case, the Final Order defined the COSS as "a benchmark for evaluating customer class cost responsibility with the fundamental purpose of aiding in the accurate and reasonable design of rates by identifying all the capital and operating costs incurred by the utility in serving its customers, and then directly assigning or allocating these costs to each individual rate class ***based on established principles of cost-causation***." Docket No. R-2020-3018835, Order at 187-88 (Feb. 19, 2021) (emphasis added). It is critical that the Commission recognized that the COSS must be based on cost causation.

Q. WHAT IS COST CAUSATION?

A. This fundamental principle of ratemaking assigns costs to those classes of customers that are responsible for the incurrences of costs. The Commission has been consistent in its policy that considers cost causation as a fundamental principle and the bedrock of cost

assignment in the ratemaking process. Failure to adhere to proper cost causation will create mis-allocations of costs which result in cross-class subsidization. Cross-class subsidization refers to a situation where one class of customers is allocated excessive costs for their distribution services in order to subsidize the cost for another customer class. This practice is counter to the purpose of a cost of service study, it can lead to economic inefficiencies, market distortions, and an inefficient allocation of resources.

This principle may not be violated just because some customers do not like bearing the costs or want to lessen the impact of the cost of the benefits they receive at the expense of others, nor may it be violated because a utility wishes to benefit one customer class at the expense of another. In the landmark case *Lloyd v. Pennsylvania Public Utility Commission*, 904 A.2d 1010 (Pa. Cmwlth. 2004) (*Lloyd*), the Commonwealth Court declared cost of service as the "polestar" of ratemaking and directed the Commission to set non-discriminatory reasonable rates.

Q. WHAT ARE THE COST CLASSIFICATION CATEGORIES USED IN A COST OF SERVICE STUDY?

A. Costs are classified as demand related, energy or commodity related, or customer related. It is critical in a COSS to accurately determine cost causation by identifying the primary causative factor. In some cases, there is only one causative factor.

Q. WHAT EXPENSES ARE DEMAND DRIVEN?

A. Demand costs vary and are dependent on the peak or maximum throughput. Engineering planning will examine the peak design day[2] and base engineering designs on meeting throughput demands on that day. Components of the distribution system that are demand driven are gas mains, and the related operation and maintenance expense. This is the major component of rate base for a natural gas utility. Company witness Mr. Johnson stated, "Mains and services account for the majority of the Company's gross plant investment and distribution O&M expenses, excluding gas costs." (Columbia Statement No. 6, 9:15-16). Specifically, total mains investment of $3,217,304,248[3] represents 92.2% of Columbia's proposed rate base claim of $3,489,087,567[4] in this proceeding.

Q. WHAT EXPENSES ARE ENERGY DRIVEN?

A. The largest energy cost (also known as commodity or average demand cost) is the cost of purchased gas. The cost of purchased gas is not under consideration in this rate case as this is a base rate proceeding and we are considering the non-gas revenues of the Company. Other non-gas costs that are energy driven would be variable operation and maintenance expenses that can be identified as related to throughput. An example of this would be the O&M cost of a natural gas compressor. Such a piece of equipment would experience higher operating hours with greater throughput and incur correspondingly higher O&M expenses, similar to an automobile. If the car has been parked in the garage mostly since an owner has been working from home the maintenance needs (oil changes, filter, belts,

[2] The "design day" is the forecast peak gas usage that the distribution system would deliver under extreme cold weather conditions. Determination of design day considers historical peak day data, along with forecasts of temperature, customer growth, and system pressure considerations.

[3] Exhibit JLC-2 at 7 (PSU 3-002).

[4] Columbia Exhibit 111, Schedule 2, Page 2, Line 12

brake pads, tires) have been less than when the car was driven for a daily commute to the office.

Q. WHAT EXPENSES ARE CUSTOMER DRIVEN?

A. Expenses that vary directly with the number of customers would be meters and services, customer contact centers, billing systems and a portion of distribution mains. Each customer has a gas meter. Of course, the small residential meter may cost less than a larger industrial meter, but the meter costs are clearly customer driven. Customer contact centers need to be sized appropriately to manage the volume of daily calls, and they must grow as the number of customers increases. The size of the customer in terms of demand or volume does not make an impact on the number of calls to the call center. The billing system produces bills for Columbia's 444,200 customers.[5] Again, size in terms of demand or volume does not matter as all customer bills are calculated, printed or imaged, and mailed or emailed.

Q. WHAT COST OF SERVICE STUDIES DID THE COMPANY UNDERTAKE?

A. Company witness Mr. Johnson (Statement No. 6) explained that as in past base rate cases the Company conducted two COSS and then produced an average of the two, so three studies in all. The two studies, known as the customer-demand study and the peak & average study, allocate the cost of mains differently. Mr. Johnson also produced the average study. In prior rate cases, as recently as the 2020 Columbia base rate case, Columbia's rate design witnesses used the average study as the primary guide for allocation

[5] Columbia Exhibit No. 3, Page 1

of the revenue increase, but Mr. Johnson did not use the average study in this rate case as the primary guide for allocation. Instead, Mr. Johnson used the peak & average COSS which, as Mr. Johnson and I agree, favors the residential class. (Columbia Statement No. 6, 4:13-14).

Q. WHY DID THE COMPANY USE THE PEAK & AVERAGE COSS IN THIS RATE PROCEEDING?

A. The only reason Mr. Johnson stated was, "Columbia recognizes this Commission's preference for the use of the peak and average study, and therefore used the peak and average study as the primary guide for the allocation of the revenue increase in this case." *Id.,* 4:18-20 Mr. Johnson abandoned the Company's long practice of using the average study, not because use of the peak & average study was a more accurate reflection of cost causation, but only because the Commission, in the litigated 2020 rate case, relied on the Peak & Average study due to alleged "errors"[6] in the other Customer-Demand study presented by Columbia, which Columbia has subsequently fixed. To obtain a balanced

[6] In the 2020 base rate proceeding, Company witness Mr. Notestone did not make computational mistakes in the Customer-Demand study but OCA's Mr. Mierzwa opined that a different methodology of treatment of mains investment was appropriate and that Mr. Notestone's method was an error.

recommendation the Company, at the very least, should average the two COSS methods. The Company did, in fact, do this and presents it as a third COSS.

Q. WAS THERE A PREFERENCE EXPRESSED FOR THE CUSTOMER DEMAND COSS IN COLUMBIA'S 2020 BASE RATE CASE?

A. In her Recommended Decision[7] ALJ Dunderdale stated, "The ALJ recommends the Commission use the Peak & Average COSS, as promoted by OCA, in ***this*** base rate proceeding. ***Columbia Gas' Customer Demand COSS would be the preferred method***, but it contains serious flaws that skews its reliability and makes it unsuitable for use at this time and with this NGDC." Docket No. R-2020-3018835, R.D. at 394 (Dec. 4, 2020) (emphasis added).

Q. DID COLUMBIA MAKE THE SAME "ERRORS" IN THE CUSTOMER/DEMAND COSS IN THIS PROCEEDING?

A. No. The "errors" that were referred to stem from an argument advanced by OCA Witness Mr. Mierzwa that Mr. Notestone, Columbia's COSS witness in its 2020 base rate case, should not have separated gas main investment by operating pressure. The Commission stated:

> Mr. Mierzwa argued that the Company's separation of mains investment by operating pressure should be removed, primarily due to its use of original cost instead of net investment in the development of its allocation factors for each of the distribution mains categories. More specifically, Mr. Mierzwa challenged the Company's separation of mains by pressure group in the study because the allocation uses original cost and not net investment. Mr. Mierzwa asserted that the separation of pressure groups based on gross plant investment does not take into account the age of the

[7] Docket No. R-2020-3018835 (R.D. issued Dec. 4, 2020).

> pipe, and low-pressure pipe is generally older and, therefore, more depreciated than regulated pressure pipe. Mr. Mierzwa contended that because 53% of the low-pressure system is constructed of steel, and because steel pipe is generally older and, therefore, more depreciated than plastic pipe, customers served off low pressure pipe should be assigned less net investment than regulated pressure customers.

Docket No. R-2020-3018835, Order at 194 (Feb. 19, 2021). In the COSS in this case, Mr. Johnson did not separate gas mains investment by operating pressure, thus, correcting the alleged error. Therefore, instead of using the Peak & Average COSS to determine revenue allocation the Customer-Demand method should be used.

Q. WHAT DID THE COMMISSION STATE IN ITS FINAL ORDER IN COLUMBIA'S 2020 BASE RATE CASE?

A. "(W)e are not persuaded to reverse the ALJ's Recommended Decision that adopted the OCA's P&A ACCOSS and methodology in this proceeding." Docket No. R-2020-3018835, Order at 211 (Feb. 19, 2021). Since the ALJ's Recommended Decision stated that the Customer-Demand COSS would be the preferred method were it not for errors, the Peak & Average COSS was only used because the best COSS contained some "errors." That is not the case in this proceeding because those past "errors" are not present in the

current Customer-Demand COSS. My recommendations will be based on the Customer-Demand COSS – the preferred method.

Q. WHY IS THE CUSTOMER DEMAND COSS THE PREFERRED METHOD FOR COST ALLOCATION AS STATED IN THE 2020 COLUMBIA RATE CASE RECOMMENDED DECISION?

A. It is important to make decisions based on facts and engineering. Since the key issue in selecting a COSS is the treatment of expenses on gas mains, and we know that gas mains and their maintenance costs are the largest component of the rate base and operating expenses, it is critical that the process to plan, design, and construct gas mains be the basis of the COSS. Therefore, I reviewed the responses to several data requests investigating the actual engineering process to determine the design of the distribution system and the sizing of the gas mains.

Q. HOW DOES THE COMPANY DETERMINE THE ENGINEERING REQUIREMENTS NECESSARY FOR THE INSTALLATION OF GAS MAINS?

A. I reviewed the responses to several data requests about this subject, which I have included as Exhibit JLC-2. The critical and significant data collected by the Company when designing its system is the total BTU/hr connected load. See Exhibit JLC-2, Responses to PSU 1-001, PSU 1-002, PSU 1-006, PSU 1-011. In its response to PSU 1-001, Mr. McCaul, Columbia's Vice President of Operations, stated:

> In general, sizing mainlines within our distribution systems is based upon many factors. They include: the MAOP (maximum allowable operating pressure), the normal operating pressure, the minimum operating pressure (under peak conditions), the delivery pressure requested on behalf the

> customer, the length of main, and of course load information (typically in terms of Mcfh - 1000 cubic foot per hour).

Exhibit JLC-2 at 1. PSU I-002 examined the process of planning a new construction project for a residential customer. The Company listed the following data it collects regarding the layout and location of the property and gas line:

- Where is the house line stubbed or marked? Left/right/other-specify
- What delivery pressure is needed at the meter outlet?
  - 7" W.C. (standard delivery pressure)
  - 2 PSI
- What is the approximate distance in feet from the property line to the meter location?
- Is the construction site within 6" of final grade with foundation backfilled?
- ***What is the total BTU load?*** (emphasis added)
- Are there any obstructions that would hinder the service line installation?
- Are private utilities marked?

Exhibit JLC-2 at 2. Critically, the only factor regarding gas usage that the Company considers was the request for "total BTU load" and nothing regarding annual consumption. Similar data requests examined the planning process for commercial and industrial customers, and likewise the planning and engineering process relied solely on total BTU load, and not on annual consumption.

When asked about meter and service line sizing in response to PSU 1-006, Columbia stated:

> The connected load of a customer moving into an existing facility would be based upon the total rating (either in BTUs - British Thermal Units, or cubic

> feet of gas per hour) of the gas appliances to be used by the customer. This information is provided to Columbia of PA, Inc., by the customer.
>
> Once the load information has been determined, the service line would be sized based upon the factors identified in the response to PSU 1-001.

Exhibit JLC-2 at 3. To be clear, the term "connected load" does not refer to annual throughput or annual load but instead the demand of the customer. This is clearly stated in the response to PSU I-011:

> Question No. PSU 1-011:
>
> Explain how Columbia determines total BTU load during engineering work associated with customer connections and pipeline sizing? What does a customer have to do to obtain such information?
>
> Response:
>
> For engineering work associated with a proposed new customer connection and pipeline sizing, the total BTU load is provided to Columbia of PA, Inc. by the customer. It is typically in the form of BTUs (British Thermal Units) or cubic feet of gas per hour.
>
> For engineering work associated with existing loads and pipeline sizing, Field Engineers use Synergi Gas, Columbia's modeling software program (which models our pipeline systems), to assist in sizing mainlines, to help ensure safe and reliable service to all our customers.
>
> This load information (in Synergi Gas) is in terms of Mcfh (thousand cubic feet of gas per hour) and is based on current usage of our existing customers and any new information provided Columbia (such as proposed new loads mentioned above). Our particular model is distinct to Columbia's pipeline system and is proprietary. This information is not provided to customers.

Exhibit JLC-2 at 4. None of the data used for pipe sizing and distribution system planning, engineering, and construction include annual commodity usage. Repeatedly Columbia asserts it considers the demand load information, expressed in terms of BTU/hr. The Company collects this BTU/hr data through its web-based tool or through customer interviews. My review of the Company's data request responses, including the Company

manuals and procedures, have identified that connected load, along with delivery pressure and length of pipe necessary to attach to the customer, are the only data used in gas main design and sizing.

The process that Columbia uses is similar to the process that I am familiar with during my twenty-plus years working for natural gas distribution companies. As Director of Residential and Commercial Marketing for Peoples Gas, and Vice President of Marketing for Citizens Utilities, I regularly reviewed new gas main line project documents that contained engineering data to determine line sizes, and as a Registered Professional Engineer in the Commonwealth, I am familiar with the process that the facilities design engineer goes through in pipeline design.

Q. IS ANNUAL ENERGY CONSUMPTION CONSIDERED IN THE ENGINEERING DESIGN OF GAS MAINS?

A. No. The annual throughput, or annual load, or in COSS jargon, the "average demand", is not used in the design and determination of gas main piping. Instead, the cost causer of gas mains is the demand, not the commodity use, of the customer. All sizing of pipe (the pipe diameter, and subsequent system operating pressure) is determined by the demand, which is based on connected load in BTU/hr.

Q. WHAT COST OF SERVICE STUDY IS BASED ON COST CAUSATION OF GAS MAINS INSTALLATION AND OPERATION?

A. The cost of service study that is based on cost causation is the Customer-Demand study conducted by Columbia. It properly determines the allocation of gas main piping costs based on how the piping system was designed using the connected demand. The Peak & Average method used in the other COSS conducted by the Company does not apply cost

causation accurately because it allocates the costs of gas mains based in large part on the average demand or annual throughput and that is a violation of cost causation principles. This allocation result in cost-shifting and cross-class subsidization, which is contrary to the principles of ratemaking. The allocation of revenue that Mr. Johnson presented based on the Peak & Average COSS must also be rejected.

Thus, the Customer-Demand COSS should be the preferred approach by the Commission, as ALJ Dunderdale correctly concluded in Columbia's 2020 base rate case.

Q. HOW ACCURATELY DID THE PEAK & AVERAGE COSS CALCULATE THE COST OF GAS MAINS?

A. The Peak & Average COSS is inaccurate and contradicted by actual data. The Peak & Average COSS allocated $351,627,221 to the LDS/LGSS class, a class that has 80 customers.[8] In the response to PSU Set 3-001, Mr. Johnson himself pointed out that assumptions embedded in the Peak & Average COSS related to miles of dedicated mains are not reasonable assumptions.[9] He explained:

> The Peak and Average study assigned average cost of 13 miles of pipe to each of the 80 LDS/LGSS customers. It is reasonable to assume Columbia has not built 13 miles of dedicated mains to each LDS/LGSS customer.

Exhibit JLC-2 at 12. Thus, the allocated increase to the LDS/LGSS class is exceptionally excessive.

[8] Exhibit JLC-2 at 7-8.

[9] Exhibit JLC-2 at 5-6 ("From the information in GASCOS-004, the sum of 3" and greater diameter pipe is 25,780,275 feet and $1,693,771,400 resulting in an average cost per foot of $65.70 for 3" and greater diameter pipe. This average cost per foot can be used to reasonably estimate the mileage of mains pipe assigned to the LDS/LGSS rate class").

Moreover, actual data proves that the allocation is excessive. In response to OCA Set 4-14, which requested information regarding the 10 largest non-MLDS customers based on annual throughput, Columbia presented the distance from each of those customers to the nearest upstream customer. Mr. Johnson explained:

> The information in PSU 3-004 (OCA 4-014) shows Columbia was required to extend its system in the range of 170 feet (0.03 miles) of pipe to 7,618 feet (1.4 miles) of pipe to connect its ten largest customers.

Exhibit JLC-2 at 11. This shows a drastic error in the Peak and Average COSS. Given the average extension length between .03 miles and 1.4 miles compared to the 13 miles that the Peak & Average COSS allocated to the LDS/LGSS customers, this COSS is unrealistic and it results in excessive allocation with no basis in cost causation. For these reasons, the Peak and Average COSS should be rejected as a basis for cost allocation.

Q. DID THE CUSTOMER-DEMAND COSS PRODUCE A MORE ACCURATE ALLOCATION OF MAINS COST?

A. Absolutely. The Customer-Demand COSS allocated mains cost of $99,118,341 to the LDS/LGSS class (Exhibit 111, Schedule 1, Page 3, Line 19). Exhibit JLC-2 at 9. Using the average cost per foot of main of $65.70, the results in the assignment of 1,508,650 feet or about 285 miles. Dividing the 285 miles of mains assigned to the 80 customers of the LDS/LGSS class results in the assignment of approximately 3.5 miles of main for each LDS/LGSS customer. While this assignment is clearly better than the Peak & Average assignment, it is still more than twice the actual maximum mains length of 1.4 miles determined from the data in OCA Set 4-14. Even the allocation used in the Customer-Demand COSS allocates an excessive amount of mains cost to the LDS/LGSS class.

Q. WHAT MODIFICATION CAN BE MADE TO THE CUSTOMER-DEMAND COSS TO PRODUCE A RESULT THAT REPRESENTS ACTUAL DATA?

A. To be conservative, using the maximum distance of 1.4 miles determined from the data provided in response to OCA 4-14, that would correlate to a mains cost of 0.40[10] times the $99,118,341[11] that was used in the Company's Customer-Demand COSS, or $39,647,336. I used this amount in the Company's Customer-Demand COSS[12] and that lowered the rate base of the LDS/LGSS class from $85,515,193 to a more appropriate $30,753,663[13]. To achieve the Company's requested rate of return on rate base of 8.167% the LDS/LGSS class would need to contribute total revenue of $15,800,000. I recognize this is a reduction from the current class revenue of $27,382,567. To adhere to the principles expressed in the *Lloyd* decision[14] such a reduction would move to the appropriate class revenue requirement and eliminate the cross-class subsidy that the LGS/LGSS class provides to the other rate classes.

Q. IS YOUR RECOMMENDATION TO ASSIGN $15,800,000 OF MAINS INVESTMENT TO THE LDS/LGSS CLASS?

A. Yes, as this is consistent with the principles expressed in *Lloyd*.

V. ACCOUNT MANAGEMENT ISSUES

Q. WHAT ACCOUNT MANAGEMENT ISSUES HAS PENN STATE EXPERIENCED SINCE THE PREVIOUS BASE RATE CASE?

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[10] 1.4 miles divided by 3.5 miles.
[11] Exhibit JLC-2 at 9.
[12] Columbia Exhibit 111, Schedule 1. For simplification $39,647,336 was entered in Columbia Exhibit 111, Sch. 1, Pg. 3, Line 19, and Lines 21, 22, and 24 were set to zero.
[13] Columbia Exhibit 111, Schedule 1, Page 10, Line 21.
[14] *Lloyd*, 904 A.2d 1010.

A. Penn State experienced an account shut-off and lock-out by Columbia on Monday afternoon, April 8, 2024. It remained undetected until late in the evening when the outdoor temperatures dropped. Columbia did not restore service until about 10am on April 9, 2024. Unfortunately, this incident occurred at Penn State's Schreyer House, where the University President resides. Penn State conducted an investigation and was unable to locate any shut-off notices notifying the residence or Penn State staff of the impending termination.

After considerable research, Penn State learned the account shutoff occurred due to the account being unpaid for approximately two months after the account had been transferred to a third-party individual, presumably by someone else that had stolen the person's identity. Moreover, the third-party had changed the billing address away from the service address or the PSU business office, which presumably is why Penn State was not receiving bills or shut-off notices. PSU Police have opened a case, and Columbia initiated an internal Security and Compliance review.

Q. WHAT SAFEGUARDS SHOULD BE IN PLACE TO PREVENT SUCH AN OCCURRENCE?

A. Columbia should modify its existing procedures to prevent unauthorized account transfers to third parties. Specifically, I recommend that the Company alert existing customers when a person initiates a request to start, stop, or transfer gas service to a service property with an active gas account at the time of the request and at least forty-eight (48) hours prior to the change taking effect. Such notice should be sent by mail to the service property, and billing address if different, and by e-mail if Columbia has the existing customer's email address. As the Company indicated in response to PSU 4-007, this is not something it currently does. Exhibit JLC-2 at 14-15.

The Company should also create a process whereby customers may opt-in to a higher level of account security, incorporating (a) two-factor authentication and (b) limitations on changes that can be made through the Company's website, which will help prevent third parties from accessing a customer's account information online. With respect to two-factor authentication, this usually would involve knowing a secure password, followed by entering a number texted to a smartphone before a customer is allowed to access their account online. Such procedures are common today for a wide range of services such as on-line shopping, banking, and email access. With respect to limiting changes that can be made through the Company's online website, a customer should be allowed to opt-in to a feature whereby certain changes, such as account transfers, can only be made by speaking directly to an employee of Columbia Gas after the employee has verified the that the caller is authorized to make changes on behalf of the customer. As the Company indicated in response to PSU 4-010, this is not something it currently does. Exhibit JLC-2 at 18.

I also note that the Company currently has outstanding discovery requests on this issue and reserve the right to supplement or modify its recommendations upon receiving the discovery responses.

Q. WHAT IS THE SUMMARY OF YOUR TESTIMONY?

A. To ensure that the correct cost allocation of the revenue requirement is based on cost causation, the allocations based on the modifications I made to the Customer-Demand COSS presented by the Company must be used. Mr. Johnson's recommendation of allocating revenue using the Peak & Average COSS, which does not adhere to cost

causation principles and does not reflect the actual amounts spent on customer classes, must be rejected.

Additionally, Columbia must establish safeguards to prevent unauthorized attempts to establish natural gas service or transfer ownership of a customer account as recommended in my direct testimony.

Q: DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit JLC-1

JAMES L. CRIST

PRESIDENT, LUMEN GROUP, INC.
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Phone: 412.487.9708 ● Cell: 412.613.8886 ● E-mail: JLCrist@aol.com

DEMONSTRATED AREAS OF EXPERTISE

- **GENERAL MANAGEMENT** — Proven executive-level management expertise with excellent capabilities in developing, implementing, and supervising corporate-wide policies and procedures in areas including sales, marketing, customer service, public relations, rates, regulatory affairs, and administration. Possess a unique combination of abilities to set goals, develop winning business strategies, organize structures and work methods, and train the right people for the right positions to make it all work. Skilled in strategic short and long-term planning and budgeting with effective abilities in reducing the "fat" and increasing organizational efficiency. A creative, decisive leader who can successfully meet challenges and overcome obstacles to achieve profit objectives.

- **REGULATORY STRATEGY** — A thorough strategist with an extensive background in utility business unit operation (electric, natural gas, water/wastewater) the full range of rate and regulatory functions, from tariff development and special contract negotiation. Proven personal testifying skills with an outstanding record of developing and presenting successful written and oral testimony, along with settlement negotiations.

- **PERSONNEL MANAGEMENT** — Effective interpersonal communications skills support outstanding capabilities in recruiting, training, motivating, and directing staff at all levels. Proven ability to build productive, highly motivated teams of sales/marketing, operations, technical, and customer service personnel who contribute to top organizational performance.

- **PERSONAL ATTRIBUTES** — A determined, hardworking, challenge-driven executive with the skills and experience to bring excellence to any business organization. A high-energy mover and shaper ... experienced in successful start-ups and turn-arounds. An excellent communicator - written and verbal. A frequent speaker at professional symposiums, able to interpret and communicate complex concepts for diverse audiences. An engineering/technical specialist and a management generalist. Active in civic and community affairs.

EMPLOYMENT HISTORY

LUMEN GROUP, INC., Pittsburgh, PA — 1996 - Present
President - A consulting practice specializing in strategic planning, business planning, regulatory strategy, marketing and venture development in the electric, natural gas and energy services industries. Please see Addendum for amplification of consulting assignments.

ACN ENERGY, Farmington Hills, MI — 2004-2005
Vice President, Consumer Markets

OPTIRON, Pittsburgh, PA — 2003-2004
Vice President, Marketing

E R I SERVICES, Pittsburgh, PA — 1996
Vice President, Marketing & Product Development

CITIZENS UTILITIES, Harvey, LA & Stamford, CT — 1994 - 1995
Vice President, Marketing

CONSOLIDATED NATURAL GAS, Pittsburgh, PA — 1977 - 1994
Director, Residential & Commercial Marketing (1988 - 1994)
Manager, Technical Sales/Market Development (1985 - 1988)
Market Development Specialist (1982 - 1985)
Project Engineer (1979 - 1982) ... promoted from ... **Process Engineer** (1977 - 1979)

OCCIDENTIAL CHEMICAL CORP., Niagara Falls, NY — 1975 - 1977
Research Engineer

PENNSYLVANIA STATE UNIVERSITY, State College, PA — 1988
CLEVELAND STATE UNIVERSITY, Cleveland, OH — 1984
Instructor (Evening Division) - Economics, Engineering Economics

JAMES L. CRIST

SELECTED ACCOMPLISHMENTS

VICE PRESIDENT, CONSUMER MARKETS - ACN ENERGY

Retained for a turnaround assignment with an independent energy marketing company. Participated on the executive management team and directed a decentralized 3-person market management staff responsible for sales to 85,000 customers. Worked directly with the parent company executives and business unit management to create market-driven strategies for the corporation. Sharpened marketing and sales efforts of an energy marketing company operating in seven states and packaged company for eventual sale to Commerce Energy.

- Primary executive responsible for sales. Directed a team of market managers that was responsible for all aspects of 11 different markets (electric and natural gas) around the country. Provided direction and support to sales channel organization of commissioned representatives. Turned around five-year annual loss to significant gain in 2004. Tightened focus on market decisions.
- Directed regulatory involvement to insure compliance with market rules. Focused on maintaining positive relationships with state utility regulators to avoid penalties.
- Led weekly operations meetings during absence of COO. This involved direction of call center, provisioning, billing, credit & collection, and marketing.
- Worked in a team setting with other executives (VP Finance, VP Supply, COO) to provide consistent, professional focus to workforce experiencing changing environment.
- Directed development of annual business plan and budget with targets resulting in both goal achievements and income improvements.
- During transition period working with merger partner Commerce Energy's executive team to train and advise incoming executives.
- Directed customer service improvements in the customer acquisition process which resulting in replacing outdated paper/fax process with phone order process.
- Organized and directed trade show presence at national sales convention for alliance sales channel to create awareness of new product and market focus.

VICE PRESIDENT, MARKETING - OPTIRON

Retained as part of executive team in venture capital startup company developing new CIS/CRM software for the energy industry. Worked closely with CEO, COO, and Director of Sales to determine business strategy and develop marketing strategy to create market awareness and brand attributes in medium and small energy companies.

- Added in-house marketing communications function and personnel and revamped all marketing materials.
- Added new website functionality and content.
- Implemented first print advertising campaign in industry publications.
- Using industry contacts, positioned Option as expert presenter at several conferences and trade shows.
- Developed business plan to identify sales prospects and created competitive database of CIS/CRM vendors.
- Participated in development of exit strategy plan resulting in the successful sale to large software company.

VICE PRESIDENT, MARKETING & PRODUCT DEVELOPMENT - ERI Services

Assumed responsibility for creating a new corporate marketing vision and strategy to facilitate entry into new deregulated energy markets nationally.

- Recruited and selected an exceptional management team and integrated marketing and sales activities into one functional operating unit.
- Established the product innovation process to identify and create new and profitable market-driven service offerings.
- Directed strategic branding to launch the new corporate identity; managed a $2 million national advertising campaign; and developed over $1 million of new sales/marketing collateral materials.
- Instituted financial controls that reduced costs 60% in the Iowa market rollout while maintaining 80% market share and high customer satisfaction.

VICE PRESIDENT, MARKETING - Citizens Utilities

Directed a decentralized 20-person sales staff and a five person marketing staff. Worked directly with the Board of Directors, Corporate President, and Sector Vice President to create market-driven sales strategies for the corporation. Revamped and redirected sales efforts of a five-state energy utility with 440,000 customers.

- Increased industrial sales revenues by reorganizing unregulated gas marketing effort.
- Revamped merchandising utilizing inbound telemarketing in Louisiana Gas.
- Revised training programs for entire sales force, identifying and correcting missing technical and equipment training, adding a greater competency in the commercial and industrial sectors.
- Developed first business plan in sales and marketing organization with monthly budget monitoring and

targets resulting in both goal achievements and cost improvements.

- Launched an aggressive direct marketing program that increased sales 500% over previous year.
- Increased share of gas transportation business in Arizona by 15% in first year of operation through marketing efforts.
- Created a telephone long distance business in Louisiana that captured a 20% share (2nd to AT & T).

DIRECTOR, RESIDENTIAL & COMMERCIAL MARKETING - Consolidated Natural Gas

Managed a marketing staff of 12 and a "dotted-line" 24-person field sales force. Directed marketing and sales efforts in consumer, business, and manufacturing markets with $154 million revenue.

- Added $6 million in revenue by developing new products in gas transportation, supply, and agency.
- Directed sales activities in residential, commercial, institutional and governmental accounts for both product sales and technology sales.
- Produced $600,000 annual revenue and doubled competitive project wins by revamping market approaches to residential and commercial new construction.
- Secured 50% increase in customer decisions over 5 gas companies and 4 electric companies.
- Experienced in PUC and Legislature lobbying. Increased revenues $2.3 million through regulatory strategy/testifying and received major competitive program approval.

MANAGER, TECHNICAL SALES / MARKET DEVELOPMENT - Consolidated Natural Gas

Directed new market development and competitive market support.

- Focused on commercial and industrial accounts and increased the depth of relationship beyond the typical utility provider of service to a rich full service information provider and business partner.
- Captured $150,000 in new business annually by competitive pricing analysis, sales tool development, and market approach.
- Developed total advertising and promotional plan launching new market programs.
- Compiled extensive technical database and developed economic model for project analysis, eliminating a $100,000 operating budget expense.
- Led statewide coalition with customers and government agencies for fair treatment of new technology.

EDUCATION - PROFESSIONAL

UNIVERSITY OF PITTSBURGH, Pittsburgh, PA 1982
M.B.A. Degree

CARNEGIE - MELLON UNIVERSITY, Pittsburgh, PA 1975
B.S. Degree in Chemical Engineering

Registered Professional Engineer AGA Hall of Fame, 4/1991

JAMES L. CRIST
Lumen Group, Inc.
Suite 101, 4226 Yarmouth Drive ● Allison Park, PA 15101
Phone: 412.487.9708 ●Cell: 412.613.8886 ●E-mail: JLCrist@AOL.com

AMPLIFICATION OF LUMEN GROUP CONSULTING ASSIGNMENTS

A consulting practice specializing in strategic planning, business planning, marketing and venture development in the telecommunications, energy, and services industries.

REGULATORY

Represented the National Energy Marketers Association and their members in Equitable-Dominion Peoples merger case. Developed strategy, presented written and oral testimony and negotiated on behalf of clients. Worked with other interveners and FTC on anti-competitive issues.

UTILITY RATE NEGOTIATION

Represented large client group seeking to obtain rate reduction from electric utility. Prepared strategy, wrote testimony, and exceeded expectations by achieving a 40% reduction in charges, producing a $2 million annual reduction.

STRATEGIC PLANNING FOR ON-SITE POWER GENERATION

Participated in proposal development for a 27-MW power plant on Kauai. Handled critical customer needs assessment in rapid turnaround fashion to meet proposal deadline. Maintained relationships with clients, vendors and proposal partners. Our proposal was selected as the preferred bidder out of five strong competitors.

NEW BUSINESS START-UP / TARIFF NEGOTIATIONS

Participated in the development of a new gas distribution utility in New York. Handled tariff development, pricing structure, transportation contracting, and operations, maintenance, and emergency manual preparation.

SALES STRATEGY/BUSINESS DEVELOPMENT

Developed sales strategy to focus on profitable accounts and markets. Developed sales training and account management plans and provided consulting to energy marketing organizations to improve overall sales.

BUSINESS STRATEGY/BUSINESS DEVELOPMENT

Developed business strategy to verticalize eCommerce/Customer Relationship Management product for the energy/utility industry. Produced sales training for global applications, product promotion presentations, developed alliance relationships with system integrators and software partners, developed business. Client is market leader in North America.

JOINT VENTURE/PRODUCT DEVELOPMENT

Assembled joint ventures resulting in sales to offer new hedge-based weather risk management retail product. Identified venture partners, and developed business arrangements and closed million-dollar deals

ENERGY PROCUREMENT

Served as energy expert on project team that obtained long-term natural gas supply for major government facilities. Prepared project specifications, negotiated with suppliers, prepared RFP, negotiated major reduction in delivery charges. This project resulted in annual cost reduction of $2.5 million.

NEW BUSINESS DEVELOPMENT - TELECOMMUNICATIONS

Analyzed use of electric utility assets for possible telecommunications business venture. Wrote the business plan that identifies regulatory and non-regulatory issues, marketing plans, financial analysis, and organizational requirements. Launched the new non-regulated business unit in 1996.

JOINT VENTURE DEVELOPMENT - TELECOMMUNICATIONS

Conducted analysis of potential joint venture partners for new unregulated telecommunications venture, bypassing the Bell operating company. Held screening discussions with potential partners and selected lead candidate for venture. Developed working agreement with partners along with business case to launch venture.

JOINT VENTURE DEVELOPMENT - TELECOMMUNICATIONS & ENERGY

Developed strategic plan for joint venture involving gas, electric, and telecommunications partners. Screened potential business partners and held discussions with lead candidates. Assembled justification for top management approval.

PRODUCT DEVELOPMENT - UNREGULATED ENERGY SERVICES

Developed energy products for start-up subsidiary of major energy utility. Identified potential products and selected most likely candidates for further development. Developed market plans and sales plans for products.

MARKET PLAN - DIRECT MARKETING

Developed the market plan for large, global direct marketing agency to enter the energy industry. Identified strategies, strengths, weaknesses, and target prospects. Initiated sales effort and developed new business.

CORPORATE IMAGE DEVELOPMENT

Developed complete business unit identity for a new operations and services company. Produced capabilities brochure for use with prospects.

MARKET RESEARCH

Conducted market research to identify new customer/new business opportunities for major energy utility. Comprehensive project with two additional similar projects were completed. Entailed determination of goals, development of research methodology, script preparation, vendor selection, data analysis, and development of action plan.

MARKET DEVELOPMENT

Organized intervener group in Illinois consisting of retail marketers and intervened in three rate proceedings (Nicor Gas base case, WPS-Peoples merger case, Peoples Gas base case) and secured significant improvements in rules and procedures enabling marketers to increase their business and profitability. Developed strategy and presented written and oral testimony.

PARTIAL LIST OF REGULATORY EXPERIENCE OF JAMES L. CRIST

1. Philadelphia Gas Works, Base Rate Case, Docket R-2023-3037933, Representing Grays Ferry Cogeneration Partnership
2. Columbia Gas of Kentucky, Tariff Filing of Columbia Gas of Kentucky to Extend Its Small Volume Gas Transportation Service, Case No. 2021-00386, Representing Interstate Gas Supply, Inc, Constellation New Energy Gas Division, LLC, Xoom Energy Kentucky, LLC
3. Chattanooga Gas Company, Petition for Approval of Tariff Amendments, Docket No. 22-00004, Representing Chattanooga Regional Manufacturers Association
4. Chattanooga Gas Company, Petition for Approval of its 2021 Annual Rate Review Filing, Docket No. 22-0032, Representing Chattanooga Regional Manufacturers Association
5. Duke Energy Ohio, Application for Tariff Approval, Case No. 20-0054-GA-ATA, Representing Retail Energy Supply Association
6. Black Hills Wyoming Gas, Application for Authority to Revise Certain Tariff Provisions, Docket 30026-GA-21, Representing Wyoming Community Gas
7. West Penn Power Company, Default Service Program, Docket P-2021-3030021, Representing the Pennsylvania State University
8. Columbia of PA General Base Rate Increase, Docket R-2021-3025775, Representing the Pennsylvania State University
9. Columbia of PA General Base Rate Increase, Docket R-2020-3018835, Representing the Pennsylvania State University
10. Dominion Energy Ohio Motion, Case No. 18-1419-GA-EXM, Representing Retail Energy Supply Association
11. Aqua America/Peoples Natural Gas Merger, Docket R-2018-3006061, Representing Natural Gas Supplier Parties and Retail Energy Supply Association
12. Peoples Natural Gas General Base Rate Increase, Docket R-2018-3006818, Representing Peoples Industrial Intervenors
13. Duquesne Light Company General Base Rate Increase, Docket R-2018-3000124, Representing the Duquesne Industrial Intervenors
14. Columbia of PA General Base Rate Increase, Docket R-2018-2647577, Representing the Pennsylvania State University
15. West Penn Power Company, Default Service Program, Docket R-2017-2637866, Representing the Pennsylvania State University
16. Vectren Energy Delivery Ohio, Alternative Rate Plan, Case No. 18-0049-GA-ALT, Representing Retail Energy Supply Association
17. Columbia of PA Gas Cost Increase, Docket R-2017-2591326, Representing the Pennsylvania State University
18. West Penn Power Company, General Base Rate Increase, Docket R-2016-2537359, Representing the Pennsylvania State University
19. Columbia of PA General Base Rate Increase, Docket R-2016-2529660, Representing the Pennsylvania State University
20. UGI Utilities General Base Rate Increase, Docket R-2015-2518438, Representing Dominion Retail, Inc., Shipley, Choice, LLC, Interstate Gas Supply, Inc., Amerigreen Energy, and Rhoads Energy
21. Columbia of PA General Base Rate Increase, Docket R-2015-2468056, Representing the Pennsylvania State University
22. West Penn Power Company, General Base Rate Increase, Docket R-2014-2428742, Representing the Pennsylvania State University
23. Herman Oil & Gas Company, General Base Rate Increase, R-2014-2414379, Representing Herman Oil & Gas Company
24. Columbia of PA General Base Rate Increase, Docket R-2014-2406274, Representing the Pennsylvania State University
25. Ameren Gas- General Base Rate Increase, Docket No. 13-0192, Representing Dominion Retail and Interstate Gas Supply of Illinois
26. Columbia of PA General Base Rate Increase, Docket R-2012-2321748, Representing the Pennsylvania State University, Dominion Retail, Interstate Gas Supply, and Shipley Energy
27. Columbia of PA Petition for Approval of a Distribution System Improvement Charge Docket R-2012-2338282, Representing the Pennsylvania State University
28. PUC PA Generic Investigation Regarding Gas-On-Gas Competition, Docket No. P-2011-2277868, Representing the Pennsylvania State University
29. Ameren Gas- General Base Rate Increase, Docket 11-0282 (Cons.), Representing Dominion Retail and Interstate Gas Supply of Illinois
30. Water and Power Authority (USVI)- Electric Base Rate Case, Docket 575, June 2009, Representing Frenchman's Reef Marriott
31. Water and Power Authority (USVI)- Water Base Rate Case, Docket 576, June 2009, Representing Frenchman's Reef Marriott

32. Public Service of New Mexico 2010 Base Rate Case, Informal rate design workshops pursuant to the stipulation in NMPRC Case No. 08-00273-UT, Representing City of Albuquerque
33. Public Service of New Mexico, Electric base case at Case No. 08-00273-UT, Representing City of Albuquerque
34. Public Service of New Mexico 2009 Renewable Energy Procurement Plan for 2010, Case No. 09-00260-UT, Representing City of Albuquerque and Santa Fe County
35. Public Service of New Mexico, Gas sale case at Case No. 08-00078-UT, Representing City of Albuquerque
36. UGI Utilities, Central Penn Gas, Penn Natural Gas, Gas Cost Increase, Docket No. R-2011-2238953, Representing Shipley Energy, Rhodes Energy, and CenterPoint Energy
37. UGI Utilities- Gas Division, Gas Cost Increase, Docket No. R-2010-2172933, Representing Shipley Energy
38. Columbia of PA General Base Rate Increase, Docket R-2010-2215623, Representing the Pennsylvania State University, Dominion Retail, Interstate Gas Supply, and Shipley Energy
39. Columbia of PA General Base Rate Increase, Docket R-2009-2149262, Representing the Pennsylvania State University, Dominion Retail, Interstate Gas Supply, and Shipley Energy
40. Columbia of PA General Base Rate Increase, Docket R-2008-2011621, Representing Hess Energy, Dominion Retail, Interstate Gas Supply, and Shipley Energy
41. Columbia of PA Gas Cost Increase, Docket R-2008-2028039, Representing Dominion Retail, Interstate Gas Supply, and Shipley Energy
42. PPL Electric Utilities Voluntary Purchase of Accounts Receivables Program and Merchant Function Charge, Docket No. P-2009-2129502
43. Nicor Gas Company, Provision of facilities and services and the transfer of assets between Nicor Gas Company and Nicor Inc., Docket No. 09-0301, Representing Dominion Retail
44. North Shore Gas and Peoples Gas Light and Coke Company, General Base Rate Increase, Dockets 09-0166 and 09-0167, Representing Dominion Retail, Interstate Gas Supply and Nicor Advanced Energy
45. Nicor Gas Company, Base Rate Increase, Docket No. 08-0363, Representing Interstate Gas Supply and Dominion Retail
46. North Shore Gas and Peoples Gas Light and Coke Company, General Base Rate Increase, Dockets 07-0241 and 07-0242, Representing Dominion Retail, Interstate Gas Supply and U.S. Energy Savings
47. WPS Resources, Peoples Energy, Peoples Gas Light and Coke Company, North Shore Gas Company, Application pursuant to Section 7-204 of the Public Utilities Act for authority to engage in a Reorganization, Docket 06-0540, Representing Dominion Retail, Interstate Gas Supply, US Energy Savings, MxEnergy, and Direct Energy Services.
48. Allegheny Energy, Approval of Retail Electric Default Service Program and Competitive Procurement Plan, Docket No. P-2008-2021608, Representing the Pennsylvania State University
49. Allegheny Energy, Generation Rate Cap, Docket No. P-2007-2001828, Representing the Pennsylvania State University
50. Equitable Gas Company, Rate Increase, Docket R-2008-2029325, Representing Independent Oil & Gas Association and Hess Corp.
51. Equitable Gas Company and Peoples Gas, Merger Case, Docket A-122250F5000, Representing National Energy Marketers, Hess Corporation, and Constellation New Energy.

Exhibit JLC-2

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 1

Question No. PSU 1-001:

Provide all documents or manuals used to determine sizing of distribution system piping in new construction. Explain any differences in procedures that depend on customer classification (residential, commercial, industrial)

Response:

In general, sizing mainlines within our distribution systems is based upon many factors. They include: the MAOP (maximum allowable operating pressure), the normal operating pressure, the minimum operating pressure (under peak conditions), the delivery pressure requested on behalf the customer, the length of main, and of course connected load information (typically in terms of Mcfh - 1000 cubic foot per hour).

Columbia Gas of PA, Inc., will determine the size mainline to be utilized based on flow guidelines provided per our Gas Standards. See PSU 1-001 HIGHLY CONFIDENTIAL Attachment A to this response. There are different criteria used dependent on the pressure range of our operating systems, to minimize pressure drop, so we can meet the new load demand, as well as the demands of our current customers. Columbia will also determine if the main should be comprised of medium and high density plastic , or steel, depending on the MAOP or capacity needed.

Also, Synergi, Columbia's software modeling software (which models our systems) is used to confirm recommendations of sizing mainlines, to help ensure safe and reliable service to all our customers.

These same processes and procedures apply to residential, commercial, and industrial accounts.

Columbia Gas of Pennsylvania, Inc.

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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 1

Question No. PSU 1-002:

Provide forms, or screenshots of data collection, that are used to initiate a new construction project for a residential customer.

Response:

For a new construction project for a residential customer, the data collection occurs over the phone in our New Business center or via an online form submission https://www.columbiagaspa.com/partner-with-us/builders-and-and-developers. Whether by phone or form submission, the following data is collected to initiate new service:

- Where is the house line stubbed or marked? Left/right/other-specify
- What delivery pressure is needed at the meter outlet?
  - 7" W.C. (standard delivery pressure)
  - 2 PSI
- What is the approximate distance in feet from the property line to the meter location?
- Is the construction site within 6" of final grade with foundation backfilled?
- What is the total BTU load?
- Are there any obstructions that would hinder the service line installation?
- Are private utilities marked?

Columbia Gas of Pennsylvania, Inc.

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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 1

Question No. PSU 1-006:

Explain the process of determining the connected load used when initiating service with a commercial customer moving into an existing facility. Explain once connected load is determined how connected load is considered in the determination of meter size and service line size.

Response:

The connected load of a customer moving into an existing facility would be based upon the total rating (either in BTUs - British Thermal Units, or cubic feet of gas per hour) of the gas appliances to be used by the customer. This information is provided to Columbia Gas of PA, Inc., by the customer.

Once the load information has been determined, the service line would be sized based upon the factors identified in the response to PSU 1-001.

In general, sizing the meter would utilize the same factors as listed above, with the exception of length. Per the manufacturer's specifications of what meters Columbia use, the meter would be sized accordingly based upon the pressure going through the meter to accurately measure the load requested by the customer.

Columbia Gas of Pennsylvania, Inc.

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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 1

Question No. PSU 1-011:

Explain how Columbia determines total BTU load during engineering work associated with customer connections and pipeline sizing? What does a customer have to do to obtain such information?

Response:

For engineering work associated with a proposed new customer connection and pipeline sizing, the total BTU load is provided to Columbia Gas of PA, Inc. by the customer. It is typically in the form of BTUs (British Thermal Units) or cubic feet of gas per hour.

For engineering work associated with existing loads and pipeline sizing, Field Engineers use Synergi Gas, Columbia's modeling software program (which models our pipeline systems), to assist in sizing mainlines, to help ensure safe and reliable service to all our customers.

This load information (in Synergi Gas) is in terms of Mcfh (thousand cubic feet of gas per hour) and is based on current usage of our existing customers and any new information provided Columbia (such as proposed new loads mentioned above). Our particular model is distinct to Columbia's pipeline system and is proprietary. This information is not provided to customers.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 3

Question No. PSU 3-001:

Regarding Standard Data Request Question No. GASCOS-004:

a. Indicate the pipe diameters that serve customers in the LDS/LGSS rate class.
b. From data determined in subpart (a), indicate the number of LDS/LGSS customers attached to main(s) less than 3" in diameter. For each customer, indicate the Quantity (Feet) and Amount ($)
c. Provide the average cost per foot for pipe sizes attached to LDS/LGSS customers. Explain the calculation. If inclusion of customer(s) identified in subpart (b) does not significantly impact the calculation, please explain.

Response:

a. The mains investment by pipe diameter information shown on GASCOS-004 was pulled from the Company's plant accounting system. The Company's plant accounting system does not differentiate plant information, including mains data, by rate class. However, it can be determined that all customers, with the exception of a few mains from four LDS customers, that make up the LDS/LGSS rate class are attached to either 3" or greater diameter pipe.

b. There are four customers whose consumption is at least partially served from a 2" main. Two of these customers have a total of 14 secondary meters off their primary account. Because the Company's plant accounting system does not differentiate plant information, including mains data, by individual customer, Quantity (Feet) and Amount ($) of the 2" mains attached to each of these customers is not available.

c. From the information in GASCOS-004, the sum of 3" and greater diameter pipe is 25,780,275 feet and $1,693,771,400 resulting in an average cost per foot of $65.70 for 3" and greater diameter pipe. This average cost per foot can be used to

reasonably estimate the mileage of mains pipe assigned to the LDS/LGSS rate class without including the 2" pipe attached to the four LDS customers discussed above.

The inclusion of the customers identified in subpart (b) does not significantly impact the calculation because the 4 LDS/LGSS rate class customers served off of 2" pipe, only received 113,494 Dth of their total usage from the 2" pipe of which these customers were attached to. It is important to note that 113,494 Dth represents less than 1% of the 11,495,611 Dth for the total LDS/LGSS rate class as shown on Exhibit KLJ-2, Page 4, Line 1, to Witness Johnson's Direct Testimony.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 3

Question No. PSU 3-002:

In the Peak & Average COSS:

a. What was the mains cost allocated to the LDS/LGSS class?
b. How many miles of mains were allocated to the LDS/LGSS customer class.
c. How many customers are in the LDS/LGSS class and what is the average assignment of miles of mains per customer?

Response:

a. As shown on Exhibit 111, Schedule 2, Page 3, Lines 19-24, the LDS/LGSS class was allocated the following mains gross plant investment:

- $345,074,107 in Gross Plant Account 376.00 – Mains (Line 19),
- $2,570,242 in Gross Plant Account 376.08 – Mains CSL Replacements (Line 21),
- $3,981,559 in Gross Plant Account 376.30 – Mains Bare Steel (Line 22), and
- $1,313 in Gross Plant Account 376.80 – Mains Cast Iron (Line 24),
- Total Mains Gross Plant $351,627,221 allocated to LDS/LGSS

The $351,627,221 in mains gross plant investment allocated to the LDS/LGSS class represents 10.929% of total mains gross plant investment ($3,217,304,248) in the Peak & Average Allocated Cost of Service Study.

b. In the Peak & Average Allocated Cost of Service Study, mains costs are allocated based on allocation factor 5, not the amount of miles servicing each customer class. Allocation factor 5 assigns mains costs to each rate schedule based on an equal weighting of design day and annual throughput. Please see Page 4 on Exhibit KLJ-2 to Witness Johnson's Direct Testimony detailing the calculation of allocation factor 5.

c. Please see Page 5 on Exhibit KLJ-2 to Witness Johnson's Direct Testimony showing the average number of customers in each rate class. The LDS/LGSS customer class has 80 customers (see Page 5, Line 19, on Exhibit KLJ-2). As noted above, the number of miles servicing each customer class is not used to allocate costs in the Peak & Average Allocated Cost of Service Study. However, dividing $351,627,221 by the average cost per foot of $65.70 for 3" and greater diameter pipe would result in the assignment of 5,351,989 feet or about 1,014 miles of mains pipe to the LDS/LGSS class. Dividing the 1,014 miles of mains pipe assigned to the LDS/LGSS rate class by the 80 customers that make up the LDS/LGSS rate class results in the assignment of approximately 13 miles of mains for each LDS/LGSS customer.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 3

Question No. PSU 3-003:

In the Customer-Demand COSS:

a. What was the mains cost allocated to the LDS/LGSS class?
b. How many miles of mains were allocated to the LDS/LGSS customer class.
c. How many customers are in the LDS/LGSS class and what is the average assignment of miles of mains per customer?

Response:

a. As shown on Exhibit 111, Schedule 1, Page 3, Lines 19-24, the LDS/LGSS class was allocated the following mains gross plant investment:

- $97,118,341 in Gross Plant Account 376.00 – Mains (Line 19),
- $724,512 in Gross Plant Account 376.08 – Mains CSL Replacements (Line 21),
- $1,122,341 in Gross Plant Account 376.30 – Mains Bare Steel (Line 22), and
- $370 in Gross Plant Account 376.80 – Mains Cast Iron (Line 24),
- Total Mains Gross Plant of $99,118,341 allocated to LDS/LGSS

The $99,118,341 in mains gross plant investment allocated to the LDS/LGSS class represents 3.081% of total mains gross plant investment ($3,217,304,248) in the Customer/Demand Allocated Cost of Service Study.

b. In the Customer/Demand Allocated Cost of Service Study, mains costs are allocated based on allocation factor 20, not the amount of miles servicing each customer class. Allocation factor 20 assigns mains costs to each rate schedule based on a design day (demand component) and customers (customer component). A minimum 2” system approach is used to determine the customer related cost component of mains. 54.901% was determined to be the customer component based on the minimum 2” system approach. Please see Page 7 on Exhibit KLJ-1 and Page 31 on Exhibit KLJ-2

to Witness Johnson's Direct Testimony with information detailing the calculation of allocation factor 20.

c. Please see Page 31 on Exhibit KLJ-2 to Witness Johnson's Direct Testimony showing the average number of customers in each rate class and how those customer counts were used in the calculation of allocation factor 20. The LDS/LGSS customer class has 80 customers (see Page 31, Line 6, on Exhibit KLJ-2). As noted above, the number of miles servicing each customer class is not used to allocate costs in the Customer/Demand Allocated Cost of Service Study. However, dividing $99,118,341 by the average cost per foot of $65.70 for 3" and greater diameter pipe would result in the assignment of 1,508,644 feet or about 286 miles of mains pipe to the LDS/LGSS class. Dividing the 286 miles of mains pipe assigned to the LDS/LGSS rate class by the 80 customers that make up the LDS/LGSS rate class results in the assignment of approximately 3.6 miles of mains for each LDS/LGSS customer.

Columbia Gas of Pennsylvania, Inc.

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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 3

Question No. PSU 3-005:

Based on data provided in response to Question 4, explain the range of mains extension necessary to connect the 10 largest customers.

Response:

The 10 largest customers are defined by the 10 largest non-MLDS customers Columbia serves based solely on customer throughput. The information in PSU 3-004 (OCA 4-014) shows Columbia was required to extend its system in the range of 170 feet (0.03 miles) of pipe to 7,618 feet (1.4 miles) of pipe to connect its ten largest customers.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 3

Question No. PSU 3-006:

Explain why the Peak & Average COSS allocates an excessive amount of mains cost to the LDS/LGSS class when compared to the Customer-Demand COSS.

Response:

Each of Columbia's customers have a unique cost that contributes to the total cost to serve the rate class in which those customers are included. Obvious distinctions in customer costs are: 1) the distance from the transmission main to the customer meter; 2) the design day capacity of the customer; 3) the age of the pipe; 4) the customer density on the distribution main; 5) the geographic location of the main (urban vs. rural); 6) the number of customers and capacity requirements downstream of the customer; and 7) the operating pressure of the main. All are contributing factors to cost. Not one individual allocated cost of service study accounts for each of these contributing factors, which is why after choosing an ACOSS it is important to analyze the results for reasonableness.

The Peak and Average study assigned average cost of 13 miles of pipe to each of the 80 LDS/LGSS customers. It is reasonable to assume Columbia has not built 13 miles of dedicated mains to each LDS/LGSS customer. Therefore, the Company believes the Peak and Average study along with the Customer/Demand study is better used as an outside limit in the determination of a reasonable range for allocating mains costs.

As noted in Witness Johnson's Direct Testimony (Statement No. 6, Pages 4-5), Columbia has filed two studies in its base rate proceedings since the early 1980s that provide the outside limits of the possible allocations of mains to the various classes of service. The customer-demand study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class, while the peak and average study (Exhibit No. 111, Schedule 2) produces results that are generally more favorable to the residential class. Columbia has in the past submitted that the results of two such studies

provided a reasonable range of returns for use as a guide in establishing appropriate rates. Columbia continues to believe that the two studies provide the reasonable range of returns for use in revenue allocation. However, Columbia recognizes the Commission's preference for the use of the peak and average study, and therefore used the peak and average study as the primary guide for the allocation of the revenue increase in this case. Columbia also filed a third study, as presented in Exhibit No. 111, Schedule 3, which is an average of the customer-demand study and the peak and average study. The average study with its equal weighting of the two studies, provides the Company, the parties and the Commission with another set of returns that can be used as a guide in revenue allocation. In other words, the average study serves as another tool that can be used by the parties to inform the revenue allocation in setting cost-based rates.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 4

Question No. PSU 4-007:

When establishing or transferring service at or to a property, does Columbia provide a notification to the previous or current owner/customer that a service account has been requested to be established or transferred to that property?

a. If so, what notices are provided, how are they provided, and when? Please provide example copies.
b. If not, why not?

Response:

a. The previous or current owner/customer of a service account is provided their final bill statement that includes the "Final Service" notification on the bill. (Please see the Account Profile section of attachment PSU 4-007 Attachment A.) There is no other communication sent to the previous or current owner/customer of that service account.

In terms of when the bill is sent: The final bill goes out following the shutoff service.

In terms of how the bill is sent: If the current owner/customer was signed up for paperless billing, the final service bill will be sent via email to the current owner's/customers' preferred email address. If the current owner/customer is not signed up for paperless billing, the final bill will be sent via USPS mail.

The process for the Start/Initiate order and the Transfer/Move order is different. If there is a Start order, we do not require the new account holder to have the current account holder's personal information at that address as this is the private information of the current account holder. The new account holder does not have the PII (account number, phone number last 4 of SSN, new mailing address, etc.) of the existing account holder when they begin new service. In this case, we do not notify the former resident by

mail at the existing service address because the new account holder does not have/will be unable to provide the new mailing address of the previous account holder/tenant. In the Move service process, the customer who has the existing Columbia Gas account must validate their current account information (Account Number, Phone Number, Last 4 of SSN) in order to remove their name from their existing service address and add the new address to their name. Given this validation of their own account, we do not send a piece of mail/digital notification to the homeowner as they have identified themselves as the original account holder.

b. N/A

Columbia Gas of Pennsylvania
A NiSource Company

Account Number: [redacted]
Statement Date: 12/27/2023
86

Contact Us

Phone
Emergency Service 24/7
1-888-460-4332
For gas leaks or odors of gas

Customer Service
1-888-460-4332
7 a.m. - 7 p.m. Mon. - Fri.

For bill questions or complaints
For hearing-impaired relay call 711.

Web
Make payments and access your account at ColumbiaGasPA.com

Payments 24/7
Pay by check, credit/debit card, PayPal, Amazon Pay, Venmo.
Call 1-866-694-1828 (Paymentus convenience fee may apply)

Mail Payments
Columbia Gas of Pennsylvania
PO BOX 70285
Philadelphia PA 19176-0285

Authorized Payment Locations
Find locations online at ColumbiaGasPA.com

Your Safety

In case of an emergency, such as odor of gas, carbon monoxide or fire:
1. Leave the area immediately.
2. Leave windows and doors in their positions and avoid doing anything that could cause a spark.
3. From a safe area, call **911** and Columbia Gas at **1-888-460-4332.**

Always Call 8-1-1 Before You Dig
If you're planning a home or landscaping project, call PA One Call at 8-1-1 at least three business days before digging. A representative will mark the approximate location of underground utility lines for free.

811 Know what's below. Call before you dig.

Employee Identification
All of our employees and contractors carry photo identification. If someone claims to represent us, ask to see identification. Call the police if you see suspicious activity.

Account Profile

Customer Name: [redacted]

Account Number: [redacted]

Your Contact Information: [redacted]

Type of Customer:
Residential
Final Service
Paperless Billing

- Is your contact information correct? Make all changes on the reverse side.

Account Summary

Previous Amount Due on 01/08/2024	$1,010.67
Payments Received by 12/21/2023 Thank You	-$1,010.67
Balance on 12/26/2023	$0.00
Charges for Gas Service This Period	+$447.77
Current Charges Due by 01/19/2024	**$447.77**

- For more information regarding these charges, see the Detail Charges section.

Financial Support
If you are struggling to pay your bill we can help. Flexible payment plans are available to customers experiencing a financial hardship. Any customer who is having trouble paying their bill should visit ColumbiaGasPA.com or call 1-888-460-4332 to learn about payment arrangements and/or financial assistance programs.

Thank you for being a Columbia Gas customer. We appreciate your business and are pleased to provide the following information as a credit reference.

Customer Name [redacted]

Service Address [redacted]

Period Serviced: 10/17/1995 To 12/25/2023
Credit Rating: Excellent
Best Wishes, Columbia Gas

Usage Summary

Meter Number: [redacted]

Service Address: [redacted]

Meter Readings - 14 Billing Days

Estimated Reading on 12/25		4393
Actual Reading on 12/11	-	4121
Gas Used (Ccf)		**272**
Therm Multiplier	X	1.0664
Total Therms Used (thm)		**290**

▼ Please fold on the perforation below, detach and return with your payment.

Web
ColumbiaGasPA.com

Phone
1-888-460-4332

Account Number: [redacted]
Amount Due by 01/19/2024: $447.77
Amount Enclosed: $.

[redacted]
PO Box 16581
Columbus, OH 43216-6581

Columbia Gas of Pennsylvania
A NiSource Company

00012790 1 SP 0.660
**********SNGLP
[redacted]

Make check payable to:
COLUMBIA GAS
PO BOX 70285
PHILADELPHIA PA 19176-0285

14340736001000000000044777702321

Account Number: 14340736 001 000 0
Statement Date: 12/27/2023
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Helpful Definitions

Customer Charge is a flat charge to cover a portion of the cost of installing, maintaining and replacing Columbia Gas pipelines, meters and other equipment, as well as servicing your account.

Distribution Charges are the service charges for the delivery of natural gas to a retail customer from the point of receipt into the Columbia Gas distribution system.

Estimated Readings are calculated based on your typical monthly usage rather than on an actual meter reading.

Gas Cost Adjustment is the amount billed or credited each month to account for the difference between Columbia's projected and actual gas supply costs.

Gas Supply Charges are the charges for basic natural gas supply service which is billed in therms.

Pass-through Charges are charges that Columbia Gas must pay to third parties for the ability to deliver natural gas to Columbia's system and universal service charges, as applicable.

Therm (thm) is equal to 100,000 BTUs and is used to measure your gas usage.

Therm Multiplier is applied to meter readings to convert the volumetric meter reading into therms for billing.

Legal Information

Public Utility Commission
The Pennsylvania Public Utility Commission (PUC) is the state regulatory agency that provides oversight, policy guidance, and direction of distribution prices and services from Columbia Gas of Pennsylvania and suppliers.

Rate Schedule
Copies of rate schedules are available for inspection upon request. Call 1-888-460-4332 for an explanation of charges and how to verify the accuracy of a bill.

Bankruptcy Notices
Mail to Columbia Gas of Pennsylvania, Revenue Recovery, PO Box 117, Columbus, OH 43216.

Other Correspondence (except payments)
Mail to Columbia Gas of Pennsylvania, P.O. Box 2318, Columbus, OH 43216-2318 or contact us at ColumbiaGasPA.com.

Detail Charges

Rate Schedule RSS

Gas Supply Charges 290 thm at $0.27441 per thm	$79.57
Gas Cost Adjustment 290 thm at -$0.01500 per thm	-$4.35
Supply	**+$75.22**
Customer Charge	$16.75
Distribution Charges 290 thm at $0.91069 per thm	$264.10
Pass-through Charges 290 thm at $0.31258 per thm	$90.65
Energy Efficiency Rider 290 thm at $0.00361 per thm	$1.05
Delivery	**+$372.55**
Total Current Utility Charges	**$447.77**

- Your bill includes $4.94 in state taxes, not including sales tax.

Columbia Gas of Pennsylvania Price to Compare per therm $0.28808
The Price to Compare is the price to use when comparing Columbia's gas cost to gas supply prices offered by other natural gas suppliers in the CHOICE program. This price may change in January, April, July and October each year.

Shopping Information

When shopping for a natural gas supplier, be prepared to provide the following:

Account Number: [redacted]
Rate Schedule: Residential Sales Service

If you are already purchasing gas through a supplier, be aware of your current contract terms and expiration date.

Change Contact Information

By providing Columbia Gas a telephone number, it enables us to call/text you about your utility service, future service appointments and other important information pertaining to your account and you're agreeing to receive autodialed calls/texts and prerecorded voice calls. Please notify us if you wish to opt out or if you no longer use this number. Thank you in advance.

Address

City

State Zip Code

Phone Number

Add or Edit Email

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 4

Question No. PSU 4-010:

Can a customer have an account flagged on Columbia's information technology systems so that gas service at a property address cannot be started, stopped, or transferred without explicit verified permission from authorized users at an existing account address? If yes, please explain how that is done.

Response:

A customer cannot have an account flagged on Columbia's information technology systems so that gas service at a property address cannot be started, stopped, or transferred without explicit verified permission from authorized users at an existing account address.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3046519
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

Corrected
PSU Statement No. 1-R

REBUTTAL TESTIMONY OF JAMES L. CRIST, P.E.
ON BEHALF OF
THE PENNSYLVANIA STATE UNIVERSITY

PUBLIC REDACTED VERSION

Dated: July 11, 2024

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc. I previously presented direct testimony and now I am presenting rebuttal testimony on behalf of The Pennsylvania State University ("Penn State" or "PSU" or the "University").

Q. WHAT ARE THE ISSUES YOU WILL ADDRESS IN THIS REBUTTAL TESTIMONY?

A. I will respond to the several allocated cost of service study ("ACOS" or "COSS"[1]) recommendations made by the Office of Consumer Advocate ("OCA") witness Mr. Mierzwa, the Pennsylvania Public Utility Commission's Bureau of Investigation and Enforcement ("I&E") witness Mr. Sakaya, and the Office of Small Business Advocate ("OSBA") witness Mr. Ewen. Because their views are not based on cost causation, they skew the revenue responsibility, which is unacceptable.

In response to their recommendations, I will also provide additional evidence demonstrating that the Peak & Average ACOS that they prefer is not based on cost causation and produces a result that is so unrealistic it cannot be used to set rates in this proceeding. The Customer-Demand ACOS performed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Columbia Gas" or the "Company"), should be used as a starting point, but actual mains investment must be directly assigned to the LDS/LGSS class. This recommendation is based on cost causation, is valid, and should be utilized to allocate any increase granted by the Commission. In the alternative, should the Commission decide not

[1] Both Allocated Cost of Service ("ACOS") and Cost of Service Study ("COSS") refer to the same thing. Both terms have been used in the testimony of other witnesses, and myself, and in previous Commission recommendations and orders.

to use the Customer-Demand ACOS, the Average ACOS submitted by the Company should be used. Moreover, in any ACOS, because the data now exist regarding the cost of gas mains used by the LDS/LGSS class, that actual data should be used instead of the allocation formula that grossly overstates the cost of gas mains.

Q. WHAT ACOS DID THE COMPANY USE TO DETERMINE THE REVENUE RESPONSIBILITY OF EACH CUSTOMER CLASS?

A. The Company used the Peak & Average ACOS results to determine its revenue allocation proposal in this proceeding, even though, as the Company acknowledged, this methodology heavily favors the residential class. Company witness Mr. Johnson explained:

> Columbia has filed two studies in its base rate proceedings since the early 1980s that provide the outside limits of the possible allocations of mains to the various classes of service. The customer-demand study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class, while the peak and average study (Exhibit No. 111, Schedule 2) produces results that are generally more favorable to the residential class. Columbia has in the past submitted that the results of two such studies provided a reasonable range of returns for use as a guide in establishing appropriate rates. Columbia continues to believe that the two studies provide the reasonable range of returns for use in revenue allocation. However, Columbia recognizes this Commission's preference for the use of the peak and average study, and therefore used the peak and average study as the primary guide for the allocation of the revenue increase in this case.

Columbia Gas Statement No. 6, 4:9-20.

The Company's decision to utilize the Peak & Average ACOS is a departure from the Company's practice in nine previous rate cases from 2008 through 2020 where the Company used its Average ACOS as the basis for determining class rates of return and

revenue allocation.[2] In its 2021 and 2022 base rate cases, the Company departed from its historic practice of utilizing the Average ACOS because in the Company's 2020 base rate case the Administrative Law Judge ("ALJ") identified an error in the Customer-Demand study, finding that the Customer-Demand ACOS would be the preferred method if not for the error. Docket No. R-2020-3018835, R.D. at 394 (Dec. 4, 2020). In my direct testimony, I further explained the ALJ's findings and the changes the Company has made to the Customer-Demand ACOS in this case to address and remove the issue. Based on the ACOSs filed by the Company in this case, the Customer-Demand ACOS should be the basis for revenue allocation as it is the preferred method and the error has since been corrected. PSU Statement No. 1, 13:4-15:2.

Q. WHAT ACOS DID OCA WITNESS MR. MIERZWA RECOMMEND?

A. Mr. Mierzwa recommended the use of the Company's Peak & Average ACOS. In his direct testimony, Mr. Mierzwa reviews the methodologies used in the three ACOSs conducted by the Company. He explains that the investment in distribution mains is allocated differently in two of the ACOSs. In the Customer-Demand ACOS, the cost of mains is allocated to the individual rate classes based on the number of customers in the rate class (the "customer" part of "customer-demand"), and also based on the design peak day demands of the customers in each rate class (the "demand" part of "customer-demand"). OCA Statement No. 5, 6:18-21.

He then describes the Peak & Average method where main investment is allocated 50 percent based on the design peak day demands and 50 percent based on the annual

[2] The Average ACOS is simply an average of the results from the Company's Customer-Demand ACOS and Peak & Average ACOS.

demand, which is the same as total annual throughput. OCA Statement No. 5, 6:21-14. He also explained that the Company produced an Average ACOS, which is an average of the Customer-Demand and Peak & Average studies. OCA Statement No. 5, 6:24-26.

Mr. Mierzwa continues his testimony explaining that the primary guide for the distribution of revenue was the Company's Peak & Average ACOS because of the Commission's decision at Docket No. R-2020-3018835. He states that he agrees with using the Peak & Average ACOS to determine revenue distribution. OCA Statement No. 5, 7:4 – 9:5.

Q. WHAT IS MR. MIERZWA'S OPINION OF THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. Mr. Mierzwa states that the revenue increase Columbia proposed for customer classes SGSS/DS-1, SGSS/DS-2, SDS/LGSS, and LDS/LGSS customers is not enough and that these customer classes should be allocated an even greater share of the overall revenue increase. Specifically, Mr. Mierzwa wants to increase the SGSS/DS-1 group from $50.7 million to $63.7 million, the SGSS/DS-2 group from $55.9 million to 71.6 million, the SDS/LGSS group from $36.7 million to $45.8 million and the LDS/LGSS group from $27.2 million to $38.3 million, according to his Table 3. Examination of Table 3 shows that Mr. Mierzwa's intention is to increase the LDS/LGSS class by over 40.7% while increasing the residential classes by only 17.3%. *See* OCA Statement No. 5, 12:6-7.

Q. WHAT IS MR. MIERZWA'S REASON FOR WANTING TO SHIFT ADDITIONAL REVENUE RESPONSIBILITY TO THE LDS/LGSS CUSTOMERS?

A. According to Mr. Mierzwa, the Peak & Average method results showed a relative rate of return at present rates for the LDS/LGSS customers of 0.34. OCA Statement No. 5, 12:8-9.

Q. CAN YOU RESPOND TO OCA WITNESS MIERZWA'S CLAIMS REGARDING THE LOW RELATIVE RATE OF RETURN OF THE LDS/LGSS CLASS?

A. The total revenue requirement and the class allocation of revenues in the previous eight rate cases from 2008 through 2018 were determined through a settlement process that resulted in "black box" settlements. In such settlements the parties in the case, including the Company, reach agreement on the total revenue increase and how that increase will be allocated to the customer rate classes. It is not specified in the settlements what ACOS was used or what class rates of return were calculated. The resulting class revenue allocations are included as part of the settlement recommendations submitted to the ALJ and then incorporated into the ALJ's recommended decision and generally adopted and approved by the Commission. It is important to note that the parties that represent the interests of the different customer groups (residential, commercial, industrial) all compromise and reach agreement through the give-and-take discussions of the settlement process. "It is the Commission's policy to encourage settlements. In most cases, the parties work diligently to find common grounds upon which to settle the case in whole or part."[3]

In those eight previous base rate cases between 2008 and 2018, the revenue allocations proposed by the Company in its filings were based on the results from the Average ACOS, then further modified by settlement discussions of all the parties, and

[3] Pennsylvania Public Utility Commission A Guide To Utility Ratemaking, James H. Cawley & Norman J. Kennard (2018) at 47.

ultimately approved by the Commission. I have been involved in those discussions and found them to be productive and fair. Unlike those prior settlements, in the Company's 2020 base rate case proceeding, the revenue requirement was fully litigated and, as I described in my direct testimony, the ALJ recommendation for the ACOS methodology was that the Peak & Average ACOS should be used due to some perceived flaws in the preferred method, the Customer-Demand ACOS, which have since been corrected. Subsequently, in the Company's 2021 and 2022 base rate cases, the revenue allocations proposed by the Company were based on the results from the Peak & Average ACOS. However, allocation was ultimately determined by settlement and approved by the Commission.[4] The Commission was clear when approving the 2022 base rate case settlement that the allocation of the rate increase was not based on any particular ACOS: "the revenue allocation under the Non-Unanimous Settlement was a compromise between the Parties' competing revenue allocation proposals, which albeit were guided by the ACCOSS methodology utilized by each Party's expert."

Thus, utilizing the Peak & Average ACOS methodology and comparing it to rates previously developed as part of a settlement to determine relative rates of return compares apples to oranges and is logically inappropriate. When comparing the class rates of return under current rates, which are the product of black box settlements, to the Company's proposal in this rate case, which is based on the Company's Peak & Average ACOS, a method that greatly favors residential customers, it is not surprising that the LDS/LGSS would be shown to have a low relative rate of return. Mr. Mierzwa wants to "fix" that by

[4] Note that OSBA challenged the revenue allocation and rate design provisions in the 2022 Settlement, but the Commission ultimately approved those provisions without modification. Docket Number R-2022-3031211, Opinion and Order at 99 (Dec. 8, 2022).

moving additional revenue responsibility to the LDS/LGSS customers resulting in a 40.7% rate hike, which is twice the overall increase. This is unconscionable. His method is not appropriate because it is not based on cost causation and a 40.7% increase does not demonstrate gradualism, but would indeed be rate shock. If Mr. Mierzwa would have considered the relative rate of return of the LDS/LGSS class using the Customer-Demand COSS his recommendation would be in the opposite direction. Specifically, the relative ROR under current rates in the Customer-Demand ACOS is 2.93 and under proposed rates is 2.65, both are exceptionally high.

Q. IS THE COMPANY'S PROPOSED REVENUE DISTRIBUTION JUST AND REASONABLE?

A. No. It is not reasonable to rely on the Peak & Average ACOS to force exorbitant rate increases onto LDS/LGSS customers. Simply put, the forecasting method of the Peak & Average ACOS produces a result that is so unrealistic it must be disregarded.

In his response to PSU 3-006, Company witness Johnson explains why the Peak & Average COSS assigns an unrealistic cost to the LDS/LGSS class:

> Question No. PSU 3-006:
>
> Explain why the Peak & Average COSS allocates an excessive amount of mains cost to the LDS/LGSS class when compared to the Customer-Demand COSS.
>
> Response:
>
> Each of Columbia's customers have a unique cost that contributes to the total cost to serve the rate class in which those customers are included. Obvious distinctions in customer costs are: 1) the distance from the transmission main to the customer meter; 2) the design day capacity of the customer; 3) the age of the pipe; 4) the customer density on the distribution main; 5) the geographic location of the

> main (urban vs. rural); 6) the number of customers and capacity requirements downstream of the customer; and 7) the operating pressure of the main. All are contributing factors to cost. Not one individual allocated cost of service study accounts for each of these contributing factors, which is why after choosing an ACOSS it is important to analyze the results for reasonableness.
>
> The Peak and Average study assigned average cost of 13 miles of pipe to each of the 80 LDS/LGSS customers. It is reasonable to assume Columbia has not built 13 miles of dedicated mains to each LDS/LGSS customer.

In my direct testimony, I presented the analysis of actual gas mains data provided by Columbia that showed that the Peak & Average COSS had greatly overstated the amount of mains investment allocated to the LDS/LGSS class compared to the amount based on the data of the ten largest LDS/LGSS customers. Specifically, the Peak & Average COSS allocated 13 miles of gas main per customer instead of [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] miles per customer, which is what the actual data demonstrates. The gross over-assignment resulted in an allocation of $351,627,221 of gas mains cost to the LDS/LGSS class, when the amount that should have been assigned, calculated based on data of the ten largest customers, was only $39,753,663.

The impact of this unrealistic result is evident in the Company's proposed increase for the LDS/LGSS customers of 22.2% when compared to the decrease of revenue requirement that I presented in my direct testimony and am updating in this testimony based on new information received through discovery.

Moreover, my position is further supported by the Company's engineering process. As I demonstrated in my direct testimony, when designing and constructing its pipelines, the Company does not consider average demand. Rather, pipeline design and construction, and, therefore, the cost, is based primarily on the number of customers and the peak demand of those customers.

Q. WHAT NEW DATA DEMONSTRATES THE INACCURACY OF THE PEAK & AVERAGE COSS?

A. I have received more comprehensive data from the Company in response to PSU 5-001. I asked the Company to provide for each LDS/LGSS customer, the annual throughput, design day demand, and the distance between the customers' most upstream meter and the meter of the next closest upstream customer. Now instead of calculating the feet of gas mains based on the ten largest customers of the LDS/LGSS group, I am able to calculate the feet of gas mains based on all 80 customers of the LDS/LGSS class. The data show that the longest distance of any LDS/LGSS customer gas mains is only **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** miles and that the average distance for these customers is only **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** miles, a little over **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Yet, in contrast, the Peak & Average COSS would assign 13 miles of gas main to each LDS/LGSS customer, or a total of 1,040 miles, which is clearly wrong. This highlights how unrealistically overstated the Peak & Average COSS assessment of 13 miles ***per LDS/LGSS customer*** is and why the Peak & Average COSS is a misrepresentation of actual costs caused by the LDS/LGSS customer class. More detailed information is included in CONFIDENTIAL Exhibit JLC-1R.

Q. WHAT IS THE ACCURATE AMOUNT OF GAS MAINS COST THAT SHOULD BE ASSIGNED TO THE LDS/LGSS CLASS?

A. Now that accurate data exist for all the customers of the LDS/LGSS class, the calculation of the gas mains investment can be performed and that amount can be allocated to the

LDS/LGSS class by direct assignment in the ACOS. Direct assignment is appropriate and preferable when data exists for all customers of a class. Columbia did direct assignment of gas mains cost for the Mainline class, MDS. Direct assignment must also now be done for LDS/LGSS because the data exists to do so. Gas mains costs can be calculated in a similar manner as I did in my direct testimony. The length of gas mains assigned to the LDS/LGSS class is [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] miles and based on the average cost per foot of main of $65.70, that results in [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] of mains cost that should be used in the COSS.

Q. WHAT IS THE RESULT OF THE COSS USING THE CORRECT MAINS COST THAT IS BASED ON THE ACTUAL MILES OF GAS MAINS USED BY THE LDS/LGSS CUSTOMER CLASS?

A. Similar to the calculations explained in my direct testimony, I used the mains cost of [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in the Company's Customer-Demand COSS[6] and that lowered the rate base of the LDS/LGSS class from $85,515,193 to a more appropriate [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]. To achieve the Company's requested rate of return on rate base of 8.71%, the LDS/LGSS class would need to contribute total revenue of $4,900,000. I recognize this is a reduction from the current class revenue of $27,382,567. To adhere to

[5] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** x $65.70/foot x 5280 ft/mi = **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
[6] Columbia Exhibit 111, Schedule 1. For simplification = **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was entered in Columbia Exhibit 111, Sch. 1, Pg. 3, and Pg. 4, Line 19, and Lines 21, 22, and 24 were set to zero.
[7] Columbia Exhibit 111, Schedule 1, Page 10, Line 21.

the principles expressed in the *Lloyd* decision[8] such a reduction would move to the appropriate class revenue requirement and eliminate the cross-class subsidy that the LGS/LGSS class provides to the other rate classes.

Q. WHAT ACOS DID THE BUREAU OF INVESTIGATION AND ENFORCEMENT WITNESS MR. SAKAYA RECOMMEND?

A. Similar to Mr. Mierzwa in his direct testimony (I&E Statement No. 3), Mr. Sakaya explained that the Company conducted a customer-demand ACOS, a Peak & Average ACOS, and an Average ACOS. I&E Statement No. 3, 15:3-9. He also explained that the allocation of revenue was based on the Peak & Average ACOS, and that is consistent with the Order issued at Docket No. R-2020-3018835, and that he agrees on that basis to use the Peak & Average ACOS. I&E Statement No. 3, 15:18 – 17:5. However, he did not address that the ALJ in that case preferred the Customer-Demand ACOS, and given the correction to the Customer-Demand method here, I strongly disagree with Mr. Sakaya that the Peak& Average ACOS is "consistent" with the prior Commission order adopting the ALJ's decision because the ALJ stated the Customer-Demand method was "preferred" but for the error in that year's study, which, of course, has been corrected in this rate case. Mr. Sakaya did not attempt to allocate additional revenue requirement to the LDS/LGSS customers as Mr. Mierzwa did, and Mr. Sakaya recommended a proportional scale back of revenue assignment if the Commission grants less than the Company's requested increase. I&E Statement No. 3, 23:4-9.

[8] *Lloyd v. Pennsylvania Public Utility Commission*, 904 A.2d 1010 (Pa. Cmwlth. 2004) (*Lloyd*).

Q. WHAT DID OSBA WITNESS MR. EWEN OBSERVE REGARDING COLUMBIA'S ACOS PROCESS?

A. Similar to Mr. Mierzwa and Mr. Sakaya, Mr. Ewen explained the process the Company went through conducting a Customer-Demand ACOS, a Peak & Average ACOS, and an Average ACOS. He stated, "(t)he Company has consistently submitted two alternative ACOS models in its base rate filings stretching back to at least 2008, with a third version that is an average of the two. The models differ only in how mains plan costs are classified and allocated." OSBA Statement No. 1, 11:17-19

Mr. Ewen continues, "The Company's "AVE" model is a simple average of these two methods. It should be recognized that the Company's two methods produce enormously divergent results." OSBA Statement No. 1, 12:7-8.

Q. DOES MR. EWEN AGREE WITH THE COMMISSION'S FINDINGS AT DOCKET NO. R-2020-3018835 REGARDING MAINS ALLOCATION?

A. No. He states, "While we disagree with the Commission's finding regarding mains cost allocation in the 2020 base rate case, I rely generally on the method employed by the Company in its P&A ACOSS for reasons of Commission precedent." OSBA Statement No. 1, 12:18-20. However, in this case the facts have changed. If there was any precedent from that decision, it should be stated in a proper context which is: although the Customer-Demand ACOS would have been preferred, it was not selected due to an error in that years' Customer-Demand study. Here, there are no errors in the Company's Customer-Demand ACOS, and I presented substantial evidence showing that the Customer-Demand ACOS is the only cost of service methodology based on actual cost-causation. The Commission is

not bound by a previous decision made with different facts under different circumstances, particularly given the proper and qualified context of what the ALJ and Commission actually ruled.[9] The Commission said as much in Columbia Gas' 2022 proceeding in response to an OSBA argument that the Commission is required to use the P&A method for allocation Columbia's mains investment:

> We note that even in cases in which the revenue allocation methodology is litigated, a determination regarding which ACCOSS should be used should be determined on a case-by-case basis. We have observed that "the inherent distinctions between utilities and rate cases may result in different methodologies to be reasonable for different reasons. In other words, the best-suited ACCOSS may depend on the circumstances of the situation on a case-by-case basis." *Pa. PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929 (Order entered June 22, 2021), at 230-231.

Docket No. R-2022-3031211, Opinion and Order at 107, fn. 30. Thus, there is nothing preventing the Commission from determining that the Customer-Demand ACOS is the appropriate method to use to set rates in this proceeding.

Q. WHAT IS YOUR SUMMARY OF THE REASONS THE OCA, I&E, AND OSBA WITNESSES OPINE TO USE THE PEAK & AVERAGE ACOS?

A. Mr. Mierzwa, Mr. Sakaya, and Mr. Ewen all based their agreement with the Company using the Peak & Average ACOS on the Commission Order from the 2020 Columbia rate case, an Order based on an ALJ recommendation to use the Peak & Average method even though "Customer Demand COSS would be the preferred method." R.D. at 394.

[9] While I am not a lawyer, I have been advised by counsel that the Commission is not required by law to follow its decisions or "precedent" (a doctrine known as "*stare decisis*"). *PECO Energy Co. v. Pa. Pub. Util. Comm'n*, 791 A.2d 1155, 1166 (Pa. 2002) (*PECO*); *see also Baker v. U.S.*, 338 F. Supp. 331, 336 (Pa. E.D. 1972) ("[I]t is well settled that an administrative body is not bound by the rule of stare decisis, and inconsistency of its holding with prior holdings in and of itself does not make the decision capricious.") The Commission is only required to explain why a different result or conclusion is warranted where it rules differently in like circumstances. *PECO*, 791 A.2d at 1166.

It is important to establish at this point that the Customer-Demand ACOS is the cost of service method that is based on actual cost causation and is the only ACOS that can be used here. As I further explain below, the Customer-Demand ACOS is based on actual cost causation because it appropriately assigns mains expenses based both on the number of customers and peak demand.

Q. WHY SHOULD A PORTION OF MAINS EXPENSE BE ALLOCATED BASED ON THE NUMBER OF CUSTOMERS?

A. Natural gas pipelines are installed to provide service to customers. Unless all the customers are living in one massive apartment building, the distribution pipelines need to be extended across a company's distribution service territory. When more customers are added, more pipelines must be extended. It is a clear causal relationship that establishes why the customer component of the Customer-Demand ACOS is necessary. The Columbia System serves the suburbs of Pittsburgh along with numerous rural regions in Pennsylvania. Thus, the density of customers served by Columbia is less dense than if it served the major urban cities in the Commonwealth. This illustrates the reason that allocation of the cost of distribution mains should be done on a customer basis because customers in the less dense areas require more feet of natural gas distribution mains piping to reach them than customers situated in highly dense urban areas. Cost of gas mains are clearly dependent on the number of customers and installing mains to reach those customers. In the case of Columbia, the primary driver of its recent and current rate filings are the increasing capital costs of its distribution system due to extensions to add additional customers or the accelerated pipe replacement program underway to replace older pipe with new plastic gas

piping. Both of these functions clearly are customer-driven and that supports allocating a portion of the distribution system costs on a customer basis.

Q. WHY SHOULD A PORTION OF MAINS EXPENSE BE ALLOCATED BASED ON PEAK DEMAND AND NOT AVERAGE DEMAND?

A. One of the resources for rate design is the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual (June 1989). The NARUC Manual on pages 23 and 24 states:

> Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

Average demand is based on annual usage and is clearly identified as not appropriate to use as a basis for gas mains allocation. Peak design day demand is the appropriate allocator and the Customer-Demand ACOS is the appropriate study.

Q. IS THERE VALUE AT EXAMINING REGULATORY COMMISSION RULINGS OUTSIDE OF PENNSYLVANIA?

A. Yes. In New York, National Fuel Gas Distribution ("NFGD"), Case No. 16-G-0257, allocated mains based on the number of customer and demand using a regression analysis and the zero-intercept radius methodology stating, "The first step in determining the allocation of Distribution Mains (Plant Account 376) is the split between Customer and

Demand." Direct Testimony of Cost of Service and Rate Design Panel, 29:9-11. The Company performed a regression analysis, which determined that 58.56% of mains investment was customer-related and 41.44% was demand-related. NFGD's customer-demand study was recommended by the Administration Law Judge (R.D. at 5) and adopted by the New York State Public Service Commission (Order at 88) in 2017.

Q. WHAT OTHER BASE RATE CASE DECISION APPROVED PEAK DEMAND FOR A GAS COMPANY'S MAINS ALLOCATION DETERMINANT?

A. The Maryland Public Service Commission ("MDPSC") recognized that distribution mains are demand related and should be allocated to all customers based on each class' contribution to peak demand. On June 13, 2016, the Order was issued in the Baltimore Gas & Electric ("BGE") base rate case No. 9406. The MDPSC approved BGE's ACOS method which bases the allocation on demand, using the non-coincident peak, which is the customer's highest demand during the year. "Distribution mains and associated O&M are classified as demand-related and allocated to all customer classes based on each class' contribution to the winter period total non-coincident peak ("NCP") demand (therms per hour)." Direct Testimony of David E. Greenberg, 31:1-3. This supports my point that in the Customer-Demand ACOS costs should be classified by peak demand, not average demand. The MDPSC reached the same conclusion three years later in BGE's 2019 gas rate case, stating that it "will accept the Staff's approach and its recommended GCOSS[10]". Case No. 9484, Order at 79. The Staff recommended "using the traditional single year Non-Coincident Peak ("NCP") method to determine the allocator for all four of customer

[10] Gas Cost of Service Study

classes." Order at 75, case No. 9484. Notably, the MDPSC declined to adopt the Office of People's Counsel ("OPC") witness Watkin's recommendation of using the Peak & Average cost of service method.

Q. DO OTHER GAS DISTRIBUTION COMPANIES USE A CUSTOMER-DEMAND COST OF SERVICE MODEL?

A. Yes. In New York, Orange & Rockland ("O&R") produced an Embedded Cost of Service Study for its Gas Department in 2016 for its base rate filing, Case No. 14-G-0494, and again in 2021 for its base rate filing, Case No. 21-G-0073. In that study, O&R submitted Exhibit GRP-1, Schedule 1:

> Line 7, Distribution Demand ("Demand Component")
> The Distribution Demand ("Demand Component") consists of the balance of the distribution mains system not allocated to the customer component, and represents fixed costs related primarily to mains. It also includes distribution pressure governors and regulating equipment, used in distributing gas from the sellers to the firm classes of services. These costs are allocated to the firm classes in proportion to their maximum one-hour non-coincident use on a zero-degree day.
>
> Line 8, Distribution Customer ("Customer Component")
> The Distribution Customer ("Customer Component") consists of the distribution mains system that would be required to connect gas customers with a minimum predominant size pipe, regardless of their demand for gas. It is apportioned to the classes based on the number of services for each class.

Again, the Customer-Demand method is the ACOS that is based on cost causation and should be accepted as the ACOS in this proceeding.

Q. IS THERE A STATUTE THAT PROHIBITS THE COMMISSION FROM CONSIDERING NEW METHODS DIFFERENT FROM THE PEAK & AVERAGE ACOS?

A. No. The Commission is free to improve on its past decisions based on new information and considerations. And the Commission must consider the actual facts that are before it in this case. That is why I have misgivings about comments like Mr. Ewen's that precedent dictates the Peak & Average ACOS method. As I explained above, they are wrong.

Q. WHY SHOULD RECOMMENDATIONS OF MR. MIERZWA, MR. EWEN AND MR. SAKAYA TO USE ONLY THE PEAK & AVERAGE COSS TO DETERMINE REVENUE ALLOCATION BE DISREGARDED?

A. Unfortunately, Columbia based its revenue allocation on the recommendation in the only case since 2008 where the allocation was result of litigation, and ignored the other ten base rate cases where revenue allocation was determined by settlement through negotiation and compromise. It used the Peak and Average COSS even though the ALJ herself in the 2020 base rate case proceeding acknowledged that were it not for "errors", the Customer-Demand COSS would be the preferred method. Therefore, in absence of "errors" (there are none in the current Customer-Demand COSS) that study should be the preferred method. Examining the revenue allocations that Mr. Johnson produced using the Customer-Demand study, results in an allocation that is diametrically opposed to the allocation of the Peak & Average study, as illustrated in Table R-1

Table R-1: Comparison of COSS Results
Rate of Return at Current Rates

Class	Columbia P&A	Columbia C-D	Columbia Ave
TOTAL COMPANY	6.130	6.130	6.130
RSS/RDS	7.442	4.538	5.786
SGS/DS-1	6.692	7.032	6.859
SGS/DS-2	6.626	14.986	9.652
SDS/LGSS	6.962	24.063	11.830

LDS/LGSS	2.104	18.011	5.664

This illustrates the drastic differences that result based on which ACOS study is selected.

Q. WHAT IS THE SUMMARY OF YOUR TESTIMONY?

A. Rates must be set based on the cost of service and cost of service is based on cost causation (the "polestar" of cost of service). This is not just my opinion; it is the result spelled out in the Commonwealth Court decision in the *Lloyd* case[11]. In my direct testimony and this rebuttal testimony I identified serious issues with the method used by the Company to determine revenue responsibility. Its Peak & Average COSS that uses average demand (annual throughput) to assign costs is not supported in the actual method Columbia uses to design, engineer, and build its gas pipeline system. The engineering procedures I submitted proved that only the peak demands and the number of customers are the data used by the Company in construction of its distribution system.

Expanding on that, the company has now provided pipeline data on every customer in the LDS/LGSS customer class and that data show that the entire 80-member class is satisfied through [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] miles of gas mains, whereas the Peak & Average COSS indicate it would require over a thousand miles of gas mains[12]. This significant difference proves the Peak & Average COSS produces unrealistic results.

The Customer-Demand cost of service study is the only cost of service study in this case that is based on cost causation, and, therefore, the allocations based on the Customer-Demand ACOS presented by the Company in Exhibit 111, Schedule 1, must be used with

[11] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006)
[12] 80 customers x 13 miles/customer = 1,040 miles

the modifications I have made now that data exist for the actual amount of gas mains for the LDS/LGSS class. Mr. Johnson's recommendation of allocating revenue using a study that does not adhere to cost causation principles must be rejected. Basing revenue allocation on a Commission decision that resulted from an order that was issued during the most bizarre year of the pandemic that skews the historically balanced revenue allocation and burdens all other classes to solely benefit the residential class is wrong. This unjust and unfair situation must be corrected. The Commission must direct that the revenue allocation of the Customer-Demand ACOS as shown in CGPA Exhibit 111, Schedule 1 with my modification to use the actual, known mains costs for the LDS/LGSS class

Q: DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Exhibit JLC-1R

No Public Version Available

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3046519
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

Corrected
PSU Statement No. 1-R

REBUTTAL TESTIMONY OF JAMES L. CRIST, P.E.
ON BEHALF OF
THE PENNSYLVANIA STATE UNIVERSITY

PUBLIC REDACTED VERSION

Dated: July 11, 2024

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc. I previously presented direct testimony and now I am presenting rebuttal testimony on behalf of The Pennsylvania State University ("Penn State" or "PSU" or the "University").

Q. WHAT ARE THE ISSUES YOU WILL ADDRESS IN THIS REBUTTAL TESTIMONY?

A. I will respond to the several allocated cost of service study ("ACOS" or "COSS"[1]) recommendations made by the Office of Consumer Advocate ("OCA") witness Mr. Mierzwa, the Pennsylvania Public Utility Commission's Bureau of Investigation and Enforcement ("I&E") witness Mr. Sakaya, and the Office of Small Business Advocate ("OSBA") witness Mr. Ewen. Because their views are not based on cost causation, they skew the revenue responsibility, which is unacceptable.

In response to their recommendations, I will also provide additional evidence demonstrating that the Peak & Average ACOS that they prefer is not based on cost causation and produces a result that is so unrealistic it cannot be used to set rates in this proceeding. The Customer-Demand ACOS performed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Columbia Gas" or the "Company"), should be used as a starting point, but actual mains investment must be directly assigned to the LDS/LGSS class. This recommendation is based on cost causation, is valid, and should be utilized to allocate any increase granted by the Commission. In the alternative, should the Commission decide not

[1] Both Allocated Cost of Service ("ACOS") and Cost of Service Study ("COSS") refer to the same thing. Both terms have been used in the testimony of other witnesses, and myself, and in previous Commission recommendations and orders.

to use the Customer-Demand ACOS, the Average ACOS submitted by the Company should be used. Moreover, in any ACOS, because the data now exist regarding the cost of gas mains used by the LDS/LGSS class, that actual data should be used instead of the allocation formula that grossly overstates the cost of gas mains.

Q. WHAT ACOS DID THE COMPANY USE TO DETERMINE THE REVENUE RESPONSIBILITY OF EACH CUSTOMER CLASS?

A. The Company used the Peak & Average ACOS results to determine its revenue allocation proposal in this proceeding, even though, as the Company acknowledged, this methodology heavily favors the residential class. Company witness Mr. Johnson explained:

> Columbia has filed two studies in its base rate proceedings since the early 1980s that provide the outside limits of the possible allocations of mains to the various classes of service. The customer-demand study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class, while the peak and average study (Exhibit No. 111, Schedule 2) produces results that are generally more favorable to the residential class. Columbia has in the past submitted that the results of two such studies provided a reasonable range of returns for use as a guide in establishing appropriate rates. Columbia continues to believe that the two studies provide the reasonable range of returns for use in revenue allocation. However, Columbia recognizes this Commission's preference for the use of the peak and average study, and therefore used the peak and average study as the primary guide for the allocation of the revenue increase in this case.

Columbia Gas Statement No. 6, 4:9-20.

The Company's decision to utilize the Peak & Average ACOS is a departure from the Company's practice in nine previous rate cases from 2008 through 2020 where the Company used its Average ACOS as the basis for determining class rates of return and

revenue allocation.[2] In its 2021 and 2022 base rate cases, the Company departed from its historic practice of utilizing the Average ACOS because in the Company's 2020 base rate case the Administrative Law Judge ("ALJ") identified an error in the Customer-Demand study, finding that the Customer-Demand ACOS would be the preferred method if not for the error. Docket No. R-2020-3018835, R.D. at 394 (Dec. 4, 2020). In my direct testimony, I further explained the ALJ's findings and the changes the Company has made to the Customer-Demand ACOS in this case to address and remove the issue. Based on the ACOSs filed by the Company in this case, the Customer-Demand ACOS should be the basis for revenue allocation as it is the preferred method and the error has since been corrected. PSU Statement No. 1, 13:4-15:2.

Q. WHAT ACOS DID OCA WITNESS MR. MIERZWA RECOMMEND?

A. Mr. Mierzwa recommended the use of the Company's Peak & Average ACOS. In his direct testimony, Mr. Mierzwa reviews the methodologies used in the three ACOSs conducted by the Company. He explains that the investment in distribution mains is allocated differently in two of the ACOSs. In the Customer-Demand ACOS, the cost of mains is allocated to the individual rate classes based on the number of customers in the rate class (the "customer" part of "customer-demand"), and also based on the design peak day demands of the customers in each rate class (the "demand" part of "customer-demand"). OCA Statement No. 5, 6:18-21.

He then describes the Peak & Average method where main investment is allocated 50 percent based on the design peak day demands and 50 percent based on the annual

[2] The Average ACOS is simply an average of the results from the Company's Customer-Demand ACOS and Peak & Average ACOS.

demand, which is the same as total annual throughput. OCA Statement No. 5, 6:21-14. He also explained that the Company produced an Average ACOS, which is an average of the Customer-Demand and Peak & Average studies. OCA Statement No. 5, 6:24-26.

Mr. Mierzwa continues his testimony explaining that the primary guide for the distribution of revenue was the Company's Peak & Average ACOS because of the Commission's decision at Docket No. R-2020-3018835. He states that he agrees with using the Peak & Average ACOS to determine revenue distribution. OCA Statement No. 5, 7:4 – 9:5.

Q. WHAT IS MR. MIERZWA'S OPINION OF THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. Mr. Mierzwa states that the revenue increase Columbia proposed for customer classes SGSS/DS-1, SGSS/DS-2, SDS/LGSS, and LDS/LGSS customers is not enough and that these customer classes should be allocated an even greater share of the overall revenue increase. Specifically, Mr. Mierzwa wants to increase the SGSS/DS-1 group from $50.7 million to $63.7 million, the SGSS/DS-2 group from $55.9 million to 71.6 million, the SDS/LGSS group from $36.7 million to $45.8 million and the LDS/LGSS group from $27.2 million to $38.3 million, according to his Table 3. Examination of Table 3 shows that Mr. Mierzwa's intention is to increase the LDS/LGSS class by over 40.7% while increasing the residential classes by only 17.3%. *See* OCA Statement No. 5, 12:6-7.

Q. WHAT IS MR. MIERZWA'S REASON FOR WANTING TO SHIFT ADDITIONAL REVENUE RESPONSIBILITY TO THE LDS/LGSS CUSTOMERS?

A. According to Mr. Mierzwa, the Peak & Average method results showed a relative rate of return at present rates for the LDS/LGSS customers of 0.34. OCA Statement No. 5, 12:8-9.

Q. CAN YOU RESPOND TO OCA WITNESS MIERZWA'S CLAIMS REGARDING THE LOW RELATIVE RATE OF RETURN OF THE LDS/LGSS CLASS?

A. The total revenue requirement and the class allocation of revenues in the previous eight rate cases from 2008 through 2018 were determined through a settlement process that resulted in "black box" settlements. In such settlements the parties in the case, including the Company, reach agreement on the total revenue increase and how that increase will be allocated to the customer rate classes. It is not specified in the settlements what ACOS was used or what class rates of return were calculated. The resulting class revenue allocations are included as part of the settlement recommendations submitted to the ALJ and then incorporated into the ALJ's recommended decision and generally adopted and approved by the Commission. It is important to note that the parties that represent the interests of the different customer groups (residential, commercial, industrial) all compromise and reach agreement through the give-and-take discussions of the settlement process. "It is the Commission's policy to encourage settlements. In most cases, the parties work diligently to find common grounds upon which to settle the case in whole or part."[3]

In those eight previous base rate cases between 2008 and 2018, the revenue allocations proposed by the Company in its filings were based on the results from the Average ACOS, then further modified by settlement discussions of all the parties, and

[3] Pennsylvania Public Utility Commission A Guide To Utility Ratemaking, James H. Cawley & Norman J. Kennard (2018) at 47.

ultimately approved by the Commission. I have been involved in those discussions and found them to be productive and fair. Unlike those prior settlements, in the Company's 2020 base rate case proceeding, the revenue requirement was fully litigated and, as I described in my direct testimony, the ALJ recommendation for the ACOS methodology was that the Peak & Average ACOS should be used due to some perceived flaws in the preferred method, the Customer-Demand ACOS, which have since been corrected. Subsequently, in the Company's 2021 and 2022 base rate cases, the revenue allocations proposed by the Company were based on the results from the Peak & Average ACOS. However, allocation was ultimately determined by settlement and approved by the Commission.[4] The Commission was clear when approving the 2022 base rate case settlement that the allocation of the rate increase was not based on any particular ACOS: "the revenue allocation under the Non-Unanimous Settlement was a compromise between the Parties' competing revenue allocation proposals, which albeit were guided by the ACCOSS methodology utilized by each Party's expert."

Thus, utilizing the Peak & Average ACOS methodology and comparing it to rates previously developed as part of a settlement to determine relative rates of return compares apples to oranges and is logically inappropriate. When comparing the class rates of return under current rates, which are the product of black box settlements, to the Company's proposal in this rate case, which is based on the Company's Peak & Average ACOS, a method that greatly favors residential customers, it is not surprising that the LDS/LGSS would be shown to have a low relative rate of return. Mr. Mierzwa wants to "fix" that by

[4] Note that OSBA challenged the revenue allocation and rate design provisions in the 2022 Settlement, but the Commission ultimately approved those provisions without modification. Docket Number R-2022-3031211, Opinion and Order at 99 (Dec. 8, 2022).

moving additional revenue responsibility to the LDS/LGSS customers resulting in a 40.7% rate hike, which is twice the overall increase. This is unconscionable. His method is not appropriate because it is not based on cost causation and a 40.7% increase does not demonstrate gradualism, but would indeed be rate shock. If Mr. Mierzwa would have considered the relative rate of return of the LDS/LGSS class using the Customer-Demand COSS his recommendation would be in the opposite direction. Specifically, the relative ROR under current rates in the Customer-Demand ACOS is 2.93 and under proposed rates is 2.65, both are exceptionally high.

Q. IS THE COMPANY'S PROPOSED REVENUE DISTRIBUTION JUST AND REASONABLE?

A. No. It is not reasonable to rely on the Peak & Average ACOS to force exorbitant rate increases onto LDS/LGSS customers. Simply put, the forecasting method of the Peak & Average ACOS produces a result that is so unrealistic it must be disregarded.

In his response to PSU 3-006, Company witness Johnson explains why the Peak & Average COSS assigns an unrealistic cost to the LDS/LGSS class:

> Question No. PSU 3-006:
>
> Explain why the Peak & Average COSS allocates an excessive amount of mains cost to the LDS/LGSS class when compared to the Customer-Demand COSS.
>
> Response:
>
> Each of Columbia's customers have a unique cost that contributes to the total cost to serve the rate class in which those customers are included. Obvious distinctions in customer costs are: 1) the distance from the transmission main to the customer meter; 2) the design day capacity of the customer; 3) the age of the pipe; 4) the customer density on the distribution main; 5) the geographic location of the

> main (urban vs. rural); 6) the number of customers and capacity requirements downstream of the customer; and 7) the operating pressure of the main. All are contributing factors to cost. Not one individual allocated cost of service study accounts for each of these contributing factors, which is why after choosing an ACOSS it is important to analyze the results for reasonableness.
>
> The Peak and Average study assigned average cost of 13 miles of pipe to each of the 80 LDS/LGSS customers. It is reasonable to assume Columbia has not built 13 miles of dedicated mains to each LDS/LGSS customer.

In my direct testimony, I presented the analysis of actual gas mains data provided by Columbia that showed that the Peak & Average COSS had greatly overstated the amount of mains investment allocated to the LDS/LGSS class compared to the amount based on the data of the ten largest LDS/LGSS customers. Specifically, the Peak & Average COSS allocated 13 miles of gas main per customer instead of [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] miles per customer, which is what the actual data demonstrates. The gross over-assignment resulted in an allocation of $351,627,221 of gas mains cost to the LDS/LGSS class, when the amount that should have been assigned, calculated based on data of the ten largest customers, was only $39,753,663.

The impact of this unrealistic result is evident in the Company's proposed increase for the LDS/LGSS customers of 22.2% when compared to the decrease of revenue requirement that I presented in my direct testimony and am updating in this testimony based on new information received through discovery.

Moreover, my position is further supported by the Company's engineering process. As I demonstrated in my direct testimony, when designing and constructing its pipelines, the Company does not consider average demand. Rather, pipeline design and construction, and, therefore, the cost, is based primarily on the number of customers and the peak demand of those customers.

Q. WHAT NEW DATA DEMONSTRATES THE INACCURACY OF THE PEAK & AVERAGE COSS?

A. I have received more comprehensive data from the Company in response to PSU 5-001. I asked the Company to provide for each LDS/LGSS customer, the annual throughput, design day demand, and the distance between the customers' most upstream meter and the meter of the next closest upstream customer. Now instead of calculating the feet of gas mains based on the ten largest customers of the LDS/LGSS group, I am able to calculate the feet of gas mains based on all 80 customers of the LDS/LGSS class. The data show that the longest distance of any LDS/LGSS customer gas mains is only **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** miles and that the average distance for these customers is only **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** miles, a little over **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**. Yet, in contrast, the Peak & Average COSS would assign 13 miles of gas main to each LDS/LGSS customer, or a total of 1,040 miles, which is clearly wrong. This highlights how unrealistically overstated the Peak & Average COSS assessment of 13 miles ***per LDS/LGSS customer*** is and why the Peak & Average COSS is a misrepresentation of actual costs caused by the LDS/LGSS customer class. More detailed information is included in CONFIDENTIAL Exhibit JLC-1R.

Q. WHAT IS THE ACCURATE AMOUNT OF GAS MAINS COST THAT SHOULD BE ASSIGNED TO THE LDS/LGSS CLASS?

A. Now that accurate data exist for all the customers of the LDS/LGSS class, the calculation of the gas mains investment can be performed and that amount can be allocated to the

LDS/LGSS class by direct assignment in the ACOS. Direct assignment is appropriate and preferable when data exists for all customers of a class. Columbia did direct assignment of gas mains cost for the Mainline class, MDS. Direct assignment must also now be done for LDS/LGSS because the data exists to do so. Gas mains costs can be calculated in a similar manner as I did in my direct testimony. The length of gas mains assigned to the LDS/LGSS class is [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] miles and based on the average cost per foot of main of $65.70, that results in [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] of mains cost that should be used in the COSS.

Q. WHAT IS THE RESULT OF THE COSS USING THE CORRECT MAINS COST THAT IS BASED ON THE ACTUAL MILES OF GAS MAINS USED BY THE LDS/LGSS CUSTOMER CLASS?

A. Similar to the calculations explained in my direct testimony, I used the mains cost of [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in the Company's Customer-Demand COSS[6] and that lowered the rate base of the LDS/LGSS class from $85,515,193 to a more appropriate [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]. To achieve the Company's requested rate of return on rate base of 8.71%, the LDS/LGSS class would need to contribute total revenue of $4,900,000. I recognize this is a reduction from the current class revenue of $27,382,567. To adhere to

[5] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** x $65.70/foot x 5280 ft/mi = **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.
[6] Columbia Exhibit 111, Schedule 1. For simplification = **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** was entered in Columbia Exhibit 111, Sch. 1, Pg. 3, and Pg. 4, Line 19, and Lines 21, 22, and 24 were set to zero.
[7] Columbia Exhibit 111, Schedule 1, Page 10, Line 21.

the principles expressed in the *Lloyd* decision[8] such a reduction would move to the appropriate class revenue requirement and eliminate the cross-class subsidy that the LGS/LGSS class provides to the other rate classes.

Q. WHAT ACOS DID THE BUREAU OF INVESTIGATION AND ENFORCEMENT WITNESS MR. SAKAYA RECOMMEND?

A. Similar to Mr. Mierzwa in his direct testimony (I&E Statement No. 3), Mr. Sakaya explained that the Company conducted a customer-demand ACOS, a Peak & Average ACOS, and an Average ACOS. I&E Statement No. 3, 15:3-9. He also explained that the allocation of revenue was based on the Peak & Average ACOS, and that is consistent with the Order issued at Docket No. R-2020-3018835, and that he agrees on that basis to use the Peak & Average ACOS. I&E Statement No. 3, 15:18 – 17:5. However, he did not address that the ALJ in that case preferred the Customer-Demand ACOS, and given the correction to the Customer-Demand method here, I strongly disagree with Mr. Sakaya that the Peak& Average ACOS is "consistent" with the prior Commission order adopting the ALJ's decision because the ALJ stated the Customer-Demand method was "preferred" but for the error in that year's study, which, of course, has been corrected in this rate case. Mr. Sakaya did not attempt to allocate additional revenue requirement to the LDS/LGSS customers as Mr. Mierzwa did, and Mr. Sakaya recommended a proportional scale back of revenue assignment if the Commission grants less than the Company's requested increase. I&E Statement No. 3, 23:4-9.

[8] *Lloyd v. Pennsylvania Public Utility Commission*, 904 A.2d 1010 (Pa. Cmwlth. 2004) (*Lloyd*).

Q. WHAT DID OSBA WITNESS MR. EWEN OBSERVE REGARDING COLUMBIA'S ACOS PROCESS?

A. Similar to Mr. Mierzwa and Mr. Sakaya, Mr. Ewen explained the process the Company went through conducting a Customer-Demand ACOS, a Peak & Average ACOS, and an Average ACOS. He stated, "(t)he Company has consistently submitted two alternative ACOS models in its base rate filings stretching back to at least 2008, with a third version that is an average of the two. The models differ only in how mains plan costs are classified and allocated." OSBA Statement No. 1, 11:17-19

Mr. Ewen continues, "The Company's "AVE" model is a simple average of these two methods. It should be recognized that the Company's two methods produce enormously divergent results." OSBA Statement No. 1, 12:7-8.

Q. DOES MR. EWEN AGREE WITH THE COMMISSION'S FINDINGS AT DOCKET NO. R-2020-3018835 REGARDING MAINS ALLOCATION?

A. No. He states, "While we disagree with the Commission's finding regarding mains cost allocation in the 2020 base rate case, I rely generally on the method employed by the Company in its P&A ACOSS for reasons of Commission precedent." OSBA Statement No. 1, 12:18-20. However, in this case the facts have changed. If there was any precedent from that decision, it should be stated in a proper context which is: although the Customer-Demand ACOS would have been preferred, it was not selected due to an error in that years' Customer-Demand study. Here, there are no errors in the Company's Customer-Demand ACOS, and I presented substantial evidence showing that the Customer-Demand ACOS is the only cost of service methodology based on actual cost-causation. The Commission is

not bound by a previous decision made with different facts under different circumstances, particularly given the proper and qualified context of what the ALJ and Commission actually ruled.[9] The Commission said as much in Columbia Gas' 2022 proceeding in response to an OSBA argument that the Commission is required to use the P&A method for allocation Columbia's mains investment:

> We note that even in cases in which the revenue allocation methodology is litigated, a determination regarding which ACCOSS should be used should be determined on a case-by-case basis. We have observed that "the inherent distinctions between utilities and rate cases may result in different methodologies to be reasonable for different reasons. In other words, the best-suited ACCOSS may depend on the circumstances of the situation on a case-by-case basis." *Pa. PUC v. PECO Energy Company – Gas Division*, Docket No. R-2020-3018929 (Order entered June 22, 2021), at 230-231.

Docket No. R-2022-3031211, Opinion and Order at 107, fn. 30. Thus, there is nothing preventing the Commission from determining that the Customer-Demand ACOS is the appropriate method to use to set rates in this proceeding.

Q. WHAT IS YOUR SUMMARY OF THE REASONS THE OCA, I&E, AND OSBA WITNESSES OPINE TO USE THE PEAK & AVERAGE ACOS?

A. Mr. Mierzwa, Mr. Sakaya, and Mr. Ewen all based their agreement with the Company using the Peak & Average ACOS on the Commission Order from the 2020 Columbia rate case, an Order based on an ALJ recommendation to use the Peak & Average method even though "Customer Demand COSS would be the preferred method." R.D. at 394.

[9] While I am not a lawyer, I have been advised by counsel that the Commission is not required by law to follow its decisions or "precedent" (a doctrine known as "*stare decisis*"). *PECO Energy Co. v. Pa. Pub. Util. Comm'n*, 791 A.2d 1155, 1166 (Pa. 2002) (*PECO*); *see also Baker v. U.S.*, 338 F. Supp. 331, 336 (Pa. E.D. 1972) ("[I]t is well settled that an administrative body is not bound by the rule of stare decisis, and inconsistency of its holding with prior holdings in and of itself does not make the decision capricious.") The Commission is only required to explain why a different result or conclusion is warranted where it rules differently in like circumstances. *PECO*, 791 A.2d at 1166.

It is important to establish at this point that the Customer-Demand ACOS is the cost of service method that is based on actual cost causation and is the only ACOS that can be used here. As I further explain below, the Customer-Demand ACOS is based on actual cost causation because it appropriately assigns mains expenses based both on the number of customers and peak demand.

Q. WHY SHOULD A PORTION OF MAINS EXPENSE BE ALLOCATED BASED ON THE NUMBER OF CUSTOMERS?

A. Natural gas pipelines are installed to provide service to customers. Unless all the customers are living in one massive apartment building, the distribution pipelines need to be extended across a company's distribution service territory. When more customers are added, more pipelines must be extended. It is a clear causal relationship that establishes why the customer component of the Customer-Demand ACOS is necessary. The Columbia System serves the suburbs of Pittsburgh along with numerous rural regions in Pennsylvania. Thus, the density of customers served by Columbia is less dense than if it served the major urban cities in the Commonwealth. This illustrates the reason that allocation of the cost of distribution mains should be done on a customer basis because customers in the less dense areas require more feet of natural gas distribution mains piping to reach them than customers situated in highly dense urban areas. Cost of gas mains are clearly dependent on the number of customers and installing mains to reach those customers. In the case of Columbia, the primary driver of its recent and current rate filings are the increasing capital costs of its distribution system due to extensions to add additional customers or the accelerated pipe replacement program underway to replace older pipe with new plastic gas

piping. Both of these functions clearly are customer-driven and that supports allocating a portion of the distribution system costs on a customer basis.

Q. WHY SHOULD A PORTION OF MAINS EXPENSE BE ALLOCATED BASED ON PEAK DEMAND AND NOT AVERAGE DEMAND?

A. One of the resources for rate design is the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual (June 1989). The NARUC Manual on pages 23 and 24 states:

> Demand or capacity costs vary with the quantity or size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers or their annual usage. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size.

Average demand is based on annual usage and is clearly identified as not appropriate to use as a basis for gas mains allocation. Peak design day demand is the appropriate allocator and the Customer-Demand ACOS is the appropriate study.

Q. IS THERE VALUE AT EXAMINING REGULATORY COMMISSION RULINGS OUTSIDE OF PENNSYLVANIA?

A. Yes. In New York, National Fuel Gas Distribution ("NFGD"), Case No. 16-G-0257, allocated mains based on the number of customer and demand using a regression analysis and the zero-intercept radius methodology stating, "The first step in determining the allocation of Distribution Mains (Plant Account 376) is the split between Customer and

Demand." Direct Testimony of Cost of Service and Rate Design Panel, 29:9-11. The Company performed a regression analysis, which determined that 58.56% of mains investment was customer-related and 41.44% was demand-related. NFGD's customer-demand study was recommended by the Administration Law Judge (R.D. at 5) and adopted by the New York State Public Service Commission (Order at 88) in 2017.

Q. WHAT OTHER BASE RATE CASE DECISION APPROVED PEAK DEMAND FOR A GAS COMPANY'S MAINS ALLOCATION DETERMINANT?

A. The Maryland Public Service Commission ("MDPSC") recognized that distribution mains are demand related and should be allocated to all customers based on each class' contribution to peak demand. On June 13, 2016, the Order was issued in the Baltimore Gas & Electric ("BGE") base rate case No. 9406. The MDPSC approved BGE's ACOS method which bases the allocation on demand, using the non-coincident peak, which is the customer's highest demand during the year. "Distribution mains and associated O&M are classified as demand-related and allocated to all customer classes based on each class' contribution to the winter period total non-coincident peak ("NCP") demand (therms per hour)." Direct Testimony of David E. Greenberg, 31:1-3. This supports my point that in the Customer-Demand ACOS costs should be classified by peak demand, not average demand. The MDPSC reached the same conclusion three years later in BGE's 2019 gas rate case, stating that it "will accept the Staff's approach and its recommended GCOSS[10]". Case No. 9484, Order at 79. The Staff recommended "using the traditional single year Non-Coincident Peak ("NCP") method to determine the allocator for all four of customer

[10] Gas Cost of Service Study

classes." Order at 75, case No. 9484. Notably, the MDPSC declined to adopt the Office of People's Counsel ("OPC") witness Watkin's recommendation of using the Peak & Average cost of service method.

Q. DO OTHER GAS DISTRIBUTION COMPANIES USE A CUSTOMER-DEMAND COST OF SERVICE MODEL?

A. Yes. In New York, Orange & Rockland ("O&R") produced an Embedded Cost of Service Study for its Gas Department in 2016 for its base rate filing, Case No. 14-G-0494, and again in 2021 for its base rate filing, Case No. 21-G-0073. In that study, O&R submitted Exhibit GRP-1, Schedule 1:

> Line 7, Distribution Demand ("Demand Component")
> The Distribution Demand ("Demand Component") consists of the balance of the distribution mains system not allocated to the customer component, and represents fixed costs related primarily to mains. It also includes distribution pressure governors and regulating equipment, used in distributing gas from the sellers to the firm classes of services. These costs are allocated to the firm classes in proportion to their maximum one-hour non-coincident use on a zero-degree day.
>
> Line 8, Distribution Customer ("Customer Component")
> The Distribution Customer ("Customer Component") consists of the distribution mains system that would be required to connect gas customers with a minimum predominant size pipe, regardless of their demand for gas. It is apportioned to the classes based on the number of services for each class.

Again, the Customer-Demand method is the ACOS that is based on cost causation and should be accepted as the ACOS in this proceeding.

Q. IS THERE A STATUTE THAT PROHIBITS THE COMMISSION FROM CONSIDERING NEW METHODS DIFFERENT FROM THE PEAK & AVERAGE ACOS?

A. No. The Commission is free to improve on its past decisions based on new information and considerations. And the Commission must consider the actual facts that are before it in this case. That is why I have misgivings about comments like Mr. Ewen's that precedent dictates the Peak & Average ACOS method. As I explained above, they are wrong.

Q. WHY SHOULD RECOMMENDATIONS OF MR. MIERZWA, MR. EWEN AND MR. SAKAYA TO USE ONLY THE PEAK & AVERAGE COSS TO DETERMINE REVENUE ALLOCATION BE DISREGARDED?

A. Unfortunately, Columbia based its revenue allocation on the recommendation in the only case since 2008 where the allocation was result of litigation, and ignored the other ten base rate cases where revenue allocation was determined by settlement through negotiation and compromise. It used the Peak and Average COSS even though the ALJ herself in the 2020 base rate case proceeding acknowledged that were it not for "errors", the Customer-Demand COSS would be the preferred method. Therefore, in absence of "errors" (there are none in the current Customer-Demand COSS) that study should be the preferred method. Examining the revenue allocations that Mr. Johnson produced using the Customer-Demand study, results in an allocation that is diametrically opposed to the allocation of the Peak & Average study, as illustrated in Table R-1

Table R-1: Comparison of COSS Results
Rate of Return at Current Rates

Class	Columbia P&A	Columbia C-D	Columbia Ave
TOTAL COMPANY	6.130	6.130	6.130
RSS/RDS	7.442	4.538	5.786
SGS/DS-1	6.692	7.032	6.859
SGS/DS-2	6.626	14.986	9.652
SDS/LGSS	6.962	24.063	11.830

LDS/LGSS	2.104	18.011	5.664

This illustrates the drastic differences that result based on which ACOS study is selected.

Q. WHAT IS THE SUMMARY OF YOUR TESTIMONY?

A. Rates must be set based on the cost of service and cost of service is based on cost causation (the "polestar" of cost of service). This is not just my opinion; it is the result spelled out in the Commonwealth Court decision in the *Lloyd* case[11]. In my direct testimony and this rebuttal testimony I identified serious issues with the method used by the Company to determine revenue responsibility. Its Peak & Average COSS that uses average demand (annual throughput) to assign costs is not supported in the actual method Columbia uses to design, engineer, and build its gas pipeline system. The engineering procedures I submitted proved that only the peak demands and the number of customers are the data used by the Company in construction of its distribution system.

Expanding on that, the company has now provided pipeline data on every customer in the LDS/LGSS customer class and that data show that the entire 80-member class is satisfied through [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] miles of gas mains, whereas the Peak & Average COSS indicate it would require over a thousand miles of gas mains[12]. This significant difference proves the Peak & Average COSS produces unrealistic results.

The Customer-Demand cost of service study is the only cost of service study in this case that is based on cost causation, and, therefore, the allocations based on the Customer-Demand ACOS presented by the Company in Exhibit 111, Schedule 1, must be used with

[11] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006)
[12] 80 customers x 13 miles/customer = 1,040 miles

the modifications I have made now that data exist for the actual amount of gas mains for the LDS/LGSS class. Mr. Johnson's recommendation of allocating revenue using a study that does not adhere to cost causation principles must be rejected. Basing revenue allocation on a Commission decision that resulted from an order that was issued during the most bizarre year of the pandemic that skews the historically balanced revenue allocation and burdens all other classes to solely benefit the residential class is wrong. This unjust and unfair situation must be corrected. The Commission must direct that the revenue allocation of the Customer-Demand ACOS as shown in CGPA Exhibit 111, Schedule 1 with my modification to use the actual, known mains costs for the LDS/LGSS class

Q: DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Exhibit JLC-1R

No Public Version Available

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3046519
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

PSU Statement No. 1-SR

SURREBUTTAL TESTIMONY OF JAMES L. CRIST, P.E.
ON BEHALF OF
THE PENNSYLVANIA STATE UNIVERSITY

PUBLIC REDACTED VERSION

Dated: July 25, 2024

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc. I previously presented direct and rebuttal testimony and now I am presenting surrebuttal testimony on behalf of The Pennsylvania State University ("Penn State" or "PSU" or the "University").

Q. WHAT ARE THE ISSUES YOU WILL ADDRESS IN THIS SURREBUTTAL TESTIMONY?

A. I will respond to the rebuttal testimony of Mr. Kempic and Mr. Johnson presented on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"). I will also respond to the rebuttal testimonies of the Office of Consumer Advocate ("OCA") witness Mr. Mierzwa and the Office of Small Business Advocate ("OSBA") witness Mr. Ewen.

In summary, the Customer-Demand Cost of Service Study (COSS) is based on cost causation, is valid, and should be utilized as the starting point for revenue allocation. However, as I previously discussed, the Customer-Demand COSS must be further modified so that actual mains investment is directly assigned to the LDS/LGSS class, rather than by formulaic allocation. In the alternative, should the Commission decide not to use the Customer-Demand ACOS, the Average ACOS submitted by the Company should be used. Moreover, in any ACOS, because the data now exist regarding the cost of gas mains used by the LDS/LGSS class, that actual data should be used instead of the allocation formula that grossly overstates the cost of gas mains.

Lastly, while I previously recommended that the LDS/LGSS receive a rate decrease based on my modified COSS results, I am now recommending that the LDS/LGSS rates be kept the same since it is general Commission practice that no rate class receive a rate

decrease when other rate classes are receiving a rate increase. The revenue increase allocated to the LDS/LGSS class under the Company's proposal should be assigned to the other rate classes on a proportional basis.

Q. DID COLUMBIA GAS PRESIDENT MR. KEMPIC PROVIDE SUPPORT FOR THE USE OF THE CUSTOMER-DEMAND COSS?

A. Yes. Mr. Kempic provided additional evidence that the distribution system is designed based on design peak day demand, which is a basis of allocation used in the Customer-Demand COSS. Mr. Kempic also provided additional evidence that the Company does not design the distribution system based on annual or average demand, which is a basis of allocation used in the Peak and Average COSS. By way of background, in my direct testimony, I provided significant evidence that the gas distribution system is designed based on the number of customers and the forecast peak demand. I submitted Columbia's engineering and design procedures that demonstrated that the Company does not use annual demand (also known as "average demand") but instead uses the design peak day demand to plan, design, engineer, and construct the gas mains and ancillary equipment of its distribution system. In Mr. Kempic's rebuttal testimony (Statement 1-R) he reinforces my point, stating:

> "It is important to recognize that a gas utility's delivery service costs (i.e. non-gas costs) are fixed costs that do not vary with throughput. A gas utility designs and installs a distribution system that is capable of meeting its customers' design day requirements at the time of initial installation. These facilities include the city gate, mains and pressure regulating facilities, services, and meters all designed to meet the design day requirements of the gas utility's customers. Placing these facilities in service permits the gas utility to serve the changes in load due to extreme weather (the design day peak load) or the prevailing economic conditions. Once facilities are installed

> to serve customers, the costs associated with these facilities are by their nature fixed and do not vary as a function of the volume of gas consumed by customers. In other words, when Columbia invests a million dollars to replace a pipe (for instance), that cost exists regardless of how much gas is delivered through that pipe;" *id*. 2:19-3:12

The Peak & Average COSS bases cost allocation on the volume of gas consumed by customers, and Mr. Kempic points out clearly that such usage has no bearing on the cost of the gas distribution system. He emphasizes that the design and installation of Columbia's distribution system is based on design day peak load requirements, and that is what the Customer-Demand COSS bases cost allocations on. The Customer-Demand COSS is the only COSS whose basis is cost causation.

Q. WHAT DID COMPANY WITNESS MR. JOHNSON DISCUSS?

A. Mr. Johnson does state that the "error" in the Customer-Demand COSS identified by the ALJ in the 2020 rate case regarding the separation by operating pressure of customers, design day volumes, and throughput was not repeated in this proceeding. That "error" was the reason that the Peak & Average COSS was ultimately selected by the ALJ and Commission over the Customer-Demand COSS for allocation of costs in the Company's 2020 rate case. Mr. Johnson also agrees that Columbia has not built 13 miles of dedicated mains to each LDS/LGSS customer as the Peak & Average study allocated. This overallocation of gas mains by the Peak & Average study is my largest concern with that study, as it grossly overstates the amount of distribution system costs allocated to the LDS/LGSS customers.

Mr. Johnson does state that the Commission should consider the Peak & Average COSS, the Customer-Demand COSS, and the Average COSS because each COSS serve as

useful reference points in guiding revenue allocation. He states, "the Company believes the use of the three studies is appropriate." (Statement 6-R, 8:18).

Q. WAS MR. JOHNSON WILLING TO UPDATE HIS COSS WITH ACTUAL DATA OF THE LENGTH OF MAINS SERVING THE LDS/LGSS CLASS?

A. He was not, and this is a concern. The LDS/LGSS class contains only 80 customers and, through issuance of data requests, I learned the actual distance of gas mains used to supply the 80 LDS/LGSS customers. Cost of service studies should primarily rely on direct allocation of costs if such costs can be reasonably obtained. In the case of the 80 LDS/LGSS customers, Columbia has produced the distances of mains pipe to reach that entire customer group. That data are more accurate than the allocations done by resulting from Mr. Johnson's model. Actual data show that the costs allocated to the LDS/LGSS class are overstated under all three COSSs produced by the Company. The revenue requirement to that class should be reduced accordingly.

Q. WHAT DID MR. JOHNSON CITE AS THE MAXIMUM INCREASE USED BY THE COMMISSION?

A. Mr. Johnson referred to the 2020 rate case (Docket No. R-2020-3018835) and explained that 1.5 times average system increase represents the upper bound for rate gradualism used by the Commission. For that reason, he rejects OCA witness Mierzwa's allocated revenue requirement to the LDS/LGSS class, which assigns 2.0 times the system average increase to the LDS/LGSS class. I agree with Mr. Johnson.

Q. WHAT WERE OCA WITNESS MR. MIERZWA'S CONCERNS ABOUT YOUR REBUTTAL TESTMONY?

A. In OCA Statement No. 5R, Mr. Mierzwa observes that

> "the Company's Customer-Demand cost study allocates distribution mains costs 45 percent based on peak demand and 55 percent based on the number of customers. In the Peak & Average study, distribution mains costs are allocated 50 percent based on peak demand and 50 percent based on annual throughput. Therefore, it is not clear why, if mains are sized based on peak demands as Mr. Crist claims, the Customer-Demand method should be utilized in this case when it results in less of an allocation of mains costs based on peak demand than the Peak & Average method." *id*, 7:2-9

I will make it clear. The Customer-Demand COSS allocates gas mains cost based on the number of customers and the peak demand of the customer classes and both of those components are evidenced by the principles of cost causation. While the Peak & Average method does consider peak demand, which is a cost causer, it also determines cost allocation of distribution system expense based on annual throughput or average demand. Annual throughput or average demand are no basis on which to allocate costs because annual throughput or average demand are not what drives the design of the system and thus the costs of the system. I have provided substantial evidence obtained through data requests concerning Columbia's design, engineering, and construction practices that proves that annual throughput plays no part in the cost of the gas distribution system. The "average" component of the Peak & Average COSS is not an appropriate basis for cost allocation of gas mains. I also cited the rebuttal testimony of Columbia President, Mr. Kempic, who emphasizes that point. Mr. Mierzwa's insistence that the Peak & Average COSS is the only methodology that should be considered should be disregarded.

Q. HOW DO YOU ADDRESS MR. MIERZWA'S COMMENTS ABOUT THE GAS MAINS ALLOCATION?

A. Mr. Mierzwa makes several comments concerning the miles of distribution pipeline or gas mains allocated to the LDS/LGSS class. However, all of his comments have the same fatal flaw, in that they fail to give credibility to actual measured data and instead rely on various cost allocation theories. Forecasted cost allocation must be done when there is an absence of hard data that identifies specific costs and enables assignment of those costs directly to the customer class that caused the costs to be incurred. I will explain how each of his comments try to hang onto theory, but crumbles in the face of hard evidence.

Mr. Mierzwa first alleges that because Columbia collects revenues on a volumetric basis, this proves investment is based on annual throughput. In this example, Mr. Mierzwa has the tail wagging the dog. That is, while Columbia may collect its revenues based on volumetric throughput, that is not proof that gas mains investment is caused by annual throughput. Indeed, in every base rate proceeding, the Company strives to shift revenue collection responsibility out of volumetric-based charges and into fixed charges, knowing that the amount of annual throughput is not how the distribution system was designed, *i.e.,* that the true cost of a customer is largely independent of the amount of gas the customer uses.

Q. HOW DO YOU ADDRESS MR. MIERZWA'S CONCERN REGARDING THE MILES OF GAS MAINS ALLOCATED TO THE LDS/LGSS CLASS?

A. On page 8 of his testimony, Mr. Mierzwa takes issue with my calculation that the Peak & Average study allocates 13 miles of distribution mains to each of the 80 LDS/LGSS

customers and the basis for his disagreement is that the Company's plant accounting system does not differentiate plant information by rate class. I too wanted to obtain class-specific data and issued a data request seeking that information. I obtained the specific plant information for the LDS/LGSS class. Because there are only 80 customers in the class, the Company was able to ascertain the data on each of the 80 customers and provided it in CONFIDENTIAL data response (PSU Set 5-001). I used that customer-specific data in my Rebuttal Testimony to provide a more accurate analysis of the cost of the gas mains actually caused by the 80 LDS/LGSS customers. *See* Exhibit JLC-1R. Mr. Mierzwa ignores the data that exist for the 80 LDS/LGSS customers (*i.e.*, the entire LDS/LGSS class) that show the feet of gas mains pipe installed to provide service to each of the 80 customers. Now that real data are available, it is no longer necessary to guess and rely upon highly inaccurate estimates of how much piping cost should be allocated to the customer class.

Q. MR. MIERZWA REJECTS YOUR USE OF THE AVERAGE COST OF GAS MAINS IN YOUR ANALYSIS TO CALCULATE THE MILES OF MAINS ASSIGNED TO THE LDS/LGSS CLASS. HOW DO YOU RESPOND TO THIS CRITICISM?

A. As I have already explained, I requested and received the actual data for all 80 customers, and I present the data Mr. Johnson provided in his response to PSU 3-002 as Exhibit JLC-1SR. We know that the average distance of gas mains installed in total to the LDS/LGSS class is not 13 miles, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**, not 1,014[1] miles that the Peak & Average model calculated. Mr. Mierzwa cites the average cost per foot of pipe for 6-inch mains and 8-inch mains and claims that those costs, which are greater than the average cost that was provided to me by the Company, show that I have overstated the miles of mains allocated to LDG/LGSS customers, claiming, "if LDS-LGSS customers are served by a 6-inch or 8-inch main, Mr. Crist has overstated the miles of distribution mains allocated to LDS/LGSS customers."[2] I believe Mr. Mierzwa got his thoughts reversed and meant to say that I understated the miles of distribution mains. Regardless, the new data showing the actual distances of the mains used to provide service to the LDS/LGSS customers removes any need to estimate based on allocation of costs. Company witness Mr. Johnson, who provided the data, stated, "The Company agrees with Mr. Crist, and stated its agreement in data request PSU 3-006, that it is reasonable to assume Columbia has not built 13 miles of dedicated mains to each LDS/LGSS customer." (Statement 6-R, 7:2-4)

Q. MR. MIERZWA PRODUCES A MAP OF PENNSYLVANIA THAT IDENTIFIES COLUMBIA'S SERVICE TERRITORY. IS THAT EVIDENCE THAT THERE SHOULD BE 13 MILES OF GAS MAINS NEEDED TO SERVE EACH LDS/LGSS CUSTOMER?

[1] In the data response to PSU 3-002(c). Mr. Johnson states, "Please see Page 5 on Exhibit KLJ-2 to Witness Johnson's Direct Testimony showing the average number of customers in each rate class. The LDS/LGSS customer class has 80 customers (see Page 5, Line 19, on Exhibit KLJ-2). As noted above, the number of miles servicing each customer class is not used to allocate costs in the Peak & Average Allocated Cost of Service Study. However, dividing $351,627,221 by the average cost per foot of $65.70 for 3" and greater diameter pipe would result in the assignment of 5,351,989 feet or about 1,014 miles of mains pipe to the LDS/LGSS class. Dividing the 1,014 miles of mains pipe assigned to the LDS/LGSS rate class by the 80 customers that make up the LDS/LGSS rate class results in the assignment of approximately 13 miles of mains for each LDS/LGSS customer.

[2] OCA Statement 5R, 9:4-6

A. No. Mr. Mierzwa can make estimates, produce maps, or attempt to include other mains costs or transmission line distances in his arguments, but the Company's response to PSU 5-001 is hard data provided by the Company and attested to by Columbia's COSS witness, Mr. Johnson. It shows the distance of gas main that serves the 80 LDS/LGSS customers to be significantly less than what is assigned to LDS/LGSS customers in the Peak & Average COSS. The cost of gas mains is the largest expense of the distribution system, and the large cost allocation to the LDS/LGSS class by the Peak & Average COSS should not be relied on.

Q. HOW HAVE IMPROVMENTS IN DATA MANAGEMENT ENABLED GREATER ACCURACY IN THE COST OF SERVICE STUDY?

A. Data management technology such as the Geographic Information System used by Columbia have allowed it to determine with accuracy the gas mains distances assigned to each of the 80 customers of the LDS/LGSS class. Now that accurate cost details are available it allows for direct assignment of those costs to the customers, and that is the first step of cost allocation. "Costs exclusively incurred on behalf of one customer or class of customers should be directly assigned to that customer or class."[3] After known costs are directly assigned, then the remaining costs can be allocated based on cost causation.

Q. WHAT DO THE DRASTICALLY DIFFERENT OUTPUTS OF THE PEAK & AVERAGE COSS AND THE CUSTOMER-DEMAND COSS INDICATE?

[3] Page 144, A Guide To Utility Ratemaking, James H. Cawley & Norman J. Kennard, Pennsylvania Public Utility Commission

A. I provided substantial evidence in my direct testimony that the Customer-Demand COSS was based on the actual engineering design and construction practices used to build Columbia's distribution system. Mr. Johnson summarized the results of Columbia's COSS in Exhibit KLJ-5, Unitized Returns at Current Rates and Proposed Rate. In Exhibit JLC-2SR, I compare the rates of return at current rates and calculated the difference between the rates of return of the Peak & Average method and the Customer-Demand method and present the absolute value of those differences. Viewing the data this way we can learn several things. It is easy to see that the two COSS methodologies produce drastically different results, and those results show major divergences for the two classes SDS/LGSS and LDS/LGSS. While the smaller customer classes of RSS/RDS, SGS/DS-1, and SGS/DS-2 show differences of 0.06 to 1.35, the SDS/LGSS and LDS/LGSS classes show extreme differences of 2.79 and 2.60, respectively. Mr. Johnson explained in his direct testimony that he views the results of the two studies set a range of reasonableness[4] and that revenue allocation should be done within that range, and produces a third study that averaged the results of the Peak & Average and Customer-Demand studies. The differences in rates of return I present in my Exhibit JLC-2SR show that, for the SDS/LGSS and LDS/LGSS classes, selecting only one of the Company's COSSs as guide for revenue allocation will have markedly different cost allocations than if the other study was chosen. An issue as important as revenue allocation should not be so lopsided due to the selection of a particular COSS. In conducting the Average COSS, Mr. Johnson strives to address this unfairness.

[4] "Columbia continues to believe that the two studies provide the reasonable range of returns for use in revenue allocation" Statement No. 6, 4:16-18

To be clear, the evidence I presented in direct, rebuttal, and surrebuttal testimony prove that the only COSS that is based on cost causation is the Customer-Demand study and that is the study that I recommend be used, subject to the modifications I recommended in by rebuttal testimony. However, if the Commission declines to select the Customer-Demand COSS, then it should desire to avoid large swings in revenue and determine the revenue allocations based on the Average COSS. That would mitigate the huge differences in the relative rates of return of the two of the SDS/LGSS and LDS/LGSS customer classes.

Q. WHAT ARE YOUR CONCERNS ABOUT OSBA WITNESS MR. EWEN'S REBUTTAL TESTMONY?

A. Mr. Ewen's rebuttal testimony (OSBA Statement No. 1-R) highlights the issue I just discussed, which is the extreme results obtained for two customer classes when one COSS, in this case the Peak & Average COSS, is selected. Mr. Ewen states, "I agree with Mr. Crist that economies of scale exist for serving larger customers." *Id*., 2:5-6. However, Mr. Ewen relies on the Peak & Average COSS solely because it was used in the previous rate case. He then produces a revenue allocation for the LDS/LGSS customers that almost doubles the results compared to Columbia's proposal, adding over $5 million to the $6.06 million Columbia had assigned, which takes the 22.2% increase to an outrageous 41.0%. He runs roughshod over principles of gradualism which would normally limit a class increase to 1.5 times the system increase and proposes a doubling of the increase. Mr. Ewen's recommendation should be rejected.

Q. WHAT IS YOUR RECOMMENED REVENUE INCREASE ALLOCATION?

A. In my direct and rebuttal testimony, I demonstrated that assigning gas mains investments to the LDS/LGSS class based on actual data, not on a theoretical allocation, would produce a revenue decrease to the LDS/LGSS class. I recognize, however, that in base rate cases it is not realistic to expect the Commission would reduce the revenue assignment to one class while increasing revenue responsibility to all other classes. Therefore, my recommended allocation, which I presented as a data response Columbia's Set I to PSU and attached as Exhibit JLC-3SR, provides the revenue increase allocation based on Columbia's updated proposed Revenue Requirement of $123.6 million. If the Commission determines a lesser amount is justified, then I recommend a proportional scale back of revenue responsibility for those customer classes receiving a rate increase.

Q. WHAT IS THE SUMMARY OF YOUR SURREBUTTAL TESTIMONY?

A. There is strong support for the use of the Customer-Demand COSS evidence by testimony of several witnesses. Columbia President Mr. Kempic explained that the gas mains are designed and built based on peak demand, not annual throughput. Columbia cost of service witness, Mr. Johnson, testified that the current Customer-Demand COSS does not contain the "errors" that the Commission found objectionable in its 2020 ruling. He also rejects assigning any customer class a revenue increase greater than 1.5 times the overall system increase. OCA witness Mr. Mierzwa ignores hard evidence concerning gas mains that provide service to each of the 80 customers in the LDS/LGSS class, and wishes that costs were allocated based on model estimates instead of direct allocation, which is not consistent with accepted cost of service practices. OSBA witness Mr. Ewen agrees with me that the Customer-Demand model accurately considers economies of scale, but then

completely ignores the data showing the extreme divergence of the two COSSs to make his own revenue allocation proposal. His revenue allocation proposal violates gradualism by proposing a doubling of the revenue increase allocated to LDS/LGSS.

Evidence concerning cost causation is overwhelming and the Commission should determine revenue responsibility using the results of selected the Customer-Demand COSS, which is based on cost causation - the polestar of cost of service. Because actual data on the cost of gas mains installed to the 80 LDS/LGSS customer class, that cost should be used in any COSS the Commission selects. My recommendation on revenue assignment is presented as Exhibit JLC-3SR.

Q: DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

EXHIBIT JLC-1SR

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
Data Requests

THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 3

Question No. PSU 3-002:

In the Peak & Average COSS:

a. What was the mains cost allocated to the LDS/LGSS class?
b. How many miles of mains were allocated to the LDS/LGSS customer class.
c. How many customers are in the LDS/LGSS class and what is the average assignment of miles of mains per customer?

Response:

a. As shown on Exhibit 111, Schedule 2, Page 3, Lines 19-24, the LDS/LGSS class was allocated the following mains gross plant investment:

- $345,074,107 in Gross Plant Account 376.00 – Mains (Line 19),
- $2,570,242 in Gross Plant Account 376.08 – Mains CSL Replacements (Line 21),
- $3,981,559 in Gross Plant Account 376.30 – Mains Bare Steel (Line 22), and
- $1,313 in Gross Plant Account 376.80 – Mains Cast Iron (Line 24),
- Total Mains Gross Plant $351,627,221 allocated to LDS/LGSS

The $351,627,221 in mains gross plant investment allocated to the LDS/LGSS class represents 10.929% of total mains gross plant investment ($3,217,304,248) in the Peak & Average Allocated Cost of Service Study.

b. In the Peak & Average Allocated Cost of Service Study, mains costs are allocated based on allocation factor 5, not the amount of miles servicing each customer class. Allocation factor 5 assigns mains costs to each rate schedule based on an equal weighting of design day and annual throughput. Please see Page 4 on Exhibit KLJ-2 to Witness Johnson's Direct Testimony detailing the calculation of allocation factor 5.

c. Please see Page 5 on Exhibit KLJ-2 to Witness Johnson's Direct Testimony showing the average number of customers in each rate class. The LDS/LGSS customer class has 80 customers (see Page 5, Line 19, on Exhibit KLJ-2). As noted above, the number of miles servicing each customer class is not used to allocate costs in the Peak & Average Allocated Cost of Service Study. However, dividing $351,627,221 by the average cost per foot of $65.70 for 3" and greater diameter pipe would result in the assignment of 5,351,989 feet or about 1,014 miles of mains pipe to the LDS/LGSS class. Dividing the 1,014 miles of mains pipe assigned to the LDS/LGSS rate class by the 80 customers that make up the LDS/LGSS rate class results in the assignment of approximately 13 miles of mains for each LDS/LGSS customer.

EXHIBIT JLC-2SR

Columbia Gas of Pennsylvania, Inc.
ACOS Study Results

Unitized Returns at Current Rates and Proposed Rates

Exhibit JLC-2SR

Ln.	Study (Mains Allocation Method)	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
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	Difference (P&A-CD)	0.47	0.06	1.36	2.79	2.60	0.00	0.38

EXHIBIT JLC-3SR

Exhibit JLC-3SR

Pennsylvania State University's Revenue Allocation Proposal

	Total	RS/RDS/RC2	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS/NSS	Flex/NCS
Proposed Revenue Allocation - FE PA	$123,662,880	$85,966,865	$11,200,816	$12,347,921	$8,107,229	$6,039,535	($798)	$1,312
Percent Allocation to Rate Classes - FE PA	100.00%	69.51%	9.06%	9.99%	6.56%	4.88%	0.00%	0.00%
Proposed Revenue Allocation- PSU	$123,662,455	$90,367,717	$11,778,615	$12,987,678	$8,528,445	$0	$0	$0
Adjusted Allocation Percentages - PSU	100.00%	73.08%	9.52%	10.50%	6.90%	0.00%	0.00%	0.00%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	Docket No. R-2024-3046519
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

PSU Statement No. 1-SR

SURREBUTTAL TESTIMONY OF JAMES L. CRIST, P.E.
ON BEHALF OF
THE PENNSYLVANIA STATE UNIVERSITY

PUBLIC REDACTED VERSION

Dated: July 25, 2024

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND ON WHOSE BEHALF YOU ARE TESTIFYING.

A. I am James L. Crist, President of Lumen Group, Inc. I previously presented direct and rebuttal testimony and now I am presenting surrebuttal testimony on behalf of The Pennsylvania State University ("Penn State" or "PSU" or the "University").

Q. WHAT ARE THE ISSUES YOU WILL ADDRESS IN THIS SURREBUTTAL TESTIMONY?

A. I will respond to the rebuttal testimony of Mr. Kempic and Mr. Johnson presented on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"). I will also respond to the rebuttal testimonies of the Office of Consumer Advocate ("OCA") witness Mr. Mierzwa and the Office of Small Business Advocate ("OSBA") witness Mr. Ewen.

In summary, the Customer-Demand Cost of Service Study (COSS) is based on cost causation, is valid, and should be utilized as the starting point for revenue allocation. However, as I previously discussed, the Customer-Demand COSS must be further modified so that actual mains investment is directly assigned to the LDS/LGSS class, rather than by formulaic allocation. In the alternative, should the Commission decide not to use the Customer-Demand ACOS, the Average ACOS submitted by the Company should be used. Moreover, in any ACOS, because the data now exist regarding the cost of gas mains used by the LDS/LGSS class, that actual data should be used instead of the allocation formula that grossly overstates the cost of gas mains.

Lastly, while I previously recommended that the LDS/LGSS receive a rate decrease based on my modified COSS results, I am now recommending that the LDS/LGSS rates be kept the same since it is general Commission practice that no rate class receive a rate

decrease when other rate classes are receiving a rate increase. The revenue increase allocated to the LDS/LGSS class under the Company's proposal should be assigned to the other rate classes on a proportional basis.

Q. DID COLUMBIA GAS PRESIDENT MR. KEMPIC PROVIDE SUPPORT FOR THE USE OF THE CUSTOMER-DEMAND COSS?

A. Yes. Mr. Kempic provided additional evidence that the distribution system is designed based on design peak day demand, which is a basis of allocation used in the Customer-Demand COSS. Mr. Kempic also provided additional evidence that the Company does not design the distribution system based on annual or average demand, which is a basis of allocation used in the Peak and Average COSS. By way of background, in my direct testimony, I provided significant evidence that the gas distribution system is designed based on the number of customers and the forecast peak demand. I submitted Columbia's engineering and design procedures that demonstrated that the Company does not use annual demand (also known as "average demand") but instead uses the design peak day demand to plan, design, engineer, and construct the gas mains and ancillary equipment of its distribution system. In Mr. Kempic's rebuttal testimony (Statement 1-R) he reinforces my point, stating:

> "It is important to recognize that a gas utility's delivery service costs (i.e. non-gas costs) are fixed costs that do not vary with throughput. A gas utility designs and installs a distribution system that is capable of meeting its customers' design day requirements at the time of initial installation. These facilities include the city gate, mains and pressure regulating facilities, services, and meters all designed to meet the design day requirements of the gas utility's customers. Placing these facilities in service permits the gas utility to serve the changes in load due to extreme weather (the design day peak load) or the prevailing economic conditions. Once facilities are installed

> to serve customers, the costs associated with these facilities are by their nature fixed and do not vary as a function of the volume of gas consumed by customers. In other words, when Columbia invests a million dollars to replace a pipe (for instance), that cost exists regardless of how much gas is delivered through that pipe;" *id*. 2:19-3:12

The Peak & Average COSS bases cost allocation on the volume of gas consumed by customers, and Mr. Kempic points out clearly that such usage has no bearing on the cost of the gas distribution system. He emphasizes that the design and installation of Columbia's distribution system is based on design day peak load requirements, and that is what the Customer-Demand COSS bases cost allocations on. The Customer-Demand COSS is the only COSS whose basis is cost causation.

Q. WHAT DID COMPANY WITNESS MR. JOHNSON DISCUSS?

A. Mr. Johnson does state that the "error" in the Customer-Demand COSS identified by the ALJ in the 2020 rate case regarding the separation by operating pressure of customers, design day volumes, and throughput was not repeated in this proceeding. That "error" was the reason that the Peak & Average COSS was ultimately selected by the ALJ and Commission over the Customer-Demand COSS for allocation of costs in the Company's 2020 rate case. Mr. Johnson also agrees that Columbia has not built 13 miles of dedicated mains to each LDS/LGSS customer as the Peak & Average study allocated. This overallocation of gas mains by the Peak & Average study is my largest concern with that study, as it grossly overstates the amount of distribution system costs allocated to the LDS/LGSS customers.

Mr. Johnson does state that the Commission should consider the Peak & Average COSS, the Customer-Demand COSS, and the Average COSS because each COSS serve as

useful reference points in guiding revenue allocation. He states, "the Company believes the use of the three studies is appropriate." (Statement 6-R, 8:18).

Q. WAS MR. JOHNSON WILLING TO UPDATE HIS COSS WITH ACTUAL DATA OF THE LENGTH OF MAINS SERVING THE LDS/LGSS CLASS?

A. He was not, and this is a concern. The LDS/LGSS class contains only 80 customers and, through issuance of data requests, I learned the actual distance of gas mains used to supply the 80 LDS/LGSS customers. Cost of service studies should primarily rely on direct allocation of costs if such costs can be reasonably obtained. In the case of the 80 LDS/LGSS customers, Columbia has produced the distances of mains pipe to reach that entire customer group. That data are more accurate than the allocations done by resulting from Mr. Johnson's model. Actual data show that the costs allocated to the LDS/LGSS class are overstated under all three COSSs produced by the Company. The revenue requirement to that class should be reduced accordingly.

Q. WHAT DID MR. JOHNSON CITE AS THE MAXIMUM INCREASE USED BY THE COMMISSION?

A. Mr. Johnson referred to the 2020 rate case (Docket No. R-2020-3018835) and explained that 1.5 times average system increase represents the upper bound for rate gradualism used by the Commission. For that reason, he rejects OCA witness Mierzwa's allocated revenue requirement to the LDS/LGSS class, which assigns 2.0 times the system average increase to the LDS/LGSS class. I agree with Mr. Johnson.

Q. WHAT WERE OCA WITNESS MR. MIERZWA'S CONCERNS ABOUT YOUR REBUTTAL TESTMONY?

A. In OCA Statement No. 5R, Mr. Mierzwa observes that

> "the Company's Customer-Demand cost study allocates distribution mains costs 45 percent based on peak demand and 55 percent based on the number of customers. In the Peak & Average study, distribution mains costs are allocated 50 percent based on peak demand and 50 percent based on annual throughput. Therefore, it is not clear why, if mains are sized based on peak demands as Mr. Crist claims, the Customer-Demand method should be utilized in this case when it results in less of an allocation of mains costs based on peak demand than the Peak & Average method." *id*, 7:2-9

I will make it clear. The Customer-Demand COSS allocates gas mains cost based on the number of customers and the peak demand of the customer classes and both of those components are evidenced by the principles of cost causation. While the Peak & Average method does consider peak demand, which is a cost causer, it also determines cost allocation of distribution system expense based on annual throughput or average demand. Annual throughput or average demand are no basis on which to allocate costs because annual throughput or average demand are not what drives the design of the system and thus the costs of the system. I have provided substantial evidence obtained through data requests concerning Columbia's design, engineering, and construction practices that proves that annual throughput plays no part in the cost of the gas distribution system. The "average" component of the Peak & Average COSS is not an appropriate basis for cost allocation of gas mains. I also cited the rebuttal testimony of Columbia President, Mr. Kempic, who emphasizes that point. Mr. Mierzwa's insistence that the Peak & Average COSS is the only methodology that should be considered should be disregarded.

Q. HOW DO YOU ADDRESS MR. MIERZWA'S COMMENTS ABOUT THE GAS MAINS ALLOCATION?

A. Mr. Mierzwa makes several comments concerning the miles of distribution pipeline or gas mains allocated to the LDS/LGSS class. However, all of his comments have the same fatal flaw, in that they fail to give credibility to actual measured data and instead rely on various cost allocation theories. Forecasted cost allocation must be done when there is an absence of hard data that identifies specific costs and enables assignment of those costs directly to the customer class that caused the costs to be incurred. I will explain how each of his comments try to hang onto theory, but crumbles in the face of hard evidence.

Mr. Mierzwa first alleges that because Columbia collects revenues on a volumetric basis, this proves investment is based on annual throughput. In this example, Mr. Mierzwa has the tail wagging the dog. That is, while Columbia may collect its revenues based on volumetric throughput, that is not proof that gas mains investment is caused by annual throughput. Indeed, in every base rate proceeding, the Company strives to shift revenue collection responsibility out of volumetric-based charges and into fixed charges, knowing that the amount of annual throughput is not how the distribution system was designed, *i.e.,* that the true cost of a customer is largely independent of the amount of gas the customer uses.

Q. HOW DO YOU ADDRESS MR. MIERZWA'S CONCERN REGARDING THE MILES OF GAS MAINS ALLOCATED TO THE LDS/LGSS CLASS?

A. On page 8 of his testimony, Mr. Mierzwa takes issue with my calculation that the Peak & Average study allocates 13 miles of distribution mains to each of the 80 LDS/LGSS

customers and the basis for his disagreement is that the Company's plant accounting system does not differentiate plant information by rate class. I too wanted to obtain class-specific data and issued a data request seeking that information. I obtained the specific plant information for the LDS/LGSS class. Because there are only 80 customers in the class, the Company was able to ascertain the data on each of the 80 customers and provided it in CONFIDENTIAL data response (PSU Set 5-001). I used that customer-specific data in my Rebuttal Testimony to provide a more accurate analysis of the cost of the gas mains actually caused by the 80 LDS/LGSS customers. *See* Exhibit JLC-1R. Mr. Mierzwa ignores the data that exist for the 80 LDS/LGSS customers (*i.e.*, the entire LDS/LGSS class) that show the feet of gas mains pipe installed to provide service to each of the 80 customers. Now that real data are available, it is no longer necessary to guess and rely upon highly inaccurate estimates of how much piping cost should be allocated to the customer class.

Q. MR. MIERZWA REJECTS YOUR USE OF THE AVERAGE COST OF GAS MAINS IN YOUR ANALYSIS TO CALCULATE THE MILES OF MAINS ASSIGNED TO THE LDS/LGSS CLASS. HOW DO YOU RESPOND TO THIS CRITICISM?

A. As I have already explained, I requested and received the actual data for all 80 customers, and I present the data Mr. Johnson provided in his response to PSU 3-002 as Exhibit JLC-1SR. We know that the average distance of gas mains installed in total to the LDS/LGSS class is not 13 miles, **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**, not 1,014[1] miles that the Peak & Average model calculated. Mr. Mierzwa cites the average cost per foot of pipe for 6-inch mains and 8-inch mains and claims that those costs, which are greater than the average cost that was provided to me by the Company, show that I have overstated the miles of mains allocated to LDG/LGSS customers, claiming, "if LDS-LGSS customers are served by a 6-inch or 8-inch main, Mr. Crist has overstated the miles of distribution mains allocated to LDS/LGSS customers."[2] I believe Mr. Mierzwa got his thoughts reversed and meant to say that I understated the miles of distribution mains. Regardless, the new data showing the actual distances of the mains used to provide service to the LDS/LGSS customers removes any need to estimate based on allocation of costs. Company witness Mr. Johnson, who provided the data, stated, "The Company agrees with Mr. Crist, and stated its agreement in data request PSU 3-006, that it is reasonable to assume Columbia has not built 13 miles of dedicated mains to each LDS/LGSS customer." (Statement 6-R, 7:2-4)

Q. MR. MIERZWA PRODUCES A MAP OF PENNSYLVANIA THAT IDENTIFIES COLUMBIA'S SERVICE TERRITORY. IS THAT EVIDENCE THAT THERE SHOULD BE 13 MILES OF GAS MAINS NEEDED TO SERVE EACH LDS/LGSS CUSTOMER?

[1] In the data response to PSU 3-002(c). Mr. Johnson states, "Please see Page 5 on Exhibit KLJ-2 to Witness Johnson's Direct Testimony showing the average number of customers in each rate class. The LDS/LGSS customer class has 80 customers (see Page 5, Line 19, on Exhibit KLJ-2). As noted above, the number of miles servicing each customer class is not used to allocate costs in the Peak & Average Allocated Cost of Service Study. However, dividing $351,627,221 by the average cost per foot of $65.70 for 3" and greater diameter pipe would result in the assignment of 5,351,989 feet or about 1,014 miles of mains pipe to the LDS/LGSS class. Dividing the 1,014 miles of mains pipe assigned to the LDS/LGSS rate class by the 80 customers that make up the LDS/LGSS rate class results in the assignment of approximately 13 miles of mains for each LDS/LGSS customer.

[2] OCA Statement 5R, 9:4-6

A. No. Mr. Mierzwa can make estimates, produce maps, or attempt to include other mains costs or transmission line distances in his arguments, but the Company's response to PSU 5-001 is hard data provided by the Company and attested to by Columbia's COSS witness, Mr. Johnson. It shows the distance of gas main that serves the 80 LDS/LGSS customers to be significantly less than what is assigned to LDS/LGSS customers in the Peak & Average COSS. The cost of gas mains is the largest expense of the distribution system, and the large cost allocation to the LDS/LGSS class by the Peak & Average COSS should not be relied on.

Q. HOW HAVE IMPROVMENTS IN DATA MANAGEMENT ENABLED GREATER ACCURACY IN THE COST OF SERVICE STUDY?

A. Data management technology such as the Geographic Information System used by Columbia have allowed it to determine with accuracy the gas mains distances assigned to each of the 80 customers of the LDS/LGSS class. Now that accurate cost details are available it allows for direct assignment of those costs to the customers, and that is the first step of cost allocation. "Costs exclusively incurred on behalf of one customer or class of customers should be directly assigned to that customer or class."[3] After known costs are directly assigned, then the remaining costs can be allocated based on cost causation.

Q. WHAT DO THE DRASTICALLY DIFFERENT OUTPUTS OF THE PEAK & AVERAGE COSS AND THE CUSTOMER-DEMAND COSS INDICATE?

[3] Page 144, A Guide To Utility Ratemaking, James H. Cawley & Norman J. Kennard, Pennsylvania Public Utility Commission

A. I provided substantial evidence in my direct testimony that the Customer-Demand COSS was based on the actual engineering design and construction practices used to build Columbia's distribution system. Mr. Johnson summarized the results of Columbia's COSS in Exhibit KLJ-5, Unitized Returns at Current Rates and Proposed Rate. In Exhibit JLC-2SR, I compare the rates of return at current rates and calculated the difference between the rates of return of the Peak & Average method and the Customer-Demand method and present the absolute value of those differences. Viewing the data this way we can learn several things. It is easy to see that the two COSS methodologies produce drastically different results, and those results show major divergences for the two classes SDS/LGSS and LDS/LGSS. While the smaller customer classes of RSS/RDS, SGS/DS-1, and SGS/DS-2 show differences of 0.06 to 1.35, the SDS/LGSS and LDS/LGSS classes show extreme differences of 2.79 and 2.60, respectively. Mr. Johnson explained in his direct testimony that he views the results of the two studies set a range of reasonableness[4] and that revenue allocation should be done within that range, and produces a third study that averaged the results of the Peak & Average and Customer-Demand studies. The differences in rates of return I present in my Exhibit JLC-2SR show that, for the SDS/LGSS and LDS/LGSS classes, selecting only one of the Company's COSSs as guide for revenue allocation will have markedly different cost allocations than if the other study was chosen. An issue as important as revenue allocation should not be so lopsided due to the selection of a particular COSS. In conducting the Average COSS, Mr. Johnson strives to address this unfairness.

[4] "Columbia continues to believe that the two studies provide the reasonable range of returns for use in revenue allocation" Statement No. 6, 4:16-18

To be clear, the evidence I presented in direct, rebuttal, and surrebuttal testimony prove that the only COSS that is based on cost causation is the Customer-Demand study and that is the study that I recommend be used, subject to the modifications I recommended in by rebuttal testimony. However, if the Commission declines to select the Customer-Demand COSS, then it should desire to avoid large swings in revenue and determine the revenue allocations based on the Average COSS. That would mitigate the huge differences in the relative rates of return of the two of the SDS/LGSS and LDS/LGSS customer classes.

Q. WHAT ARE YOUR CONCERNS ABOUT OSBA WITNESS MR. EWEN'S REBUTTAL TESTMONY?

A. Mr. Ewen's rebuttal testimony (OSBA Statement No. 1-R) highlights the issue I just discussed, which is the extreme results obtained for two customer classes when one COSS, in this case the Peak & Average COSS, is selected. Mr. Ewen states, "I agree with Mr. Crist that economies of scale exist for serving larger customers." *Id*., 2:5-6. However, Mr. Ewen relies on the Peak & Average COSS solely because it was used in the previous rate case. He then produces a revenue allocation for the LDS/LGSS customers that almost doubles the results compared to Columbia's proposal, adding over $5 million to the $6.06 million Columbia had assigned, which takes the 22.2% increase to an outrageous 41.0%. He runs roughshod over principles of gradualism which would normally limit a class increase to 1.5 times the system increase and proposes a doubling of the increase. Mr. Ewen's recommendation should be rejected.

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completely ignores the data showing the extreme divergence of the two COSSs to make his own revenue allocation proposal. His revenue allocation proposal violates gradualism by proposing a doubling of the revenue increase allocated to LDS/LGSS.

Evidence concerning cost causation is overwhelming and the Commission should determine revenue responsibility using the results of selected the Customer-Demand COSS, which is based on cost causation - the polestar of cost of service. Because actual data on the cost of gas mains installed to the 80 LDS/LGSS customer class, that cost should be used in any COSS the Commission selects. My recommendation on revenue assignment is presented as Exhibit JLC-3SR.

Q: DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

EXHIBIT JLC-1SR

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2024 RATE CASE PROCEEDING

Docket No. R-2024-3046519
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THE PENNSYLVANIA STATE UNIVERSITY INTERROGATORIES
Set 3

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- Total Mains Gross Plant $351,627,221 allocated to LDS/LGSS

The $351,627,221 in mains gross plant investment allocated to the LDS/LGSS class represents 10.929% of total mains gross plant investment ($3,217,304,248) in the Peak & Average Allocated Cost of Service Study.

b. In the Peak & Average Allocated Cost of Service Study, mains costs are allocated based on allocation factor 5, not the amount of miles servicing each customer class. Allocation factor 5 assigns mains costs to each rate schedule based on an equal weighting of design day and annual throughput. Please see Page 4 on Exhibit KLJ-2 to Witness Johnson's Direct Testimony detailing the calculation of allocation factor 5.

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EXHIBIT JLC-2SR

Columbia Gas of Pennsylvania, Inc.
ACOS Study Results

Unitized Returns at Current Rates and Proposed Rates

Exhibit JLC-2SR

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	Difference (P&A-CD)	0.47	0.06	1.36	2.79	2.60	0.00	0.38

EXHIBIT JLC-3SR

Exhibit JLC-3SR

Pennsylvania State University's Revenue Allocation Proposal

	Total	RS/RDS/RC2	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS/NSS	Flex/NCS
Proposed Revenue Allocation - FE PA	$123,662,880	$85,966,865	$11,200,816	$12,347,921	$8,107,229	$6,039,535	($798)	$1,312
Percent Allocation to Rate Classes - FE PA	100.00%	69.51%	9.06%	9.99%	6.56%	4.88%	0.00%	0.00%
Proposed Revenue Allocation- PSU	$123,662,455	$90,367,717	$11,778,615	$12,987,678	$8,528,445	$0	$0	$0
Adjusted Allocation Percentages - PSU	100.00%	73.08%	9.52%	10.50%	6.90%	0.00%	0.00%	0.00%

PENNSYLVANIA WEATHERIZATION PROVIDERS TASK FORCE

PWPTF Statement No. 1

Direct Testimony of Jennifer Warabak

In Re: Columbia Gas Company of Pennsylvania, Inc.

Docket Number: R-2024-3046519 et al.

Q. Please state your full name and business address.

A. Jennifer Warabak, 165 Amber Lane, PO Box 1127, Wilkes-Barre, Pennsylvania 18703-1127.

Q. By whom are you employed and in what capacity?

A. I am employed by the Commission on Economic Opportunity (CEO) as Executive Director. I am submitting this testimony on behalf of the Pennsylvania Weatherization Providers Task Force as a member of the Task Force.

Q. What are the interests of the Task Force in this rate case?

A. The Pennsylvania Weatherization Providers Task Force, Inc., is a Pennsylvania non-profit corporation and a statewide association of thirty-seven (37) organizations providing utility assistance and energy conservation services in each of the Commonwealth's sixty-seven counties. The Task Force, through its member agencies, a number of which are Pennsylvania community-based organizations, administers universal service programs for a number of utility companies. The Task Force members serve low-income ratepayers, and it is part of our responsibility to our constituency to advocate for their interests in regulatory proceedings and this proposed request will certainly have an impact upon those low-income ratepayers. In addition to the affordability of transmission and distribution rates, the Task Force is particularly interested in the adequacy and operation of a company's universal service program.

Q. What background and experience in energy issues qualify you to submit testimony in this case?

A. I was appointed as the acting Executive Director of the Commission on Economic Opportunity in October 2022. I have been employed at CEO for over 20 years and during my tenure I have been involved in numerous energy related programs that CEO operates. From 2004 to 2016, I was CEO's Energy Services Coordinator where I supervised CEO's energy programs. During that time, I managed eight hardship utility programs and managed the LIHEAP Crisis program for Luzerne County on behalf of the Pennsylvania Department of Human Services as well as other utility customer assistance programs for several utility companies. In 2016 I became CEO's Program and Planning Coordinator where I evaluated program effectiveness and recommended modifications and/or improvements across the spectrum of programs offered by CEO, in the areas of energy, housing, job training etc.

During my tenure in those positions, CEO's experience and the expertise of its staff in energy programs has been recognized on state and national levels. CEO's energy related programs have been acknowledged by receipt of a Superior Achievement Award from the United States Department of Energy. CEO has weatherized more than 27,000 homes under the U.S. Department of Energy Weatherization Assistance Program. CEO also serves as a subcontractor for universal programs operated by several Pennsylvania gas and electric utility companies. CEO is also the PA Department of Public Welfare's contracted operator of the crisis component of the Low-Income Home Energy Assistance Program (LIHEAP) in Luzerne and Wyoming Counties. CEO was also a major contractor for PPL in the Low-Income Renewable Energy Pilot, and secured funding and installed

several solar thermal water heating systems for the former PG Energy and UGI Gas Division.

Q. Before addressing the specifics of your testimony, does the Task Force take a position on whether the Company's rate increase should be granted?

A. Our focus is on the funding and availability of universal service programs and opposing rate designs that discourage conservation. In this case, we do not necessarily oppose a rate increase, but do oppose any rate increase unless it is accompanied by measures that would provide additional relief to the Company's customers, particularly low-income customers, from the effects of a rate increase.

Q. Please describe the other areas of your testimony.

A. My testimony will address the Company's proposal to increase the fixed monthly charge for residential customers as well as proposals to help low-income customers deal with any resulting rate increase.

In its request for a rate increase the Company does not propose any additional increase in funding or measures that would help low-income customers deal with the proposed rate increase. Further, an increase in the fixed monthly charge, as requested by the Company, would negatively impact a customer's motive and ability to conserve energy. The company's proposal if granted would increase rates, discourage conservation and leave a customer with less ability to conserve energy and less ability to reduce their bills. Despite the impact of its proposal on residential customers, and in particular low-income customers, the Company's proposal offers nothing in the way of changes or

increases in funding to its low-income programs, programs that would help mitigate the negative impact of the Company's proposals especially considering these difficult economic times. Further this is the third request for a rate increase made by this Company since 2012.

Despite these difficult financial times for all, the Company proposes a general increase in distribution rates of approximately $124.1 million. If the Company's request is approved in its entirety, the total monthly bill for an average residential customer using 70 therms of gas per would increase from $118.16 to $136.92 per month, or 15.88%. Despite this requested increase in rates, the Company is not proposing any increased assistance to help low-income customers deal with a rate increase.

Q. What rate design issue would you like to address?

A. In this case the Company is proposing to increase its fixed monthly charge from $16.75 to $26.00, an increase of over 55%. I am concerned about this proposal and the Task Force opposes any increase to the fixed monthly customer charges.

Part of the proposed increase to residential customer's rates will be due to this increase in the fixed monthly customer charge. This increase in the monthly fixed charge concerns me, as it has the Commission, because it discourages conservation and impacts a customer's ability to save money through conservation; as the Company moves towards charging customers based upon the Company's fixed costs and away from a customer's consumption there is less incentive, and ability, to conserve. One of the only defenses a family, particularly a poor family, has against the sharp increases in energy costs is to conserve – lower the thermostat, seal air leaks, change filters regularly, add more

insulation, get a more efficient heating unit, etc. The Company's proposal to increase the fixed costs greatly impacts a customer's motive to conserve and the ability to lessen the impact of any rate increase. The combined effect of an increase in rates and an increase in fixed monthly charges, without any changes to universal service funding or other measures to help low-income customers, not only results in higher rates but also lessens the ability of customers to deal with those increases. In particular, the negative impact would be particularly harsh on the Company's low-income customers and the Company's proposed request ignores the interests of its low-income customers.

Q. How does the effect of the Company's requests impact upon your testimony in this case?

A. I believe that should a rate increase be granted there should be relief offered in the form of increases to universal funding programs and other relief that would help low-income customers deal with any increase granted. For a typical residential customer, these requested increases are substantial, but for a low-income customer, the effects can be dramatic, especially in this economic climate. High utility costs are not the only challenge for a poor person. Our agencies have been helping low-income people for years and know firsthand that they face financial challenges on many fronts -- housing, energy costs, food and health care -- and a dramatic increase in any of those areas can have a devastating impact.

It is for these reasons that if an increase is granted it should be conditioned upon an increase in funding and relief to the Company's low-income customers.

Q. Should a request for a rate increase be granted what type of measures would you suggest be implemented for low-income customers?

A. As a result of this proceeding rates are likely to increase, a customer's ability to conserve will decrease (if the fixed monthly charge is increased) yet no additional relief is being provided to customers that would allow them to increase their conservation of energy and decrease their monthly bills. I would like to see an increase in funding that would help low-income customers deal with an increase in rates, what would be the third since 2021, and in funding that would help low-income customers conserve energy.

Q. Turning now to universal service programs what issues would you like to address?

A. I want to address the Company's low-income usage reduction program (LIURP). Despite the expected increase that will likely result from this proceeding, the Company is not proposing any increase to LIURP funding. We are proposing that LIURP funding be, at a minimum, increased by the commensurate increase in rates for the residential class that results from this proceeding. That is, if the Company's residential customers' rates are increased by 6% in this proceeding, then we are proposing that annual LIURP funding be increased by 6%.

Q. Are there any other universal service topics that you want to address?

A. Yes. The Task Force recommends that the Company's contribution to its hardship fund be increased commensurate with the percentage increase in rates to the residential class that results from this proceeding. Although modest in comparison to other universal service funding, the proposal will help customers deal with a rate increase in these

difficult economic times.

I also recommend that hardship funding be distributed in accordance with the percentage of low-income customers in the counties served by the Company.

Q. Can you please summarize your recommendations?

A. Yes. The Task Force is recommending the following:

1. That the Company's request to increase its fixed residential monthly customer charge be denied;

3. That annual funding for LIURP be increased commensurate with the percentage increase to the residential class that results from this proceeding and that any unused funds be carried over and added to the following year's funding;

4. That the Company's contribution to its Hardship fund be increased commensurate with the percentage increase in residential rates that result from this proceeding;

5. That Hardship funds be distributed in accordance with the percentage of low-income customers in the counties served by the Company.

Q. Does this conclude your testimony?

A. Yes

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	Docket No. R-2024-3046519
	:	
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

The undersigned certified that he served a copy of the foregoing Pennsylvania Weatherization Providers Task Force Petition to Intervene upon the following participants this 18th day of March, 2024, via electronic mail:

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