COLUMBIA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2022-3031211
Columbia Gas of Pennsylvania, Inc.	)	

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

March 18, 2022

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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 Gas of Pennsylvania, Inc. and its various departments, including Field Operations, Construction, Safety, Pipeline Safety Compliance, 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's 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. 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-2015-2468056, R-2016-2529660, and R-2021-3024296.

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 2021 and at the outset of 2022, 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 440,000 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 3.5 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 and Columbia's operations and maintenance expenditures on compliance activities and operations safety enhancements. 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 accelerated pipeline replacement program, as well as Columbia's 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 2023, Columbia is filing this base rate case using the Fully Projected Future Test Year ("FPFTY") authorized by 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. Due to the scale of Columbia's investments in replacement pipe, 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 $82.2 million, as detailed and supported in testimony of Company witness Miller (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 6,518,690 feet (over 1,234 miles) of cast iron and bare steel pipe. Additionally, during that time period Columbia replaced additional pipe that needed to be replaced, but which is not presently counted as "priority pipe".

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, in light of the large, ongoing and growing capital program which is necessary to retire and replace aging infrastructure, a rate increase is unavoidable. 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 as the Commonwealth recovers from the impact of COVID-19, particularly 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. Further, by implementing Picarro mobile leak detection technology, Columbia is reducing risk on its system by providing improved information to drive prioritized pipeline replacement and reducing methane emissions.

b. <u>Other Objectives</u>

Q. Does Columbia have other objectives in this case?

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

Continued Funding of Enhanced Safety Measures: The Company continues to focus its efforts and resources on the top risks to the Company's system and is expanding focus in several critical areas to maintain and enhance its operational capabilities. These efforts are identified and supported by NiSource's implementation of Safety Management System ("SMS") across its six-state footprint. NiSource's SMS focuses on leveraging employees who are performing the work to identify risks so that the risks can be mitigated. In addition, Columbia's SMS provides a proven structure to continually assess and improve processes and procedures to keep employees, contractors, customers, and the public safe. As Columbia's SMS identifies risks, the Company uses an objective risk-based approach to prioritize the mitigation efforts which need to be undertaken as well as the sequencing of those efforts to provide the highest risk reduction at the best possible cost to the customer.

As outlined in Company Witness Anstead's testimony in Columbia Statement No 14, the Company is proposing to implement a number of additional safety programs, as identified below:

- Cross Bore Spend Acceleration
- Abnormal Operation Conditions Mitigation
- Additional Resources for Leak Repair
- Safety and Health Coordinators
- Natural Gas Methane Detectors for Residential Households
- Blackline Safety Devices for Lone Worker Employees

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 level. 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. 11.

Your Energy Your Future (YEYF): As the industry is evolving and increasing focus on various measures of sustainability, the Company is looking to develop a comprehensive and collaborative approach that allows customers access to programs that reduce the impact of carbon emissions related to natural gas on the environment. In the Company's previous base rate case at Docket R-2021-3024296, the Company sought and obtained approval for the addition of Renewable Natural Gas (RNG) quality standards to the Company's tariff, thereby outlining the standards for introducing RNG to Columbia's gas distribution system in order to protect the system and customer's equipment. In continuation of our sustainability measures, the Company is proposing a residential energy efficiency program, which will build upon the success of Columbia's WarmWise Low Income Usage Reduction Program (LIURP) which has helped low-income customers reduce their consumption, reduce their carbon footprint and reduce their gas bills for years. The Company's residential energy efficiency program will be discussed in Company Witness Love's testimony at Columbia Statement No. 16.

Q. Does the Company have any other ongoing initiatives?

A. Yes. The Company continues its efforts to maximize efficiencies, improve process discipline, reduce risk and reduce costs through its enterprise-wide ongoing initiative "NiSource Next". NiSource Next is a comprehensive, multi-year program designed to deliver long-term, sustainable capability enhancements and cost efficiency improvements that reflect NiSource's commitment to safety, risk mitigation and customer service. Examples of successful measures in improving process efficiency and reducing costs include, but are not limited to, shifting select functions to an external service provider and leveraging technology to standardize and improve service delivery. This initiative has also resulted in improvements made within our digitization channels, which have allowed the Company to improve a customer's experience in interacting with Columbia through delivering customer services in the manner in which customers wish to be served. For example, we developed and released a new smart phone app that enables customers to start, disconnect and transfer services right from their phone. It's been our experience that many customers, especially the newest generation of customers, like the speed and efficiency of conducting their business right on their phone rather than calling our call center.

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 bare steel, cast iron and wrought iron facilities as soon as possible. In addition, as Columbia's infrastructure replacement program has been operating for almost 15 years, the program is now mature, and Columbia has made considerable progress in replacing the cast iron and bare steel on its system. While our efforts in this regard are not complete, we are at a juncture where risks beyond bare steel, cast iron and wrought iron now need to be considered and addressed. First generation plastic (i.e. plastic pipe installed before pre-1982) and pre-1971 coated steel pipe are examples of such risks. When these types of pipe are identified in connection with the Company's primary efforts to replace bare steel, cast iron and wrought iron, these types of pipe are included in the project in order to address that risk at the same time the cast iron or bare steel is being replaced. While both pre-1971 and first-generation plastic pipe are being replaced and are helping to reduce leakage and risks on the Company's system, neither of these two categories of pipe are included in our reports that focus on "Priority Pipe", even though these two categories of pipe are considered "Replacement Pipe" in the budgets and footages in the Company's filings and reports. The Company will therefore be adding pre-1971 coated steel pipe as well as first generation plastic pipe to the category of "priority pipe" in the Company's next Long Term Infrastructure Improvement Plan. As Columbia's infrastructure program continues to mature, the Company will remain focused on implementing an efficient pipe replacement program. Doing so will enable the Company to maximize the capital spend to remove priority pipe. For example, when Columbia encounters short, non-contiguous segments of plastic pipe as part of a replacement project, Columbia analyzes whether it's more cost effective to upgrade those segments or simply replace them. Columbia then takes the action that makes the most economic sense for the customers.

In addition, as Columbia' SMS and DIMP programs continue to mature and identify risks that need to be considered and addressed, Columbia may identify additional risks that warrant "priority" replacement. 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	**2022**	**2023**	**2024**	**2025**	**2026**
Growth	$43,580	$41,793	$44,290	$48,904	$61,358
Betterment	$15,603	$6,825	$15,125	$9,780	$10,069
Public Improvement	$13,750	$7,100	$7,500	$7,000	$7,500
Replacement	$275,831	$342,392	$341,438	$371,463	$384,945
Support Services	$10,431	$3,085	$4,013	$3,800	$3,699
Total Net Capital	**$359,195**	**$401,195**	**$412,366**	**$440,948**	**$467,571**

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

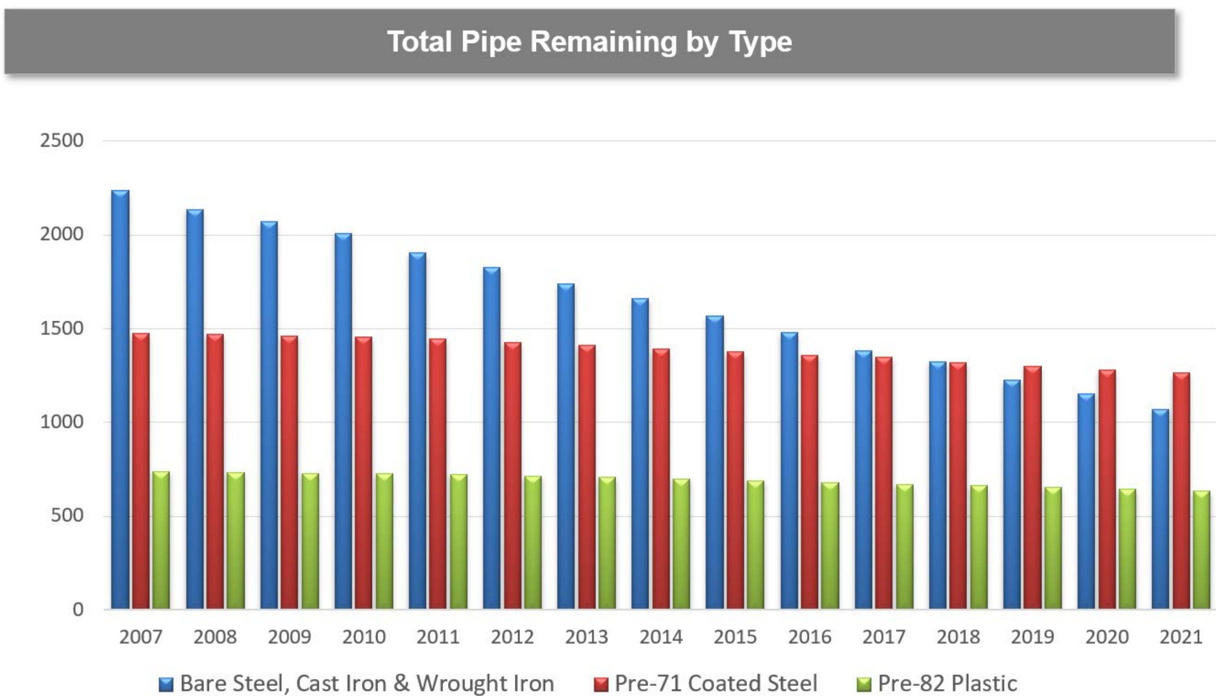
NGDC	Miles of Pipe (2020)
Columbia Gas	7,696.40
PGW	3,045.42
PECO	6,937.40
UGI[1]	12,074.00
Peoples[2]	13,070.20
National Fuel	4,850.28

[1] All companies/ divisions combined.
[2] All companies/ divisions combined.

The size of the Company's capital program is largely driven by the amount of pipe that needs to be maintained and ultimately replaced. Just under 14% of Columbia's total inventory of pipe is either bare steel or cast iron, approximately 7% is pre-1982 plastic, and approximately 15% is pre-1971 coated pipe. Both pre-1982 plastic and pre-1971 coated pipe is reaching the end of their useful life and because Columbia has focused primarily on replacing bare steel and cast-iron pipe over the last decade, the inventories of pre-1982 plastic and pre-1971 coated steel have not been substantially reduced. As stated above, 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. However, 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

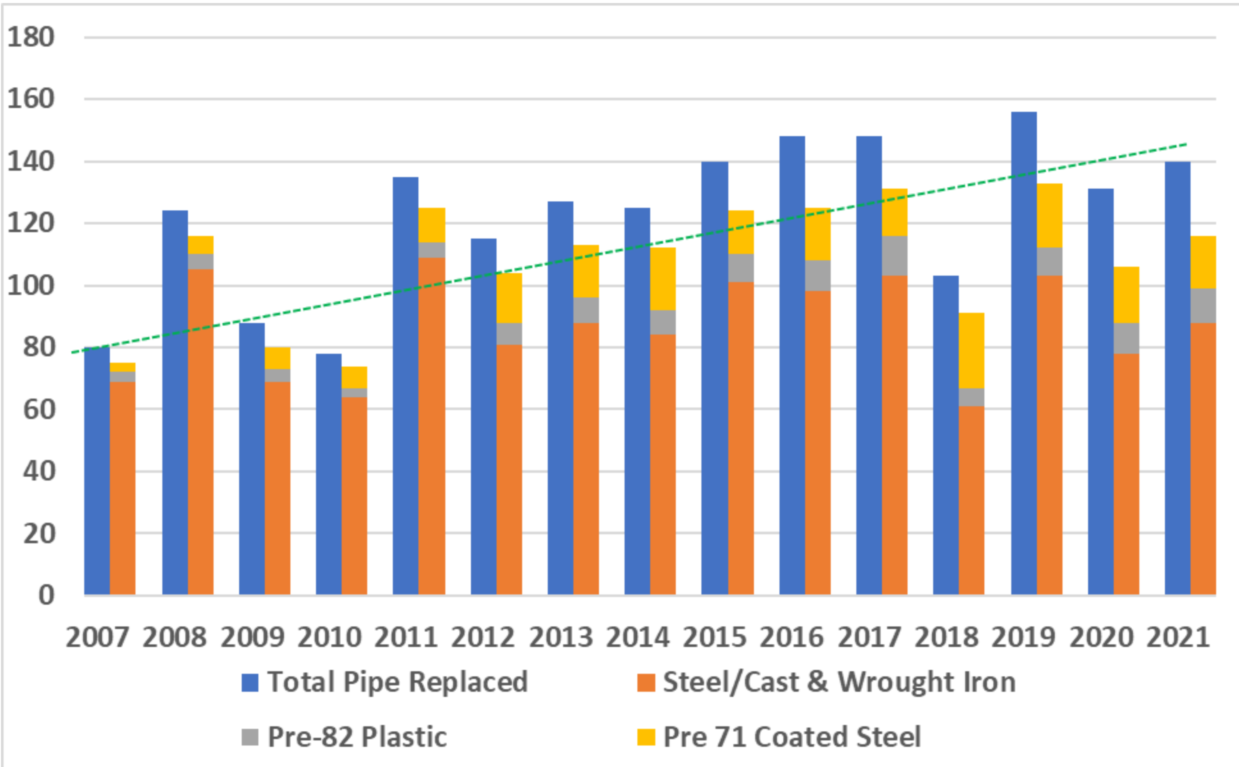


It is now time to focus on replacing these types of pipes even if they are not adjacent to a bare steel replacement project to reduce the risk associated with these pipe inventories. It makes sense to do it now before the pipe fails, and since gas prices remain relatively low in Pennsylvania, in addition 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 2018, the Company resumed its normal performance levels by replacing 98 miles of bare steel, cast iron and wrought iron in 2019. In 2020 the Company replaced 73 miles of bare steel, cast iron and wrought iron, then in 2021 the Company replaced 83 miles of bare steel, cast iron and wrought iron, 11 miles of pre-1982 plastic and 17 miles of pre-1971 coated steel, for a total of 111 miles of pipe that needed to be replaced.

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. SMS asset groups are analyzing risk in several areas:

- Evaluate risks associated with bridge/water crossings: Risks associated with bridge/water crossings are unique from other buried main line facilities. These risks include external corrosion, vehicular damage, location of pipeline, general condition of the bridge, soil erosion of the stream banks and impact from debris in waterway. The gas mains SMS asset group conducted a study in 2020/2021 to analyze risks associated with 71 bridge and aerial crossings. In addition, in light of the recent bridge collapse in Pittsburgh, Columbia continues to assess bridge crossings with a greater focus on the condition of the bridge itself rather than a targeted focus on the Company's facilities.

- Evaluate risk associated with by-pass valves on regulator stations without secondary relief. As part of its Gas Distribution Integrity Management Program ("DIMP"), Columbia will include the issues of bypass valves (including the determination of whether bypass valves are opened or closed, active monitoring, remote access and pressure relief on its regulator stations that include bypass valves) in its identification and ranking of risk, segment by segment, across its system.
- Evaluate risk to regulator stations with inadequate security (ex. Onsite cameras, fencing, improved locks, etc.) to ensure compliance with TSA requirements.
- Evaluate risk to regulator stations due to vehicular damage. Columbia contracted with TRC Companies, Inc. (a third-party engineering consultant) in 2020 to obtain an independent third-party assessment of risks associated with Columbia's distribution regulator stations. As a result of the study, TRC provided Columbia with insight into to the overall threat to our regulator stations from vehicular traffic.
- Evaluate risk to distribution systems without SCADA or remote monitoring: Over 75% of Columbia Gas of Pennsylvania's systems already have remote monitoring which provides our centralized Gas Control

function with visibility to system pressures and allows Columbia to monitor and respond to changes in system pressures. Nevertheless, about 25% of our distribution systems are not electronically monitored, so Columbia believes it is important to understand the risk associated with those unmonitored systems.

- Evaluate the prudency of accelerating and prioritizing regulator station replacement to proactively avoid risk of failure and to ensure compliance with future or proposed PHMSA regulations. Many regulation stations have been in service for decades and are reaching the ends of their useful lives. As part of Columbia's pipeline modernization effort, several the district regulator stations will be modified or eliminated as Columbia seeks to eliminate as many low-pressure systems as possible. Some regulator stations will need to be modified to provide intermediate or medium pressure once the particular distribution system is entirely replaced and converted to intermediate or medium pressure. Other low-pressure stations may be eliminated entirely as they may no longer be needed since intermediate and medium pressure systems are more efficient. However, these modifications or eliminations cannot be made now since the modernization program is not yet completed and the low-pressure regulator stations are still needed Columbia will begin assessing the redesign and replacement of district regulator stations which will be needed, and which must be upgraded due to their antiquated designs or to comply with the upcoming due dates of PHMSA regulations.

- In Line Inspection (ILI): As outlined in the testimony of Company Witness Brumley at Columbia Statement 14, ILI of transmission pipelines where viable is an advanced inspection technique that is in use across 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.
- Odorization: As outlined in the testimony of Columbia Witness Brumley, the Company plans to strategically install odorization equipment at certain points of delivery. Columbia is also planning to tie some of its smaller distribution systems together, to more efficiently manage odorization and to enhance safe and reliable service to our customers.

Q. How will SMS impact the Company's infrastructure replacement plan going forward?

A. Replacement of bare steel, wrought iron and cast iron mains and services have been the priorities that drive infrastructure modernization based on information that has been available to Columbia and because of the large inventories of bare steel and cast iron. The Company has effectively eliminated most of its cast iron and plans to retire the remaining 1.3 miles of cast iron in 2022. Through Columbia's SMS and DIMP efforts, we have identified additional categories of risks that need to be addressed.

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

A. In addition to the 83 miles of bare steel, wrought iron and cast-iron pipe replaced in 2021, the Company replaced an additional 28 miles of first generation plastic pipe installed prior to 1982 and pre-1971 coated steel. As Company Witnesses Anstead 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. Through the risk ranking methodologies contained in the Company's SMS and DIMP programs, the Company has identified risks regarding the failure of both pre-1982 plastic pipe and pre-1971 coated steel pipe that warrant replacement of those assets on a prioritized and targeted basis instead of only when they are adjacent to bare steel or cast-iron pipe scheduled for replacement. As we move forward and these facilities continue to age and the Company continues to reduce the inventory of cast iron, wrought iron and bare steel further, the Company will include the replacement of pre-1982 plastic and pre-1971 steel in the prioritization of priority pipe. Consequently, the Company will be incorporating pre-1982 plastic and pre-1971 steel pipe as priority pipe in its next update to its Long-Term Infrastructure Improvement Plan.

Q. How is SMS different than other pipeline safety programs and initiatives? (DIMP, TIMP, Damage Prevention, Public Awareness, Infrastructure modernization, etc.)?

A. SMS is a proactive and systematic and all-encompassing approach to managing safety, including the structures, policies, and procedures an organization uses to direct and control activities. The API has developed RP 1173 Pipeline Safety Management Systems to provide an SMS tailored for pipeline operators. While leadership commitment is critical to a successful SMS, the identification of risk happens at all levels of an organization.

SMS builds upon pipeline safety programs and initiatives, such as DIMP and TIMP. Indeed, a Pipeline SMS places particular emphasis on proactive thinking of what can go wrong in a systematic manner, clarifying safety responsibilities throughout the pipeline operator's organization (including contractor support), the important role of top management and leadership at all levels, encouraging the non-punitive reporting of and response to safety concerns, and providing safety assurance by regularly evaluating operations to identify and address risks. These factors, plus a strong safety culture, work together to make safety programs and processes more effective, comprehensive, and integrated.

While other pipeline safety programs and initiatives, such as DIMP, TIMP, Damage Prevention, Public Awareness and Infrastructure Modernization, address specific areas of risk, these programs in large part rely on previously gathered data and react to that data. SMS is a much more proactive, systematic and holistic approach to risk management when compared to DIMP, TIMP, Public Awareness and Infrastructure Replacement programs. An SMS encompasses, supplements and supports all other safety programs and initiatives, while providing all employees with the support and resources to own risk management.

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. <u>REVENUE REQUIREMENT</u>

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

A. As described in the testimony of Company Witness Miller (Columbia Statement No. 4), Columbia reviewed its costs to serve its customers using a FPFTY ending December 31, 2023, 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 8.08%. Company witness Moul (Columbia Statement No. 8) demonstrates that Columbia should be granted an opportunity to earn a 11.2% rate of return on common equity.

IV. <u>MANAGEMENT EFFECTIVENESS</u>

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. 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 would observe that the Commission's auditors employ a ranking category system that ranges from "Meets Expected Performance" 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%	6%	0%	55%	20%
Minor Improvement Necessary	45%	27%	44%	58%	45%	47%
Moderate Improvement Necessary	18%	36%	50%	33%	0%	33%
Significant Improvement Necessary	0%	0%	0%	8%	0%	0%
Major Improvement Necessary	0%	9%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%

* People's represents People's Natural Gas, the former Equitable Gas and People's TWP

As Figure 5 illustrates, Columbia achieved the "Meets Expected Performance" ranking category in 36% of the categories evaluated by the auditors, with only one peer, NFG, 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. A review of the information in Figure 5 and Exhibit MK-1 shows that, based upon Commission audits, Columbia's performance exceeds that of its peers.

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

A. The Company typically utilizes the Commission issued Annual Utility Consumer Report and Evaluation ("UCARE") report to assess performance, however, as a result of the impact of COVID, the Bureau of Consumer Services has not yet issued the 2020 report. Therefore, the 2019 UCARES report is the most recent data available. Should the Company receive the 2020 report during this proceeding, the Company will share the results for 2020.

Q. What were the results of the 2019 UCARES report?

A. The overall information contained in the Activities report describes how well utilities handle consumer complaints. The report focuses on three main categories: Consumer Complaints, Payment Arrangement Requests ("PAR") and Compliance with Commission regulations. As shown in Figure 6, below, overall, Columbia's 2019 performance, as reflected in the UCARE report with regard to the seven major natural gas companies, is among the best in most categories in the gas industry. In the measure of Residential Consumer Complaints, Columbia had the lowest consumer complaint rate of 0.34 per 1,000 residential customers in the gas industry, as noted in Figure 6 below. Columbia's consumer complaint rate was also better than any of the seven major natural gas companies, which averages 0.91.

Figure 6

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

Utility	Consumer Complaint Rate	Justified Consumer Complaint Rate
Columbia	0.34	0.01
NFG	0.49	0.05
Peoples	0.68	0.01
Peoples-Equitable	0.66	0.04
PGW	1.92	0.16*
UGI South	0.81	0.09
UGI North	1.50	0.16
Average	**0.91**	**0.07**

* Justified consumer complaint rate based on a probability sample of cases.

Per Figure 7 below, Columbia's Justified Consumer Rate per 1,000 residential customers is at 0.01, which is the same as 2017 and 2018. Columbia's Justified Consumer Rate is better than the natural gas utility average rate of 0.07. Columbia's rate has consistently remained one of the lowest of all natural gas companies, at a rate of 0.01 for years 2017-2019. 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

2017-19 Justified Residential
Consumer Complaint Rates
Major Natural Gas Distribution Companies

Utility	2017	2018	2019
Columbia	0.01	0.01	0.01
NFG	0.04	0.05	0.05
Peoples	0.00	0.02	0.01
Peoples-Equitable	0.01	0.04	0.04
PGW*	0.14	0.15	0.16
UGI South	0.03	0.14	0.09
UGI North	0.04	0.29	0.16
Average	**0.04**	**0.10**	**0.07**

* Justified consumer complaint rate based on a probability sample of cases.

Columbia's Payment Arrangement Request ("PAR") rate was 1.17 in 2019 and the Justified PAR rate was 0.03. Columbia had the best score amongst all seven

Pennsylvania gas utility companies, as shown in Figure 8 below.

Figure 8

2019 Residential Payment Arrangement Request (PAR) Rates/
Justified PAR Rates
Major Natural Gas Distribution Companies

Utility	PAR Rate	Justified PAR Rate
Columbia	1.17	0.03
NFG	3.10	0.24
Peoples	2.59	0.19*
Peoples-Equitable	2.76	0.20
PGW	9.87	1.06*
UGI South	6.35	0.75*
UGI North	9.58	1.03*
Average	**5.06**	**0.50**

* Based on a probability sample of cases.

In the measure of Commission Infractions, Columbia had an infraction rate per 1,000 residential customers of 0.00 in 2019, which is the lowest and best of all seven major natural gas companies. Figure 9, below, is illustrative.

Figure 9

Commission Infraction Rates
Major Natural Gas Distribution Companies

Utility	2017	2018	2019
Columbia	0.00	0.01	0.00
NFG	0.03	0.05	0.07
Peoples	0.00	0.03	0.01
Peoples-Equitable	0.00	0.02	0.03
PGW	0.12	0.17	0.19
UGI South	0.02	0.16	0.14
UGI North	0.06	0.34	0.24

Q. Can you provide an overview of Columbia's 2021 Quality of Service Performance Report?

A. Yes, Columbia's "Quality of Service Performance Report," which was filed on January 31, 2022, 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.

1. <u>Call Center Performance:</u>

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 was pleased with the results of its 2021 Quality of Service Performance Report.

Columbia's call volume increased significantly in 2021. In 2020, 384,798 calls were offered compared to 469,552 calls offered in 2021, an increase of 22%. Columbia has continued to hold a firm 0% busy out rate for the last 12 years, while the metric "Calls Answered within 30 Seconds" dropped to 74% In addition, Columbia experienced an abandonment rate of 7.23%, which is an increase over 2020's rate of 2.04% The drop in Calls Answered within 30 Seconds and the increased abandonment rate, combined with difficulties in hiring and retaining call center employees due to COVID-19, are largely related to the 22% spike in additional calls. Columbia nevertheless took actions to address these performance issues, including incentives for overtime, enhanced training, and intensified recruiting and hiring efforts. Examples of actions taken to:

- Increasing the CSR starting wage by 22%, going from $14.50 to $17.70 per hour to intensify recruiting and hiring efforts
- Introduced a new career leveling program for the Columbia Gas Customer Service Representatives that includes career pay progression based on tenure, knowledge and performance
- Expanded the geographic recruiting search up to eighty miles from the Smithfield, Pennsylvania, customer care center

Columbia continues to recruit employees through NiSource job postings, radio and digital print advertising, and social media postings. The Company also continues to focus on retention of current call center employees and has partnered with an outside vendor focused on employee engagement and retention. Through collaborative efforts with our vendor, we are better able to interactively diagnose and address workplace issues, while making continual improvements. The Company is currently working on solutions of how to best incorporate this system with our current at home work force. As a result of COVID and transitioning to remote work, Columbia has incorporated virtual screening, testing, and interviewing into our hiring practices, which provides for greater flexibility for the Company, and for candidates. In addition, the Company has expanded the geographic recruiting search area to up to 80 miles from the Smithfield, Pennsylvania customer care center. This modification also includes strategic diversity recruitment efforts with community-based organization such as Pittsburgh Community Services, Inc. (PCSI), Pennsylvania Career Link, community church leaders, Fayette County NAACP, and the African American Chamber of Commerce of Western Pennsylvania. The effectiveness of virtual recruiting has helped to widen our talent selection pool. Finally, Columbia has also implemented virtual new hire training to onboard new customer service representatives.

Residential and Small Commercial Billing Data:

For the tenth 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 4 million bills to customers in 2021. In addition, over 1.2 million paperless bills were issued to customers. Approximately 4.7 million payments were posted to customer accounts; of those, 69% were electronic payments.

2. Meter Reading:

In 2021, Columbia read over 5.3 million meters, with 99.94% of meters read on the scheduled meter reading date. Columbia experienced a slight increase in the number of meters not read monthly in accordance with 56.12 (4)(ii). In 2020, 21 meters were not read monthly, compared to 22 meters not read monthly in 2021. 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 Collector 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. Due to Covid-19 and the Company's policy not to enter the customer's home unless there is a safety issue, the number of unread meters did increase slightly; however, the percentage of unread meters out of the total 5.3 million meters read remains insignificant.

3. <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 2021. In 2021, Columbia's "First Contact Resolution" rate was 88.96%. This statistic indicates the success our call center 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 2021.

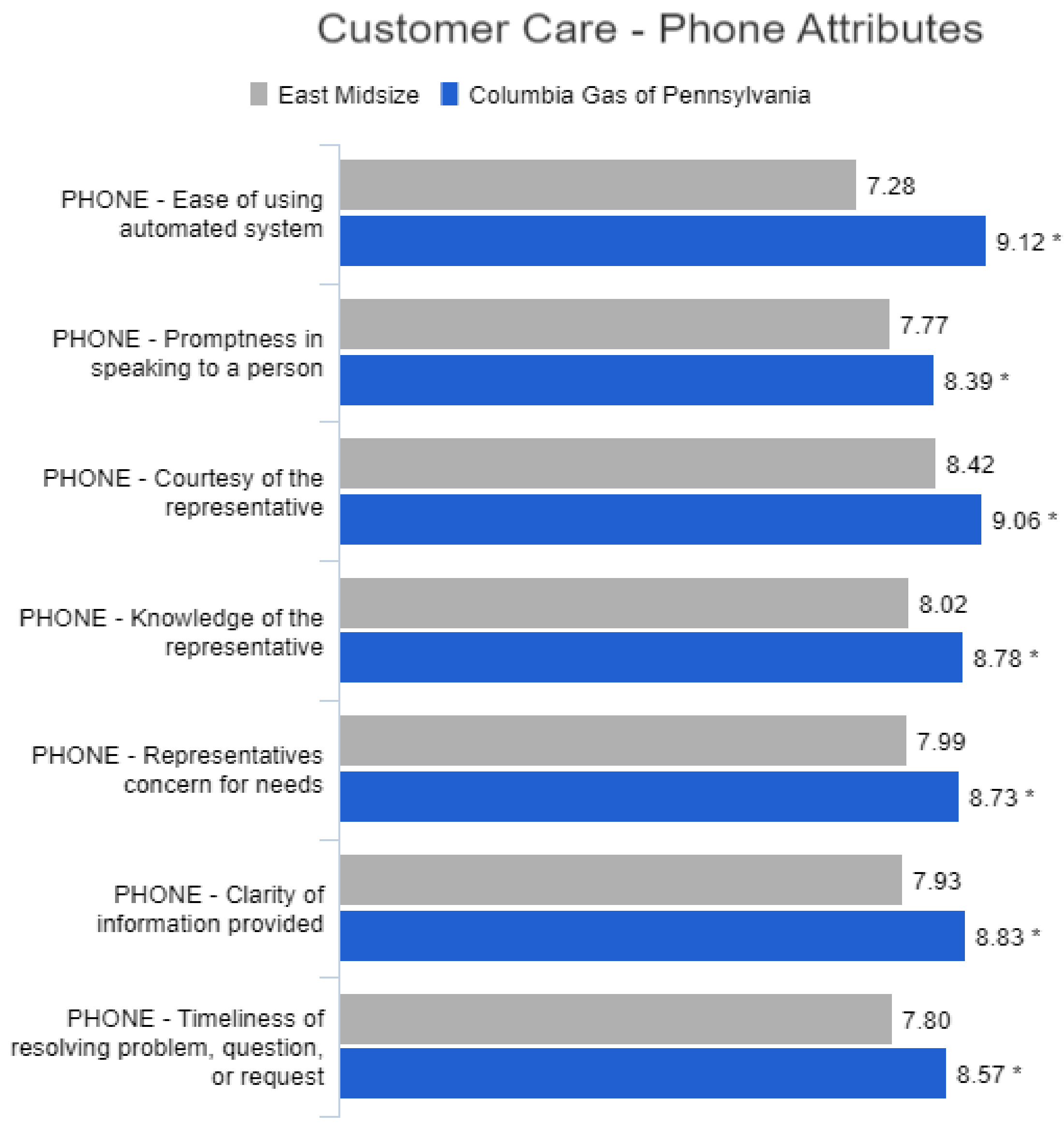
Figure 10

Phone Rep Performance	
	YE 2021
Overall satisfaction	90.58%
Put on hold after speaking with a rep	17.97%
Rep explained reason for hold	91.03%
Being courteous and professional	92.02%
Treated as a respected customer	91.36%
Showing concern for the situation	87.18%
Displaying knowledge in job	88.09%
Adequately answering questions	87.82%
How well rep listened to customer	90.14%
Having authority to make decisions	86.31%
Working quickly and efficiently	87.41%
Clarity of speech, speed, tone, and volume	91.25%
First contact resolution	88.96%

CPA Automated Phone Service	
	YE 2021
Overall satisfaction	75.60%
Offering choices that helped get directly to the information wanted	71.63%
Ease of navigating prompts	72.34%
Ease of getting connected to live representative	69.70%
Number of steps required to complete the transaction	66.92%
IVR first contact resolution	64.52%

In addition to the MSR Survey, the company's JD Power phone satisfaction score was 886, which ranks first in the East Midsize segment of peer gas utilities for this category. Phone satisfaction is based the attributes below in Figure 11 below.

Figure 11



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 2021
Willing to accommodate needs	92.55%
Told when work would take place	93.95%
Arrived on time	95.80%
Total time to resolve	93.19%
CPA Field Work Crew Performance Ratings	
	YE 2021
Overall satisfaction with performance	95.82%
Courteous and professional	97.42%
Displayed skill and knowledge	96.63%
Explained work being performed	96.20%
Adequately answered questions	95.98%
Aware of service performed	94.23%
Worked quickly and efficiently	96.95%
Being respectful of your property	98.06%
Left work property as found before work began	98.70%
Work crew identified themselves	98.00%
Completed work on the first visit	91.98%

Q. How did Columbia perform in the 2021 J.D. Power Residential Customer Satisfaction Survey?

A. Columbia achieved an overall Customer Satisfaction Index ("CSI") score of 766 in the annual J.D. Power Gas Residential survey, ending in second place for the mid-sized Eastern natural gas utilities. This is an increase of 1 point over the Company's 2020 final survey result of 765. The Company outperformed the mid-sized Eastern utility average of 748 by 22 points.

In addition, Columbia Gas scored above the mid-sized eastern utility averages in all seven categories and had the top number one mid-sized eastern ranking in the Safety & Reliability and Billing & Payment categories.

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

A. Over the past 17 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 2.25% in 2021. It also reduced its net write-off for the same period from 2.79% to 1.55%.

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

A. Based on information contained in the 2020 Universal Service and Collections Report, as seen below, Columbia had the 2nd most affordable Customer Assistance Program ("CAP") in the Commonwealth. This is the first time Columbia has not been the lowest due to a drop in avg bill by NFG. Columbia's average bill is still $11 per month lower than the statewide average for gas utilities. Further, as per Figure

13 below, Columbia CAP has the lowest default rates, in each poverty level, than all other gas utilities across Pennsylvania.

Figure 13

	Avg CAP Payment	CAP Default Rates 0 - 50%	CAP Default Rates 51% - 100%	CAP Default Rates 101%- 150%
Columbia	**$51**	**2.00%**	**2.20%**	**2.30%**
NFG	$48	2.20%	2.20%	2.30%
PECO Gas	$52	13.60%	9.60%	11.80%
Peoples	$73	8.60%	7.20%	18.30%
PGW	$78	4.90%	3.60%	4.10%
UGI Utilities- Gas	$68	17.80%	15.40%	23.40%

Columbia's most recent independent Universal Services Evaluation, completed in 2017, found that Columbia's Universal Services programs were well-managed, with attention to detail, quality control and efficiency. Key highlights included in the report are as follows:

- Columbia's CAP administrative costs are among the lowest as compared to other Pennsylvania natural gas distribution companies. Columbia's CAP is well-managed with adequate controls put into place for limiting program costs. The Company has taken extraordinary steps in ensuring quality and consistency with its Low Income Usage Reduction Program ("LIURP") implementation. Columbia's LIURP process and procedures are well-written and easily understood.
- The "Vision Database" is exceptional in tracking LIURP workflow and is regarded as a useful tool by both the internal and external LIURP teams. The

data base, adopted in April of 2016, is a contact management, invoicing and reporting data base for customers.

In addition, Columbia has developed an extensive outreach strategy to increase awareness of available resources and programs to identified low-income customers and to customers that may be low income but are not identified in Columbia's system. The Company's "We're Here For You" Campaign will be discussed in greater detail in Company Witness Davis's testimony at Columbia Statement No. 14.

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 2021 includes:

- Implemented the 12-month rolling budget plan in February 2022, as required per the 2020 rate case at Docket R-2020-3018835
- Launched our new customer Mobile app, which enables customers to perform bill payment, and allows self-service to start, stop, and move orders online

- Implementation of IT natural language Interactive Voice Response (IVR) system that enables the customer to interact with the system conversationally is expected in March 2022.
- Hiring of bi-lingual (English & Spanish) Customer Service Representatives (CSRs) to increase call efficiencies and to provide a more seamless customer experience than transferring the phone call to the traditional translation services line for all of our Spanish speaking customers.
- Launched a Chatbot feature on our websites and mobile phone applications that will allow customers to self-serve online and receive automated assistance with transactions such as billing, usage, and password reset.
- Increased communication channels for CSRs though providing the ability to text or email generic information to customers such as mailing addresses, website addresses, phone numbers and other short pertinent information.
- Provided simplified paperless enrollment capabilities through the website: gopaperfreetoday.com and one-click paperless email enrollment
- Added an Energy Assistance Resource Center to the website allowing customers to easily find programs and help paying their bill
- Added the Picarro Advanced Leak Detection web page, including video, to educate customers on the new Advanced Leak Detection capabilities.

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

A. Yes, the Company along with the other operating Companies in NiSource adopted a Safety Plan approach in 2021 and will continue these efforts in 2022. This multifaceted plan will coordinate with and leverage certain aspects of the "NiSource Next" initiative that is described earlier in my testimony. The Safety Plan is an evolution process to continuously improve and add layers of protection to our existing safety practices and build on the success of previous efforts. The Safety Plan will include enhancements to processes, training, tools, and support, all of which are designed to improve safety and eliminate high-consequence events. Some of the process improvements being implemented under the Safety Plain in 2022 include:

- "Quality Control Audit Plan/Quality Assurance Audit Plan": This effort builds off the work started in 2021, and includes a field quality control audit plan and a quality assurance audit plan which have been developed in accordance with a risk-based assessment of the critical tasks which are performed by our workers. Audit teams will focus their audit efforts in these areas sharing metrics/reporting supported by our Quality Management System linking finding and corrective actions based on the riskiest work performed in the organization.
- "Process Safety Review": Continuation of the work started in 2021 where process safety reviews for all 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. Based off this work, improvements to processes and procedures will be implemented in 2022 which will strengthen existing prevention and mitigation barriers to injuries and safety events, and which may also represent opportunities for continuous improvement in process safety.

- "Incidents & Near Miss Reporting": Columbia will soon implement a new event reporting tool to support event identification, 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 to further promote safe behavior and improve overall performance. Some of the support for employees under the Safety Plan includes:

- "Supporting Field Materials". This support effort builds upon the "check" and "act" phases of the "Plan, Do, Check, Act" (PDCA) continuous improvement methodology. The Standard Operating Procedures (SOPs) that were developed and implemented in 2021 will be reviewed for effectiveness and usability and improvements will be made to the documents, process and technology associated with these SOPs leading to enhanced usage reporting, information/data gathered during the use of the SOPs and additional safeguards for those executing the work.

- "Refresher Training", in which Columbia will deliver the Refresher Training that was developed in 2021 as well as developing and implementing additional refresher training for applicable employees on all critical operations processes.
- "Safety Technology" pilots and implementation that focus on both employee personal safety through items like wearable personal safety devices to detect and communication hazards and incidents, to customer/community safety looking at next generation safety endpoints/meters that can detect and react to abnormalities.

The 2022 Safety Plan was carefully designed to target those critical processes which if not precisely followed could result in high consequence events. Our goal is to eliminate those 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 we serve, 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, through company, employee and NiSource Foundation[3] donations, we support organizations assisting people in meeting their basic needs, such as food, clothing, and shelter. In addition, we 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.

Columbia, in addition to the NiSource Foundation, donated more than $835,000 in 2021 to 115 non-profit organizations throughout the 26-county and 450 community service area in 2021, where we deliver natural gas. Donations supported safety, economic and workforce development, environmental stewardship, STEM & energy education, as well as basic needs and hardship assistance.

Contributions made to the community by Columbia, its employees and the NiSource Foundation in 2021 include the following:

- United Way: Columbia employees pledged over $108,000 of their personal income to the United Way, in support of education, financial stability and community health.

[3] Donations 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.

- In addition to direct employee donations, nine county United Way organizations in our service area received more than $38,000 in donations to support local programs addressing local needs.
- American Red Cross: Supporting emergency first response, COVID-19 relief, home safety programs and military family support $79,000 in donations were made to the American Red Cross.
- Dollar Energy Fund: Through donations and sponsorships, Columbia provided $195,000 in support to the non-profit Dollar Energy Fund providing utility assistance to income-eligible families experiencing hardship.
- Food Banks: Supporting basic needs during a time when so many families relied on essential food donations in 2021, $95,000 in donations were made to local/regional food banks and organizations addressing food insecurity issues.
- First Responder Training: Because safety remains a priority, Columbia partnered with the Northeast Gas Association to provide a free, computer-based first responder natural gas safety training program. Through the program, we trained more than 100 local first responders on how to respond safely to natural gas emergencies. In addition, the local fire departments with the most completed trainings in each of our four

operations areas received a $1,000 NiSource Foundation donation to purchase needed equipment.

- Customer Safety: The safety of our customers is paramount. In order to enhance customer safety in targeted communities, $10,000 in NiSource 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 Melissa Bartos, Vice President of Concentric Energy Advisors, provides demand forecasting services for Columbia. In Columbia Statement No. 2, she explains how residential and commercial sales volumes are normalized for weather. The results of the normalization procedure are contained in Company witness Siegler's' testimony (Columbia Statement No. 3) and Exhibit 3, Schedule 4. Company witness Bartos also explains the projection of the future test year and fully projected future test year customer and load growth.
- Company witness Judith Siegler is a Lead Regulatory Analyst for NiSource Corporate Services Company ("NCSC"). In Columbia Statement No. 3,

Company witness Siegler 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, 2022 and for the twelve months ending December 31, 2023 (FPFTY).

- Company witness Kelley Miller is a Lead Regulatory Analyst for NCSC. In Columbia Statement No. 4, Company witness Miller presents Columbia's cost of service and quantifies the revenue deficiency based on operating costs and revenues, as adjusted. Company witness Miller supports Columbia's cost of service Operating & Maintenance ("O&M") expenses.
- Company witness John J. Spanos is the President 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 Julie Covert is a Lead Analyst for NCSC. In Columbia Statement No. 6, 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 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 Fully Projected Future Test Year (twelve-months ending December 31, 2023).

- 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 Gas of Pennsylvania for the Fully Projected Future Test Year that are included in Columbia witness Miller's cost of service analysis for Columbia Gas of Pennsylvania.
- Company witness Jennifer Harding is the Director of Income Tax at 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 Kevin Johnson is a Lead Regulatory Analyst for NCSC. In Company Statement No. 11, he testifies about Columbia's allocated cost of service studies. Company witness Johnson will also address the Company's RNA proposal, revenue allocation and rate design.
- 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. Included in these changes is proposed tariff language to provide for the Green Tariff Rider and the residential energy efficiency rider.
- Company witness Deborah Davis is Columbia's Manager of Universal Services. In Columbia Statement No. 13, Company witness Davis addresses Columbia's efforts to raise voluntary contributions for Columbia's Hardship Fund, Columbia's "We're Here For You" outreach initiative, as well as a proposal to address the large carryover of Low Income Usage Reduction Program (LIURP) funding as a result of the COVID- 19 pandemic.
- Company witness Curtis Anstead is the Vice President and General Manager for Columbia. In Columbia Statement No. 14, Company witness Anstead 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 2022.

- Company witness Nicholas Bly is the Director of Rates and Regulatory Affairs for Columbia. 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 Miller's cost of service analysis.
- Company Witness Theodore Love is a Partner in the Green Energy Economics Group. In Columbia Statement 16, Company Witness Love will introduce the Company's proposed Residential Energy Efficiency program, as well as discuss the benefits of energy efficiency to customers.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to the one exhibit 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.

COLUMBIA GAS OF PENNSYLVANIA, INC.

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. <u>Recommendation Summary</u>

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:

- <u>INITIATION</u> – 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. <u>Benefits</u>

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. <u>Benefits</u>

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
PECO Energy Company
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 Interest 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			
Facilities Management	X				
Risk Management	X				
Legal		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 $2,933,000 to $5,667,000 in annual savings and $2,200,000 to $3,110,000 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
Focused Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Reduce overtime levels, specifically non-storm overtime, for C&M and DSO. (Recommendation VII-2)	$2,400,000 – $5,000,000	$0
Reduce gas line hit damages by mitigating mapping data errors and implementing a preemptive and comprehensive program to locate facilities with an emphasis on plastic pipe. (Recommendation VIII-1)	$200,000	$0
Perform a periodic comprehensive system-wide review of emergency and inactive inventory and eliminate inventory, as appropriate (Recommendation X-1)	$333,000 – $467,000	$2,200,000 – $3,110,000
Totals	$2,933,000 – $5,667,000	$2,200,000 – $3,110,000

For the majority of recommendations, it is not possible or practical to estimate quantitative benefits as their benefits are of a qualitative nature or there was insufficient data 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 processes or to implement good business practices will result in improved effectiveness and efficiency of a specific function but cannot be easily quantified.

The Company will have varying ways to implement the recommendations and as a result the Audit Staff has not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted by the reader that the cost of implementing certain recommendations could be significant. The Audit Staff forecasted possible costs for implementation of the Company's expansion of inspection activities of contractor performed work to range between $500,000 and $700,000. It should be noted that the Audit Staff did not attempt to quantify resultant savings from increased inspection activity but contends that the net long term savings should ultimately outweigh the cost.

E. <u>Recommendation Summary</u>

Chapters III through XVII 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 estimated overall level of benefits rankings are not solely based on quantifiable dollars but rather the Audit Staff's 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.

COLUMBIA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
v.	)	Docket No. R-2022-3031211
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
MELISSA BARTOS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

TABLE OF CONTENTS

I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Melissa Bartos. My business address is 293 Boston Post Road West, Suite 500, Marlborough MA 01752.

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

A. I am employed by Concentric Energy Advisors ("Concentric"). My current title is Vice President.

Q. Please briefly describe your professional experience.

A. My entire career, which expands over twenty years, has been in energy consulting. I began my career with Reed Consulting Group, which was later purchased and merged into Navigant Consulting, Inc. I joined what is now Concentric Energy Advisors in 2002. Both firms specialize in consulting for the energy industry.

Q. Please describe your educational background.

A. I received a Bachelor of Arts in Mathematics and Psychology with a concentration in Computer Science in 1998 from the College of the Holy Cross in Worcester, Massachusetts. I received a Master of Science degree in Mathematics with a concentration in Statistics in 2003 from the University of Massachusetts at Lowell.

Q. What are your responsibilities in your current position?

A. In my current position as a Vice President at Concentric, I am responsible for the execution of numerous projects related to the energy industry. I specialize in demand forecasting, rates and regulatory issues and market analysis. My resume is attached as Appendix A.

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

agency?

A. I previously testified before the Pennsylvania Public Utility Commission in the Company's previous rate case (R-2021-3024296), and I have testified before several other state, federal, and Canadian provincial regulatory agencies on dozens of occasions. My testimony list is attached as Appendix B

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

A. I will be addressing the twelve-month period ending November 30, 2021 as the Historic Test Year ("HTY"), the twelve-month period ending November 30, 2022 as the Future Test Year ("FTY"), and the twelve-month period ending December 31, 2023 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 Judith Siegler'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. <u>Weather Normalization of Historical Test Year</u>

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, 2021). The previous base rate case filing defined normal weather as the 20-year average ending in 2020. 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 1984 through 2021 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 71% 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 1988 through the five years ended 2021. As measured by the smallest difference over the five-year period, the 20-year average HDD outperforms the 30-year average HDD in 94% or 32 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
1983		5893	5880				
1984	6040	5904	5898	147	160	x	
1985	5340	5879	5892	564	558		x
1986	5593	5863	5887	286	299	x	
1987	5495	5842	5885	368	392	x	
1988	5960	5835	5881	119	75		x
1989	5816	5824	5882	19	65	x	
1990	5010	5779	5852	814	872	x	
1991	4919	5734	5815	860	933	x	
1992	5572	5719	5796	162	243	x	
1993	5512	5733	5771	207	284	x	
1994	5739	5747	5768	6	32	x	
1995	5518	5746	5757	229	250	x	
1996	5962	5738	5759	216	205		x
1997	5649	5714	5750	89	110	x	
1998	4619	5636	5701	1095	1131	x	
1999	5185	5594	5672	451	516	x	
2000	5442	5560	5657	152	230	x	
2001	5435	5517	5644	125	222	x	
2002	5348	5491	5627	169	296	x	
2003	5876	5502	5648	385	249		x
2004	5384	5469	5645	118	264	x	
2005	5607	5482	5648	138	38		x
2006	5216	5463	5617	266	432	x	
2007	5342	5456	5591	121	275	x	
2008	5573	5436	5571	117	18		x
2009	5447	5418	5552	11	124	x	
2010	5460	5440	5530	42	92	x	
2011	5459	5467	5502	19	71	x	
2012	4711	5424	5463	756	791	x	
2013	5526	5425	5459	102	63		x
2014	5998	5438	5457	573	540		x
2015	5524	5438	5463	86	67		x
2016	4774	5379	5436	664	689	x	
2017	4760	5334	5411	619	676	x	
2018	5692	5388	5403	358	281		x
2019	5250	5391	5384	138	153	x	
2020	4858	5362	5379	533	526		x
2021	5079	5344	5384	283	300	x	
				Mean Absolute Error		Frequency of Lowest Absolute Error	
			1984-2021	300	329	27	11
						Relative Frequency of Lowest Absolute Error	
					1984-2021	71%	29%

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
1983		5893	5880				
1984	6040	5904	5898				
1985	5340	5879	5892				
1986	5593	5863	5887				
1987	5495	5842	5885				
1988	5960	5835	5881	-1037	-970		x
1989	5816	5824	5882	-1315	-1288		x
1990	5010	5779	5852	-1520	-1586	x	
1991	4919	5734	5815	-2117	-2236	x	
1992	5572	5719	5796	-1931	-2149	x	
1993	5512	5733	5771	-2348	-2574	x	
1994	5739	5747	5768	-2369	-2658	x	
1995	5518	5746	5757	-1636	-2000	x	
1996	5962	5738	5759	-367	-771	x	
1997	5649	5714	5750	-217	-600	x	
1998	4619	5636	5701	-1177	-1366	x	
1999	5185	5594	5672	-1803	-1906	x	
2000	5442	5560	5657	-1874	-1928	x	
2001	5435	5517	5644	-2358	-2465	x	
2002	5348	5491	5627	-2541	-2719	x	
2003	5876	5502	5648	-893	-1218	x	
2004	5384	5469	5645	-486	-876	x	
2005	5607	5482	5648	-151	-633	x	
2006	5216	5463	5617	-155	-788	x	
2007	5342	5456	5591	-28	-708	x	
2008	5573	5436	5571	-386	-1116	x	
2009	5447	5418	5552	-158	-1042	x	
2010	5460	5440	5530	-372	-1201	x	
2011	5459	5467	5502	-35	-804	x	
2012	4711	5424	5463	-628	-1305	x	
2013	5526	5425	5459	-578	-1251	x	
2014	5998	5438	5457	65	-605	x	
2015	5524	5438	5463	17	-431	x	
2016	4774	5379	5436	-803	-976	x	
2017	4760	5334	5411	-539	-732	x	
2018	5692	5388	5403	-376	-545	x	
2019	5250	5391	5384	-1189	-1286	x	
2020	4858	5362	5379	-1857	-1982	x	
2021	5079	5344	5384	-1255	-1541	x	

	Mean Absolute Error		Frequency of Lowest Error	
1988-2021	-1012	-1360	32	2
2012-2021	-714	-1065	10	0

	Relative Frequency of Lowest Error	
1988-2021	94%	6%
2012-2021	100%	0%

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 1984-2021 Absolute Values Columbia Gas of Pennsylvania			
	20-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	6.9%
Maximum	1.4%	0.8%	19.6%

III. <u>Demand Forecast Methodology for Future Test Year and Fully Projected Future Test Year</u>

A. <u>Demand Forecast Methodology Overview</u>

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 2021 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 several 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, real natural gas prices, energy intensity, and several 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 proposed residential energy efficiency program incorporated into the residential demand forecast?

A. No. The Company's proposed residential energy efficiency program is not yet approved so there is no experience regarding the impact of the Company's energy efficiency program on residential demand, therefore it is premature to incorporate the potential effects of the program into the demand forecast.

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 several 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, real natural gas prices, and several 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.

CONCENTRIC ENERGY ADVISORS

MELISSA F. BARTOS

Vice President

Ms. Bartos is a financial and economic consultant with more than twenty years of experience in the energy industry. In the last several years, she has focused on natural gas markets issues, including conducting comprehensive market assessments for various clients considering infrastructure investments and developing detailed demand forecasts for a number of gas distribution companies. Ms. Bartos has also designed, built, and enhanced numerous financial and statistical models to support clients in asset-based transactions, energy contract negotiations, reliability studies, asset and business valuations, rate and regulatory matters, cost-of-service analysis, and risk management. Her modeling experience includes building Monte-Carlo simulation models, designing an allocated cost-of-service model, statistical modeling using SPSS, and programming using Visual Basic for Applications (VBA). Ms. Bartos has also provided expert testimony on multiple occasions regarding natural gas demand forecasting and supply planning issues, natural gas markets, and marginal cost studies.

REPRESENTATIVE PROJECT EXPERIENCE

Natural Gas Market Assessments

- Reviewed and evaluated long-term natural gas supply and demand, existing natural gas pricing dynamics, and future implications associated with new natural gas infrastructure in New England, New York, and New Jersey.
- Provided an analysis of the existing Gulf Coast natural gas market, the client's natural gas pipeline competitors, changing flows, and how those factors may affect transportation values to the client going forward.
- Prepared a comprehensive study examining the costs associated with improving natural gas pipeline access from western Canada and the eastern U.S. to Atlantic Canada.
- Produced a report on the benefits associated with incremental natural gas supplies delivered to New York City.
- Prepared an independent natural gas supply and pipeline transportation route assessment associated with natural gas for the client's proposed LNG export terminal.

Natural Gas Expansion

- Conducted a study that examined potential commercial and industrial conversions from oil-based fuels to natural gas in various east coast U.S. markets.
- Produced a report that identified growth potential in off-system stationary and mobile markets in the mid-west that could be served by compressed natural gas or liquefied natural gas.
- Performed an external audit and filed expert testimony associated with two natural gas utilities' hurdle rate/contribution in aid of construction calculations for new off main customers.

- Produced a report that identified and reviewed innovative cost model approaches that utilities and regulators are using across the U.S. that allow expansion of gas distributions systems to new communities.
- Assisted in developing a strategy to identify residential natural gas growth opportunities within the client's franchise area.
- Presented at two Northeast Gas Association conferences regarding "Regulatory Policy and Residential Main Extensions".

Demand Forecasting

- Filed expert testimony regarding the development of demand forecast models and the evaluation of natural gas resource plans for multiple northeast gas utilities.
- Provided litigation support regarding demand forecasting techniques with respect to certain natural gas pipeline and storage decisions for a mid-west gas utility.
- Reviewed demand forecasting practices and procedures and recommended certain changes to improve the methodology and accuracy of the forecast for a multi-state utility.
- For a mid-west gas utility, developed a natural gas demand forecast that was utilized for supply and capacity decisions.

Ratemaking and Utility Regulation

- Participated in the rate case of a large North American gas distribution company, which determined the client's five-year incentive regulation plan, including performing benchmarking and productivity analyses that were filed with the regulator.
- Developed a marginal cost study, including data collection, analysis and testimony development, in support of rate case filings for a number of New England utilities.
- Provided comprehensive analysis, drafted testimony and provided litigation support regarding the appropriate return on equity for a New England water utility, and for proposed wind and coal electric generation facility additions for a mid-west combination utility.
- Performed a detailed analysis of the components included in the client's lost and unaccounted for gas calculation.
- Conducted multiple natural gas portfolio asset optimization analyses to evaluate performance of the client's asset manager for regulatory purposes.
- On behalf of multiple New England gas companies, participated in the 2009 Avoided Energy Supply Cost Study Group (for New England), which worked with third-party consultants to develop the marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs.
- Conducted a study to determine the cost of significantly reducing peak day natural gas demand for a northeast gas utility through energy efficiency, conservation and demand management measures. Project involved researching natural gas energy efficiency plans in multiple U.S. states and Canadian provinces, reviewing energy efficiency potential studies, and exploring geothermal, peak pricing and direct load control options.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Vice President
Assistant Vice President
Project Manager
Senior Consultant

Navigant Consulting, Inc. (1996 – 2002)
Senior Consultant

EDUCATION

University of Massachusetts at Lowell
M.S., Mathematics (Statistics), 2003

College of the Holy Cross
B.S., Mathematics and Psychology, *magna cum laude*, 1998

PROFESSIONAL ASSOCIATIONS

Member of the American Statistical Association

Member of the Northeast Energy and Commerce Association

Member of the Northeast Gas Association

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	2014	Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	Docket No. 13-06-02	CIAC Hurdle Rate Calculation
Federal Energy Regulatory Commission				
PennEast Pipeline Company, LLC	2015	PennEast Pipeline Company, LLC	Docket No. CP15-558	Market Conditions/Need
PennEast Pipeline Company, LLC	2016	PennEast Pipeline Company, LLC	Docket No. CP15-558	Market Conditions/Need
Millennium Pipeline Company, LLC	2017	Millennium Pipeline Company, LLC	Docket No. CP16-486	Market Conditions/Need
Laclede Gas Company	2017	Spire STL Pipeline, LLC	Docket No. CP17-40	Market Conditions/Need
Spire Missouri Inc. (Laclede Gas Company)	2021	Spire STL Pipeline, LLC	Docket No. CP17-40	Market Conditions/Need
Indiana Utility Regulatory Commission				
Northern Indiana Public Service Company LLC (Gas)	2021	Northern Indiana Public Service Company LLC (Gas)	Cause # 45621	Weather Normalization; Demand Forecast
Kentucky Public Service Commission				
Columbia Gas of Kentucky, Inc.	2021	Columbia Gas of Kentucky, Inc.	Case No. 2021-00183	Demand Forecast
Maine Public Utilities Commission				
Northern Utilities, Inc.	2011	Northern Utilities	Docket No. 2011-526	Integrated Resource Plan; Demand Forecast
Massachusetts Department of Public Utilities				
New England Gas Company	2008	New England Gas Company	D.P.U. 08-11	Integrated Resource Plan; Demand Forecast; Supply Planning
New England Gas Company	2010	New England Gas Company	D.P.U. 10-61	Integrated Resource Plan; Demand Forecast; Supply Planning
Berkshire Gas Company	2010	Berkshire Gas Company	D.P.U. 10-100	Integrated Resource Plan; Demand Forecast

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
New England Gas Company	2012	New England Gas Company	D.P.U. 12-41	Integrated Resource Plan; Demand Forecast; Supply Planning
Berkshire Gas Company	2012	Berkshire Gas Company	D.P.U. 12-62	Integrated Resource Plan; Demand Forecast
NSTAR Gas Company	2014	NSTAR Gas Company	D.P.U. 14-63	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2014	Berkshire Gas Company	D.P.U. 14-98	Integrated Resource Plan; Demand Forecast
Liberty Utilities (New England Gas Company)	2015	Liberty Utilities (New England Gas Company)	D.P.U. 15-75	Marginal Cost of Service Study
Berkshire Gas Company	2016	Berkshire Gas Company	D.P.U. 16-103	Integrated Resource Plan; Demand Forecast
Eversource Energy	2017	Eversource Energy (NSTAR Electric and WMECO)	D.P.U. 17-05	Marginal Cost of Service Study
National Grid (Boston Gas Company and Colonial Gas Company)	2017	National Grid (Boston Gas Company and Colonial Gas Company)	D.P.U. 17-170	Marginal Cost of Service Study
Bay State Gas Company d/b/a/ Columbia Gas of Massachusetts	2018	Bay State Gas Company d/b/a/ Columbia Gas of Massachusetts	D.P.U. 18-45	Marginal Cost of Service Study
Berkshire Gas Company	2018	Berkshire Gas Company	D.P.U. 18-40	Marginal Cost of Service Study
Berkshire Gas Company	2018	Berkshire Gas Company	D.P.U. 18-107	Integrated Resource Plan; Demand Forecast
NSTAR Gas Company	2019	NSTAR Gas Company	D.P.U. 19-120	Marginal Cost of Service Study
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	2019	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	D.P.U. 19-135	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2020	Berkshire Gas Company	D.P.U. 20-139	Integrated Resource Plan; Demand Forecast
Boston Gas d/b/a National Grid	2020	Boston Gas d/b/a National Grid	D.P.U. 20-120	Marginal Cost Study
New Hampshire Public Utilities Commission				

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Northern Utilities, Inc.	2011	Northern Utilities	DG 2011-290	Integrated Resource Plan; Demand Forecast
Liberty Utilities (EnergyNorth Natural Gas)	2017	Liberty Utilities (EnergyNorth Natural Gas)	DG 17-048	Marginal Cost of Service Study
Liberty Utilities (Granite State Electric)	2019	Liberty Utilities (Granite State Electric)	De 19-064	Marginal Cost of Service Study
New Jersey Board of Public Utilities				
South Jersey Gas Company	2015	South Jersey Gas Company	GR15010090	Energy Efficiency Cost Benefit Analysis
Ontario Energy Board				
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study
Enbridge Gas Distribution	2013	Enbridge Gas Distribution	EB-2012-0459	Incentive Rate Making
Pennsylvania Public Utility Commission				
Columbia Gas of Pennsylvania, Inc.	2021	Columbia Gas of Pennsylvania, Inc	R-2021-3024296	Weather Normalization; Demand Forecast
Public Utilities Commission of Ohio				
Columbia Gas of Ohio, Inc.	2021	Columbia Gas of Ohio, Inc.	Case No. 21-637-GA-AIR	Adjustments to Demand
Régie de l'énergie du Québec				
TransCanada Pipelines Ltd.	2014	TransCanada Pipelines Ltd.	R-3900-2014	Natural Gas Market Assessment
Washington Utilities and Transportation Commission				
Puget Sound Energy, Inc.	2015	Puget Sound Energy, Inc.	UG-151663	Distributed LNG Market Assessment

COLUMBIA STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2022-3031211
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
JUDITH SIEGLER
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Judith Siegler. 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 began my employment with Northern Indiana Public Service Company, Inc. in 2009 in the Rates and Regulatory Department as a Senior Regulatory Analyst. My responsibilities included providing regulatory support for NiSource's three Indiana companies' (Northern Indiana Public Service Company, Inc., Northern Indiana Fuel & Light Company, Inc., and Kokomo Gas and Fuel) Gas Cost Adjustment ("GCA") filings. In 2010, I was involved in the preparation of a petition to the Indiana Utility Regulatory Commission, seeking approval to merge the three companies into Northern Indiana Public Service Company, LLC ("NIPSCO"). In 2012, I accepted a position under the group that prepares the revenue proof, rate design, tariffs and rules and regulations in NIPSCO's gas and electric rate cases. Since 2015, I have held the position Lead Regulatory Analyst in the Rates and Regulatory Department of NCSC. Prior to NCSC and NIPSCO, I worked as an analyst and then as an accountant in the casino industry, and as a public accountant.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Accounting from Purdue University in 2002 and a Masters of Business Administration from Indiana Wesleyan University in 2017.

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 and its electric company, NIPSCO. These filings include Avoided Cost – Cogeneration, Productivity Report, Reliability Report, Interconnection Report, Net Metering Report, Marginal Cost Study, Gas Compliance Filing, Electric Compliance Filing, and Universal Service Fee Filing and Report. I also provide regulatory support for other NiSource companies, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company").

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

A. Yes, I submitted direct testimony before the Maryland Public Service Commission on behalf of Columbia Gas of Maryland in Case No. 9609 and Case No. 9644, the Commonwealth of Kentucky Public Service Commission on behalf of Columbia Gas of Kentucky in Case No. 2021-00183, and the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company LLC in Cause No. 45621. I have testified before the Commonwealth of Kentucky Public Service Commission on behalf of Columbia Gas of Kentucky in Case No. 2021-00183.

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 revenues.

II. Purpose and Summary of Testimony

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

A. I will sponsor and describe 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 two additional exhibits that support the Company's revenue proposal. Each exhibit, identified below, will be addressed later in my testimony.

Exhibit No.	Description
Exhibit JS-1	Calculation of the Merchant Function Charge
Exhibit JS-2	Annualization of Forfeited Discounts (Account 487)

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 present 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, 2021. 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 backup 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 Melissa Bartos (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.

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") and Merchant Function Charge ("MFC") and Rider Customer Choice ("CC") by customer class used in reconciling per books revenue to annualized revenue in Exhibit 3, Page 9.

Q. How was pro forma revenue at present 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. Present 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 present rates was calculated using the Purchased Gas Cost ("PGC") rate and Rider USP rate as of January 1, 2022, which is the most recent available at the time the schedules were developed. The Merchant Function Charge ("MFC") rate (please refer to Exhibit JS–1, attached to this testimony) was updated to reflect the January 1, 2022 PGC rate and the proposed residential and non-residential uncollectible expense ratio as calculated by Company witness Miller and shown in Exhibit No. 4, Schedule 2, Page 27, Lines 7 and 14. The State Tax Adjustment Surcharge ("STAS") last changed January 1, 2016 and remains at 0%.

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

A. Exhibit JS-2, attached to this testimony, compares Account 487 revenue to total billed revenue for the three years ending November 2019, November 2020 and November 2021, 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 JS-2, page 1. The historic three year average percentage of billed revenue is applied to annualized future test year ("FTY") revenue and annualized FPFTY revenue (Exhibit 103), resulting in annualized Forfeited Discounts revenue for those test years shown on Exhibit JS-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), Consumption (Dth) (Column 2), Revenue at Present Rates (Column 3), proposed adjustment (Column 4), and Revenue at Proposed Rates (Column 5). The summary serves as a comparison of revenue at present 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, 2021. Columns 2 through 6 show the calculated split of per books gas cost, Rider USP, GPC, MFC and CC by customer class calculated on Exhibit 3, Schedules 8 and 9. The weather adjustment calculated on Exhibit 3, Schedule 4 is shown in Exhibit 3, Page 9, Column 9. Column 10 reflects pricing out the test year billing determinants (bills and volumes) at the most current base rates. Column 11 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 present rates as calculated on Exhibit 3 Schedule 1. Column 1 shows pro forma Delivery Service revenue at present rates. Column 2 shows a summary of gas costs at present rates in effect as of January 1, 2022. Column 3 shows a summary of Rider USP at present rates in effect as of January 1, 2022. Column 5 shows a summary of the MFC. Detailed calculations by rate schedule for Columns 1 through 6 are shown in Exhibit 3, Schedule 1. Column 7 shows total revenue at present 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 Bartos 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 present 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 Bartos 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 Present Rates (Column 3), proposed adjustment (Column 4), and Revenue at Proposed Rates (Column 5). The summary serves as a comparison of revenue at present 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 present 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 Witness Bartos' testimony for an explanation of the forecast models.

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, 2022

Line No.	Description	Reference		Rate $	
1	PGCC Rate	Exhibit 1-A, Schedule 1, Page 1, Col. 3, Line 5 (1/01/2022 Quarterly GCR Filing)		3.2815	
2	Total Commodity Cost of Gas			**3.2815**	per Dth
3	Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 27, Line 7	0.0144397		
4	Non-Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 27, Line 14	0.0042117		
5	Merchant Function Charge - Residential Sales Service	(Line 4 x Line 5)		0.0474	per Dth
6	Merchant Function Charge - Small General Sales Service	(Line 4 x Line 6)		0.0138	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, 2021

Line No.		12 Mos November 2019	12 Mos November 2020	12 Mos November 2021	Total 3 Year Average	
1	Per Books Acct 487	$ 1,080,703	$ 502,806	$ 451,085	$ 2,034,593	
2	Per Books Billed Revenue	$ 602,529,915	$ 552,327,378	$ 652,705,000	$ 1,807,562,293	
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.1794%	0.0910%	0.0691%	0.1126%	
4	Historic Test Year Sales Revenue (Ex. 3, Page 10, Line 6)					$ 624,925,175
5	Historic Test Year Revenue -Transportation Revenue (Ex. 3, Page 10, Line 9)					$ 166,750,505
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$ 791,675,680
7	3 Year Average					0.1126%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$ 891,427
9	Historic Test Year Acct 487 (Ex. 3, Page 9)					$ 451,085
10	Annualization Adjustment (Line 8 - Line 9)					$ 440,342

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2022

Line No.		12 Mos November 2019	12 Mos November 2020	12 Mos November 2021	Total 3 Year Average	
1	Per Books Acct 487	$ 1,080,703	$ 502,806	$ 451,085	$ 2,034,593	
2	Per Books Billed Revenue	$ 602,529,915	$ 552,327,378	$ 652,705,000	$ 1,807,562,293	
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.1794%	0.0910%	0.0691%	0.1126%	
4	Future Test Year Sales Revenue (Ex. 103, Page 11, Line 5)					$ 645,770,596
5	Future Test Year Transportation Revenue (Ex. 103, Page 11, Line 8)					$ 164,321,364
6	Total Sales and Transportation Revenue (Line 4 + Line 5)					$ 810,091,960
7	3 Year Average					0.1126%
8	Annualized Forfeited Discounts (Line 4 * Line 6)					$ 912,164
9	Future Test Year Acct 487 (Ex. 103, Page 10)					$ 891,427
10	Annualization Adjustment (Line 7 - Line 8)					$ 20,737

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending December 31, 2023

Line No.		12 Mos November 2019	12 Mos November 2020	12 Mos November 2021	Total 3 Year Average	
1	Per Books Acct 487	$ 1,080,703	$ 502,806	$ 451,085	$ 2,034,593	
2	Per Books Billed Revenue	$ 602,529,915	$ 552,327,378	$ 652,705,000	$ 1,807,562,293	
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.1794%	0.0910%	0.0691%	0.1126%	
4	Fully Projected Future Test Year Sales Revenue (Ex. 103, Page 15, Line 5)					$ 654,202,206
5	Fully Projected Future Test Year Transportation Revenue (Ex. 103, Page 15, Line 8)					$ 159,278,757
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$ 813,480,963
7	3 Year Average					0.1126%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$ 915,980
9	Fully Projected Future Test Year Acct 487 (Ex. 103, Page 14)					$ 912,164
10	Annualization Adjustment (Line 8 - Line 9)					$ 3,816

COLUMBIA STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
v.	)	Docket No. R-2022-3031211
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
KELLEY K. MILLER
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. Kelley K. Miller, 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 a Lead Regulatory Analyst.

Q. What are your responsibilities as Lead Regulatory Analyst?

A. My primary responsibilities include providing support for base rate cases and other regulatory filings for several NiSource operating companies, including, but not limited to, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company").

Q. What is your educational and professional background?

A. I graduated cum laude from Ohio Wesleyan University with a Bachelor's of Arts degree in Accounting and Economics with Management Concentration in 1985. I began my professional career with the Columbia Gas System in Columbus, Ohio in 1986, beginning in the Management Information Department as an Accountant. I was promoted to Senior Accountant in 1987 in the Consolidation Accounting Department of the Columbia Gas System in Wilmington, Delaware. In 1989, I was offered and accepted a promotion to the position of Lead Accountant for Columbia Gas of Ohio as a member of Columbia Distribution Company's Financial Accounting and Reporting Architecture Team. As a member of this team, I was responsible for acting as a liaison between the Accounting departments and the project team that designed and implemented new accounting systems including the General Ledger, Employee Time Reporting and Labor Account Distribution. I remained in this role until all new systems were implemented in 1993. At that time, I was assigned the role of Lead Accountant, first for Columbia Gas of Maryland, and then Columbia. Responsibilities in this role included, but were not limited to, coordinating the monthly closing process, preparing journal entries, preparing financial statements and overseeing and preparing account reconciliations. I remained in this role until 1997, when I decided to leave the workforce to start a family. During the years from 1997 to 2009 I remained out of full-time employment. In October of 2009, I accepted the position of Regulatory Analyst for NCSC. In April 2011, I was promoted to Senior Regulatory Analyst and in March of 2012, I was promoted to my current position as Lead Regulatory Analyst.

Q. Have you ever testified before a regulatory Commission?

A. Yes, I was the Cost of Service witness for Columbia in Docket Nos. R-2014-2406274, R-2015-2468056, R-2016-2529660, R-2018-2647577, R-2020-3018835 and R-2021-3024296, and for Columbia Gas of Virginia in Docket No. PUR-2018-00131.

<u>Statement of Purpose</u>

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, 2023 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 witness Paloney (Columbia Statement No. 9)), 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. What test years will you be addressing in this testimony?

A. I will be addressing the twelve month period ended November 30, 2021 as the "historic test year" or "HTY", the twelve month period ending November 30, 2022 as the "future test year" or "FTY" and the twelve month period ending December 31, 2023 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, 2023 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 $82,151,953 based upon pro forma revenue requirement for the twelve months ending December 31, 2023. Columbia's computation of the revenue deficiency reflects total rate base of $2,958,295,013. 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, 2021. 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, Page 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 Siegler (Columbia Statement No. 3) and are included on lines 1 through 12. Company witness Siegler also provides the level of Gas Supply Expense and Off System Sales Expense that are included on lines 14 and 15, 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 O&M Expense level as presented on line 17. Lines 18 and 19, 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 20, 23 and 24, respectively, have been provided by Company witness Harding (Columbia Statement No. 9), and Rate Base on line 26 has been provided by Company witness Covert (Columbia Statement No. 6). The Percentage Rate of Return at Proposed Rates on Line 27, 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 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 8.08% shown on Exhibit 400 using the HTY data.

III. <u>HTY – Exhibit 4 - Operation & Maintenance Expenses</u>

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

A. In the HTY, Columbia recorded $207,142,211 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, 2019) and Column 2 (twelve months ended November 30, 2020).

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 expense explained and adjusted to a three year average experience;

u) Adjust USP Rider expense to match revenue; and

v) 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 782 active Columbia employees as of November 2021. 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 $432,260 as calculated in Schedule 2, Page 1, Line 5, and a downward lobbying adjustment of $6,342 to remove labor relating to lobbying on Line 6, resulting in a total labor annualization and normalization adjustment of $425,918 is added to the actual HTY labor expense level of $36,081,489 in Schedule 1, Page 2. Total Pro Forma HTY labor expense level is $36,507,407 as shown on Exhibit 4, Schedule 1, Page 2.

B. <u>Incentive Compensation</u>

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 $3,636,110 was decreased by $2,450,065 to reflect the actual level of expense associated with incentive compensation paid in 2021. 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. <u>Prepaid Pension Deferral Amortization Expense</u>

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 $1,393,016 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. Outside Services

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 remove non-recurring outside services and legal fees associated with Columbia's previous base rate cases, Docket Nos. R-2020-3018835 and R-2021-3024296.

F. Rents and Leases

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 $2,436,607. This amount was then reconciled with the per book test year level of $2,431,098. The resulting adjustment is an increase of $5,509. 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 $435,496 and remains unchanged as seen on Exhibit 4, Schedule 1, Page 2, Line 9.

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 June 1 through May 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 $307,629 represents an amount including both actual experience and adjustments to an injury and damages accrual account. An upward adjustment of $20,047 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 ("GDP") Deflator. 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. Downward adjustments were made to the HTY to remove certain employee expenses which Columbia is not seeking to include for recovery in this proceeding and to move one item that is better classified as Company Memberships. Detail 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 four primary items. Ratemaking adjustments in Column 2 totaling $192,945 were made to first remove expenses inadvertently recorded as Company Memberships in the historic test year and to add to Company Memberships, expenses that were inadvertently classified to Employee Expenses and Advertising. Next, annualization adjustments were made for the American Gas Association dues reflective of the payments made relating to calendar year 2021. Column 2, Line 28 additionally contains the removal of an accrual item recorded in the HTY. Lastly, adjustments in Column 4, totaling a decrease of $42,842, 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 $595,855 is made to recognize inclusion of this amount as both recovery of gas cost and gas purchase expense by Company witness Siegler. 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. Additionally, an adjustment was made to correctly reflect a utility expense that was originally classified as Advertising. The remaining historic test year level of $2,160,296 represents other utility costs, such as electric and telecommunications (internet service, cell phones, land lines, etc.), not recovered through the 1307(f) process.

L. <u>Advertising</u>

Exhibit 4: *Schedule 1, Page 2, Line 15; Schedule 2, Page 15*

Q. Was advertising adjusted?

A. Yes. Columbia has made an adjustment to remove the expenses associated with its advertising that do not represent a recoverable operating expense. The Company has removed $171,829 of brand advertising and other small misclassified items from HTY costs. Please see Exhibit 4, Schedule 2, page 15 for details.

M. <u>Materials and Supplies</u>

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. Please see Exhibit 4, Schedule 2, page 16 for details.

N. <u>Other O&M</u>

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 non-recurring costs totaling $351,664. Please see Exhibit 4, Schedule 2, page 17 for details.

O. <u>Commission, OCA and OSBA Assessments</u>

Exhibit 4: *Schedule 1, Page 2, Line 19; Schedule 2, Page 18*

Q. Please explain the $117,663 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 $2,386,816 reflects the most recent invoice amount (September 10, 2021) received as of the submission of this base rate filing.

P. <u>NiSource Corporate Services Company ("NCSC")</u>

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 provides a range of services to the individual operating companies within NiSource, including Columbia, and also coordinates the allocation and billing of charges to the NiSource operating companies for services provided by both NCSC directly and by third-party vendors. NCSC was established to provide centralized services economically and efficiently. The rendering of services on a centralized basis enables Columbia to realize substantial economic and other benefits such as efficient use of personnel and equipment, and the availability of personnel with specialized areas of expertise.

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 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 2021;
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 $68,856,996.

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 2021 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 22. Net NCSC labor, payroll taxes and benefits adjustment is determined by applying the percentage of NCSC labor charged to O&M and is derived on Exhibit 4 Schedule 2 Page 21 Line 27.

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. Exhibit 4, Schedule 2, Page 23 shows that no adjustment is required as the HTY correctly reflects the annualized level of amortization expense of $90,313. Columbia anticipates that this Regulatory Asset will be fully amortized during the FPFTY, in June 2023.

R. Charitable Contributions

Exhibit 4: *Schedule 1, Page 2, Line 23; 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. <u>Rate Case Expense Normalization</u>

Exhibit 4: *Schedule 1, Page 2, Line 24; 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 cases has been removed from the pro forma HTY expense and are detailed in lines 1 through 4. On line 5, 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, and Page 16. 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. <u>Uncollectible Accounts Expense</u>

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 29 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, 2019, 2020 and 2021 to determine an uncollectible experience factor to produce normalized uncollectible expense for this the HTY, FTY and FPFTY.

Q. Has Columbia continued the deferral of incremental Uncollectible Expense relating to COVID-19 as permitted by the Commission's Order for Columbia's previous base rate case?

A. Yes. Columbia is permitted to defer incremental Uncollectible Expense through December 29, 2021. During the Twelve Months Ended November 30, 2021, or the HTY, Columbia deferred $2,060,776 of incremental Uncollectible Expense to a Regulatory Asset.

Q. Is the Company proposing recovery of deferred Uncollectible Expense due to COVID-19 in this immediate proceeding?

A. Yes. As permitted in Final Order for Columbia's previous base rate case, R-2021-3024296, recovery of previously deferred incremental Uncollectible Expense, begins January 1, 2021. Columbia is proposing to update to the final amounts, the deferral and recovery of incremental Uncollectible Expense, which I address later in my testimony.

U. Normal Uncollectible Accounts

(Uncollectible Accounts & Uncollectible Accounts – Unbundled Gas)

Exhibit 4: *Schedule 1, Page 2, Line 25, 26 & 27; Schedule 2, Pages 26 – 28*

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, 2019, 2020 and 2021. 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 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 Siegle (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 Siegler 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 total increase to expense of $1,588,374 as shown on Exhibit 4, Schedule 1, Page 2, Lines 25, 26 and 27. This amount has been developed by comparing an annualized DIS net write-off as described above and comparing that to the actual uncollectible expense level recorded in Columbia's historic test year ending November 30, 2021. Note also that the COVID-19 Deferral amount on line 27 has been incorporated into this adjustment as a reduction to the "Per Books" Uncollectible Accounts Expense.

V. <u>Rider USP Costs</u>

(Uncollectible CAP – Rider USP & Rider USP – LIURP/Energy Efficiency)

Exhibit 4: *Schedule 1, Page 2, Line 28; Schedule 2, Page 29*

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 29.

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 $41,231,122 for the normalized HTY as determined by Company witness Siegler. Consequently, the adjustment reflects changes that are necessary to match the expense with the revenues supported by Company witness Siegler. 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. <u>Interest on Customer Deposits</u>

Exhibit 4: *Schedule 1, Page 2, Line 29; Schedule 2, Page 30*

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 3% 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 Proforma 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

$82,151,953 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 $82,151,953 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 effective State Income Tax rate is then applied at 9.99%. 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 11 by Total Sales and Transportation Revenues on Exhibit 102, Schedule 3, Page 3, Column 8, Line 9. 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. FTY/FPFTY – Exhibit 104 – Operations and Maintenance Expense

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 (Columns 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) followed by the differences (Columns 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 & Bly.

Q. Did you utilize the O&M budget for all the O&M items on Exhibit No. 104?

A. No. Lines 1 through 21 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 23 through 29 of these same pages. These items include:

- Line 23 – 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 24– 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 Siegler.
- Lines 25 & 26 – Uncollectible Accounts – Unbundled – Gas & Total Rider USP – the amounts are adjusted to reflect the amounts included in revenues as provided by Company witness Siegler.
- Line 27 – Interest on Customer Deposits – this item is not included in the O&M budget.
- Line 28 – COVID Amortization is a new item beginning in 2022.
- Line 29 – 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) Removal of non-recurring expense for NiSource Next from Other O&M;
j) NCSC costs adjusted to annualize labor and remove non-recoverable items;
k) Removal of other lobbying expenses from Company Memberships and Materials and Supplies;
l) Normalization of rate case expense;
m) Adjust Uncollectible expense;
n) Adjust Rider USP expense to match revenue;
o) Adjustment for COVID-19 Deferral of Uncollectible Expense Amortization; and
p) Other Adjustments to the FPFTY.

A. Labor

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 $515,401 and for the FPFTY of $444,966. 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 52.54% 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. Prepaid Pension Deferral Amortization Adjustment

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 $1,653,000 and $1,769,000, 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. <u>Rents and Leases</u>

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 a decrease to the budget of $811,981 for the FTY claim and a decrease of $802,824 for the FPFTY claim.

Q. Were there additional adjustments to rents and leases for the FTY and FPFTY besides the annualization adjustments?

A. Yes. The FTY and the FPFTY both include the elimination of rents for Uniontown and Connellsville to reflect the construction of a new Company-owned facility for the Uniontown Operation Center. Also the FTY and the FPFTY no longer includes lease expense for the Monaca Training Center which was purchased in December 2021.

F. <u>Injuries and Damages</u>

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 $327,676 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, 2021.

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G. <u>Utilities and Gas Used in Company Operations</u>

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. <u>Advertising</u>

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. <u>NiSource Corporate Services Company "NCSC"</u>

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 3% increase of budgeted labor charges from December 2021 through February 2022, which annualizes labor for the months prior to the budgeted annual 3% 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 2023 through February 2023.

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. <u>Other Lobbying Expense</u>

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. <u>Normalization – Rate Case Expenses</u>

Exhibit 104: *Schedule 1, Page 2, Line 23; 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, demand forecasting 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 $1,254,200. Columbia proposes to normalize these costs over twelve months.

L. <u>Normal Uncollectible Accounts Expense</u>

(Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

Exhibit 104: *Schedule 1, Page 2, Line 24 & 25; 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 $1,581,571 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 Siegler. 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>Total Rider USP Costs</u>

Exhibit 104: *Schedule 1, Page 2, Line 26; Schedule 2, Page 16*

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 $42,206,902 for the FTY and $42,198,344 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 Siegler computes the increase to Rider USP resulting from the proposed rate increase.

N. <u>Amortization of Deferred COVID-19 Uncollectible Expense</u>

Exhibit 104: *Schedule 1, Page 2, Line 28; Schedule 2, Page 17*

Q. Was Columbia granted permission to defer and amortize incremental uncollectible expense due to COVID-19?

A. Yes. The Final Order from Columbia's prior base rate case, R-2021-3024296 included the following, starting on Page 13:

> COVID-19 Related Uncollectible Accounts Expense — The Company agrees to discontinue the deferral of COVID-19

> related Uncollectibles Accounts Expense as of the implementation dates of the rates contemplated by this Settlement, or earlier if directed by the Commission. The amount of $5,579,245 representing deferrals through December 31, 2020 shall be amortized over a five-year period beginning January 1, 2022. The Company shall introduce its claim for incremental uncollectible expenses subsequent to December 31, 2020 in its next base rate proceeding.

Q. Is Columbia updating its deferral for incremental Uncollectible Expense due to COVID-19 in this proceeding?

A. Yes. As presented on Page 17 of Exhibit 104, Schedule 2, the Company has included an annual amount of amortization in the FTY, as approved in the order, in the amount of $1,115,849. For the FPFTY, the deferral has been updated to include all adjustments to the deferral through December 29, 2021 (the implementation date of new base rates), which is an overall decrease of $415,033. Columbia is proposing to defer the resulting balance of $4,048,363 over 4 years, or $1,012,091 annually, which is the level of amortization for this item that is included in the FPFTY.

O. Other Adjustments

Exhibit 104: *Schedule 1, Page 2, Line 29; Schedule 2, Page 18*

Q. Please explain the FPFTY other adjustments.

A. The Company has identified the following proposed O&M adjustments for the FTY that are not in the budget:

- Lines 1 through 3 – Additional O&M for Labor Expense, along with the associated Benefits, Incentive Compensation and Payroll Taxes (Supported by Witness Paloney, Statement No. 9).

For the FPFTY, the following adjustments for O&M Expense are included

- Line 4 – Additional O&M Expense for Cross Bores (supported by Company witness Curtis Anstead, Columbia Statement No. 14).
- Line 5 – Additional O&M Expense for Abnormal Operating Conditions Remediation (supported by Company witness Curtis Anstead, Columbia Statement No. 14).
- Line 6 – Additional O&M Expense for Picarro (supported by Company witness Curtis Anstead, Columbia Statement No. 14).
- Lines 7 & 8 – Additional O&M for Labor Expense, along with the associated Benefits, Incentive Compensation and Payroll Taxes (Supported by Witness Paloney, Statement No. 9).
- Line 9 – Additional O&M Expense for Additional Safety Positions (supported by Company witness Curtis Anstead, Columbia Statement No. 14).
- Line 10 – Additional O&M Expense for Natural Gas Methane Gas Detectors (supported by Company witness Curtis Anstead, Columbia Statement No. 14).
- Line 11 – Additional O&M Expense for Education Costs.
- Line 12 – Additional O&M Expense for Blackline Safety Devices (supported by Company witness Curtis Anstead, Columbia Statement No. 14).

Q. Does this complete your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
v.	)	Docket No. R-2022-3031211
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
JOHN J. SPANOS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

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 college graduation in 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 and February 2018.

Q. Will you outline your experience in the field of depreciation?

A. I have over 35 years of depreciation experience which includes expert testimony in over 390 cases before approximately 41 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 700 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, 2021. Exhibit No. 109, Schedule No. 1, Attachment A presents the results of the depreciation study as of November 30, 2022. Exhibit No. 109, Schedule No. 1, Attachment B presents the results of the depreciation study as of December 31, 2023. 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 "2021 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2021," includes the results of the depreciation study as related to the original cost as of November 30, 2021. The report also includes the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment A, titled "2022 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2022," includes the results of the depreciation study as related to the estimated original cost as of November 30, 2022. 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 "2023 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2023," includes the results of the depreciation study as related to the estimated original cost as of December 31, 2023.

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 at November 30, 2022, and December 31, 2023.

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 2017?

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, 2022, estimated?

A. The book reserve as of November 30, 2022, 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, 2021. Annual accruals were estimated using the annual accruals calculated as of November 30, 2021. 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, 2022.

Q. Was the book reserve as of December 31, 2023, 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 2016. 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 1939-2016. 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 2017 through 2021.

Table 1, pages V-4 through V-6 presents the estimated survivor curve, the original cost as of November 30, 2022, 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, 2022, of the book depreciation reserve as of November 30, 2021. 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, 2017 through 2021.

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, 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. 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, 2023, are organized and presented in the same manner as those as of November 30, 2022.

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, 2021. 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, 2021, are organized and presented in the same manner as those as of November 30, 2022.

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 67 percent of the original cost of depreciable gas plant as of November 30, 2022.

The retirement rate method was used to analyze the survivor characteristics of this group. The life tables for the 1939-2016 and 1977-2016 experience bands are presented on pages VI-51 through VI-58 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 71-R1, on page VI-50.

The calculations of the annual depreciation related to the original cost as of November 30, 2021, of gas plant are presented by type main on pages II-31 through II-37 of Exhibit No. 9. The calculation is based on the 71-R1 survivor curve, the attained age, and the allocated book reserve. The calculations as of November 30, 2022, are presented by type main on pages VII-33 through VII-37 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, 2023 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 2016 through 2020 for the calculation as of November 30, 2021, and on experience during the period 2017 through November 30, 2021, plus estimates for the last month of 2021 for the calculation as of November 30, 2022.

The amortization for the December 31, 2023 calculation is based on experience during the period 2018 through November 30, 2021, plus estimates for the period December 2021 through December 2022. 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, 2023, of the plant and book depreciation reserve as of November 30, 2022

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 and February 2018.

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 Pipeline Company Ltd., Interprovincial Pipeline 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 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 and Newtown Artesian 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-	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-	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.		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

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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 Commission	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.	201	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	201	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	201	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.		IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	201	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	201	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	201	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	201	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	201	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	201	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	201	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	201	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	201	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	201	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	201	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	201	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	201	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	201	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	201	WA UTC	Docket UE-19 / UG-19	Puget Sound Energy	Depreciation
320.	201	PA PUC	Docket No. R-2019-	City of Lancaster	Depreciation
321.	201	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	201	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	201	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	201	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	201	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. Com.	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.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
331.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
334.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
335.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
336.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
337.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
338.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation
339.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
340.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West	Depreciation
341.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
342.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
343.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
344.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
345.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
346.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
347.	2020	OR PSC	UE 374	Pacificorp	Depreciation
348.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
349.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
350.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy	Depreciation
351.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
352.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
353.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
354.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
355.	2020	OR PSC	UE 388	Northwest Natural Gas Company	Depreciation
356.	2020	MO PSC	Case No. GR-2021-0241	Ameren Missouri Gas	Depreciation
357.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
358.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
359.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
360.	2021	NC Util. Com.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
361.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
362.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation
363.	2021	KS PSC	21-BHCG-418-RTS	Black Hills Kansas Gas	Depreciation
364.	2021	KY PSC	Case No. 2021-00190	Duke Energy Kentucky	Depreciation
365.	2021	OR PSC	Docket UM 2152	Portland General Electric	Depreciation
366.	2021	ILL CC	Docket No. 20-0810	North Shore Gas Company	Depreciation
367.	2021	FERC	ER21-1939-000	Duke Energy Progress	Depreciation
368.	2021	FERC	ER21-1940-000	Duke Energy Carolina	Depreciation
369.	2021	KY PSC	Case No. 2021-00183	NiSource Columbia Gas of Kentucky	Depreciation
370.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation
370.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
371.	2021	OH PUC	Case No. 21-0596-ST-AIR	Aqua Ohio	Depreciation
372.	2021	PA PUC	Docket No. R-2021-3026116	Hanover Borough Municipal Water Works	Depreciation
373.	2021	OR PSC	UM-2180	Idaho Power Company	Depreciation
374.	2021	ID PUC	Case No. IPC-E-21-18	Idaho Power Company	Depreciation
375.	2021	WPSC	6690-DU-104	Wisconsin Public Service Company	Depreciation
376.	2021	PAPUC	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
377.	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
378.	2021	TX PUC	Texas PUC Docket No. 52195; SOHA Docket No. 473-21-2606	El Paso Electric	Depreciation
379.	2021	MO PSC	Case No. GR.2021-0108	Spire Missouri	Depreciation
380.	2021	WV PSC	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
381.	2021	FERC	ER21-2736	Duke Energy Carolinas	Depreciation
382.	2021	FERC	ER21-2737	Duke Energy Progress	Depreciation
383.	2021	IN URC	Cause #45621	Northern Indiana Public Service Company	Depreciation
384.	2021	PA PUC	Docket No. R-2021-3026682	City of Lancaster	Depreciation
385.	2021	OH PUC	Case No. 21-887-EL-AIR; Case No. 21-888-EL-ATA; Case No. 889-El-AAM	Duke Energy Ohio	Depreciation
386.	2021	AK PSC	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
387.	2021	OK CC	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
388.	2021	FERC	Case ER-22-392-001	El Paso Electric	Depreciation
389.	2021	FERC	Case ER-21-XXX	MidAmerican Electric	Depreciation
390.	2021	ILL CC		MidAmerican Gas	Depreciation
391.	2022	MO PSC	Case No. ER-2022-0129	Evergy Metro	Depreciation
392.	2022	MO PSC	Case No. ER-2022-0130	Evergy Missouri West	Depreciation

PLANT ROLLFORWARD

Account	2022 NOV 30 Begin. Balance	2022 DECEMBER Additions	Retirements	Ending Balance	2023 JANUARY Additions	Retirements	Ending Balance
350.20	1,932.08			1,932.08			1,932.08
351.00	3,294,840.03			3,294,840.03			3,294,840.03
352.01	1,126,771.93			1,126,771.93			1,126,771.93
352.02	1,072,969.88			1,072,969.88			1,072,969.88
352.10	206,940.78			206,940.78			206,940.78
353.00	389,345.13			389,345.13			389,345.13
354.00	948,176.70			948,176.70			948,176.70
355.00	104,476.92			104,476.92			104,476.92
374.40	4,619,075.10	35,829.23	1,920.00	4,652,984.33	10,334.59	414.22	4,662,904.70
374.50	3,233,171.42			3,233,171.42			3,233,171.42
375.34	6,857,841.44	157,499.34	8,440.00	7,006,900.78	45,429.12	2,011.19	7,050,318.71
375.60	86,227.87			86,227.87			86,227.87
375.70	42,192,056.20	225,930.00		42,417,986.20			42,417,986.20
375.80	16,515.17			16,515.17			16,515.17
376.00	2,380,709,588.84	33,449,126.08	1,762,327.33	2,412,396,387.59	10,847,542.17	933,634.43	2,422,310,295.33
378.00	157,110,988.70	5,668,205.85	85,040.65	162,694,153.90	2,054,886.21	88,392.93	164,660,647.18
379.10	135,966.90			135,966.90			135,966.90
380.00	759,473,453.76	11,986,253.43	636,966.09	770,822,741.10	3,947,944.38	248,202.04	774,522,483.44
381.00	43,392,683.65	192,731.61	12,150.60	43,573,264.66	58,296.03	2,963.97	43,628,596.72
381.10	24,862,040.62	34,011.46		24,896,052.08	10,287.54		24,906,339.62
382.00	43,792,490.50	237,007.10	12,700.62	44,016,796.98	71,397.17	3,109.01	44,085,085.14
383.00	19,953,375.20	139,026.83	7,450.11	20,084,951.92	49,442.15	2,005.35	20,132,388.72
385.00	7,654,727.16	164,217.33	8,800.00	7,810,144.49	47,366.86	2,092.08	7,855,419.27
387.00	136,698.14			136,698.14			136,698.14
387.40	11,890,928.02			11,890,928.02			11,890,928.02
387.50	2,201,371.95			2,201,371.95			2,201,371.95
390.10	49,821.42			49,821.42			49,821.42
391.10	2,706,692.18		11,485.98	2,695,206.20			2,695,206.20
391.11	91,303.67			91,303.67			91,303.67
391.12	2,178,866.80		1,647,829.26	531,037.54			531,037.54
392.00	25,616.89			25,616.89			25,616.89
394.00	27,423,137.06	1,345,572.41	1,134,742.92	27,633,966.55	85,632.31		27,719,598.86
394.12	0.00			0.00			0.00
395.00	266,039.42		1,118.18	264,921.24			264,921.24
396.00	948,698.04			948,698.04			948,698.04
397.50	1,888,281.55	211,691.06	11,344.00	2,088,628.61	47,210.18	6,393.44	2,129,445.35
398.00	950,950.58		136.82	950,813.76			950,813.76
303.00	47,459,794.63	4,149,711.36	459,807.81	51,149,698.18		129,276.91	51,020,421.27
303.60	10,074,348.44	2,030,834.76		12,105,183.20			12,105,183.20
362.10				0.00			0.00
375.71	6,363,928.38	217,070.00		6,580,998.38			6,580,998.38
Total Plant	**3,615,892,133.15**	**60,244,717.85**	**5,802,260.37**	**3,670,334,590.63**	**17,275,768.71**	**1,418,495.57**	**3,686,191,863.77**

PLANT ROLLFORWARD

	2023			2023		
	FEBRUARY			MARCH		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,294,840.03			3,294,840.03
352.01			1,126,771.93			1,126,771.93
352.02			1,072,969.88			1,072,969.88
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	14,790.06	472.59	4,677,222.17	12,953.65	804.04	4,689,371.78
374.50			3,233,171.42			3,233,171.42
375.34	65,014.62	1,985.76	7,113,347.57	56,942.09	3,151.67	7,167,137.99
375.60			86,227.87			86,227.87
375.70			42,417,986.20			42,417,986.20
375.80			16,515.17			16,515.17
376.00	15,524,158.26	1,113,067.55	2,436,721,386.04	13,596,603.82	1,370,366.55	2,448,947,623.31
378.00	2,940,793.23	85,084.32	167,516,356.09	2,575,650.15	110,116.11	169,981,890.13
379.10			135,966.90			135,966.90
380.00	5,649,990.79	285,547.37	779,886,926.86	4,948,460.66	444,933.55	784,390,453.97
381.00	83,428.75	3,032.68	43,708,992.79	73,069.83	4,903.37	43,777,159.25
381.10	14,722.71		24,921,062.33	12,894.67		24,933,957.00
382.00	102,178.08	3,145.81	44,184,117.41	89,491.15	5,057.40	44,268,551.16
383.00	70,757.74	2,249.54	20,200,896.92	61,972.12	3,799.09	20,259,069.95
385.00	67,787.76	2,072.82	7,921,134.21	59,370.90	3,295.94	7,977,209.17
387.00			136,698.14			136,698.14
387.40			11,890,928.02			11,890,928.02
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,695,206.20			2,695,206.20
391.11			91,303.67			91,303.67
391.12			531,037.54			531,037.54
392.00			25,616.89			25,616.89
394.00	122,550.30		27,842,149.16	107,333.87		27,949,483.03
394.12			0.00			0.00
395.00			264,921.24			264,921.24
396.00			948,698.04			948,698.04
397.50	67,563.53	6,393.44	2,190,615.44	59,174.52	6,604.74	2,243,185.22
398.00			950,813.76			950,813.76
303.00		95,510.34	50,924,910.93		12,408.54	50,912,502.39
303.60			12,105,183.20			12,105,183.20
362.10			0.00			0.00
375.71			6,580,998.38			6,580,998.38
Total Plant	**24,723,735.83**	**1,598,562.22**	**3,709,317,037.38**	**21,653,917.43**	**1,965,441.00**	**3,729,005,513.81**

PLANT ROLLFORWARD

	2023			2023		
	APRIL			MAY		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,294,840.03			3,294,840.03
352.01			1,126,771.93			1,126,771.93
352.02			1,072,969.88			1,072,969.88
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	11,412.01	1,557.19	4,699,226.60	14,038.50	2,239.49	4,711,025.61
374.50			3,233,171.42			3,233,171.42
375.34	50,165.30	5,425.33	7,211,877.96	61,710.91	8,084.20	7,265,504.67
375.60			86,227.87			86,227.87
375.70		1,512.62	42,416,473.58			42,416,473.58
375.80			16,515.17			16,515.17
376.00	11,978,444.20	1,489,102.60	2,459,436,964.91	14,735,301.07	1,799,489.20	2,472,372,776.78
378.00	2,269,116.76	364,054.87	171,886,952.02	2,791,357.37	396,579.32	174,281,730.07
379.10			135,966.90			135,966.90
380.00	4,359,534.23	476,434.42	788,273,553.78	5,362,887.57	570,373.34	793,066,068.01
381.00	64,373.63	8,729.69	43,832,803.19	79,189.34	12,873.01	43,899,119.52
381.10	11,360.06		24,945,317.06	13,974.58		24,959,291.64
382.00	78,840.63	8,912.99	44,338,478.80	96,985.91	13,184.38	44,422,280.33
383.00	54,596.69	7,273.35	20,306,393.29	67,162.21	10,495.25	20,363,060.25
385.00	52,305.05	5,693.24	8,023,820.98	64,343.13	8,474.27	8,079,689.84
387.00			136,698.14			136,698.14
387.40			11,890,928.02			11,890,928.02
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,695,206.20			2,695,206.20
391.11			91,303.67			91,303.67
391.12			531,037.54			531,037.54
392.00			25,616.89			25,616.89
394.00	94,559.84		28,044,042.87	116,322.93		28,160,365.80
394.12			0.00			0.00
395.00			264,921.24			264,921.24
396.00			948,698.04			948,698.04
397.50	52,132.04	7,027.34	2,288,289.92	64,130.30	7,661.24	2,344,758.98
398.00			950,813.76			950,813.76
303.00			50,912,502.39			50,912,502.39
303.60			12,105,183.20			12,105,183.20
362.10			0.00			0.00
375.71		1,453.31	6,579,545.07			6,579,545.07
Total Plant	**19,076,840.44**	**2,377,176.95**	**3,745,705,177.30**	**23,467,403.82**	**2,829,453.70**	**3,766,343,127.42**

PLANT ROLLFORWARD

	2023			2023		
	JUNE			JULY		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,294,840.03			3,294,840.03
352.01			1,126,771.93			1,126,771.93
352.02			1,072,969.88			1,072,969.88
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	19,305.53	2,166.87	4,728,164.27	16,677.48	1,905.48	4,742,936.27
374.50			3,233,171.42			3,233,171.42
375.34	84,863.91	7,891.92	7,342,476.66	73,311.41	7,840.40	7,407,947.67
375.60			86,227.87			86,227.87
375.70	204,296.98	12,303.94	42,608,466.62		1,844.68	42,606,621.94
375.80			16,515.17			16,515.17
376.00	20,263,762.98	1,916,417.65	2,490,720,122.11	17,505,262.27	2,022,248.48	2,506,203,135.90
378.00	3,838,632.41	387,942.45	177,732,420.03	3,316,080.40	445,370.84	180,603,129.59
379.10			135,966.90			135,966.90
380.00	7,374,961.80	669,628.38	799,771,401.43	6,371,010.21	668,736.06	805,473,675.58
381.00	108,899.97	12,534.52	43,995,484.97	94,075.45	12,039.97	44,077,520.45
381.10	19,217.64		24,978,509.28	16,601.55		24,995,110.83
382.00	133,373.56	12,847.63	44,542,806.26	115,217.45	12,467.93	44,645,555.78
383.00	92,360.45	10,163.60	20,445,257.10	79,787.44	9,049.49	20,515,995.05
385.00	88,483.71	8,270.53	8,159,903.02	76,438.44	8,188.60	8,228,152.86
387.00			136,698.14			136,698.14
387.40			11,890,928.02			11,890,928.02
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,695,206.20			2,695,206.20
391.11			91,303.67			91,303.67
391.12			531,037.54			531,037.54
392.00			25,616.89			25,616.89
394.00	159,965.54		28,320,331.34	138,189.47		28,458,520.81
394.12			0.00			0.00
395.00			264,921.24			264,921.24
396.00			948,698.04			948,698.04
397.50	88,191.02	7,661.24	2,425,288.76	76,185.60	7,661.24	2,493,813.12
398.00			950,813.76			950,813.76
303.00	5,767,659.62		56,680,162.01			56,680,162.01
303.60	1,142,958.88		13,248,142.08			13,248,142.08
362.10			0.00			0.00
375.71	196,285.34	11,821.43	6,764,008.98		1,772.33	6,762,236.65
Total Plant	**39,583,219.34**	**3,059,650.16**	**3,802,866,696.60**	**27,878,837.17**	**3,199,125.50**	**3,827,546,408.27**

PLANT ROLLFORWARD

	2023			2023		
	AUGUST			SEPTEMBER		
Account	**Additions**	**Retirements**	**Ending Balance**	**Additions**	**Retirements**	**Ending Balance**
350.20			1,932.08			1,932.08
351.00			3,294,840.03			3,294,840.03
352.01			1,126,771.93			1,126,771.93
352.02			1,072,969.88			1,072,969.88
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	27,058.65	1,634.87	4,768,360.05	22,757.85	2,015.88	4,789,102.02
374.50			3,233,171.42			3,233,171.42
375.34	118,945.30	8,524.87	7,518,368.10	100,039.70	9,457.12	7,608,950.68
375.60			86,227.87			86,227.87
375.70		10,606.84	42,596,015.10	204,296.98	22,763.20	42,777,548.88
375.80			16,515.17			16,515.17
376.00	28,401,699.94	2,070,482.29	2,532,534,353.55	23,887,430.84	2,246,613.80	2,554,175,170.59
378.00	5,380,229.05	504,587.71	185,478,770.93	4,525,075.95	550,356.65	189,453,490.23
379.10			135,966.90			135,966.90
380.00	10,336,750.01	821,399.05	814,989,026.54	8,693,789.51	753,421.60	822,929,394.45
381.00	152,634.25	12,361.66	44,217,793.04	128,374.01	14,051.06	44,332,115.99
381.10	26,935.45		25,022,046.28	22,654.23		25,044,700.51
382.00	186,936.45	13,033.58	44,819,458.65	157,224.09	14,700.85	44,961,981.89
383.00	129,452.45	7,987.79	20,637,459.71	108,876.81	9,718.28	20,736,618.24
385.00	124,018.80	8,854.09	8,343,317.57	104,306.80	9,845.20	8,437,779.17
387.00			136,698.14			136,698.14
387.40			11,890,928.02			11,890,928.02
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,695,206.20			2,695,206.20
391.11			91,303.67			91,303.67
391.12			531,037.54			531,037.54
392.00			25,616.89			25,616.89
394.00	224,207.77		28,682,728.58	188,571.38		28,871,299.96
394.12			0.00			0.00
395.00			264,921.24			264,921.24
396.00			948,698.04			948,698.04
397.50	123,608.58	7,661.24	2,609,760.46	103,961.79	7,661.24	2,706,061.01
398.00			950,813.76			950,813.76
303.00		386,186.58	56,293,975.43	5,767,659.62	201,376.39	61,860,258.66
303.60			13,248,142.08	1,142,958.88		14,391,100.96
362.10			0.00			0.00
375.71		10,190.89	6,752,045.76	196,285.34	21,870.53	6,926,460.57
Total Plant	**45,232,476.70**	**3,863,511.46**	**3,868,915,373.51**	**45,354,263.78**	**3,863,851.80**	**3,910,405,785.49**

PLANT ROLLFORWARD

	2023			2023		
	OCTOBER			NOVEMBER		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,294,840.03			3,294,840.03
352.01			1,126,771.93			1,126,771.93
352.02			1,072,969.88			1,072,969.88
352.10			206,940.78			206,940.78
353.00			389,345.13			389,345.13
354.00			948,176.70			948,176.70
355.00			104,476.92			104,476.92
374.40	30,532.11	2,284.25	4,817,349.88	24,310.34	1,789.04	4,839,871.18
374.50			3,233,171.42			3,233,171.42
375.34	134,214.07	8,560.95	7,734,603.80	106,864.22	9,825.84	7,831,642.18
375.60			86,227.87			86,227.87
375.70			42,777,548.88			42,777,548.88
375.80			16,515.17			16,515.17
376.00	32,047,569.19	1,938,597.35	2,584,284,142.43	25,516,985.73	1,629,157.78	2,608,171,970.38
378.00	6,070,878.25	227,149.97	195,297,218.51	4,833,767.97	278,255.03	199,852,731.45
379.10			135,966.90			135,966.90
380.00	11,663,657.88	790,980.81	833,802,071.52	9,286,863.23	832,900.73	842,256,034.02
381.00	172,227.59	13,486.42	44,490,857.16	137,131.44	14,089.04	44,613,899.56
381.10	30,393.11		25,075,093.62	24,199.67		25,099,293.29
382.00	210,933.10	13,857.43	45,159,057.56	167,949.62	14,908.57	45,312,098.61
383.00	146,070.00	10,744.19	20,871,944.05	116,304.17	8,802.83	20,979,445.39
385.00	139,938.85	8,964.15	8,568,753.87	111,422.41	10,194.53	8,669,981.75
387.00			136,698.14			136,698.14
387.40			11,890,928.02			11,890,928.02
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,695,206.20			2,695,206.20
391.11			91,303.67			91,303.67
391.12			531,037.54			531,037.54
392.00			25,616.89			25,616.89
394.00	252,988.88		29,124,288.84	201,435.36		29,325,724.20
394.12			0.00			0.00
395.00			264,921.24			264,921.24
396.00			948,698.04			948,698.04
397.50	139,475.97	7,661.24	2,837,875.74	111,053.86	7,661.24	2,941,268.36
398.00			950,813.76			950,813.76
303.00		234,667.17	61,625,591.49		880,884.53	60,744,706.96
303.60			14,391,100.96		96,632.76	14,294,468.20
362.10			0.00			0.00
375.71			6,926,460.57			6,926,460.57
Total Plant	**51,038,879.00**	**3,256,953.93**	**3,958,187,710.56**	**40,638,288.02**	**3,785,101.92**	**3,995,040,896.66**

PLANT ROLLFORWARD

	2023		
	DECEMBER		
Account	Additions	Retirements	Ending Balance
350.20			1,932.08
351.00			3,294,840.03
352.01			1,126,771.93
352.02			1,072,969.88
352.10			206,940.78
353.00			389,345.13
354.00			948,176.70
355.00			104,476.92
374.40	35,829.23	1,916.08	4,873,784.33
374.50			3,233,171.42
375.34	157,499.34	11,640.76	7,977,500.76
375.60			86,227.87
375.70	204,296.98		42,981,845.86
375.80			16,515.17
376.00	37,607,614.29	1,669,633.60	2,644,109,951.07
378.00	7,124,136.19	333,936.84	206,642,930.80
379.10			135,966.90
380.00	13,687,226.77	772,088.82	855,171,171.97
381.00	202,107.97	16,351.85	44,799,655.68
381.10	35,666.11		25,134,959.40
382.00	247,528.63	17,418.90	45,542,208.34
383.00	171,412.19	9,566.79	21,141,290.79
385.00	164,217.33	12,054.56	8,822,144.52
387.00			136,698.14
387.40			11,890,928.02
387.50			2,201,371.95
390.10			49,821.42
391.10		96,741.60	2,598,464.60
391.11			91,303.67
391.12		173,736.13	357,301.41
392.00			25,616.89
394.00	296,880.80	383,704.26	29,238,900.74
394.12			0.00
395.00			264,921.24
396.00			948,698.04
397.50	163,674.14	7,661.24	3,097,281.26
398.00		2,264.03	948,549.73
303.00	5,767,659.62	1,188,910.80	65,323,455.78
303.60	1,142,958.88		15,437,427.08
362.10			0.00
375.71	196,285.34		7,122,745.91
Total Plant	**67,204,993.81**	**4,697,626.26**	**4,057,548,264.21**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023			2022							
	2022	'Accrual			'5-yr			'5-yr	DECEMBER							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS								
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,606,581
352.01	834,026	8.44							7,925	0	7,925	0	0	0		841,951
352.02	392,390	20.72							18,527	0	18,527	0	0	0		410,917
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		388,923
354.00	849,418	3.41							2,694	0	2,694	0	0	0		852,112
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,529	829	7,358	1,920	154	0		933,047
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,829,777
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	13,403	2,826	16,228	8,440	3,292	0		1,482,982
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,011
375.70	5,155,365	2.82	0.00		1	0.00		1	99,417	0	99,417	0	0	0		5,254,782
375.80	8,614	2.15							30	0	30	0	0	0		8,644
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,293,824	106,951	4,400,775	1,762,327	158,609	0		341,172,579
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	534,341	18,079	552,420	85,041	23,811	0		24,102,136
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		62,241
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	1,919,246	274,810	2,194,057	636,966	210,199	0		154,741,124
381.00	18,434,086	2.39			(17,978)			(12,056)	86,604	(1,498)	85,105	12,151	0	0		18,507,041
381.10	18,366,394	5.13							106,358	0	106,358	0	0	0		18,472,752
382.00	15,760,586	1.87			483			483	68,418	40	68,458	12,701	0	0		15,816,344
383.00	8,225,155	2.06	0.02		185	0.02		483	34,366	15	34,382	7,450	149	0		8,251,938
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	33,443	8,952	42,395	8,800	2,640	0		2,537,264
387.00	80,436	3.03							345	0	345	0	0	0		80,781
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	174	48,035	0	0	0		3,057,268
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,758,164
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,061	0	10,061	11,486	0	0		1,007,617
391.11	52,960	6.41							488	0	488	0	0	0		53,448
391.12	1,919,443	5.98							6,752	0	6,752	1,647,829	0	0		278,366
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		23,348
394.00	7,888,586	3.76			(923)			(1,253)	86,256	(77)	86,179	1,134,743	0	0	54	6,840,076
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,144	0	1,144	1,118	0	0		97,012
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		923,541
397.50	680,969	4.70			51				7,788	4	7,792	11,344	0	0		677,417
398.00	529,599	6.11							4,842	0	4,842	137	0	0		534,304
303.00	19,902,888								675,054	0	675,054	459,808	0	0		20,118,134
303.60	2,374,987								209,991	0	209,991	0	0	0		2,584,978
362.10	(156,998)				78,262			66,978	0	6,522	6,522	0	0	0		(150,476)
375.71	2,870,239								42,310	0	42,310	0	0	0		2,912,549
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,356,093**	**417,040**	**8,773,133**	**5,802,260**	**398,854**	**0**	**0**	**639,508,832**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023										
	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	JANUARY							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,626,130
352.01	834,026	8.44							7,925	0	7,925	0	0	0		849,876
352.02	392,390	20.72							18,527	0	18,527	0	0	0		429,443
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		388,950
354.00	849,418	3.41							2,694	0	2,694	0	0	0		854,807
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,560	217	6,777	414	33	0		939,377
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,832,687
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	13,589	2,772	16,361	2,011	784	0		1,496,547
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,062
375.70	5,155,365	2.82	0.00		1	0.00		1	99,682	0	99,682	0	0	0		5,354,464
375.80	8,614	2.15							30	0	30	0	0	0		8,673
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,331,091	113,936	4,445,027	933,634	84,027	0		344,599,944
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	546,955	24,881	571,836	88,393	24,750	0		24,560,829
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		64,238
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	1,938,120	274,424	2,212,545	248,202	81,907	0		156,623,560
381.00	18,434,086	2.39			(17,978)			(12,056)	86,839	(1,005)	85,834	2,964	0	0		18,589,911
381.10	18,366,394	5.13							106,453	0	106,453	0	0	0		18,579,205
382.00	15,760,586	1.87			483			483	68,646	40	68,686	3,109	0	0		15,881,921
383.00	8,225,155	2.06	0.02		185	0.02		483	34,520	40	34,560	2,005	40	0		8,284,452
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	33,877	7,495	41,372	2,092	628	0		2,575,917
387.00	80,436	3.03							345	0	345	0	0	0		81,126
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,105,296
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,772,729
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,017,657
391.11	52,960	6.41							488	0	488	0	0	0		53,935
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		281,012
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		23,142
394.00	7,888,586	3.76			(923)			(1,253)	86,721	(104)	86,616	0	0	0	54	6,926,746
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		98,153
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		922,081
397.50	680,969	4.70			51				8,260	0	8,260	6,393	0	0		679,284
398.00	529,599	6.11							4,841	0	4,841	0	0	0		539,145
303.00	19,902,888								675,054	0	675,054	129,277	0	0		20,663,912
303.60	2,374,987								209,991	0	209,991	0	0	0		2,794,970
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(144,895)
375.71	2,870,239								42,310	0	42,310	0	0	0		2,954,858
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,423,282**	**427,858**	**8,851,141**	**1,418,496**	**192,169**	**0**	**0**	**646,749,308**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023										
	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	FEBRUARY							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,645,680
352.01	834,026	8.44							7,925	0	7,925	0	0	0		857,801
352.02	392,390	20.72							18,527	0	18,527	0	0	0		447,970
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		388,978
354.00	849,418	3.41							2,694	0	2,694	0	0	0		857,501
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,577	217	6,794	473	38	0		945,661
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,835,597
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	13,692	2,772	16,464	1,986	774	0		1,510,251
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,113
375.70	5,155,365	2.82	0.00		1	0.00		1	99,682	0	99,682	0	0	0		5,454,147
375.80	8,614	2.15							30	0	30	0	0	0		8,703
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,352,883	113,936	4,466,818	1,113,068	100,176	0		347,853,519
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	555,012	24,881	579,893	85,084	23,824	0		25,031,815
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		66,235
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	1,949,488	274,424	2,223,913	285,547	94,231	0		158,467,695
381.00	18,434,086	2.39			(17,978)			(12,056)	86,974	(1,005)	85,969	3,033	0	0		18,672,847
381.10	18,366,394	5.13							106,506	0	106,506	0	0	0		18,685,711
382.00	15,760,586	1.87			483			483	68,776	40	68,817	3,146	0	0		15,947,592
383.00	8,225,155	2.06	0.02		185	0.02		483	34,619	40	34,660	2,250	45	0		8,316,817
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	34,117	7,495	41,612	2,073	622	0		2,614,834
387.00	80,436	3.03							345	0	345	0	0	0		81,471
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,153,323
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,787,295
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,027,696
391.11	52,960	6.41							488	0	488	0	0	0		54,423
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		283,659
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		22,937
394.00	7,888,586	3.76			(923)			(1,253)	87,047	(104)	86,942	0	0	0	54	7,013,743
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		99,294
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		920,621
397.50	680,969	4.70			51				8,460	0	8,460	6,393	0	0		681,351
398.00	529,599	6.11							4,841	0	4,841	0	0	0		543,986
303.00	19,902,888								675,054	0	675,054	95,510	0	0		21,243,456
303.60	2,374,987								209,991	0	209,991	0	0	0		3,004,961
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(139,313)
375.71	2,870,239								42,310	0	42,310	0	0	0		2,997,168
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,465,803**	**427,858**	**8,893,661**	**1,598,562**	**219,709**	**0**	**0**	**653,824,697**

RESERVE BRINGFORWARD

PROJECTED 2022 PROJECTED 2023

	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	MARCH							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,665,230
352.01	834,026	8.44							7,925	0	7,925	0	0	0		865,726
352.02	392,390	20.72							18,527	0	18,527	0	0	0		466,496
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,005
354.00	849,418	3.41							2,694	0	2,694	0	0	0		860,196
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,596	217	6,813	804	64	0		951,606
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,838,506
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	13,804	2,772	16,577	3,152	1,229	0		1,522,446
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,164
375.70	5,155,365	2.82	0.00		1	0.00		1	99,682	0	99,682	0	0	0		5,553,829
375.80	8,614	2.15							30	0	30	0	0	0		8,732
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,376,745	113,936	4,490,681	1,370,367	123,333	0		350,850,500
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	563,903	24,881	588,784	110,116	30,833	0		25,479,650
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		68,233
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	1,961,865	274,424	2,236,289	444,934	146,828	0		160,112,222
381.00	18,434,086	2.39			(17,978)			(12,056)	87,122	(1,005)	86,117	4,903	0	0		18,754,061
381.10	18,366,394	5.13							106,565	0	106,565	0	0	0		18,792,276
382.00	15,760,586	1.87			483			483	68,919	40	68,960	5,057	0	0		16,011,494
383.00	8,225,155	2.06	0.02		185	0.02		483	34,728	40	34,768	3,799	76	0		8,347,711
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	34,380	7,495	41,876	3,296	989	0		2,652,425
387.00	80,436	3.03							345	0	345	0	0	0		81,817
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,201,351
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,801,861
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,037,736
391.11	52,960	6.41							488	0	488	0	0	0		54,911
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		286,305
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		22,731
394.00	7,888,586	3.76			(923)			(1,253)	87,407	(104)	87,302	0	0	0	54	7,101,099
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		100,436
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		919,161
397.50	680,969	4.70			51				8,683	0	8,683	6,605	0	0		683,429
398.00	529,599	6.11							4,841	0	4,841	0	0	0		548,827
303.00	19,902,888								675,054	0	675,054	12,409	0	0		21,906,101
303.60	2,374,987								209,991	0	209,991	0	0	0		3,214,952
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(133,732)
375.71	2,870,239								42,310	0	42,310	0	0	0		3,039,477
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,512,369**	**427,858**	**8,940,227**	**1,965,441**	**303,352**	**0**	**0**	**660,496,132**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023			2023							
	2022	'Accrual			'5-yr			'5-yr	APRIL							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS								
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,684,779
352.01	834,026	8.44							7,925	0	7,925	0	0	0		873,651
352.02	392,390	20.72							18,527	0	18,527	0	0	0		485,023
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,032
354.00	849,418	3.41							2,694	0	2,694	0	0	0		862,890
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,611	217	6,828	1,557	125	0		956,752
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,841,416
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	13,900	2,772	16,672	5,425	2,116	0		1,531,577
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,215
375.70	5,155,365	2.82	0.00		1	0.00		1	99,680	0	99,681	1,513	0	0		5,651,997
375.80	8,614	2.15							30	0	30	0	0	0		8,762
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,397,095	113,936	4,511,030	1,489,103	134,019	0		353,738,408
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	571,206	24,881	596,087	364,055	101,935	0		25,609,747
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		70,230
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	1,972,383	274,424	2,246,807	476,434	157,223	0		161,725,371
381.00	18,434,086	2.39			(17,978)			(12,056)	87,245	(1,005)	86,240	8,730	0	0		18,831,571
381.10	18,366,394	5.13							106,617	0	106,617	0	0	0		18,898,893
382.00	15,760,586	1.87			483			483	69,040	40	69,080	8,913	0	0		16,071,661
383.00	8,225,155	2.06	0.02		185	0.02		483	34,819	40	34,859	7,273	145	0		8,375,151
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	34,602	7,495	42,098	5,693	1,708	0		2,687,121
387.00	80,436	3.03							345	0	345	0	0	0		82,162
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,249,379
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,816,427
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,047,776
391.11	52,960	6.41							488	0	488	0	0	0		55,399
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		288,951
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		22,526
394.00	7,888,586	3.76			(923)			(1,253)	87,723	(104)	87,619	0	0	0	54	7,188,772
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		101,577
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		917,701
397.50	680,969	4.70			51				8,874	0	8,874	7,027	0	0		685,276
398.00	529,599	6.11							4,841	0	4,841	0	0	0		553,669
303.00	19,902,888								675,054	0	675,054	0	0	0		22,581,156
303.60	2,374,987								209,991	0	209,991	0	0	0		3,424,944
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(128,150)
375.71	2,870,239								42,310	0	42,310	1,453	0	0		3,080,333
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,551,764**	**427,858**	**8,979,622**	**2,377,177**	**397,272**	**0**	**0**	**666,701,305**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023										
	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	MAY							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,704,329
352.01	834,026	8.44							7,925	0	7,925	0	0	0		881,576
352.02	392,390	20.72							18,527	0	18,527	0	0	0		503,550
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,059
354.00	849,418	3.41							2,694	0	2,694	0	0	0		865,584
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,626	217	6,844	2,239	179	0		961,177
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,844,326
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	13,995	2,772	16,767	8,084	3,153	0		1,537,107
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,266
375.70	5,155,365	2.82	0.00		1	0.00		1	99,679	0	99,679	0	0	0		5,751,676
375.80	8,614	2.15							30	0	30	0	0	0		8,792
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,418,080	113,936	4,532,015	1,799,489	161,954	0		356,308,980
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	578,390	24,881	603,271	396,579	111,042	0		25,705,397
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		72,227
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	1,983,263	274,424	2,257,688	570,373	188,223	0		163,224,463
381.00	18,434,086	2.39			(17,978)			(12,056)	87,366	(1,005)	86,362	12,873	0	0		18,905,060
381.10	18,366,394	5.13							106,671	0	106,671	0	0	0		19,005,564
382.00	15,760,586	1.87			483			483	69,159	40	69,200	13,184	0	0		16,127,676
383.00	8,225,155	2.06	0.02		185	0.02		483	34,908	40	34,948	10,495	210	0		8,399,394
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	34,824	7,495	42,319	8,474	2,542	0		2,718,424
387.00	80,436	3.03							345	0	345	0	0	0		82,507
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,297,406
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,830,992
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,057,815
391.11	52,960	6.41							488	0	488	0	0	0		55,886
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		291,598
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		22,320
394.00	7,888,586	3.76			(923)			(1,253)	88,054	(104)	87,949	0	0	0	54	7,276,775
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		102,718
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		916,241
397.50	680,969	4.70			51				9,073	0	9,073	7,661	0	0		686,688
398.00	529,599	6.11							4,841	0	4,841	0	0	0		558,510
303.00	19,902,888								675,054	0	675,054	0	0	0		23,256,210
303.60	2,374,987								209,991	0	209,991	0	0	0		3,634,935
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(122,569)
375.71	2,870,239								42,310	0	42,310	0	0	0		3,122,643
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,592,058**	**427,858**	**9,019,916**	**2,829,454**	**467,304**	**0**	**0**	**672,424,464**

RESERVE BRINGFORWARD

	2022	'Accrual	PROJECTED 2022			PROJECTED 2023			2023							
	NOV 30	Rates	COR	Salvage	'5-yr Amort of NS	COR	Salvage	'5-yr Amort of NS	JUNE							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,723,879
352.01	834,026	8.44							7,925	0	7,925	0	0	0		889,501
352.02	392,390	20.72							18,527	0	18,527	0	0	0		522,076
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,087
354.00	849,418	3.41							2,694	0	2,694	0	0	0		868,279
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,647	217	6,864	2,167	173	0		965,701
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,847,236
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	14,121	2,772	16,893	7,892	3,078	0		1,543,030
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,317
375.70	5,155,365	2.82	0.00		1	0.00		1	99,904	0	99,904	12,304	0	0		5,839,276
375.80	8,614	2.15							30	0	30	0	0	0		8,821
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,446,104	113,936	4,560,040	1,916,418	172,478	0		358,780,125
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	588,157	24,881	613,038	387,942	108,624	0		25,821,869
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		74,224
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	1,997,684	274,424	2,272,108	669,628	220,977	0		164,605,965
381.00	18,434,086	2.39			(17,978)			(12,056)	87,528	(1,005)	86,524	12,535	0	0		18,979,049
381.10	18,366,394	5.13							106,742	0	106,742	0	0	0		19,112,306
382.00	15,760,586	1.87			483			483	69,319	40	69,359	12,848	0	0		16,184,188
383.00	8,225,155	2.06	0.02		185	0.02		483	35,027	40	35,067	10,164	203	0		8,424,094
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	35,118	7,495	42,614	8,271	2,481	0		2,750,286
387.00	80,436	3.03							345	0	345	0	0	0		82,852
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,345,434
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,845,558
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,067,855
391.11	52,960	6.41							488	0	488	0	0	0		56,374
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		294,244
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		22,115
394.00	7,888,586	3.76			(923)			(1,253)	88,486	(104)	88,382	0	0	0	54	7,365,211
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		103,860
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		914,781
397.50	680,969	4.70			51				9,341	0	9,341	7,661	0	0		688,368
398.00	529,599	6.11							4,841	0	4,841	0	0	0		563,351
303.00	19,902,888								675,054	0	675,054	0	0	0		23,931,264
303.60	2,374,987								209,991	0	209,991	0	0	0		3,844,926
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(116,987)
375.71	2,870,239								42,310	0	42,310	11,821	0	0		3,153,131
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,646,149**	**427,858**	**9,074,007**	**3,059,650**	**508,014**	**0**	**0**	**677,930,806**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023										
	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	JULY							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,743,429
352.01	834,026	8.44							7,925	0	7,925	0	0	0		897,426
352.02	392,390	20.72							18,527	0	18,527	0	0	0		540,603
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,114
354.00	849,418	3.41							2,694	0	2,694	0	0	0		870,973
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,669	217	6,886	1,905	152	0		970,530
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,850,146
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	14,259	2,772	17,031	7,840	3,058	0		1,549,163
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,368
375.70	5,155,365	2.82	0.00		1	0.00		1	100,128	0	100,128	1,845	0	0		5,937,559
375.80	8,614	2.15							30	0	30	0	0	0		8,851
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,476,410	113,936	4,590,346	2,022,248	182,002	0		361,166,220
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	598,719	24,881	623,600	445,371	124,704	0		25,875,394
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		76,221
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	2,013,245	274,424	2,287,669	668,736	220,683	0		166,004,215
381.00	18,434,086	2.39			(17,978)			(12,056)	87,706	(1,005)	86,701	12,040	0	0		19,053,710
381.10	18,366,394	5.13							106,819	0	106,819	0	0	0		19,219,124
382.00	15,760,586	1.87			483			483	69,493	40	69,533	12,468	0	0		16,241,252
383.00	8,225,155	2.06	0.02		185	0.02		483	35,158	40	35,199	9,049	181	0		8,450,063
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	35,439	7,495	42,935	8,189	2,457	0		2,782,575
387.00	80,436	3.03							345	0	345	0	0	0		83,197
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,393,461
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,860,124
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,077,895
391.11	52,960	6.41							488	0	488	0	0	0		56,862
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		296,890
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		21,909
394.00	7,888,586	3.76			(923)			(1,253)	88,954	(104)	88,849	0	0	0	54	7,454,114
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		105,001
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		913,321
397.50	680,969	4.70			51				9,633	0	9,633	7,661	0	0		690,340
398.00	529,599	6.11							4,841	0	4,841	0	0	0		568,192
303.00	19,902,888								675,054	0	675,054	0	0	0		24,606,318
303.60	2,374,987								209,991	0	209,991	0	0	0		4,054,918
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(111,406)
375.71	2,870,239								42,310	0	42,310	1,772	0	0		3,193,668
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,704,601**	**427,858**	**9,132,459**	**3,199,126**	**533,237**	**0**	**0**	**683,330,903**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023										
	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	AUGUST							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,762,978
352.01	834,026	8.44							7,925	0	7,925	0	0	0		905,351
352.02	392,390	20.72							18,527	0	18,527	0	0	0		559,130
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,141
354.00	849,418	3.41							2,694	0	2,694	0	0	0		873,668
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,698	217	6,915	1,635	131	0		975,679
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,853,056
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	14,429	2,772	17,201	8,525	3,325	0		1,554,515
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,420
375.70	5,155,365	2.82	0.00		1	0.00		1	100,113	0	100,113	10,607	0	0		6,027,066
375.80	8,614	2.15							30	0	30	0	0	0		8,880
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,513,869	113,936	4,627,805	2,070,482	186,343	0		363,537,199
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	611,662	24,881	636,543	504,588	141,285	0		25,866,065
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		78,218
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	2,032,330	274,424	2,306,755	821,399	271,062	0		167,218,509
381.00	18,434,086	2.39			(17,978)			(12,056)	87,927	(1,005)	86,923	12,362	0	0		19,128,272
381.10	18,366,394	5.13							106,912	0	106,912	0	0	0		19,326,036
382.00	15,760,586	1.87			483			483	69,708	40	69,748	13,034	0	0		16,297,967
383.00	8,225,155	2.06	0.02		185	0.02		483	35,323	40	35,364	7,988	160	0		8,477,279
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	35,836	7,495	43,331	8,854	2,656	0		2,814,396
387.00	80,436	3.03							345	0	345	0	0	0		83,542
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,441,489
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,874,690
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,087,934
391.11	52,960	6.41							488	0	488	0	0	0		57,349
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		299,537
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		21,704
394.00	7,888,586	3.76			(923)			(1,253)	89,521	(104)	89,417	0	0	0	54	7,543,585
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		106,143
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		911,861
397.50	680,969	4.70			51				9,994	0	9,994	7,661	0	0		692,673
398.00	529,599	6.11							4,841	0	4,841	0	0	0		573,034
303.00	19,902,888								675,054	0	675,054	386,187	0	0		24,895,186
303.60	2,374,987								209,991	0	209,991	0	0	0		4,264,909
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(105,824)
375.71	2,870,239								42,310	0	42,310	10,191	0	0		3,225,787
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,776,292**	**427,858**	**9,204,151**	**3,863,511**	**604,961**	**0**	**0**	**688,066,581**

RESERVE BRINGFORWARD

PROJECTED 2022 PROJECTED 2023

	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	SEPTEMBER							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,782,528
352.01	834,026	8.44							7,925	0	7,925	0	0	0		913,276
352.02	392,390	20.72							18,527	0	18,527	0	0	0		577,656
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,168
354.00	849,418	3.41							2,694	0	2,694	0	0	0		876,362
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,730	217	6,947	2,016	161	0		980,449
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,855,966
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	14,623	2,772	17,395	9,457	3,688	0		1,558,764
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,471
375.70	5,155,365	2.82	0.00		1	0.00		1	100,314	0	100,314	22,763	0	0		6,104,616
375.80	8,614	2.15							30	0	30	0	0	0		8,910
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,556,844	113,936	4,670,780	2,246,614	202,195	0		365,759,169
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	626,449	24,881	651,330	550,357	154,100	0		25,812,938
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		80,216
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	2,054,223	274,424	2,328,647	753,422	248,629	0		168,545,105
381.00	18,434,086	2.39			(17,978)			(12,056)	88,181	(1,005)	87,176	14,051	0	0		19,201,397
381.10	18,366,394	5.13							107,018	0	107,018	0	0	0		19,433,054
382.00	15,760,586	1.87			483			483	69,955	40	69,995	14,701	0	0		16,353,261
383.00	8,225,155	2.06	0.02		185	0.02		483	35,513	40	35,553	9,718	194	0		8,502,919
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	36,289	7,495	43,785	9,845	2,954	0		2,845,382
387.00	80,436	3.03							345	0	345	0	0	0		83,888
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,489,516
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,889,255
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,097,974
391.11	52,960	6.41							488	0	488	0	0	0		57,837
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		302,183
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		21,498
394.00	7,888,586	3.76			(923)			(1,253)	90,168	(104)	90,064	0	0	0	54	7,633,703
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		107,284
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		910,401
397.50	680,969	4.70			51				10,410	0	10,410	7,661	0	0		695,422
398.00	529,599	6.11							4,841	0	4,841	0	0	0		577,875
303.00	19,902,888								675,054	0	675,054	201,376	0	0		25,368,864
303.60	2,374,987								209,991	0	209,991	0	0	0		4,474,900
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(100,243)
375.71	2,870,239								42,310	0	42,310	21,871	0	0		3,246,226
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,858,686**	**427,858**	**9,286,544**	**3,863,852**	**611,922**	**0**	**0**	**692,877,352**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023										
	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	OCTOBER							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,802,078
352.01	834,026	8.44							7,925	0	7,925	0	0	0		921,201
352.02	392,390	20.72							18,527	0	18,527	0	0	0		596,183
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,196
354.00	849,418	3.41							2,694	0	2,694	0	0	0		879,056
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,765	217	6,982	2,284	183	0		984,964
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,858,875
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	14,832	2,772	17,604	8,561	3,339	0		1,564,469
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,522
375.70	5,155,365	2.82	0.00		1	0.00		1	100,527	0	100,527	0	0	0		6,205,145
375.80	8,614	2.15							30	0	30	0	0	0		8,939
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,603,203	113,936	4,717,139	1,938,597	174,474	0		368,363,237
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	642,854	24,881	667,735	227,150	63,602	0		26,189,922
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		82,213
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	2,077,817	274,424	2,352,242	790,981	261,024	0		169,845,343
381.00	18,434,086	2.39			(17,978)			(12,056)	88,453	(1,005)	87,448	13,486	0	0		19,275,359
381.10	18,366,394	5.13							107,131	0	107,131	0	0	0		19,540,185
382.00	15,760,586	1.87			483			483	70,219	40	70,260	13,857	0	0		16,409,664
383.00	8,225,155	2.06	0.02		185	0.02		483	35,714	40	35,754	10,744	215	0		8,527,713
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	36,777	7,495	44,272	8,964	2,689	0		2,878,001
387.00	80,436	3.03							345	0	345	0	0	0		84,233
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,537,544
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,903,821
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,108,013
391.11	52,960	6.41							488	0	488	0	0	0		58,325
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		304,829
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		21,292
394.00	7,888,586	3.76			(923)			(1,253)	90,860	(104)	90,755	0	0	0	54	7,724,512
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		108,425
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		908,941
397.50	680,969	4.70			51				10,857	0	10,857	7,661	0	0		698,618
398.00	529,599	6.11							4,841	0	4,841	0	0	0		582,716
303.00	19,902,888								675,054	0	675,054	234,667	0	0		25,809,251
303.60	2,374,987								209,991	0	209,991	0	0	0		4,684,891
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(94,661)
375.71	2,870,239								42,310	0	42,310	0	0	0		3,288,536
Total	**636,936,813**				**5,004,484**			**5,134,298**	**8,947,979**	**427,858**	**9,375,837**	**3,256,954**	**505,525**	**0**	**0**	**698,490,709**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023										
	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	NOVEMBER							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,821,627
352.01	834,026	8.44							7,925	0	7,925	0	0	0		929,126
352.02	392,390	20.72							18,527	0	18,527	0	0	0		614,709
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,223
354.00	849,418	3.41							2,694	0	2,694	0	0	0		881,751
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,800	217	7,018	1,789	143	0		990,049
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,861,785
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	15,047	2,772	17,820	9,826	3,832	0		1,568,631
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,573
375.70	5,155,365	2.82	0.00		1	0.00		1	100,527	0	100,527	0	0	0		6,305,672
375.80	8,614	2.15							30	0	30	0	0	0		8,969
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,651,575	113,936	4,765,511	1,629,158	146,624	0		371,352,966
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	660,230	24,881	685,111	278,255	77,911	0		26,518,866
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		84,210
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	2,102,056	274,424	2,376,481	832,901	274,857	0		171,114,065
381.00	18,434,086	2.39			(17,978)			(12,056)	88,733	(1,005)	87,729	14,089	0	0		19,348,998
381.10	18,366,394	5.13							107,248	0	107,248	0	0	0		19,647,433
382.00	15,760,586	1.87			483			483	70,492	40	70,532	14,909	0	0		16,465,287
383.00	8,225,155	2.06	0.02		185	0.02		483	35,922	40	35,963	8,803	176	0		8,554,697
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	37,279	7,495	44,774	10,195	3,058	0		2,909,522
387.00	80,436	3.03							345	0	345	0	0	0		84,578
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,585,571
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,918,387
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							10,040	0	10,040	0	0	0		1,118,053
391.11	52,960	6.41							488	0	488	0	0	0		58,813
391.12	1,919,443	5.98							2,646	0	2,646	0	0	0		307,476
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		21,086
394.00	7,888,586	3.76			(923)			(1,253)	91,572	(104)	91,467	0	0	0	54	7,816,033
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		109,567
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		907,481
397.50	680,969	4.70			51				11,317	0	11,317	7,661	0	0		702,274
398.00	529,599	6.11							4,841	0	4,841	0	0	0		587,557
303.00	19,902,888								675,054	0	675,054	880,885	0	0		25,603,421
303.60	2,374,987								209,991	0	209,991	96,633	0	0		4,798,249
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(89,080)
375.71	2,870,239								42,310	0	42,310	0	0	0		3,330,846
Total	**636,936,813**				**5,004,484**			**5,134,298**	**9,040,769**	**427,858**	**9,468,628**	**3,785,102**	**506,602**	**0**	**0**	**703,667,632**

RESERVE BRINGFORWARD

			PROJECTED 2022			PROJECTED 2023										
	2022	'Accrual			'5-yr			'5-yr	2023							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	DECEMBER							
Account	Begin. Balance	11-2022	% of Rets	% of Rets	2017-2021	% of Rets	% of Rets	2018-2022	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Adjustments	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0		1,931
351.20	2,587,031	6.99			4,287			4,287	19,192	357	19,550	0	0	0		2,841,177
352.01	834,026	8.44							7,925	0	7,925	0	0	0		937,051
352.02	392,390	20.72							18,527	0	18,527	0	0	0		633,236
352.10	206,932	0.00							0	0	0	0	0	0		206,932
353.00	388,896	0.04			171			171	13	14	27	0	0	0		389,250
354.00	849,418	3.41							2,694	0	2,694	0	0	0		884,445
355.00	104,477	0.00							0	0	0	0	0	0		104,477
374.40	927,763	1.69	0.08		9,948	0.08		2,607	6,840	217	7,057	1,916	153	0		995,037
374.50	1,826,867	1.08							2,910	0	2,910	0	0	0		1,864,695
375.34	1,478,485	2.32	0.39		33,910	0.39		33,266	15,282	2,772	18,054	11,641	4,540	0		1,570,504
375.60	75,960	0.59			104			104	42	9	51	0	0	0		76,624
375.70	5,155,365	2.82	0.00		1	0.00		1	100,767	0	100,767	0	0	0		6,406,439
375.80	8,614	2.15							30	0	30	0	0	0		8,999
376.00	338,692,741	2.15	0.09		1,283,407	0.09		1,367,227	4,705,169	113,936	4,819,105	1,669,634	150,267	0		374,352,170
378.00	23,658,568	4.01	0.28		216,942	0.28		298,573	679,187	24,881	704,068	333,937	93,502	0		26,795,495
379.10	60,244	6.40			15,264			15,264	725	1,272	1,997	0	0	0		86,207
380.00	153,394,232	3.01	0.33		3,297,724	0.33		3,293,092	2,128,857	274,424	2,403,281	772,089	254,789	0		172,490,468
381.00	18,434,086	2.39			(17,978)			(12,056)	89,041	(1,005)	88,036	16,352	0	0		19,420,683
381.10	18,366,394	5.13							107,376	0	107,376	0	0	0		19,754,808
382.00	15,760,586	1.87			483			483	70,791	40	70,831	17,419	0	0		16,518,699
383.00	8,225,155	2.06	0.02		185	0.02		483	36,154	40	36,194	9,567	191	0		8,581,133
385.00	2,506,309	5.19	0.30		107,428	0.30		89,945	37,827	7,495	45,322	12,055	3,616	0		2,939,173
387.00	80,436	3.03							345	0	345	0	0	0		84,923
387.40	3,009,233	4.83	0.01		2,091	0.01		1,999	47,861	167	48,028	0	0	0		3,633,599
387.50	1,743,598	7.94							14,566	0	14,566	0	0	0		1,932,953
390.10	49,821	0.00							0	0	0	0	0	0		49,821
391.10	1,009,042	4.47							9,859	0	9,859	96,742	0	0		1,031,171
391.11	52,960	6.41							488	0	488	0	0	0		59,300
391.12	1,919,443	5.98							2,213	0	2,213	173,736	0	0		135,953
392.00	23,553	1.27			(2,791)			(2,791)	27	(233)	(205)	0	0	0		20,881
394.00	7,888,586	3.76			(923)			(1,253)	91,751	(104)	91,647	383,704	0	0	54	7,524,030
394.12					648			648	0	54	54	0	0	0	(54)	0
395.00	96,986	5.17							1,141	0	1,141	0	0	0		110,708
396.00	925,001	0.76			(24,730)			(24,730)	601	(2,061)	(1,460)	0	0	0		906,021
397.50	680,969	4.70			51				11,825	0	11,825	7,661	0	0		706,438
398.00	529,599	6.11							4,835	0	4,835	2,264	0	0		590,129
303.00	19,902,888								675,054	0	675,054	1,188,911	0	0		25,089,564
303.60	2,374,987								209,991	0	209,991	0	0	0		5,008,241
362.10	(156,998)				78,262			66,978	0	5,582	5,582	0	0	0		(83,498)
375.71	2,870,239								42,310	0	42,310	0	0	0		3,373,155
Total	**636,936,813**				**5,004,484**			**5,134,298**	**9,142,217**	**427,858**	**9,570,075**	**4,697,626**	**507,060**	**0**	**0**	**708,033,022**

COLUMBIA STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2022-3031211
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
KEVIN L. JOHNSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

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.

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-2008-2011621 supporting NCSC costs, Columbia Gas of Maryland before the Public Service Commission of Maryland in 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 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 included in this testimony. The ACOS studies are based on the fully projected future test year ending December 31, 2023.

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?

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[1] 52 Pa Code § 53.51, et. seq.

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. the table below lists all the schedules and attachments that I am sponsoring.

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	Residential Energy Efficiency Rider Calculation
Statement No. 6, Exhibit KLJ-11	Proposed Customer Charge Impacts

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, Schedule No. 2. It contains 30 pages, while the customer-demand study in Schedule 1 and the average study in 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 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 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 Commercial and Industrial 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 Commercial and Industrial 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].

[2] Per paragraph No. 46 of the Joint Petition for Partial Settlement at Docket No. R-2018-2647557.

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, 2021).

Q. What method did Columbia use in previous cases to identify and separate Account 376 – Mains before allocation to the rate classes in each study?

A. Beginning with the 2012 rate case (Docket No. R-2012-2321748), the Company separated the low pressure and two-inch (2") mains and allocated those mains to only the residential and SGS/SGDS class. Columbia recognized that the remaining rate classes were not physically served from those systems, did not benefit from those systems, and therefore should not share in the recovery of those systems' costs. Columbia performed a similar separation of mains by operating pressure in every rate case since 2012 in order to allocate the cost of those systems to the customers who used them.

Q. Have you again performed a detailed analysis of each of Columbia's low pressure and higher pressure systems in this case?

A. Similar to the Company's 2021 rate case, Columbia did not perform this analysis. Mains cost allocation factors produced from the separation of mains by pressure study are not materially different than the mains allocators produced from simply using total mains (i.e. no separation of mains by operating pressure). This is largely due to Columbia's pipe replacement efforts over the last several years which have had the effect of phasing out its low pressure mains. Columbia's low pressure mains are typically older and constructed of cast iron or steel pipe. Over time, Columbia has been replacing this low pressure pipe with plastic pipe operated under higher pressures. Therefore, the results produced from the separated mains pressure study have become less meaningful as the system has become more homogenous in terms of operating pressure.

Q. How was the demand component for each class determined?

A. The demand component by class was provided by NCSC's Commercial Operations Department and represents expected requirements under design day conditions. I note that the calculation reflects design day total requirement, and thus assumes suppliers will make deliveries necessary to meet customer requirements.

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 a Columbia Gas Transmission, LLC ("Columbia Transmission") interstate pipeline or are in close proximity to a Columbia Transmission 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. Therefore, it is appropriate to exclude them from the allocation of mains and mains related cost.

Q. Since a significant portion of the Company's investment and expense is related to mains and services does the allocation of those 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 Siegler (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.

Q. How did you handle Uncollectibles related to unbundling?

A. Columbia utilizes three systems to bill customers, 1) 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 revenue.

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. 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, 2021, 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 cost 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 provided a description for all allocation factors used for the studies. In Exhibit KLJ-2, I included all calculations of all allocation factors. And in Exhibit KLJ-3, I provided 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 CPA'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 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, included 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 23). 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 21 & 22 for the SGSS2 and SCD2 classes). No other intra-class adjustments are being supported or shown on this exhibit.

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 provides 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 present 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 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. 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 individual classes 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 0.76 under the Customer/Demand study to 1.30 under the Peak & Average study. The average ACOS study produces a residential return index of 0.99.

The SGS1/SCD1/SGD1 return indices are 1.09 for the Peak & Average study, 1.14 for the Customer/Demand study and 1.12 for the average ACOS study.

The SGS2/SCD2/SGD2 return indices are 1.09 for the Peak & Average study, 2.56 for the Customer/Demand study and 1.62 for the average ACOS study.

The SDS/LGSS return indices are 0.88 for the Peak & Average study, 2.97 for the Customer/Demand study and 1.54 for the average ACOS study.

The LDS/LGSS return indices are 0.27 for the Peak & Average study, 3.05 for the Customer/Demand study, and 0.90 for the average ACOS study.

The return index for the Main line Distribution Service ("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 29.29.

The FLEX return indices are -0.69 for the Peak & Average study, -0.14 for the Customer/Demand study, and -0.57 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 14.68% (see Exhibit 103, Schedule No. 8, Page 1, Lines 21 through 37).

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: 68.71% of the overall increase is applied to the residential class; 8.43% of the overall increase is applied to the SGS1/SCD1/SGDS1 class; 8.94% of the overall increase is applied to the SGS2/SCD2/SGDS2 class; 7.51% of the overall increase is applied to the SDS/LGS class; 6.40% of the overall increase is applied to the LDS/LGS class; 0.00% of the overall increase is applied to MLDS customers; and 0.01% 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 alternatives. 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?

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 8.08%)

[3] Columbia Gas of Pennsylvania Tariff, Supplement No. 221 to Tariff Gas – Pa. PUC. No. 9 Sixth Revised Sheet No. 68.

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. This objective recognizes that the 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. Columbia's proposed rate design thus recovers a gradual increase in revenue through the customer charges for each of the rate classes. As explained later in this testimony, the Company is proposing increasing its residential customer charge to the ACOS determined level of customer costs excluding mains.

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 (outside a 3% band) 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, the weather effects of consumption within the 3% WNA band, 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.

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 $25.47. The remaining residential revenue increase was assigned to the volumetric charge for a resulting rate of $8.7254 per Dth.

Q. How did Columbia determine a residential customer charge of $25.47?

A. Exhibit No. 111, Schedule 1, page 25, shows that the minimum monthly customer-based cost excluding distribution mains costs for the residential class is $25.47. Columbia's current charge of $16.75 was established in its 2012 rate case. Since then, residential customer-based costs excluding costs related to distribution mains improvements has increased approximately 53%[4], but the customer charge has not increased. Columbia's proposed monthly customer charge of $25.47 reflects moving the customer charge to the minimum monthly customer-based cost excluding distribution mains costs. This approximately 52% increase in the residential customer charge is in line with the 53% increase in customer-based costs excluding costs related to distribution mains since the 2012 rate case. In addition, the 52% proposed increase in the Residential customer charge amounts to an annual increase of less than 5% or approximately $0.79 per year since the 2012 rate case.

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 $34.23. 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. 1, pages 16 and 25 shows that the minimum customer costs for this rate class range from $28.36 (excluding mains) to $73.26 (including mains). Columbia's customer charge proposal of $34.23 falls near the bottom end of the range of customer-based costs. The remaining revenue is recovered through the volumetric base rates of $7.0989/Dth for SGSS1/SCD1 service and $6.9998/Dth for SGDS1 service.

[4] The approximately 53% 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 $126,491,863 on Exhibit 111, Schedule 2, Page 25, Line 37 in this case.

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 $65.36. 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 $6.0374/Dth for SGSS/SCD service and $5.9382/Dth for SGDS service.

Q. Please explain the 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 $236,058 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 $319.30 and the proposed customer charge for customers whose usage is between 110,000 therms and 540,000 therms is $1,265.29. 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 $4.7545/Dth for SDS/LGSS customers whose usage is between 64,400 therms and 110,000 therms and $4.4453/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. The table 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.

Annual Usage Levels	Proposed Cust. Charge
> 540,000 to ≤ 1,074,000 Therms	$3,261.28
> 1,074,000 to ≤ 3,400,000 Therms	$5,072.62
> 3,400,000 to ≤ 7,500,000 Therms	$9,782.40
> 7,500,000 Therms	$14,492.16

Q. How is the LDS/LGSS volumetric based rate revenue requirement shown in Exhibit 103, Schedule 8, Page 9, Line 27 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 9, Lines 29 through 32).

Q. In regard to each rate classes' proposed customer charge, why did the Company use the calculated monthly customer charge excluding mains costs shown on Exhibit 111, Schedule 2, Page 25, Line 39 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. Exhibit KLJ-11 was used to 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 were also compared to the midpoint of the calculated monthly customer charges excluding mains costs and the calculated monthly customer charges including mains costs from the Peak & Average ACOS (Line 5). It was noted on Line 7 the current customer charge percent of the calculated monthly charge excluding mains (Peak & Average basis) was between 106% and 108% for the SGS/DS-1 and SGS/DS-2 classes. It was noted on Line 8 the current customer charge percent of the midpoint of the calculated monthly charge excluding mains (Peak & Average basis) and the calculated monthly charge including mains (Customer Demand basis) was between 87% and 103% for the SDS/LGSS and LDS/LGSS classes. However, the residential class current customer charge was at 66% of the calculated monthly customer charge excluding mains (Peak & Average basis). With the residential class customer charge percent 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 as well as within the minimum amounts supported by the Company's Peak & Average ACOS calculated monthly customer charge excluding mains costs of $25.47. 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 classes' 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.

Q. Please provide a proof of the 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 1-9. Residential Sales Service is shown on page 1, and pages 2-9 provide graphs for commercial and industrial customers.

Q. What is the range of bill impacts for residential customers?

A. Please refer to Exhibit No. 111, Schedule No. 6, page 1. This page shows monthly bill impacts for residential customers at various usage levels.

Q. Has the Company performed bill impact analyses at various usage levels for commercial and industrial customers?

A. Yes. Refer to Exhibit No. 111, Schedule No. 6, pages 2-9. These pages provide monthly bill impacts for Small General Sales Service and Large General Sales Service customers at various usage levels.

Q. What other rate design proposal is Columbia making in this case?

A. Columbia is proposing the implementation of a Revenue Normalization Adjustment ("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 Statement 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 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 approximately 30% of an average residential bill is still 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 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 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, similar to the process for the Company's PGC 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 a RNA tariff that clearly shows the detail 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 computed 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 computed for the Peak Period would be applied to the next Peak Period. Likewise, the RNA computed for the Off-Peak Period would be applied to the next Off-Peak Period. For example, the RNA computed for the Peak Period beginning with October 2023 billing cycles and ending with March 2024 billing cycles would be applied to residential customers' bills for the period beginning with October 2024 billing cycles and ending with March 2025 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 compute 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	$162.85	April	$99.71
February	$166.24	May	$61.67
March	$143.19	June	$44.19
October	$42.78	July	$36.78
November	$73.39	August	$36.27
December	$127.17	September	$36.30
6-Month Total	$715.62		$314.92

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. 144 and 145 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 as a result 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 those 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 2023 billing cycles. This initial Peak Period RNA ("RNAp") would become effective with October 2023 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 1 day prior to the effective date of the Peak RNA adjustment and the Off-Peak Period RNA Filing would be filed 1 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:

Peak Period: $$RNAp = \frac{[ANBp \times (BDRBp - ADRBp)]}{FTp}$$

<u>**RNA**</u> is the Revenue Normalization Adjustment for non-CAP residential customers for the applicable period.

<u>**BDRB**</u> is the Benchmark Distribution Revenue per Bill for non-CAP residential customers for the applicable period.

<u>**ADRB**</u> 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.

<u>**ANB**</u> is the Actual Number of non-CAP residential Bills for the applicable period. ANB will be computed using a six-month average.

<u>**FT**</u> 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 compute 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 2023.

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 beginning with billing month January 2023. 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 2023 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 compute 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 2023 through March 2024. The RNAp rate effective for October 2023 billing cycles through March 2024 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 2024 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 this added unnecessary complexity to the RNA.

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 and this Rate Case (2022). For the 2022 calculation, a 3% increase in labor and benefits was assumed. The percent of customers taking Sales Service

(Line 11) and Total Sales (Line 14) were updated to reflect 2022 amounts. The 2022 calculation resulted in a calculated reduction in the Gas Procurement Charge when compared with the 2021 calculation. Since the overall fundamentals of the Gas Procurement process did not change, the Company elected to not lower the Gas Procurement Charge, but instead keep it at the 2021 calculated rate of $0.00113 per/therm.

Q. Do you have any other rate calculations you would like to discuss?

A. Yes. As noted in Witness Love's Direct Testimony (Statement 16), Columbia is proposing a Three-Year Energy Efficiency Plan ("Plan" or "EE Plan") as a way to help Columbia's residential customers use natural gas more efficiently. I have prepared the calculation on Exhibit KLJ-10 of the EE Plan Rider that will be billed to all Residential customers (excluding CAP customers). Based on the 2023 Program Costs, the Residential Energy Efficiency Rider Rate is calculated at $0.00441 per/therm. This EE Plan Rider is not included in the Company's base rate revenue requirement in this case but is being submitted as a separate request. However, the impact of the EE Plan Rider is shown on the residential bill comparisons detailed in Exhibit No. 111, Schedule 6, Page 1.

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, 2023 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, 2023. 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, 2023 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, 2021 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, 2023 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, 2021 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, 2023 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, 2021. 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, 2021. 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 percentages and used to allocate service investment and related expenses. See Exhibit KLJ-2, Page 19.

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 20.

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 27.

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 28.

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), USP Rider (Page 8, Line 8) and A&G Expenses (Page 8, Line 34). See Exhibit KLJ-2, Page 29.

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 30.

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 31.

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 32.

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 38) 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 33.

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 34.

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, 2023. See Exhibit KLJ-2, Page 2.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 1
DESIGN DAY [1] (2021-2022)

LINE NO.	Rate	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX [2]	Total
	Residential							
1	RS	308,100	0	0	0	0	0	308,100
2	RC2	29,400	0	0	0	0	0	29,400
3	RTC	111,300	0	0	0	0	0	111,300
	Commercial							
4	LDS/LGSS	0	0	0	0	15,700	0	15,700
5	LDS FLEX	0	0	0	0	0	13,600	13,600
6	SDS/LGSS	0	0	0	49,500	0	0	49,500
7	SGS2	0	0	50,300	0	0	0	50,300
8	SGS1	0	58,400	0	0	0	0	58,400
9	SCD1	0	25,500	0	0	0	0	25,500
10	SCD2	0	0	22,200	0	0	0	22,200
11	SGDS1	0	3,100	0	0	0	0	3,100
12	SGDS2	0	0	32,100	0	0	0	32,100
13	SGDS2 FLEX	0	0	0	0	0	100	100
	Industrial							
14	LDS/LGSS	0	0	0	0	33,100	0	33,100
15	LDS FLEX	0	0	0	0	0	31,200	31,200
16	SDS/LGSS	0	0	0	11,300	0	0	11,300
17	SGS2	0	0	600	0	0	0	600
18	SGDS2	0	0	1,000	0	0	0	1,000
19	Subtotal	448,800	87,000	106,200	60,800	48,800	44,900	796,500
20	EBS	0	0	0	5,077	4,075	3,748	12,900
21	Total	448,800	87,000	106,200	65,877	52,875	48,648	809,400
22	MLDS							21,000
23	Other (Co. Used)							2,400
24	Total							832,800
25	**ALLOCATOR #1**	**55.448%**	**10.749%**	**13.121%**	**8.139%**	**6.533%**	**6.010%**	**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	28,264,907	-	-	-	-	-	-	28,264,907
2	RDGSS	-	-	-	-	-	-	-	-
3	RC2 1/	2,766,018	-	-	-	-	-	-	2,766,018
4	SGSS1	-	4,107,511	-	-	-	-	-	4,107,511
5	SGSS2	-	-	3,914,532	-	-	-	-	3,914,532
6	NSS/MLSS-1	-	-	-	-	-	72,000	-	72,000
7	LGSS1 & 2	-	-	-	1,011,865		-	-	1,011,865
8	LGSS3 & greater	-	-	-	-	50,863	-	-	50,863
	Transportation								
9	RDS	4,066,034	-	-	-	-	-	-	4,066,034
10	RDGDS	-	-	-	-	-	-	-	-
11	SCD1	-	1,491,857	-	-	-	-	-	1,491,857
12	SCD2	-	-	1,538,991	-	-	-	-	1,538,991
13	SGDS1	-	292,513	-	-	-	-	-	292,513
14	SGDS2	-	-	3,419,855	-	-	-	-	3,419,855
15	SDS	-	-	-	5,985,617	-	-	-	5,985,617
16	LDS	-	-	-	-	11,285,600	-	-	11,285,600
17	FLEX							11,978,033	11,978,033
18	MLDS	-	-	-	-	-	3,122,114	-	3,122,114
19	Total Throughput Excl. Trans. (Allocator 2)	31,030,925	4,107,511	3,914,532	1,011,865	50,863	72,000	-	40,187,696
20	**ALLOCATOR #2**	77.214%	10.221%	9.741%	2.518%	0.127%	0.179%	0.000%	
21	Total Throughput Excl. MLDS (Allocator 3)	35,096,960	5,891,881	8,873,377	6,997,482	11,336,463		9,070,033	77,266,196
22	**ALLOCATOR # 3**	45.424%	7.625%	11.484%	9.056%	14.672%		11.739%	
23	**Sales and Choice Volume**	35,096,960	5,599,368	5,453,523	1,011,865	50,863	72,000	-	47,284,578
24	**ALLOCATOR #25**	74.225%	11.842%	11.533%	2.140%	0.108%	0.152%	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	155,295,878	-	-			-	-	155,295,878
2	RC2	15,197,335	-	-			-	-	15,197,335
3	RDS	7,328,214	-	-			-	-	7,328,214
4	SGSS	-	22,567,896	21,507,612			-	-	44,075,508
5	NSS	-	-	-			522,768	-	522,768
6	SCD	-	2,688,774	2,773,723			-	-	5,462,497
7	SGDS	-	104,948	1,340,105			-	-	1,445,053
8	LGS	-	-	-	5,559,491	279,454	-	-	5,838,945
9	TOTAL	177,821,427	25,361,618	25,621,440	5,559,491	279,454	522,768	-	235,166,198
10	**ALLOCATOR #4**	75.615%	10.785%	10.895%	2.364%	0.119%	0.222%	0.000%	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2021

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)		80,174,196	35,096,960	5,891,881	8,873,377	6,997,482	11,336,463	11,978,033
2	Percent Throughput		100.000%	43.775%	7.349%	11.068%	8.728%	14.140%	14.940%
3	Throughput Component		50.000%	21.887%	3.675%	5.534%	4.364%	7.070%	7.470%
4	Design Day Volumes (Total Company excl MLDS)		809,400	448,800	87,000	106,200	65,877	52,875	48,648
5	Percent Design Day Volumes		100.000%	55.448%	10.749%	13.121%	8.139%	6.533%	6.010%
6	Demand Component		50.000%	27.722%	5.375%	6.561%	4.070%	3.267%	3.005%
7	Demand/Commodity Factor		100.000%	49.609%	9.050%	12.095%	8.434%	10.337%	10.475%

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	4,058,686	0	0	0	0	0	0	4,116,692	58,006
2	RC2	299,162	0	0	0	0	0	0	303,294	4,132
3	RDS	541,794	0	0	0	0	0	0	546,145	4,351
4	RDGDS	0	0	0	0	0	0	0	0	0
5	SGSS1	0	278,580	0	0	0	0	0	280,415	1,835
6	SGSS2	0	0	32,800	0	0	0	0	32,889	89
7	NSS	0	0	0	0	0	12	0	12	0
8	SCD1	0	91,979	0	0	0	0	0	92,327	348
9	SCD2	0	0	12,817	0	0	0	0	12,843	26
10	SGDS1	0	11,359	0	0	0	0	0	11,388	29
11	SGDS2	0	0	16,849	0	0	0	0	16,924	75
12	LGSS1 & 2	0	0	0	968	0	0	0	971	3
13	LGSS3 & greater	0	0	0	0	38	0	0	38	0
14	SDS	0	0	0	4,566	0	0	0	4,581	15
15	LDS	0	0	0	0	876	0	0	877	1
16	FLEX	0	0	0	0	0	0	264	264	0
17	MLDS	0	0	0	0	0	132	0	134	2
18	Total Number of Bills	4,899,642	381,918	62,466	5,534	914	144	264	5,419,794	68,912
19	Average Number of Customers	408,304	31,827	5,206	461	76	12	22		
20	**ALLOCATOR #6**	91.566%	7.138%	1.168%	0.103%	0.017%	0.003%	0.005%		

[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	10,023,898.22	9,396,714.21	627,184.01					
2	DIS Billed Revenue - Comm/Ind Sales Only	99,628,055		56,540,092	43,087,963	0	0	0	0
3	Percent	100.000%		56.751%	43.249%	0.000%	0.000%	0.000%	0.000%
4	Allocated DIS Billed Sales Net Charge-offs	10,023,898.22	9,396,714.21	355,933.20	271,250.81	0.00	0.00	0.00	0.00
		Total	Residential	Commercial					
5	DIS Billed Net Charge-offs - Choice Only	756,372.61	636,371.63	120,000.98					
6	DIS Billed Revenue - Comm/Ind Choice Only	48,333,564		16,941,072	31,392,492	0	0	0	0
7	Percent	100.000%		35.050%	64.950%	0.000%	0.000%	0.000%	0.000%
8	Allocated DIS Billed Choice Net Charge-offs	756,372.61	636,371.63	42,060.34	77,940.64	0.00	0.00	0.00	0.00
9	Total DIS Billed Net Charge-offs	10,780,270.83	10,033,085.84	397,993.54	349,191.45	0.00	0.00	0.00	0.00
10	**ALLOCATOR #7**	100.000%	93.069%	3.692%	3.239%	0.000%	0.000%	0.000%	0.000%

EXHIBIT KLJ-2
ALLOC 8

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	60,455,900	-	15,723	1,244,486	28,900,392	24,097,635	1,968,628	4,229,036
2	**ALLOCATOR #8**	100.000%	0.000%	0.026%	2.059%	47.804%	39.860%	3.256%	6.995%

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	31,275	-	-	-	-	31,275
2	RS	1,897,114	-	-	-	-	1,897,114
3	RTC	97,116	-	-	-	-	97,116
4	Commercial Unlisted	-	34,813	-	-	-	34,813
5	SCC	-	19,304	-	-	-	19,304
6	LG1	-	-	-	-		-
7	LG2	-	-	-	6,098	-	6,098
8	SC2	-	-	23,338	-	-	23,338
9	SGS	-	757,443	-	-	-	757,443
10	SGT	-	59,232	-	-	-	59,232
11	SG3		104		-	-	104
12	SG2	-	-	135,772	-	-	135,772
13	TOTAL	2,025,505	870,896	159,110	6,098	-	3,061,609
14	**ALLOCATOR #9**	66.15800%	28.446%	5.197%	0.199%	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	847,905	673,585	82,740	83,865	7,574	100	-	41
2	487.00	FORFEITED DISCOUNTS - GMB & GTS	68,074	-	18	1,401	32,542	27,134	2,217	4,762
3		TOTAL CURRENT SALES AND TRANSPORTATION REVENUE	915,979	673,585	82,758	85,266	40,116	27,234	2,217	4,803
4		**ALLOCATOR #10**	100.000%	73.537%	9.035%	9.309%	4.380%	2.973%	0.242%	0.524%

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	10,886	1,986	2,654	1,851	2,268	-	2,299
2	374.20	LAND - OTHER DISTRIBUTION	3,361,093	1,667,404	304,179	406,524	283,475	347,436	-	352,075
3	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	47,308	8,630	11,534	8,043	9,858	-	9,989
4	374.40	LAND RIGHTS - OTHER DISTRIBUTION	4,778,411	2,370,522	432,446	577,949	403,011	493,944	-	500,539
5	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	-	-	-	-	-	-	-	-
6	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	13	6	1	2	1	1	-	1
7	374.50	RIGHTS OF WAY	3,233,171	1,603,944	292,602	391,052	272,686	334,213	-	338,675
8	374.50	DIRECT - RIGHTS OF WAY	-	-	-	-	-	-	-	-
9	375.20	M & R STRUCTURES - CITY GATE	7,026	3,486	636	850	593	726	-	736
10	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	1,991	363	485	338	415	-	420
11	375.40	M & R STRUCTURES - REGULATING	7,939,336	3,938,625	718,510	960,263	669,604	820,689	-	831,646
12	375.40	DIRECT - M & R STRUCTURES - REGULATING	27,126	-	-	-	-	-	24,324	2,802
13	375.60	M & R STRUCTURES - DIST. IND. M & R	86,228	-	1,440	11,425	29,804	28,800	-	14,759
14	375.80	M & R STRUCTURES - COMMUNICATION	16,515	8,193	1,495	1,998	1,393	1,707	-	1,730
15	376.00	MAINS	2,573,194,470	1,276,536,044	232,874,100	311,227,871	217,023,222	265,991,112	-	269,542,121
16	376.00	DIRECT - MAINS - MLDS	141,586	-	-	-	-	-	141,540	45
17	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,665,795	2,128,151	2,844,197	1,983,296	2,430,795	-	2,463,247
18	376.30	MAINS-BARE STEEL	47,177,611	23,404,341	4,269,574	5,706,132	3,978,960	4,876,750	-	4,941,855
19	376.30	DIRECT - MAINS-BARE STEEL	80,803	-	-	-	-	-	80,803	-
20	376.80	MAINS-CAST IRON	-	-	-	-	-	-	-	-
21	378.10	M & R EQUIP - GENERAL	1,444,656	716,680	130,741	174,731	121,842	149,334	-	151,328
22	378.20	M & R EQUIP - GENERAL - REGULATING	204,100,076	101,252,007	18,471,057	24,685,904	17,213,800	21,097,825	-	21,379,483
23	378.20	DIRECT - M & R EQUIP-GEN-REG	678,970	-	-	-	-	-	-	678,970
24	378.30	M & R EQUIP - LOCAL GAS PURCHASES	419,228	207,975	37,940	50,706	35,358	43,336	-	43,914
25	379.10	M & R EQUIP - CITY GATE	136,417	67,675	12,346	16,500	11,505	14,101	-	14,290
26	379.11	M & R EQUIP - EXCHANGE GAS	(450)	(223)	(41)	(54)	(38)	(47)	-	(47)
27	380.00	SERVICES	855,169,618	778,520,765	62,350,417	11,536,238	1,830,063	538,757	-	393,378
28	380.00	DIRECT - SERVICES	1,554	-	-	-	-	-	561	993
29	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
30	381.00	METERS	44,799,656	34,665,078	6,653,645	3,094,312	292,990	73,471	4,928	15,232
31	381.10	AUTOMATIC METER READING	25,134,959	19,448,929	3,733,044	1,736,072	164,383	41,221	2,765	8,546
32	382.00	METER INSTALLATIONS	45,542,208	35,239,650	6,763,929	3,145,600	297,846	74,689	5,010	15,484
33	383.00	HOUSE REGULATORS	17,656,503	16,128,686	1,243,901	250,369	27,191	4,414	530	1,413
34	384.00	HOUSE REG INSTALLATIONS	3,484,788	3,183,250	245,503	49,414	5,367	871	105	279
35	385.00	IND M&R EQUIPMENT	7,324,965	-	122,327	970,558	2,531,801	2,446,538	-	1,253,741
36	385.00	DIRECT - IND M&R EQUIPMENT	478,276	-	-	-	-	-	463,871	14,405
37	385.10	IND M&R EQUIPMENT - LG VOLUME	1,018,904	-	17,016	135,005	352,174	340,314	-	174,396
38		TOTAL	3,871,070,515	2,310,689,015	340,815,937	367,988,290	247,540,556	300,163,541	724,436	303,148,741
39		**ALLOCATOR #11**	100.000%	59.691%	8.804%	9.506%	6.395%	7.754%	0.019%	7.831%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

Page 1

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	75,951,821							
5	305.00	Structures & Improvements	0							
6	301-303	TOTAL INTANGIBLE PLANT	80,887,198	48,282,378	7,121,309	7,689,137	5,172,736	6,271,993	15,369	6,334,277
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	389,345							
15	354.00	Compressor Station Equipment	948,177							
16	355.00	Measuring & Regulating Equipment	104,477							
17	362.00	Gas Holders	0							
18	362.10	Environmental Remediation	0							
18	350-362	TOTAL UNDERGROUND STORAGE	7,169,335	5,321,439	848,993	826,839	153,424	7,743	10,897	0
19	374.10	LAND - CITY GATE & M/L IND M&R	21,944	10,886	1,986	2,654	1,851	2,268	0	2,299
20	374.20	LAND - OTHER DISTRIBUTION	3,361,093	1,667,404	304,179	406,524	283,475	347,436	0	352,075
21	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	47,308	8,630	11,534	8,043	9,858	0	9,989
22	374.40	LAND RIGHTS - OTHER DISTRIBUTION	4,778,411	2,370,522	432,446	577,949	403,011	493,944	0	500,539
23	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	0	0	0	0	0	0	0	0
24	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	13	6	1	2	1	1	0	1
25	374.50	RIGHTS OF WAY	3,233,171	1,603,944	292,602	391,052	272,686	334,213	0	338,675
26	374.50	DIRECT - RIGHTS OF WAY	0	0	0	0	0	0	0	0
27	375.20	M & R STRUCTURES - CITY GATE	7,026	3,486	636	850	593	726	0	736
28	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	1,991	363	485	338	415	0	420
29	375.40	M & R STRUCTURES - REGULATING	7,939,336	3,938,625	718,510	960,263	669,604	820,689	0	831,646
30	375.40	DIRECT - M & R STRUCTURES - REGULATING	27,126	0	0	0	0	0	24,324	2,802
31	375.60	M & R STRUCTURES - DIST. IND. M & R	86,228	0	1,440	11,425	29,804	28,800	0	14,759
32	375.70	M & R STRUCTURES - OTHER	42,981,846	25,656,294	3,784,122	4,085,854	2,748,689	3,332,812	8,167	3,365,908
33	375.71	M & R STRUCTURES - OTHER LEASED	7,122,746	4,251,638	627,087	677,088	455,500	552,298	1,353	557,782
34	375.80	M & R STRUCTURES - COMMUNICATION	16,515	8,193	1,495	1,998	1,393	1,707	0	1,730
35	376.00	MAINS	2,573,194,470	1,276,536,044	232,874,100	311,227,871	217,023,222	265,991,112	0	269,542,121
36	376.00	DIRECT - MAINS - MLDS	141,586	0	0	0	0	0	141,540	45
37	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,665,795	2,128,151	2,844,197	1,983,296	2,430,795	0	2,463,247

EXHIBIT KLJ-2
ALLOC 12

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

Page 2

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	47,177,611	23,404,341	4,269,574	5,706,132	3,978,960	4,876,750	0	4,941,855
2	376.30	DIRECT - MAINS-BARE STEEL	80,803	0	0	0	0	0	80,803	0
3	376.80	MAINS-CAST IRON	0	0	0	0	0	0	0	0
4	378.10	M & R EQUIP - GENERAL	1,444,656	716,680	130,741	174,731	121,842	149,334	0	151,328
5	378.20	M & R EQUIP - GENERAL - REGULATING	204,100,076	101,252,007	18,471,057	24,685,904	17,213,800	21,097,825	0	21,379,483
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	419,228	207,975	37,940	50,706	35,358	43,336	0	43,914
8	379.10	M & R EQUIP - CITY GATE	136,417	67,675	12,346	16,500	11,505	14,101	0	14,290
9	379.11	M & R EQUIP - EXCHANGE GAS	(450)	(223)	(41)	(54)	(38)	(47)	0	(47)
10	380.00	SERVICES	855,169,618	778,520,765	62,350,417	11,536,238	1,830,063	538,757	0	393,378
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	44,799,656	34,665,078	6,653,645	3,094,312	292,990	73,471	4,928	15,232
14	381.10	AUTOMATIC METER READING	25,134,959	19,448,929	3,733,044	1,736,072	164,383	41,221	2,765	8,546
15	382.00	METER INSTALLATIONS	45,542,208	35,239,650	6,763,929	3,145,600	297,846	74,689	5,010	15,484
16	383.00	HOUSE REGULATORS	17,656,503	16,128,686	1,243,901	250,369	27,191	4,414	530	1,413
17	384.00	HOUSE REG INSTALLATIONS	3,484,788	3,183,250	245,503	49,414	5,367	871	105	279
18	385.00	IND M&R EQUIPMENT	7,324,965	0	122,327	970,558	2,531,801	2,446,538	0	1,253,741
19	385.00	DIRECT - IND M&R EQUIPMENT	478,276	0	0	0	0	0	463,871	14,405
20	385.10	IND M&R EQUIPMENT - LG VOLUME	1,018,904	0	17,016	135,005	352,174	340,314	0	174,396
21	387.10	OTHER EQUIP DISTRIBUTION	19,450	11,610	1,712	1,849	1,244	1,508	4	1,523
22	387.20	OTHER EQUIP ODORIZATION	117,248	69,986	10,323	11,146	7,498	9,091	22	9,182
23	387.42	OTHER EQUIP RADIO	119,609	71,396	10,530	11,370	7,649	9,275	23	9,367
24	387.44	OTHER EQUIP COMMUNICATION	588,831	351,479	51,841	55,974	37,656	45,658	112	46,111
25	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11,112,902	6,633,403	978,380	1,056,393	710,670	861,694	2,112	870,251
26	387.45	DIRECT - OTHER EQUIP CUSTOMER INFO SER'	69,585	0	0	0	0	0	69,585	0
27	387.50	GPS EQUIPMENT	2,201,372	1,314,021	193,809	209,262	140,778	170,694	418	172,389
28	374-387	TOTAL DISTRIBUTION	3,935,404,105	2,349,048,842	346,473,740	374,097,227	251,650,239	305,146,572	806,232	308,181,255

EXHIBIT KLJ-2
ALLOC 12

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	2,598,465							
4	391.11	OF&E Data Handling Equipment	91,304							
5	391.12	OF&E Information Systems	357,301							
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	57,140							
11	394.11	CNG Equip - Stationary	0							
12	394.12	CNG Equip - Portable	0							
13	394.20	Shop Equipment	17,534							
14	394.30	Tools & Other	29,153,380							
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	3,097,282							
23	398.00	Miscellaneous Equipment	948,550							
24	389-398	TOTAL GENERAL PLANT	37,620,859	22,456,267	3,312,140	3,576,239	2,405,854	2,917,121	7,148	2,946,090
25		TOTAL	4,061,081,499	2,425,108,925	357,756,182	386,189,442	259,382,253	314,343,430	839,646	317,461,621
			ALLOCATOR #12	59.716%	8.809%	9.510%	6.387%	7.740%	0.021%	7.817%

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	2,573,194,470	1,276,536,044	232,874,100	311,227,871	217,023,222	265,991,112	-	269,542,121
2	376.00	DIRECT - MAINS - MLDS	141,586	-	-	-	-	-	141,540	45
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,665,795	2,128,151	2,844,197	1,983,296	2,430,795	-	2,463,247
4	376.30	MAINS-BARE STEEL	47,177,611	23,404,341	4,269,574	5,706,132	3,978,960	4,876,750	-	4,941,855
5	376.30	DIRECT - MAINS-BARE STEE	80,803	-	-	-	-	-	80,803	-
6	376.80	MAINS-CAST IRON	-	-	-	-	-	-	-	-
7		TOTAL	2,644,109,951	1,311,606,181	239,271,824	319,778,201	222,985,477	273,298,657	222,344	276,947,267
		ALLOCATOR #13	100.000%	49.606%	9.049%	12.094%	8.433%	10.336%	0.008%	10.474%

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	2,573,194,470	1,276,536,044	232,874,100	311,227,871	217,023,222	265,991,112	-	269,542,121
2	376.00	DIRECT - MAINS - MLDS	141,586	-	-	-	-	-	141,540	45
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,665,795	2,128,151	2,844,197	1,983,296	2,430,795	-	2,463,247
4	376.30	MAINS-BARE STEEL	47,177,611	23,404,341	4,269,574	5,706,132	3,978,960	4,876,750	-	4,941,855
5	376.30	DIRECT - MAINS-BARE STEEL	80,803	-	-	-	-	-	80,803	-
6	376.80	MAINS-CAST IRON	-	-	-	-	-	-	-	-
7	380.00	SERVICES	855,169,618	778,520,765	62,350,417	11,536,238	1,830,063	538,757	-	393,378
8	380.00	DIRECT - SERVICES	1,554	-	-	-	-	-	561	993
9	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
10		TOTAL	3,499,281,123	2,090,126,946	301,622,241	331,314,439	224,815,540	273,837,414	222,905	277,341,639
11		**ALLOCATOR #14**	100.000%	59.729%	8.620%	9.468%	6.425%	7.826%	0.006%	7.926%

Columbia Gas of Pennsylvania, Inc.
Services Allocation Factor
As of November 30, 2021

Billing Rate	Rate Case Rate	Classification	BLANK	P	S	*	+	Total	Average Unit Cost	Total Cost	Key
802	FLEX MDS	8"	0	0	0	1	1	2	7,612.29	15,224.58	8028"
808	FLEX	4"	0	0	0	1	0	1	5,384.15	5,384.15	8084"
809	FLEX	6"	1	0	0	0	0	1	5,982.57	5,982.57	8096"
809	FLEX	8"	0	0	0	1	0	1	7,612.29	7,612.29	8098"
810	FLEX	4"	1	0	0	0	0	1	5,384.15	5,384.15	8104"
810	FLEX	6"	1	0	0	0	0	1	5,982.57	5,982.57	8106"
831	FLEX MDS	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	831UNDER 3"
833	FLEX	8"	0	0	0	0	1	1	7,612.29	7,612.29	8338"
840	FLEX	4"	2	0	0	0	0	2	5,384.15	10,768.30	8404"
845	FLEX	4"	1	0	0	0	0	1	5,384.15	5,384.15	8454"
846	FLEX	6"	0	0	0	0	1	1	5,982.57	5,982.57	8466"
846	FLEX	10"	0	0	0	1	0	1	111.64	111.64	84610"
847	FLEX	4"	1	0	0	0	0	1	5,384.15	5,384.15	8474"
848	FLEX	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	848UNDER 3"
857	FLEX	3"	1	0	0	0	0	1	2,061.43	2,061.43	8573"
868	FLEX	UNDER 3"	0	0	0	0	1	1	1,546.77	1,546.77	868UNDER 3"
873	FLEX	6"	1	0	0	0	0	1	5,982.57	5,982.57	8736"
875	FLEX	12"	1	0	0	0	0	1	97,757.55	97,757.55	87512"
875	FLEX	6"	1	0	0	0	0	1	5,982.57	5,982.57	8756"
875	FLEX	8"	0	0	0	1	0	1	7,612.29	7,612.29	8758"
876	FLEX	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	876UNDER 3"
877	FLEX	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	877UNDER 3"
879	FLEX	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	879UNDER 3"
880	FLEX	12"	1	0	0	0	0	1	97,757.55	97,757.55	88012"
881	FLEX	4"	1	0	0	0	0	1	5,384.15	5,384.15	8814"
881	FLEX	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	881UNDER 3"
882	FLEX	8"	0	0	0	1	0	1	7,612.29	7,612.29	8828"
EDSTIB1	FLEX	6"	1	0	0	0	0	1	5,982.57	5,982.57	EDSTIB16"
LG1	SDS/LGSS	3"	3	0	0	1	0	4	2,061.43	8,245.72	LG13"
LG1	SDS/LGSS	4"	5	0	0	0	0	5	5,384.15	26,920.75	LG14"
LG1	SDS/LGSS	6"	0	0	0	1	1	2	5,982.57	11,965.14	LG16"
LG1	SDS/LGSS	UNDER 3"	22	0	1	4	2	29	1,546.77	44,856.33	LG1UNDER 3"
LG2	SDS/LGSS	3"	2	0	0	2	0	4	2,061.43	8,245.72	LG23"
LG2	SDS/LGSS	4"	12	0	0	2	1	15	5,384.15	80,762.25	LG24"
LG2	SDS/LGSS	6"	1	0	0	1	0	2	5,982.57	11,965.14	LG26"
LG2	SDS/LGSS	UNDER 3"	41	0	0	5	1	47	1,546.77	72,698.19	LG2UNDER 3"
LG3	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	LG3UNDER 3"
LG4	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	LG4UNDER 3"
LG4	LDS/LGSS	6"	1	0	0	0	0	1	5,982.57	5,982.57	LG46"
NSI	MDS/NSS	3"	1	0	0	0	0	1	2,061.43	2,061.43	NSI3"
RC2	RSS/RTS	UNDER 3"	18,379	128	85	2,641	2,860	24,093	1,546.77	37,266,329.61	RC2UNDER 3"
RC2	RSS/RTS	3"	0	1	0	0	1	2	2,061.43	4,122.86	RC23"
RC2	RSS/RTS	4"	3	0	0	0	1	4	5,384.15	21,536.60	RC24"

RC2	RSS/RTS	6"	1	0	0	0	0	1	5,982.57	5,982.57	RC26"
RC2	RSS/RTS	10"	1	0	0	0	1	2	111.64	223.28	RC210"
RS	RSS/RTS	10"	2	0	0	0	1	3	111.64	334.92	RS10"
RS	RSS/RTS	11-1/8"	1	0	0	0	0	1	0.00	0.00	RS11-1/8"
RS	RSS/RTS	3"	13	0	0	4	43	60	2,061.43	123,685.80	RS3"
RS	RSS/RTS	4"	12	1	1	4	54	72	5,384.15	387,658.80	RS4"
RS	RSS/RTS	5"	2	0	0	0	0	2	138.55	277.10	RS5"
RS	RSS/RTS	6"	6	0	0	2	3	11	5,982.57	65,808.27	RS6"
RS	RSS/RTS	8"	8	0	0	0	0	8	7,612.29	60,898.34	RS8"
RS	RSS/RTS	UNDER 3"	269,484	1,530	1,346	21,502	31,712	325,574	1,546.77	503,588,095.98	RSUNDER 3"
RTC	RSS/RTS	3"	1	0	0	0	7	8	2,061.43	16,491.44	RTC3"
RTC	RSS/RTS	4"	2	0	0	0	5	7	5,384.15	37,689.05	RTC4"
RTC	RSS/RTS	UNDER 3"	45,960	246	184	2,419	2,713	51,522	1,546.77	79,692,683.94	RTCUNDER 3"
SC2	SGSS2/SCD2/SGDS2	3"	24	0	0	4	1	29	2,061.43	59,781.47	SC23"
SC2	SGSS2/SCD2/SGDS2	4"	26	0	0	2	2	30	5,384.15	161,524.50	SC24"
SC2	SGSS2/SCD2/SGDS2	6"	0	0	0	1	0	1	5,982.57	5,982.57	SC26"
SC2	SGSS2/SCD2/SGDS2	UNDER 3"	792	4	8	113	70	987	1,546.77	1,526,661.99	SC2UNDER 3"
SCC	SGSS1/SCD1/SGDS1	3"	14	1	0	3	16	34	2,061.43	70,088.62	SCC3"
SCC	SGSS1/SCD1/SGDS1	4"	13	0	0	3	3	19	5,384.15	102,298.85	SCC4"
SCC	SGSS1/SCD1/SGDS1	5"	1	0	0	0	0	1	138.55	138.55	SCC5"
SCC	SGSS1/SCD1/SGDS1	6"	1	0	0	0	0	1	5,982.57	5,982.57	SCC6"
SCC	SGSS1/SCD1/SGDS1	UNDER 3"	4,587	36	41	1,353	1,538	7,555	1,546.77	11,685,847.35	SCCUNDER 3"
SG2	SGSS2/SCD2/SGDS2	12"	1	0	0	0	0	1	97,757.55	97,757.55	SG212"
SG2	SGSS2/SCD2/SGDS2	3"	49	0	0	8	6	63	2,061.43	129,870.09	SG23"
SG2	SGSS2/SCD2/SGDS2	4"	64	0	0	7	12	83	5,384.15	446,884.45	SG24"
SG2	SGSS2/SCD2/SGDS2	6"	6	0	0	3	2	11	5,982.57	65,808.27	SG26"
SG2	SGSS2/SCD2/SGDS2	8"	1	0	0	0	0	1	7,612.29	7,612.29	SG28"
SG2	SGSS2/SCD2/SGDS2	UNDER 3"	1,995	10	5	277	220	2,507	1,546.77	3,877,752.39	SG2UNDER 3"
SG3	SGSS1/SCD1/SGDS1	3"	1	0	0	0	0	1	2,061.43	2,061.43	SG33"
SG3	SGSS1/SCD1/SGDS1	4"	1	0	0	2	0	3	5,384.15	16,152.45	SG34"
SG3	SGSS1/SCD1/SGDS1	6"	0	0	0	1	0	1	5,982.57	5,982.57	SG36"
SG3	SGSS1/SCD1/SGDS1	UNDER 3"	16	1	0	2	0	19	1,546.77	29,388.63	SG3UNDER 3"
SG4	SGSS2/SCD2/SGDS2	3"	2	0	0	2	0	4	2,061.43	8,245.72	SG43"
SG4	SGSS2/SCD2/SGDS2	4"	3	0	0	2	0	5	5,384.15	26,920.75	SG44"
SG4	SGSS2/SCD2/SGDS2	6"	2	0	0	0	0	2	5,982.57	11,965.14	SG46"
SG4	SGSS2/SCD2/SGDS2	UNDER 3"	25	0	0	4	1	30	1,546.77	46,403.10	SG4UNDER 3"
SG4	SGSS2/SCD2/SGDS2	10"	1	0	0	0	0	1	111.64	111.64	SG410"
SGS	SGSS1/SCD1/SGDS1	10"	2	0	0	0	0	2	111.64	223.28	SGS10"
SGS	SGSS1/SCD1/SGDS1	12"	1	0	0	0	0	1	97,757.55	97,757.55	SGS12"
SGS	SGSS1/SCD1/SGDS1	16"	0	0	0	1	0	1	0.00	0.00	SGS16"
SGS	SGSS1/SCD1/SGDS1	3"	33	0	0	24	63	120	2,061.43	247,371.60	SGS3"
SGS	SGSS1/SCD1/SGDS1	4"	32	1	0	17	45	95	5,384.15	511,494.25	SGS4"
SGS	SGSS1/SCD1/SGDS1	5"	0	0	0	1	1	2	138.55	277.10	SGS5"
SGS	SGSS1/SCD1/SGDS1	6"	2	0	0	1	1	4	5,982.57	23,930.28	SGS6"
SGS	SGSS1/SCD1/SGDS1	8"	1	0	0	0	0	1	7,612.29	7,612.29	SGS8"
SGS	SGSS1/SCD1/SGDS1	UNDER 3"	12,510	115	78	4,427	5,748	22,878	1,546.77	35,387,004.06	SGSUNDER 3"
SGT	INACTIVE	3"	2	0	0	0	0	2	2,061.43	4,122.86	SGT3"
SGT	INACTIVE	4"	1	0	0	1	0	2	5,384.15	10,768.30	SGT4"
SGT	INACTIVE	UNDER 3"	19	0	0	3	1	23	1,546.77	35,575.71	SGTUNDER 3"
TAG1	SGSS1/SCD1/SGDS1	3"	3	0	0	0	1	4	2,061.43	8,245.72	TAG13"
TAG1	SGSS1/SCD1/SGDS1	UNDER 3"	123	0	0	36	21	180	1,546.77	278,418.60	TAG1UNDER 3"

TAG2	SGSS2/SCD2/SGDS2	3"	15	0	0	1	0	16	2,061.43	32,982.88	TAG23"
TAG2	SGSS2/SCD2/SGDS2	4"	19	0	0	3	1	23	5,384.15	123,835.45	TAG24"
TAG2	SGSS2/SCD2/SGDS2	6"	1	0	0	0	0	1	5,982.57	5,982.57	TAG26"
TAG2	SGSS2/SCD2/SGDS2	UNDER 3"	256	1	0	24	5	286	1,546.77	442,376.22	TAG2UNDER 3"
TAG5	SGSS1/SCD1/SGDS1	3"	5	0	0	1	5	11	2,061.43	22,675.73	TAG53"
TAG5	SGSS1/SCD1/SGDS1	4"	7	0	0	2	3	12	5,384.15	64,609.80	TAG54"
TAG5	SGSS1/SCD1/SGDS1	6"	1	0	0	0	0	1	5,982.57	5,982.57	TAG56"
TAG5	SGSS1/SCD1/SGDS1	UNDER 3"	558	2	0	69	134	763	1,546.77	1,180,185.51	TAG5UNDER 3"
TAG6	SGSS2/SCD2/SGDS2	3"	46	0	0	4	1	51	2,061.43	105,132.93	TAG63"
TAG6	SGSS2/SCD2/SGDS2	4"	58	0	0	6	5	69	5,384.15	371,506.35	TAG64"
TAG6	SGSS2/SCD2/SGDS2	6"	3	0	0	1	0	4	5,982.57	23,930.28	TAG66"
TAG6	SGSS2/SCD2/SGDS2	UNDER 3"	901	7	3	90	49	1,050	1,546.77	1,624,108.50	TAG6UNDER 3"
TI4	SDS/LGSS	12"	1	0	0	0	0	1	97,757.55	97,757.55	TI412"
TI4	SDS/LGSS	3"	18	0	0	1	1	20	2,061.43	41,228.60	TI43"
TI4	SDS/LGSS	4"	24	0	1	1	0	26	5,384.15	139,987.90	TI44"
TI4	SDS/LGSS	6"	5	0	0	1	0	6	5,982.57	35,895.42	TI46"
TI4	SDS/LGSS	UNDER 3"	125	1	0	11	6	143	1,546.77	221,188.11	TI4UNDER 3"
TI8	LDS/LGSS	3"	4	0	0	0	0	4	2,061.43	8,245.72	TI83"
TI8	LDS/LGSS	4"	15	0	0	2	1	18	5,384.15	96,914.70	TI84"
TI8	LDS/LGSS	6"	4	0	0	0	0	4	5,982.57	23,930.28	TI86"
TI8	LDS/LGSS	8"	0	1	1	0	0	2	7,612.29	15,224.58	TI88"
TI8	LDS/LGSS	UNDER 3"	22	0	0	4	2	28	1,546.77	43,309.56	TI8UNDER 3"
TIB	SDS/LGSS	3"	27	0	0	2	0	29	2,061.43	59,781.47	TIB3"
TIB	SDS/LGSS	4"	54	1	0	10	0	65	5,384.15	349,969.75	TIB4"
TIB	SDS/LGSS	6"	5	0	0	1	1	7	5,982.57	41,877.99	TIB6"
TIB	SDS/LGSS	8"	1	0	0	0	0	1	7,612.29	7,612.29	TIB8"
TIB	SDS/LGSS	UNDER 3"	111	0	0	12	5	128	1,546.77	197,986.56	TIBUNDER 3"
TIF	LDS/LGSS	3"	7	0	0	1	0	8	2,061.43	16,491.44	TIF3"
TIF	LDS/LGSS	4"	12	0	0	1	1	14	5,384.15	75,378.10	TIF4"
TIF	LDS/LGSS	6"	2	0	0	0	0	2	5,982.57	11,965.14	TIF6"
TIF	LDS/LGSS	8"	1	0	0	0	0	1	7,612.29	7,612.29	TIF8"
TIF	LDS/LGSS	UNDER 3"	50	1	1	3	1	56	1,546.77	86,619.12	TIFUNDER 3"
TIG	LDS/LGSS	3"	2	0	0	0	0	2	2,061.43	4,122.86	TIG3"
TIG	LDS/LGSS	4"	1	0	0	0	0	1	5,384.15	5,384.15	TIG4"
TIG	LDS/LGSS	6"	1	0	0	0	0	1	5,982.57	5,982.57	TIG6"
TIG	LDS/LGSS	8"	0	0	0	1	0	1	7,612.29	7,612.29	TIG8"
TIG	LDS/LGSS	UNDER 3"	2	0	0	0	0	2	1,546.77	3,093.54	TIGUNDER 3"
TIH	LDS/LGSS	6"	1	0	0	0	0	1	5,982.57	5,982.57	TIH6"
TM1	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	TM1UNDER 3"
TM1	MDS/NSS	6"	1	0	0	0	0	1	5,982.57	5,982.57	TM16"
TM2	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,546.77	1,546.77	TM2UNDER 3"
TMA	MDS/NSS	6"	1	0	0	0	0	1	5,982.57	5,982.57	TMA6"
TMB	MDS/NSS	4"	1	0	0	0	0	1	5,384.15	5,384.15	TMB4"
TMB	MDS/NSS	6"	1	0	0	1	0	2	5,982.57	11,965.14	TMB6"
TMB	MDS/NSS	8"	1	0	0	0	0	1	7,612.29	7,612.29	TMB8"
UNKNOWN			2,586	10	14	454	800	3,864	UNKNOWN	UNKNOWN	UNKNOWN
			359,297	2,098	1,769	33,599	46,183	442,946		682,534,897.25	
Check Total			0	0	0	0	0	0			

		Total Cost	Percent
	RSS/RTS	621,271,818.56	91.037%
	SGSS1/SCD1/SGDS1	49,753,729.36	7.291%
	SGSS2/SCD2/SGDS2	9,203,137.10	1.349%
	SDS/LGSS	1,458,944.88	0.214%
	LDS/LGSS	426,945.02	0.063%
	FLEX	311,002.42	0.046%
	TOTAL BEFORE MLDS/NSS	682,425,577.34	100.000%
	MLDS/NSS	0.00	
	FLEX MLDS	0.00	
	TOTAL	682,425,577.34	
	UNKNOWN	6,161,347.19	
101-1000	TOTAL ACCOUNT 380	688,586,924.53	
101-2000	CIAC	(832,898.00)	
101-4000	Relocation Reimbursements	(17,664.00)	
106	Completed Construction not Classified	228,053.00	
Total	Per Exhibit 8, Schedule 1	687,964,415.53	

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	802	0.00	0.00	0.00	0.00	0.00	781.06	0.00	781.06
2	808	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
3	809	0.00	0.00	0.00	0.00	0.00	781.06	0.00	781.06
4	810	0.00	0.00	0.00	0.00	0.00	781.06	0.00	781.06
5	831	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
6	833	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
7	840	0.00	0.00	0.00	0.00	0.00	781.06	0.00	781.06
8	845	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
9	846	0.00	0.00	0.00	0.00	0.00	781.06	0.00	781.06
10	847	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
11	848	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
12	857	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
13	873	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
14	875	0.00	0.00	0.00	0.00	0.00	781.06	0.00	781.06
15	876	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
16	877	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
17	879	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
18	880	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
19	881	0.00	0.00	0.00	0.00	0.00	955.72	0.00	955.72
20	882	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
21	EDSTIB1	0.00	0.00	0.00	0.00	0.00	390.53	0.00	390.53
22	LG1	0.00	0.00	0.00	20,565.91	0.00	0.00	0.00	20,565.91
23	LG2	0.00	0.00	0.00	38,220.27	0.00	0.00	0.00	38,220.27
24	LG3	0.00	0.00	0.00	0.00	1,171.59	0.00	0.00	1,171.59
25	LG4	0.00	0.00	0.00	0.00	1,952.65	0.00	0.00	1,952.65
26	LG5	0.00	0.00	0.00	0.00	390.53	0.00	0.00	390.53
27	NSI	0.00	0.00	0.00	0.00	0.00	0.00	61.20	61.20
28	RCC	17,318.46	0.00	0.00	0.00	0.00	0.00	0.00	17,318.46
29	RC2	1,493,755.04	0.00	0.00	0.00	0.00	0.00	0.00	1,493,755.04
30	RS	20,706,851.21	0.00	0.00	0.00	0.00	0.00	0.00	20,706,851.21
31	RTC	3,271,328.05	0.00	0.00	0.00	0.00	0.00	0.00	3,271,328.05
32	SCC	0.00	1,165,784.71	0.00	0.00	0.00	0.00	0.00	1,165,784.71
33	SC2	0.00	0.00	460,288.13	0.00	0.00	0.00	0.00	460,288.13
34	SG2	0.00	0.00	1,194,876.95	0.00	0.00	0.00	0.00	1,194,876.95
35	SG3	0.00	9,661.53	0.00	0.00	0.00	0.00	0.00	9,661.53
36	SG4	0.00	0.00	18,992.49	0.00	0.00	0.00	0.00	18,992.49
37	SGS	0.00	3,460,611.98	0.00	0.00	0.00	0.00	0.00	3,460,611.98
38	TAG1	0.00	42,737.76	0.00	0.00	0.00	0.00	0.00	42,737.76
39	TAG2	0.00	0.00	126,789.86	0.00	0.00	0.00	0.00	126,789.86
40	TAG5	0.00	213,672.59	0.00	0.00	0.00	0.00	0.00	213,672.59
41	TAG6	0.00	0.00	474,295.00	0.00	0.00	0.00	0.00	474,295.00
42	TI4	0.00	0.00	0.00	60,174.27	0.00	0.00	0.00	60,174.27
43	TI8	0.00	0.00	0.00	0.00	19,310.49	0.00	0.00	19,310.49
44	TIB	0.00	0.00	0.00	96,622.33	0.00	0.00	0.00	96,622.33
45	TIF	0.00	0.00	0.00	0.00	28,131.26	0.00	0.00	28,131.26
46	TIG	0.00	0.00	0.00	0.00	2,733.69	0.00	0.00	2,733.69
47	TIH	0.00	0.00	0.00	0.00	390.53	0.00	0.00	390.53
48	ML1	0.00	0.00	0.00	0.00	0.00	0.00	390.53	390.53
49	ML5	0.00	0.00	0.00	0.00	0.00	0.00	781.05	781.05
49	TMA	0.00	0.00	0.00	0.00	0.00	0.00	390.53	390.53
50	TMB	0.00	0.00	0.00	0.00	0.00	0.00	1,171.58	1,171.58
51	TMC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52	TM1	0.00	0.00	0.00	0.00	0.00	0.00	649.03	649.03
53	TM2	0.00	0.00	0.00	0.00	0.00	0.00	258.50	258.50
54	TOTAL	25,489,252.76	4,892,468.57	2,275,242.43	215,582.78	54,080.74	11,109.50	3,702.42	32,941,439.20
	SGT								13,636.42
	LIS								781.06
	SIS								1,171.59
	LOC								144,888.70
	LOF								1,407.53
	Total								33,103,324.50
55	**ALLOCATOR #16**	77.378%	14.852%	6.907%	0.654%	0.164%	0.034%	0.011%	100.000%

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurment Stations
As of November 30, 2021

Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
37	10034190010	501054825	SGT	TAG6	49103	30209	7,900.78	TAG6	SGSS2/SCD2/SGDS2
37	10047952001	400188814	SGT	TI4	45529	30243	11,446.47	TI4	SDS/LGSS
37	10219299006	501195093	LG2		49394	732195	41,114.02	LG2	SDS/LGSS
37	10257973005	500030237	SG4		48810	1232756	9,184.43	SG4	SGSS2/SCD2/SGDS2
37	10348091005	400518175	SG4		44452	1333017	3,025.61	SG4	SGSS2/SCD2/SGDS2
37	10375621158	500489101	SGT	TIB	47567	1333032	9,223.78	TIB	SDS/LGSS
37	10379912006	400498094	SG2		14628	1333032	4,546.21	SG2	SGSS2/SCD2/SGDS2
37	10416756005	500065176	SC2		47085	1333063	772.88	SC2	SGSS2/SCD2/SGDS2
37	10421482002	500617033	SGT	TIB	49153	551504	44,715.05	TIB	SDS/LGSS
37	10422436002	400343911	SGT	TIB	46123	10155	8,766.90	TIB	SDS/LGSS
37	10468703002	400525452	SGT	TI4	48454	1292914	11,690.05	TI4	SDS/LGSS
37	10474924002	400303837	SGS		48831	1292988	967.26	SGS	SGSS1/SCD1/SGDS1
37	10501013005	400511506	SGT	TAG6	1276	511316	2,306.59	TAG6	SGSS2/SCD2/SGDS2
37	10502637002	400473325	LG2		1352	511314	4,101.00	LG2	SDS/LGSS
37	10512980003	800800458	SG2		1268	1292906	1,708.84	SG2	SGSS2/SCD2/SGDS2
37	11595685002	400526772	SG2		810	30272	2,131.13	SG2	SGSS2/SCD2/SGDS2
37	12983111001	400473518	SGT	TIB	661	1232704	23,392.95	TIB	SDS/LGSS
37	12983117003	400473502	LG2		49426	1232718	2,234.73	LG2	SDS/LGSS
37	12983124002	400473470	SG3		593	832295	916.28	SG3	SGSS1/SCD1/SGDS1
37	12983149001	800800461	SGT	TAG6	14545	1292906	5,738.98	TAG6	SGSS2/SCD2/SGDS2
37	12983153001	800800460	SGT	TAG6	1414	1292906	5,172.69	TAG6	SGSS2/SCD2/SGDS2
37	12983176001	400490973	SGT	TAG6	14491	1292969	3,560.97	TAG6	SGSS2/SCD2/SGDS2
37	12983177001	400484946	SGT	TI4	14324	1292906	855.29	TI4	SDS/LGSS
37	12983182001	400473449	SG2		3416	1292977	1,207.92	SG2	SGSS2/SCD2/SGDS2
37	12983191002	400473426	SGT	TAG6	1444	511312	6,974.42	TAG6	SGSS2/SCD2/SGDS2
37	12983192001	400473425	SGT	TI4	1443	511396	2,931.27	TI4	SDS/LGSS
37	12983199002	400473414	SGT	TAG6	1434	511318	5,116.21	TAG6	SGSS2/SCD2/SGDS2
37	12983205001	400473388	SC2		4299	511314	5,425.75	SC2	SGSS2/SCD2/SGDS2
37	12983206002	500135694	SGT	TI4	1405	511314	2,584.87	TI4	SDS/LGSS
37	12983208001	400473368	SG2		4584	511314	2,944.67	SG2	SGSS2/SCD2/SGDS2
37	12983210001	400473364	SGT	TI4	4614	511314	2,618.96	TI4	SDS/LGSS
37	12983212001	400473357	SGT	TAG6	4548	511395	15,160.98	TAG6	SGSS2/SCD2/SGDS2
37	12983214001	400473355	SGT	TAG6	4715	511304	1,630.16	TAG6	SGSS2/SCD2/SGDS2
37	12983232001	400473302	SGT	TAG6	1335	511320	4,728.84	TAG6	SGSS2/SCD2/SGDS2
37	12983235001	800800451	SGT	TAG6	1331	511306	2,469.81	TAG6	SGSS2/SCD2/SGDS2
37	12983239001	400473287	SGT	TAG2	1323	511314	3,777.32	TAG2	SGSS2/SCD2/SGDS2
37	12983242001	400473279	SG2		1318	511303	2,708.28	SG2	SGSS2/SCD2/SGDS2
37	12983255002	400514019	SGT	TIB	1291	511395	7,185.12	TIB	SDS/LGSS
37	12983259002	400473238	SGT	TIB	1280	511396	247.56	TIB	SDS/LGSS
37	12983259002	500135609	SGT	TIB	1280	511396	247.56	TIB	SDS/LGSS
37	12983262001	400513746	SGT	TI8	44092	511363	(1,937.70)	TI8	LDS/LGSS
37	12983275001	400473402	SGT	TIB	1423	1112553	2,575.48	TIB	SDS/LGSS
37	12983276001	400473401	SGT	TI8	3382	1112553	12,914.58	TI8	LDS/LGSS
37	12983281001	400473412	SG2		1432	1112521	3,135.76	SG2	SGSS2/SCD2/SGDS2
37	12983287001	400473405	SGT	TIB	1426	1112521	6,824.22	TIB	SDS/LGSS
37	12983292002	400473346	LG1		1372	1112561	8,327.98	LG1	SDS/LGSS
37	12983293002	400473347	SGT	TI4	448	1112524	2,828.39	TI4	SDS/LGSS
37	12983297001	400473265	SGT	TIB	1302	1112569	4,567.48	TIB	SDS/LGSS
37	12983298001	400473267	SGT	TAG6	1305	1112569	1,771.37	TAG6	SGSS2/SCD2/SGDS2
37	12983301001	400473229	SGT	TAG6	4252	1112553	1,853.55	TAG6	SGSS2/SCD2/SGDS2
37	12983302001	400502918	SC2		4492	1112521	1,179.62	SC2	SGSS2/SCD2/SGDS2
37	12983308005	400473411	SGT	TIB	1431	1112569	2,375.82	TIB	SDS/LGSS
37	12983314001	400473452	SGT	TAG6	1467	1292918	3,121.92	TAG6	SGSS2/SCD2/SGDS2
37	12983315001	400473443	SG2		4413	1292998	1,427.28	SG2	SGSS2/SCD2/SGDS2
37	12983318001	400473440	SGT	TAG6	1456	1292909	2,977.62	TAG6	SGSS2/SCD2/SGDS2
37	12983325001	400511507	SGT	TAG6	1403	1292914	2,918.17	TAG6	SGSS2/SCD2/SGDS2
37	12983331001	400473315	SGT	TAG6	4471	1292989	7,100.40	TAG6	SGSS2/SCD2/SGDS2
37	12983343001	400512909	SGT	EDSTIB1	3295	1252863	2,316.71	EDSTIB1	FLEX
37	12983344001	400497701	SGT	TAG6	1469	1292986	1,721.17	TAG6	SGSS2/SCD2/SGDS2
37	12983348001	400504725	SGT	TI4	1363	1252858	1,728.41	TI4	SDS/LGSS
37	12983349001	400473387	SG2		1408	1252858	1,774.66	SG2	SGSS2/SCD2/SGDS2
37	12983354001	400473366	SGT	TAG6	4044	1292919	1,330.60	TAG6	SGSS2/SCD2/SGDS2
37	12983355011	400473369	LG2		4469	1252855	2,808.55	LG2	SDS/LGSS
37	12983355011	400484838	LG2		14322	1252855	5,698.48	LG2	SDS/LGSS

37	12983355011	500163677	LG2			47388	1252855	1,346.53	LG2	SDS/LGSS
37	12983355011	500287938	LG2			47386	1252855	1,346.53	LG2	SDS/LGSS
37	12983359001	400473342	SGT	TIB		1364	1252858	1,770.49	TIB	SDS/LGSS
37	12983370001	400495171	SG2			3323	1252863	4,538.11	SG2	SGSS2/SCD2/SGDS2
37	12983403001	400472841	SGT	TIB		718	732195	8,285.78	TIB	SDS/LGSS
37	12983415001	400473189	SGT	TI8		1005	732158	9,302.44	TI8	LDS/LGSS
37	12983428003	400502425	SGT	TIF		14126	732153	(2,300.48)	TIF	LDS/LGSS
37	12983429002	400472946	SGT	TIB		807	70409	8,319.92	TIB	SDS/LGSS
37	12983433001	400512973	SGT		810	44075	732195	4,278.82	810	FLEX
37	12983434002	400472904	SGT		808	776	732153	93,547.00	808	FLEX
37	12983443007	400488177	LG2			14348	732153	9,005.38	LG2	SDS/LGSS
37	12983451001	400473180	SGT	TI4		997	732114	9,679.14	TI4	SDS/LGSS
37	12983453001	400473149	SGT	TAG6		974	732111	3,769.98	TAG6	SGSS2/SCD2/SGDS2
37	12983462001	400473064	SGT	TAG6		893	732195	1,831.53	TAG6	SGSS2/SCD2/SGDS2
37	12983465001	400473060	SGT	TIB		890	732113	2,137.80	TIB	SDS/LGSS
37	12983467002	400473014	SGT	TIB		856	70409	6,293.59	TIB	SDS/LGSS
37	12983474002	400472983	SGT	TI8		832	732195	14,328.04	TI8	LDS/LGSS
37	12983477001	400472975	SG2			826	732195	2,722.41	SG2	SGSS2/SCD2/SGDS2
37	12983480002	400472971	SG2			746	732195	2,473.69	SG2	SGSS2/SCD2/SGDS2
37	12983498005	800800442	SGT	TIB		4410	70458	1,250.67	TIB	SDS/LGSS
37	12983501003	400473171	LG2			989	70461	20,862.41	LG2	SDS/LGSS
37	12983504001	400473099	SGT	TIB		924	70451	10,408.46	TIB	SDS/LGSS
37	12983508002	400508899	SGT	TI8		871	70424	6,374.99	TI8	LDS/LGSS
37	12983513001	400472886	SGT	TI4		760	70471	4,263.06	TI4	SDS/LGSS
37	12983537001	400473198	LG2			1013	70453	2,943.45	LG2	SDS/LGSS
37	12983545001	400473135	SGT	TAG6		960	70454	975.58	TAG6	SGSS2/SCD2/SGDS2
37	12983554002	400510507	SGT	TAG2		926	70495	732.91	TAG2	SGSS2/SCD2/SGDS2
37	12983554002	500146350	SGT	TAG2		926	70495	732.91	TAG2	SGSS2/SCD2/SGDS2
37	12983556001	400475899	SGT	TIB		906	70456	4,836.96	TIB	SDS/LGSS
37	12983557001	400473076	SGT	TAG6		908	70404	982.95	TAG6	SGSS2/SCD2/SGDS2
37	12983577003	400472935	SGT	TIB		801	70495	52,247.68	TIB	SDS/LGSS
37	12983589001	400472900	SGT	TAG6		772	70478	886.49	TAG6	SGSS2/SCD2/SGDS2
37	12983606002	400472820	SGT	TAG6		702	70495	23,896.62	TAG6	SGSS2/SCD2/SGDS2
37	12983611001	400503381	SGT	TI8		14705	70403	3,827.45	TI8	LDS/LGSS
37	12983623002	400473179	SGT	TAG5		996	310911	3,442.72	TAG5	SGSS1/SCD1/SGDS1
37	12983626001	400473108	SGT	TAG6		933	310958	622.61	TAG6	SGSS2/SCD2/SGDS2
37	12983627001	400473107	SGT	TAG6		932	310956	498.89	TAG6	SGSS2/SCD2/SGDS2
37	12983630001	400526948	SG2			4420	333908	15,255.74	SG2	SGSS2/SCD2/SGDS2
37	12983644001	400512422	SGT	TIB		1155	1252896	9,541.33	TIB	SDS/LGSS
37	12983645004	400492992	SGT		802	1121	1252804	7,202.28	802	FLEX MDS
37	12983645004	500142415	SGT		802	1121	1252804	7,202.28	802	FLEX MDS
37	12983646002	400481256	SGT	TI8		1114	1252804	14,725.43	TI8	LDS/LGSS
37	12983651001	400472750	SGT	TIF		1241	1252829	5,178.66	TIF	LDS/LGSS
37	12983654002	400472745	SGT	TAG2		1236	1252896	6,610.88	TAG2	SGSS2/SCD2/SGDS2
37	12983663001	400505567	SGT	TAG2		14764	1252821	3,352.37	TAG2	SGSS2/SCD2/SGDS2
37	12983681002	400472637	SGT	TI4		1141	1252803	15,441.32	TI4	SDS/LGSS
37	12983693004	400506899	SGT	TI4		14766	1252821	4,992.09	TI4	SDS/LGSS
37	12983778004	400526322	SGT	TI4		44903	30287	25,760.65	TI4	SDS/LGSS
37	12983801005	500151204	SGT		846	1225	30205	13,256.29	846	FLEX
37	12983801005	800800501	SGT		846	1227	30257	477.96	846	FLEX
37	12983811001	400472633	SGT	TIB		1138	30298	34,962.92	TIB	SDS/LGSS
37	12983816001	400497901	SGT	847		14538	30298	6,397.42	847	FLEX
37	12983873001	400472530	SGT	TI4		4287	30287	1,952.86	TI4	SDS/LGSS
37	12983875003	501090417	SGT	TIB		49141	30287	80,271.59	TIB	SDS/LGSS
37	12983915002	400472655	SGT	TIB		1159	30216	15,518.72	TIB	SDS/LGSS
37	12983934001	400484301	SGT	TI8		937	70452	4,620.19	TI8	LDS/LGSS
37	12983936001	400473091	SGT	TIB		916	30225	13,874.35	TIB	SDS/LGSS
37	12983938001	400473088	SGT	TIF		913	30225	25,841.42	TIF	LDS/LGSS
37	12983938002	400473011	SGT	TI8		49348	30225	25,397.78	TI8	LDS/LGSS
37	12983939001	400473057	SGT	TIF		887	30225	260,120.07	TIF	LDS/LGSS
37	12983954001	400518548	SGT	TAG2		1016	30280	1,793.76	TAG2	SGSS2/SCD2/SGDS2
37	12983968001	400473146	SGT	TAG6		971	30280	1,505.38	TAG6	SGSS2/SCD2/SGDS2
37	12983969001	400473144	SGT	TI8		4078	30280	6,739.92	TI8	LDS/LGSS
37	12983971001	400473142	SGT	TIB		968	30263	3,123.75	TIB	SDS/LGSS
37	12983976001	400473125	SC2			949	30231	2,662.32	SC2	SGSS2/SCD2/SGDS2
37	12983982001	400473103	SGT	TI4		929	30272	356.76	TI4	SDS/LGSS
37	12983988002	400473027	SG2			4097	30272	1,504.40	SG2	SGSS2/SCD2/SGDS2
37	12983988002	400498427	SG2			4285	30272	0.00	SG2	SGSS2/SCD2/SGDS2
37	12983993001	400473045	SGT	TI4		881	30235	2,455.77	TI4	SDS/LGSS
37	12983994003	400473044	SGT	TI4		880	30235	2,280.48	TI4	SDS/LGSS

37	12984057001	400472794	SGT	TAG2		14003	70452	2,817.69	TAG2	SGSS2/SCD2/SGDS2
37	12984091001	400472776	SGT	TIB		3296	1252806	2,490.72	TIB	SDS/LGSS
37	12984098001	400526718	SGT	TM1		45180	1252822	3,030.87	TM1	MDS/NSS
37	12984098003	400490002	SGT	TI8		14453	10154	2,352.32	TI8	LDS/LGSS
37	12984119001	400494178	SG2			1174	1252823	27,949.22	SG2	SGSS2/SCD2/SGDS2
37	12984122008	400472639	SGT	TIB		48825	1252822	13,064.41	TIB	SDS/LGSS
37	12984125001	400472585	SGT	TI4		4502	1252819	3,398.13	TI4	SDS/LGSS
37	12984129002	400472553	SGT	TIB		1070	1252807	4,903.64	TIB	SDS/LGSS
37	12984131002	500789128	SGT	TIB		48657	1252822	5,117.20	TIB	SDS/LGSS
37	12984147008	400520146	SGT	TI4		47452	1252807	223.81	TI4	SDS/LGSS
37	12984148002	500185413	SGT	TIB		49412	30241	45,918.09	TIB	SDS/LGSS
37	12984148003	400518885	SGT	TIB		44408	30241	7,603.27	TIB	SDS/LGSS
37	12984150004	501030792	SGT		875	49154	273860	1,061.59	875	FLEX
37	12984150004	800800371	SGT		875	4385	273804	6,048.49	875	FLEX
37	12984150007	501179703	SG2			49333	273860	1,061.59	SG2	SGSS2/SCD2/SGDS2
37	12984151020	400475666	SGT	TIF		1565	273860	287.79	TIF	LDS/LGSS
37	12984151020	400514859	SGT	TIF		48789	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	400514976	SGT	TIF		48788	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	400526997	SGT	TIF		45666	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500008214	SGT	TIF		48790	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500130476	SGT	TIF		45665	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500130460	SGT	TIF		45732	273804	268.28	TIF	LDS/LGSS
37	12984151020	500130474	SGT	TIF		48526	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500130459	SGT	TIF		48889	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500136322	SGT	TIF		45731	273804	268.28	TIF	LDS/LGSS
37	12984151020	500150517	SGT	TIF		45908	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500162068	SGT	TIF		45949	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500198356	SGT	TIF		46017	273804	268.28	TIF	LDS/LGSS
37	12984151020	500198359	SGT	TIF		46018	273804	5,166.36	TIF	LDS/LGSS
37	12984151020	500208315	SGT	TIF		46494	273804	268.28	TIF	LDS/LGSS
37	12984151020	500555580	SGT	TIF		48444	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500558423	SGT	TIF		48887	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500612327	SGT	TIF		48438	273804	268.28	TIF	LDS/LGSS
37	12984151020	500625771	SGT	TIF		48958	273860	586.51	TIF	LDS/LGSS
37	12984151020	500659013	SGT	TIF		48965	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500667297	SGT	TIF		48439	273804	268.28	TIF	LDS/LGSS
37	12984151020	500667298	SGT	TIF		48440	273860	(11,167.52)	TIF	LDS/LGSS
37	12984151020	500692603	SGT	TIF		48625	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500707423	SGT	TIF		48970	273804	268.28	TIF	LDS/LGSS
37	12984151020	500709556	SGT	TIF		48543	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500716291	SGT	TIF		48471	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500806647	SGT	TIF		48678	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500856054	SGT	TIF		48736	273804	268.28	TIF	LDS/LGSS
37	12984151020	500875536	SGT	TIF		48749	273804	268.28	TIF	LDS/LGSS
37	12984151020	500918034	SGT	TIF		48624	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500949336	SGT	TIF		48808	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	500949337	SGT	TIF		48809	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	800800356	SGT	TIF		4371	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	800800357	SGT	TIF		4373	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	800800358	SGT	TIF		4374	273860	1,555.96	TIF	LDS/LGSS
37	12984151020	800800359	SGT	TIF		4375	273860	1,235.30	TIF	LDS/LGSS
37	12984151020	800800360	SGT	TIF		4376	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	800800361	SGT	TIF		4377	273860	825.56	TIF	LDS/LGSS
37	12984151020	800800362	SGT	TIF		4378	273860	1,152.36	TIF	LDS/LGSS
37	12984151020	800800364	SGT	TIF		4380	273860	550.88	TIF	LDS/LGSS
37	12984151020	800800365	SGT	TIF		4381	273804	268.28	TIF	LDS/LGSS
37	12984151020	800800366	SGT	TIF		4382	273860	1,061.59	TIF	LDS/LGSS
37	12984151020	800800367	SGT	TIF		4383	273860	2,705.00	TIF	LDS/LGSS
37	12984151020	800800369	SGT	TIF		14823	273860	(237.74)	TIF	LDS/LGSS
37	12984151020	800800370	SGT	TIF		45243	273804	268.28	TIF	LDS/LGSS
37	12984151020	800800354	SGT	TIF		49234	273860	1,061.59	TIF	LDS/LGSS
37	12984151070	500599616	SGT	TIF		48888	273860	1,061.59	TIF	LDS/LGSS
37	12984151071	500972343	SGT	TIF		48807	273804	268.28	TIF	LDS/LGSS
37	12984151071	501078814	SGT	TIF		49357	273860	1,061.59	TIF	LDS/LGSS
37	12984151071	501102376	SGT	TIF		49356	273860	1,061.59	TIF	LDS/LGSS
37	12984156001	400498964	SGT	TI8		14387	273821	5,213.78	TI8	LDS/LGSS
37	12984156007	501140885	SGT		881	49402	1212650	0.00	881	FLEX
37	12984156007	501140884	SGT		881	49404	1212650	0.00	881	FLEX
37	12984188002	400472449	SGT	TIF		4450	273804	353,710.72	TIF	LDS/LGSS
37	12984218002	400472435	SGT	TI4		1493	551552	0.00	TI4	SDS/LGSS

37	12984219005	400472431	LG2		294	551501	1,230.28	LG2	SDS/LGSS
37	12984219005	500165435	LG2		294	551501	1,230.28	LG2	SDS/LGSS
37	12984221002	400472381	SGT	TIB	1490	551501	5,370.70	TIB	SDS/LGSS
37	12984221004	501123144	SGT	TI8	49284	551501	1,956.54	TI8	LDS/LGSS
37	12984230001	400472414	SGT	TI4	1513	551554	4,102.66	TI4	SDS/LGSS
37	12984232001	400472408	NSI		1511	551511	1,250.65	NSI	MDS/NSS
37	12984233004	400472404	SGT	TI8	1508	551553	0.00	TI8	LDS/LGSS
37	12984233004	800800336	SGT	TI8	4507	551553	1,590.31	TI8	LDS/LGSS
37	12984235003	400503659	SGT	TI4	14732	551511	4,635.06	TI4	SDS/LGSS
37	12984235003	500232234	SGT	TI4	48041	551511	1,250.65	TI4	SDS/LGSS
37	12984245001	400514975	SGT	TAG6	44087	10153	2,947.61	TAG6	SGSS2/SCD2/SGDS2
37	12984247004	400472434	SGT	TIF	297	10109	7,068.70	TIF	LDS/LGSS
37	12984247004	400472433	SGT	TIF	4339	10109	4,963.02	TIF	LDS/LGSS
37	12984247004	800800335	SGT	TIF	14446	10109	4,078.78	TIF	LDS/LGSS
37	12984250003	400507411	SGT	TI8	3215	10154	2,625.29	TI8	LDS/LGSS
37	12984250003	400507413	SGT	TI8	3215	10154	2,625.29	TI8	LDS/LGSS
37	12984251001	400507412	SGT	TI4	1510	10120	13,172.01	TI4	SDS/LGSS
37	12984252001	400472401	SGT	TAG6	1506	10160	2,716.17	TAG6	SGSS2/SCD2/SGDS2
37	12984255005	400472391	SGT	TAG6	4293	10158	3,969.19	TAG6	SGSS2/SCD2/SGDS2
37	12984257002	400472388	SGT	TIF	3334	10120	389.22	TIF	LDS/LGSS
37	12984257002	500149512	SGT	TIF	1496	10120	9,002.35	TIF	LDS/LGSS
37	12984261001	400472371	SGT	TIF	3384	10114	417.56	TIF	LDS/LGSS
37	12984262001	400517972	SGT	TIB	44406	10160	3,203.39	TIB	SDS/LGSS
37	12984264001	400472364	SGT	TIB	1477	10117	2,125.64	TIB	SDS/LGSS
37	12984269001	400498767	SGT	TI8	14635	10119	4,285.84	TI8	LDS/LGSS
37	12984270006	400498095	SGT	TIB	14526	1333072	4,269.98	TIB	SDS/LGSS
37	12984273001	400522508	SGT	TI4	44530	10105	4,338.27	TI4	SDS/LGSS
37	12984275001	400472429	SGT	TIB	1523	10157	8,704.10	TIB	SDS/LGSS
37	12984276001	400511898	SGT	TIB	44051	10157	2,268.56	TIB	SDS/LGSS
37	12984281001	400472403	SC2		1507	10157	5,011.48	SC2	SGSS2/SCD2/SGDS2
37	12984282002	400472402	SGT	TI4	3499	10119	1,353.99	TI4	SDS/LGSS
37	12984283001	400472399	SGT	TI4	3187	10158	2,708.97	TI4	SDS/LGSS
37	12984291001	400472378	SGT	TAG6	1486	10157	3,434.35	TAG6	SGSS2/SCD2/SGDS2
37	12984293002	400472376	SGT	TMB	285	10109	13,185.56	TMB	MDS/NSS
37	12984293003	500925519	SGT	TMB	48785	10109	16,768.97	TMB	MDS/NSS
37	12984296001	400472372	SGT	TAG6	1483	10104	2,598.74	TAG6	SGSS2/SCD2/SGDS2
37	12984299002	400472366	SGT	TI8	1479	10157	4,617.06	TI8	LDS/LGSS
37	12984299002	500220827	SGT	TI8	46090	10157	(4,696.74)	TI8	LDS/LGSS
37	12984318001	400051028	SGT	TI8	48031	1333063	772.88	TI8	LDS/LGSS
37	12984318001	400472328	SGT	TI8	3515	1333063	4,627.20	TI8	LDS/LGSS
37	12984318001	400472327	SGT	TI8	3636	1333063	4,224.76	TI8	LDS/LGSS
37	12984318001	400494708	SGT	TI8	48033	1333063	772.88	TI8	LDS/LGSS
37	12984318001	400505362	SGT	TI8	48677	1333063	772.88	TI8	LDS/LGSS
37	12984318001	400507194	SGT	TI8	46075	1333063	772.88	TI8	LDS/LGSS
37	12984318001	400514810	SGT	TI8	48034	1333063	772.88	TI8	LDS/LGSS
37	12984318001	500005922	SGT	TI8	48032	1333063	772.88	TI8	LDS/LGSS
37	12984318001	500119649	SGT	TI8	45688	1333063	3,470.16	TI8	LDS/LGSS
37	12984321001	400472320	SGT	TI4	3543	1333025	2,924.99	TI4	SDS/LGSS
37	12984323001	400472318	SGT	TI8	3632	1333025	32,431.00	TI8	LDS/LGSS
37	12984324001	400472317	SC2		3542	1333025	1,613.38	SC2	SGSS2/SCD2/SGDS2
37	12984325001	400472316	SGT	TIG	3631	1333025	11,349.73	TIG	LDS/LGSS
37	12984325004	501256232	LG2		49420	1333025	77,104.93	LG2	SDS/LGSS
37	12984327001	400472263	SGT	TAG6	4536	1333025	1,730.75	TAG6	SGSS2/SCD2/SGDS2
37	12984329001	400526741	SGT	TIG	45205	1333025	29,437.80	TIG	LDS/LGSS
37	12984343004	400490919	SGT	TIG	14417	1333063	16,572.15	TIG	LDS/LGSS
37	12984343004	500023117	SGT	TIG	48880	1333063	772.88	TIG	LDS/LGSS
37	12984343004	500535850	SGT	TIG	48881	1333063	772.88	TIG	LDS/LGSS
37	12984346001	400526951	SGT	TIB	44971	1333025	3,724.43	TIB	SDS/LGSS
37	12984351001	400472299	SGT	TI4	3527	1333025	5,492.43	TI4	SDS/LGSS
37	12984355001	400472293	LG1		3521	10103	1,321.13	LG1	SDS/LGSS
37	12984357001	400472287	SGT	TIF	3625	1333063	135.13	TIF	LDS/LGSS
37	12984366001	400472272	SGT	TI8	3506	1333063	5,146.65	TI8	LDS/LGSS
37	12984368001	400472269	SGT	TIB	3504	1333063	1,629.27	TIB	SDS/LGSS
37	12984378001	400496892	SGT	TAG6	14565	1333017	2,669.44	TAG6	SGSS2/SCD2/SGDS2
37	12984382001	400493516	SGT	TIB	14532	1333017	13,266.86	TIB	SDS/LGSS
37	12984392002	400472214	SGT	TIB	3569	1333074	2,526.37	TIB	SDS/LGSS
37	12984392002	400472233	SGT	TIB	3649	1333074	8,902.25	TIB	SDS/LGSS
37	12984392002	800800313	SGT	TIB	3648	1333074	3,347.55	TIB	SDS/LGSS
37	12984433001	400474737	SGT	TIB	14041	1333014	5,102.18	TIB	SDS/LGSS
37	12984438005	400517692	SGT	TI8	14678	1333029	4,838.86	TI8	LDS/LGSS

37	12984438005	400526273	SGT	TI8		44876	1333029	5,910.79	TI8	LDS/LGSS
37	12984438005	800800325	SGT	TI8		3916	1333029	4,519.57	TI8	LDS/LGSS
37	12984440001	400472099	SGT	TIB		3909	1333032	280.24	TIB	SDS/LGSS
37	12984442001	400472096	SGT	TIG		14693	1333032	6,597.70	TIG	LDS/LGSS
37	12984443001	400472090	SGT	TIB		3901	1333095	1,466.35	TIB	SDS/LGSS
37	12984447001	400526359	SGT	TI8		3894	1333032	44,110.50	TI8	LDS/LGSS
37	12984448001	400472085	SGT	TI8		3893	1333027	932.88	TI8	LDS/LGSS
37	12984450007	500793520	SGT	TIF		48680	1333027	7,214.83	TIF	LDS/LGSS
37	12984453004	400505585	SGT	TI4		3881	1333029	14,787.78	TI4	SDS/LGSS
37	12984460001	400472065	SGT	TIB		3866	1333017	1,150.36	TIB	SDS/LGSS
37	12984472001	400472020	SGT	TAG6		3803	1333027	5,226.08	TAG6	SGSS2/SCD2/SGDS2
37	12984475001	400472016	SGT	TIB		3799	1333027	77.96	TIB	SDS/LGSS
37	12984477004	400472012	SC2			3792	1333027	600.79	SC2	SGSS2/SCD2/SGDS2
37	12984477004	800800315	SC2			3793	1333027	14.60	SC2	SGSS2/SCD2/SGDS2
37	12984484006	400467049	SGT	TIB		47453	1333083	121.41	TIB	SDS/LGSS
37	12984484006	400471998	SGT	TIB		14566	1333083	4,528.52	TIB	SDS/LGSS
37	12984484006	500151812	SGT	TIB		47456	1333083	121.41	TIB	SDS/LGSS
37	12984490001	400526586	SGT	TIF		4037	1333079	57,348.04	TIF	LDS/LGSS
37	12984493001	400471935	SGT	TAG2		4516	1333095	1,233.13	TAG2	SGSS2/SCD2/SGDS2
37	12984497001	400471892	SGT	TIB		4173	1333095	530.24	TIB	SDS/LGSS
37	12984501001	400471867	SGT	TIF		4155	1333095	3,725.00	TIF	LDS/LGSS
37	12984507001	400471805	SGT	TIB		4556	1333014	5,773.32	TIB	SDS/LGSS
37	12984524001	400507001	SGT	TIB		14552	1333017	4,496.64	TIB	SDS/LGSS
37	12984528001	400507730	SGT	TIF		3971	1333029	4,984.94	TIF	LDS/LGSS
37	12984529002	400495160	SGT		831	293	290806	0.00	831	FLEX MDS
37	12984533001	400494422	SGT	TI8		14521	1333027	1,675.67	TI8	LDS/LGSS
37	12984534001	400491763	SGT	TI4		14383	1333029	323.82	TI4	SDS/LGSS
37	12984538001	400496374	SGT	TI4		14554	1333095	272.28	TI4	SDS/LGSS
37	12984541001	400472240	SGT	TIB		4443	1333074	2,583.06	TIB	SDS/LGSS
37	12984542001	400499351	SC2			14534	1333029	3,158.50	SC2	SGSS2/SCD2/SGDS2
37	12984549001	400496547	SGT	TIB		14438	1333095	1,494.85	TIB	SDS/LGSS
37	12984569008	400472068	SGT	TIF		3869	1333029	16,245.21	TIF	LDS/LGSS
37	12984569008	400492606	SGT	TIF		47118	1333029	10,688.18	TIF	LDS/LGSS
37	12984569008	400505836	SGT	TIF		47356	1333029	8,188.00	TIF	LDS/LGSS
37	12984569008	400516746	SGT	TIF		47028	1333029	8,188.00	TIF	LDS/LGSS
37	12984592001	400471991	SGT	TI8		3698	1333069	9,772.77	TI8	LDS/LGSS
37	12984598001	400471984	SGT	TI4		3751	1333005	3,433.09	TI4	SDS/LGSS
37	12984606001	400471973	SGT	TIB		3736	1333026	7,589.21	TIB	SDS/LGSS
37	12984607002	400471965	SGT	TAG6		3728	1333027	4,576.34	TAG6	SGSS2/SCD2/SGDS2
37	12984611002	400471958	SGT	TIB		3723	1333029	7,465.84	TIB	SDS/LGSS
37	12984614001	400471948	SGT	TIB		3719	1333035	7,516.16	TIB	SDS/LGSS
37	12984622002	400471919	SGT	TAG6		3765	1333032	7,304.36	TAG6	SGSS2/SCD2/SGDS2
37	12984624003	400471915	SGT	TIB		3763	1333032	4,434.71	TIB	SDS/LGSS
37	12984628004	400471893	SGT	TIB		3686	1333029	1,826.18	TIB	SDS/LGSS
37	12984643001	400471809	SGT	TI8		4526	1333017	4,064.30	TI8	LDS/LGSS
37	12984661001	400526647	SGT	TAG6		45046	1333014	2,190.07	TAG6	SGSS2/SCD2/SGDS2
37	12984661003	400500358	SGT	TIB		14657	10101	23,195.59	TIB	SDS/LGSS
37	12984661004	500738669	SGT	TIB		48592	1333032	16,365.40	TIB	SDS/LGSS
37	13188422011	500079934	SGT	TI8		49385	273806	3,326.29	TI8	LDS/LGSS
37	13188422011	500325346	SGT	TI8		49384	273806	2,119.27	TI8	LDS/LGSS
37	13237020002	500135596	SGT	TI8		4638	511396	31,407.24	TI8	LDS/LGSS
37	13241895007	501021913	SGT	TIF		49028	30225	41,497.74	TIF	LDS/LGSS
37	13241895007	501028115	SGT	TIF		49013	30225	41,497.74	TIF	LDS/LGSS
37	13264345002	400520745	SG2			1306	1292913	3,173.68	SG2	SGSS2/SCD2/SGDS2
37	13266182003	400473258	SGT	TMB		1296	1252858	2,294.81	TMB	MDS/NSS
37	13333833001	500159224	LG1			45928	551501	6,277.25	LG1	SDS/LGSS
37	13409908003	800800444	SGT	TI4		289	70406	2,190.25	TI4	SDS/LGSS
37	13418879001	500171349	SG2			45520	30205	11,235.36	SG2	SGSS2/SCD2/SGDS2
37	13503540001	500099035	SGT	TI4		45872	1252862	8,077.88	TI4	SDS/LGSS
37	13606384001	500209675	SGT	TI8		46079	1333028	15,107.81	TI8	LDS/LGSS
37	13629199001	500199977	SGT	TIF		46006	1112521	38,461.32	TIF	LDS/LGSS
37	13648145002	400473252	SC2			1289	1112521	24,071.02	SC2	SGSS2/SCD2/SGDS2
37	13676826001	500220820	SGT	845		46101	30243	27,319.26	845	FLEX
37	13801660001	500224592	SGT	TAG6		46122	1292998	7,734.44	TAG6	SGSS2/SCD2/SGDS2
37	13807449005	500843197	SGT	TAG6		48733	10160	10,929.56	TAG6	SGSS2/SCD2/SGDS2
37	13953098002	500268352	SG4			46701	511314	2,164.21	SG4	SGSS2/SCD2/SGDS2
37	13959263001	400473271	SGT	TI8		1309	1292977	9,426.78	TI8	LDS/LGSS
37	13968541002	500296548	SGT	TM2		46567	511324	286,814.93	TM2	MDS/NSS
37	14161126001	400472230	SGT	TIB		3588	1333034	4,042.39	TIB	SDS/LGSS
37	14203427002	400483822	SGT	TAG6		14283	511304	3,499.71	TAG6	SGSS2/SCD2/SGDS2

37	14238571001	500337814	SGT	TIF	46961	1333007	9,157.29	TIF	LDS/LGSS
37	14303963001	500391455	SGT	TI4	47285	30260	12,062.59	TI4	SDS/LGSS
37	14313747005	500338294	SG2		47466	10155	12,751.38	SG2	SGSS2/SCD2/SGDS2
37	14318082003	400519776	SGT	TIB	47451	1333032	10,384.96	TIB	SDS/LGSS
37	14344230001	500212008	SGT	TIB	47252	1252822	11,414.42	TIB	SDS/LGSS
37	14351364003	500354179	SGT	TIB	47333	591705	(9,801.11)	TIB	SDS/LGSS
37	14351364003	500371709	SGT	TIB	47605	591705	9,031.53	TIB	SDS/LGSS
37	14351364003	500690713	SGT	TIB	49040	591705	6,003.16	TIB	SDS/LGSS
37	14471914001	400526560	SGT	TIF	3908	1333032	13,405.54	TIF	LDS/LGSS
37	14492769002	500965975	LG2		49158	1112521	15,825.73	LG2	SDS/LGSS
37	14529317003	400472635	SGT	840	1139	1252856	13,865.46	840	FLEX
37	14529317003	800800373	SGT	840	14246	1252856	13,412.22	840	FLEX
37	14557113003	500054098	SGT	TI4	48084	551501	30,701.18	TI4	SDS/LGSS
37	14623990006	400526769	SG2		4505	1333095	1,505.78	SG2	SGSS2/SCD2/SGDS2
37	14738217002	400473525	LG1		621	832206	5,915.22	LG1	SDS/LGSS
37	14860718003	400473280	SGT	TAG6	1313	511314	14,364.41	TAG6	SGSS2/SCD2/SGDS2
37	14958276004	501161721	SGT	TIB	49323	1112501	31,261.72	TIB	SDS/LGSS
37	14962898001	400504012	SC2		4067	10104	1,319.79	SC2	SGSS2/SCD2/SGDS2
37	14997023001	400472421	SGT	TAG6	3491	10157	2,370.57	TAG6	SGSS2/SCD2/SGDS2
37	15096104001	500587558	SGT	809	47842	732195	6,753.16	809	FLEX
37	15096104002	501033523	SGT	809	49045	732195	44,763.53	809	FLEX
37	15096113001	500587559	SGT	833	47843	732195	45,474.89	833	FLEX
37	15107817004	500136220	SG4		1438	511314	1,652.12	SG4	SGSS2/SCD2/SGDS2
37	15120198003	501174545	LG2		49367	1333032	64,145.58	LG2	SDS/LGSS
37	15190290003	500990795	SGT	TIB	48924	511314	21,953.37	TIB	SDS/LGSS
37	15246690003	400478147	SG2		1122	1252821	10,996.30	SG2	SGSS2/SCD2/SGDS2
37	15310256001	400477241	SGT	TIB	3990	1333017	19.02	TIB	SDS/LGSS
37	15320799002	400514006	SGT	TAG6	4540	1252822	0.00	TAG6	SGSS2/SCD2/SGDS2
37	15386979001	400472009	SGT	TIB	3788	1333027	4,470.87	TIB	SDS/LGSS
37	15399043001	400473272	SG4		1310	1292913	1,878.81	SG4	SGSS2/SCD2/SGDS2
37	15409498002	400472801	SG2		686	30225	1,621.75	SG2	SGSS2/SCD2/SGDS2
37	15410029001	400524934	SG4		1465	511314	2,137.32	SG4	SGSS2/SCD2/SGDS2
37	15410029003	400526421	SG2		1368	511314	2,282.29	SG2	SGSS2/SCD2/SGDS2
37	15514483001	400473294	SG2		1329	1112521	1,293.77	SG2	SGSS2/SCD2/SGDS2
37	15514517001	500607489	SGT	TIF	48514	551504	29,232.95	TIF	LDS/LGSS
37	15614278001	500732771	SGT	TI4	48561	30223	5,320.06	TI4	SDS/LGSS
37	15630675002	501155646	SG2		49311	1292909	46,337.79	SG2	SGSS2/SCD2/SGDS2
37	15632066001	500494320	SGT	TIB	48533	1112512	10,803.64	TIB	SDS/LGSS
37	15674018001	500648810	SGT	TIF	48541	273801	99,366.60	TIF	LDS/LGSS
37	15878297001	500766884	SGT	TI4	48455	1333007	2,132.43	TI4	SDS/LGSS
37	15886667015	400472089	SG4		3897	1333032	4,644.35	SG4	SGSS2/SCD2/SGDS2
37	15897246001	500635532	SGT	TIB	48654	1333004	4,591.38	TIB	SDS/LGSS
37	15932079001	500755822	SGT	TIF	48661	511311	7,610.05	TIF	LDS/LGSS
37	16032404001	400493513	SG2		3428	1112521	1,471.35	SG2	SGSS2/SCD2/SGDS2
37	16266565001	400518893	SGT	TIB	934	70495	1,261.32	TIB	SDS/LGSS
37	16316862001	400489632	SGT	TIB	48727	10103	23,457.97	TIB	SDS/LGSS
37	16450594001	400526719	SGT	TIB	48743	1333083	6,816.35	TIB	SDS/LGSS
37	16656334003	501222616	LG1		49396	511304	26,250.86	LG1	SDS/LGSS
37	16804444002	500146391	SGT	TI8	861	70495	5,786.00	TI8	LDS/LGSS
37	16804444008	500175309	SGT	TIB	49139	70495	14,163.45	TIB	SDS/LGSS
37	16919869001	500215263	SGT	TAG6	48787	1333095	30,740.76	TAG6	SGSS2/SCD2/SGDS2
37	16920048001	500959190	SGT	TIB	48797	511395	9,062.42	TIB	SDS/LGSS
37	17000719005	400496375	SGT	TAG6	14550	1333027	1,701.93	TAG6	SGSS2/SCD2/SGDS2
37	17037445001	500962866	SGT	TIB	48814	511306	7,630.88	TIB	SDS/LGSS
37	17097990001	400473352	SCC		4547	1252858	1,965.53	SCC	SGSS1/SCD1/SGDS1
37	17184483002	500193058	SGT	TIB	45604	732195	(5,006.09)	TIB	SDS/LGSS
37	17187387006	400471902	SGT	TI8	4178	1333032	3,583.58	TI8	LDS/LGSS
37	17264884002	400500238	SGT	TIH	14403	1333032	8,452.11	TIH	LDS/LGSS
37	17297010001	400474558	SGT	TI4	14055	1333035	6,651.81	TI4	SDS/LGSS
37	17374299002	400473323	LG2		1351	511314	5,233.17	LG2	SDS/LGSS
37	17409498001	501027922	SGT	TIB	49021	1333095	13,667.74	TIB	SDS/LGSS
37	17439660001	400471850	SGT	TAG2	4149	1333035	290.07	TAG2	SGSS2/SCD2/SGDS2
37	17439660003	800800314	SGT	TAG2	4269	1333035	2,430.25	TAG2	SGSS2/SCD2/SGDS2
37	17446577006	400498963	SGT	TI8	14518	10160	5,361.20	TI8	LDS/LGSS
37	17509433003	501049268	SGT	TI8	49070	511306	17,829.30	TI8	LDS/LGSS
37	17556648001	500988325	LG1		49016	1252829	60,039.91	LG1	SDS/LGSS
37	17613477001	501040193	SG2		49048	832295	17,028.50	SG2	SGSS2/SCD2/SGDS2
37	17662964001	400472829	SGT	TIB	711	30252	8,688.26	TIB	SDS/LGSS
37	17692241009	501080986	SGT	TIB	49302	1333017	65,532.25	TIB	SDS/LGSS
37	17766386001	501049150	SGT	TI8	49088	1333014	35,922.76	TI8	LDS/LGSS

37	18505018001	400473396	SG2		3248	1292914	1,663.84	SG2	SGSS2/SCD2/SGDS2
37	18540737001	500487109	SGS		47705	1292909	31,397.65	SGS	SGSS1/SCD1/SGDS1
37	18553656003	500204877	SG2		48298	30272	5,399.51	SG2	SGSS2/SCD2/SGDS2
37	18660393001	501083309	SG2		40519	1252820	22,691.51	SG2	SGSS2/SCD2/SGDS2
37	18703892001	400505131	SGT	TI8	689	70477	20,627.81	TI8	LDS/LGSS
37	18776965001	400472097	SGT	TIF	3907	1333014	5,166.94	TIF	LDS/LGSS
37	18792064002	501099066	SGT	TAG6	49244	1333035	15,923.45	TAG6	SGSS2/SCD2/SGDS2
37	18836110001	400473205	SGT	TIB	1018	732111	3,880.29	TIB	SDS/LGSS
37	18885421001	500376080	SGT	TIB	49156	10119	16,178.78	TIB	SDS/LGSS
37	18897692003	400472409	SGT	TIB	1512	10160	1,660.38	TIB	SDS/LGSS
37	18941652004	400473297	SGS		1332	511318	1,795.56	SGS	SGSS1/SCD1/SGDS1
37	18973174002	400526191	SGT	873	44761	190613	52,867.22	873	FLEX
37	18985473001	501047288	SGT	TIB	49243	1333035	277.88	TIB	SDS/LGSS
37	18988904003	501281830	LG1		49425	70479	30,748.80	LG1	SDS/LGSS
37	19022293001	400473231	SG2		4575	511316	1,956.84	SG2	SGSS2/SCD2/SGDS2
37	19022293005	500132845	SG2		4575	511316	1,956.84	SG2	SGSS2/SCD2/SGDS2
37	19046540001	400508038	SGT	TIB	14064	1333017	944.86	TIB	SDS/LGSS
37	19074397001	501115733	SGT	TI8	49265	1333017	13,266.86	TI8	LDS/LGSS
37	19075101001	400473322	SG2		4421	1292916	10,041.93	SG2	SGSS2/SCD2/SGDS2
37	19114953001	500688577	SGT	TI4	48544	511312	1,115.13	TI4	SDS/LGSS
37	19117144005	501102841	SGT	TI8	49282	732108	0.00	TI8	LDS/LGSS
37	19117144005	501104644	SGT	TI8	49270	732108	44,938.18	TI8	LDS/LGSS
37	19179996001	400472978	SGT	TIG	828	30272	15,084.85	TIG	LDS/LGSS
37	19193822001	501050977	SGT	TI4	49272	10103	14,333.13	TI4	SDS/LGSS
37	19252407003	800800378	SGT	TAG6	849	30234	2,908.76	TAG6	SGSS2/SCD2/SGDS2
37	19336466001	400501188	SGT	TAG2	45609	1333032	44,110.50	TAG2	SGSS2/SCD2/SGDS2
37	19430896001	501122186	SGT	TIB	49298	70412	11,219.30	TIB	SDS/LGSS
37	19443642001	400472814	SGT	TIB	697	70403	3,872.82	TIB	SDS/LGSS
37	19531601001	400526383	SG3		1012	30225	11,525.34	SG3	SGSS1/SCD1/SGDS1
37	19592009003	501149161	LG2		49340	1252822	15,220.72	LG2	SDS/LGSS
37	19623332001	400472345	SG2		3562	1333063	7,786.78	SG2	SGSS2/SCD2/SGDS2
37	19682099001	500296730	SGT	TIB	46707	511304	26,250.86	TIB	SDS/LGSS
37	19791817001	500175440	SGT	TAG5	45528	70452	31,445.04	TAG5	SGSS1/SCD1/SGDS1
37	19817465001	400472437	LG1		3304	10104	8,152.83	LG1	SDS/LGSS
37	19845214005	400472052	SGT	TIB	3847	1333032	7,490.23	TIB	SDS/LGSS
37	19854159001	501154755	SGT	TIB	49338	273804	1,887.55	TIB	SDS/LGSS
37	19854159002	501162824	LG2		49322	1333029	8,188.00	LG2	SDS/LGSS
37	19866613001	501025433	SGT	TIB	48841	190626	21,082.43	TIB	SDS/LGSS
37	19968875005	800800311	SGT	TIB	14595	1333029	3,083.07	TIB	SDS/LGSS
37	20159378001	500153126	SGT	TI8	45642	70479	635.10	TI8	LDS/LGSS
37	20231700001	400472742	SGT	TI4	14101	1252807	5,736.00	TI4	SDS/LGSS
37	20231700003	400472014	SGT	TIB	3795	1333027	8,044.15	TIB	SDS/LGSS
37	20233976002	400473233	SG2		1275	511311	1,137.23	SG2	SGSS2/SCD2/SGDS2
37	20260616001	400500097	SGT	TM1	14666	10119	980.04	TM1	MDS/NSS
37	20271953001	500214064	LG2		47053	1252822	28,293.86	LG2	SDS/LGSS
37	20271953003	500459284	LG1		47484	1252822	590.67	LG1	SDS/LGSS
37	20352622001	400493366	SGT	TIF	14458	1333025	4,349.04	TIF	LDS/LGSS
37	20403776001	501228775	SG2		49390	10157	5,180.86	SG2	SGSS2/SCD2/SGDS2
37	20480473001	501093555	SGT	880	49361	1333014	467,690.79	880	FLEX
37	20480473002	400471977	SGT	TIB	4335	1333077	4,107.85	TIB	SDS/LGSS
37	20503074001	501173051	SGT	TIB	49398	1333029	2,105.64	TIB	SDS/LGSS
37	20540367001	501221207	SGT	810	49395	732195	32,565.34	810	FLEX
37	20556961001	400494798	SGT	TI8	14599	10160	121.29	TI8	LDS/LGSS
37	20665631001	400473191	SGT	TIF	1007	30225	5,974.11	TIF	LDS/LGSS
37	20669499001	501163330	SGT	TIB	49411	70452	31,445.04	TIB	SDS/LGSS
37	20688663001	400474751	SGT	TI4	4509	30223	3,241.16	TI4	SDS/LGSS
37	20721676001	400472176	LG2		3969	1333095	7,763.66	LG2	SDS/LGSS
37	20731842001	400473264	SG2		1303	511314	1,557.22	SG2	SGSS2/SCD2/SGDS2
37	20733007001	400473253	LG2		1290	1292977	10,041.96	LG2	SDS/LGSS
37	20733007003	400288865	SG4		46395	1292977	2,014.58	SG4	SGSS2/SCD2/SGDS2
37	20733007004	400289580	SG4		46393	1292977	2,014.58	SG4	SGSS2/SCD2/SGDS2
37	20757032003	400471986	SGT	TAG6	3754	1333017	1,646.10	TAG6	SGSS2/SCD2/SGDS2
37	20875641001	400473354	LG2		1377	1292913	936.34	LG2	SDS/LGSS
37	20886128001	400516474	LG4		3863	1333029	7,855.17	LG4	LDS/LGSS
37	20910648001	400472256	LG3		3642	1333074	279.49	LG3	LDS/LGSS
37	20914024001	400473178	SG2		995	70471	1,041.40	SG2	SGSS2/SCD2/SGDS2
37	20915520001	400490462	SGT	TIB	14386	10156	3,285.22	TIB	SDS/LGSS
37	20942667003	400472903	LG1		775	732195	1,532.00	LG1	SDS/LGSS
37	20972755003	400493347	SG4		3950	1333032	4,743.56	SG4	SGSS2/SCD2/SGDS2
37	21026587001	400472035	SGS		3824	1333029	12.68	SGS	SGSS1/SCD1/SGDS1

37	21026587003	800800310	SG2		3825	1333029	211.51	SG2	SGSS2/SCD2/SGDS2
37	21032523001	400493917	SGT	TMA	14046	70452	125,098.41	TMA	MDS/NSS
37	21032523002	400505175	SGT	882	14699	70468	23,377.51	882	FLEX
37	21051676001	400472854	LG1		733	70471	42.30	LG1	SDS/LGSS
37	21067545001	500416284	SG2		47469	1333025	17,948.01	SG2	SGSS2/SCD2/SGDS2
37	21069532001	400526998	SGT	TMB	14788	70470	33,446.59	TMB	MDS/NSS
37	21079991001	400472075	LG4		3879	1333027	0.00	LG4	LDS/LGSS

	Total Cost	**Percent**
RSS/RTS	**0.00**	**0.000%**
SGSS1/SCD1/SGDS1	**83,468.06**	**1.670%**
SGSS2/SCD2/SGDS2	**662,240.88**	**13.250%**
SDS/LGSS	**1,727,508.18**	**34.564%**
LDS/LGSS	**1,669,308.85**	**33.400%**
FLEX	**855,473.66**	**17.116%**
TOTAL BEFORE MLDS/NSS	**4,997,999.63**	**100.000%**
MLDS/NSS	**0.00**	
FLEX MLDS	**0.00**	
TOTAL	**4,997,999.63**	

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	313,341	155,436	28,354	37,896	26,424	32,387	25	32,819
2	874.00	MAINS & SERVICES	26,315,390	15,717,919	2,268,387	2,491,541	1,690,764	2,059,442	1,579	2,085,758
3	875.00	M & R - GENERAL	792,716	393,235	71,733	95,871	66,850	81,935	63	83,029
4	876.00	M & R - INDUSTRIAL	320,624	-	5,354	42,483	110,821	107,088	-	54,878
5	878.00	METERS & HOUSE REGULATORS	1,760,364	1,400,176	240,184	106,643	10,157	2,500	176	528
6	879.00	CUSTOMER INSTALLATIONS	5,858,537	5,333,436	427,146	79,032	12,537	3,691	-	2,695
7	886.00	STRUCTURES AND IMPROVEMEN	26,846	13,317	2,429	3,247	2,264	2,775	2	2,812
8	887.00	MAINS	26,524,141	13,157,566	2,400,170	3,207,830	2,236,781	2,741,535	2,122	2,778,139
9	889.00	M & R - GENERAL	1,227,221	608,775	111,051	148,420	103,492	126,846	98	128,539
10	890.00	M & R - INDUSTRIAL	153,682	-	2,567	20,363	53,119	51,330	-	26,304
11	892.00	SERVICES	5,980,905	5,444,837	436,068	80,682	12,799	3,768	-	2,751
12	893.00	METERS & HOUSE REGULATORS	533,853	424,621	72,839	32,341	3,080	758	53	160
13		TOTAL	69,807,620	42,649,318	6,066,281	6,346,348	4,329,087	5,214,055	4,119	5,198,412
14		**ALLOCATOR #18**	100.000%	61.096%	8.690%	9.091%	6.201%	7.469%	0.006%	7.447%

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	236,616,894	178,918,096	25,518,285	25,779,620	5,593,741	281,178	525,975	-
2		TOTAL DISTRIBUTION O&M	83,702,192	51,138,346	7,273,720	7,609,503	5,190,689	6,251,841	4,953	6,233,141
3		TOTAL CUSTOMER ACCOUNTS	60,713,052	58,697,865	977,111	421,008	304,812	248,134	20,406	43,716
4		TOTAL CUSTOMER SERVICE & INFORMATION	1,542,424	1,412,336	110,098	18,016	1,589	262	46	77
5		TOTAL SALES	161,087	147,501	11,498	1,882	166	27	5	8
6		TOTAL	382,735,649	290,314,143	33,890,712	33,830,027	11,090,997	6,781,442	551,385	6,276,943
	LESS:									
7		GAS PURCHASED COST	235,166,198	177,821,427	25,361,618	25,621,440	5,559,491	279,454	522,768	-
8	904.00	UNCOLLECTIBLES-DIS REVENUE	6,771,837	6,302,481	250,016	219,340	-	-	-	-
9	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	543,670	(0)	141	11,194	259,896	216,707	17,702	38,030
10	904.00	UNCOLLECTIBLES-UNBUNDLED GAS	1,581,571	1,470,866	56,684	54,021	-	-	-	-
11	904.00	DIRECT USP UNCOLLECTIBLES	42,198,344	42,198,344	-	-	-	-	-	-
12	904.00	UNCOLLECTIBLES-DIS COVID-19 DEFERRAL	936,875	871,940	34,589	30,345	-	-	-	-
13	904.00	UNCOLLECTIBLES-GMB/GTS COVID-19 DEFERRAL	75,216	(0)	20	1,549	35,956	29,981	2,449	5,261
14		TOTAL	287,273,711	228,665,058	25,703,069	25,937,889	5,855,343	526,142	542,919	43,291
15		TOTAL	95,461,938	61,649,086	8,187,643	7,892,138	5,235,654	6,255,300	8,466	6,233,652
16		**ALLOCATOR #19**	100.000%	64.579%	8.577%	8.267%	5.485%	6.553%	0.009%	6.530%

SOURCE: Exhibit 111, Schedule 1, Pages 7 and 8.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2021

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

PAGE 1
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		14,749,600	332,598,581	$22.55				
2	All Pipe		41,264,187	1,703,947,663					
3	Unit Cost of 2" x All Pipe Footage			930,507,417					
4	Customer Component			54.609%					
5	Demand Component			45.391%					
6	Number of Customers (Total Company excl MLDS)		445,896	408,304	31,827	5,206	461	76	22
7	Percent Customers		100.000%	91.569%	7.138%	1.168%	0.103%	0.017%	0.005%
8	Customer Component		54.609%	50.008%	3.898%	0.638%	0.056%	0.009%	0.003%
9	Design Day Volumes (Total Company excl MLDS)		809,400	448,800	87,000	106,200	65,877	52,875	48,648
10	Percent Design Day Volumes		100.000%	55.448%	10.749%	13.121%	8.139%	6.533%	6.010%
11	Demand Component		45.391%	25.169%	4.879%	5.956%	3.694%	2.965%	2.728%
12	**Minimum System Allocation Factor**		**100.000%**	**75.174%**	**8.777%**	**6.594%**	**3.750%**	**2.974%**	**2.731%**

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	166,484	0	0	0	0	0	0	166,484
2	RS	2,652,848	0	0	0	0	0	0	2,652,848
3	RTC	415,016	0	0	0	0	0	0	415,016
4	LG1	0	0	0	485	0	0	0	485
5	LG2	0	0	0	452	0	0	0	452
6	LG3	0	0	0	0	12	0	0	12
7	LG4	0	0	0	0	14	0	0	14
8	NSI	0	0	0	0	0	12	0	12
9	SGS	0	180,906	0	0	0	0	0	180,906
10	SG2	0	0	25,435	0	0	0	0	25,435
11	SG3	0	249	0	0	0	0	0	249
12	SG4	0	0	495	0	0	0	0	495
13	EDSTIB1	0	0	0	0	0	0	12	12
14	TAG1	0	1,195	0	0	0	0	0	1,195
15	TAG2	0	0	2,431	0	0	0	0	2,431
16	TAG5	0	6,441	0	0	0	0	0	6,441
17	TAG6	0	0	11,843	0	0	0	0	11,843
18	TIB	0	0	0	2,422	0	0	0	2,422
19	TIF	0	0	0	0	300	0	0	300
20	TIG	0	0	0	0	60	0	0	60
21	TIH	0	0	0	0	12	0	0	12
22	TI4	0	0	0	2,098	0	0	0	2,098
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	24	0	24
26	TM2	0	0	0	0	0	12	0	12
27	TM3	0	0	0	0	0	0	0	0
28	TMB	0	0	0	0	0	36	0	36
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	12	12
34	833	0	0	0	0	0	0	12	12
35	840	0	0	0	0	0	0	12	12
36	845	0	0	0	0	0	0	12	12
37	846	0	0	0	0	0	0	12	12
38	847	0	0	0	0	0	0	12	12
39	848	0	0	0	0	0	0	12	12
40	857	0	0	0	0	0	0	12	12
41	868	0	0	0	0	0	0	12	12
42	873	0	0	0	0	0	0	12	12
43	875	0	0	0	0	0	0	12	12
44	876	0	0	0	0	0	0	12	12
45	877	0	0	0	0	0	0	12	12
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	60,657	0	0	0	0	0	60,657
51	SC2	0	0	10,011	0	0	0	0	10,011
52	**Total**	**3,234,348**	**249,448**	**50,215**	**5,457**	**878**	**96**	**288**	**3,540,730**
53	**ALLOCATOR #21**	91.347%	7.045%	1.418%	0.154%	0.025%	0.003%	0.008%	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	49.609%	9.050%	12.095%	8.434%	10.337%	10.475%	100.000%
2	ALLOCATOR #20	75.174%	8.777%	6.594%	3.750%	2.974%	2.731%	100.000%
3	TOTAL OF BOTH STUDIES	124.783%	17.827%	18.689%	12.184%	13.311%	13.206%	
4	AVERAGE OF BOTH STUDIES	62.392%	8.914%	9.345%	6.092%	6.656%	6.603%	100.000%
5	**ALLOCATOR #22**	62.392%	8.914%	9.345%	6.092%	6.656%	6.603%	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	44,799,656	34,665,078	6,653,645	3,094,312	292,990	73,471	4,928	15,232
2	381.10	AUTOMATIC METER READING	25,134,959	19,448,929	3,733,044	1,736,072	164,383	41,221	2,765	8,546
3	382.00	METER INSTALLATIONS	45,542,208	35,239,650	6,763,929	3,145,600	297,846	74,689	5,010	15,484
4	383.00	HOUSE REGULATORS	17,656,503	16,128,686	1,243,901	250,369	27,191	4,414	530	1,413
5	384.00	HOUSE REG INSTALLATIONS	3,484,788	3,183,250	245,503	49,414	5,367	871	105	279
6		TOTAL	136,618,114	108,665,592	18,640,022	8,275,768	787,776	194,667	13,337	40,954
7		**ALLOCATOR #23**	100.000%	79.539%	13.644%	6.058%	0.577%	0.142%	0.010%	0.030%

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	5,114,243	3,124,598	444,428	464,936	317,134	381,983	307	380,858
10	871.00	LOAD DISPATCHING	13	282,946	140,358	25,604	34,220	23,861	29,245	23	29,636
11	874.00	MAINS & SERVICES	14	10,060,923	6,009,289	867,252	952,568	646,414	787,368	604	797,429
12	875.00	M & R - GENERAL	13	351,080	174,157	31,769	42,460	29,607	36,288	28	36,772
13	876.00	M & R - INDUSTRIAL	17	229,532	-	3,833	30,413	79,336	76,664	-	39,287
14	878.00	METERS & HOUSE REGULATORS	23	1,089,455	866,542	148,645	65,999	6,286	1,547	109	327
15	879.00	CUSTOMER INSTALLATIONS	15	4,806,287	4,375,500	350,426	64,837	10,286	3,028	-	2,211
16	880.00	OTHER	18	2,331,924	1,424,712	202,644	211,995	144,603	174,171	140	173,658
17	885.00	SUPERVISION & ENGINEERING	18	150,135	91,727	13,047	13,649	9,310	11,214	9	11,181
18	886.00	STRUCTURES AND IMPROVEMENTS	13	7,253	3,598	656	877	612	750	1	760
19	887.00	MAINS	13	3,764,467	1,867,402	340,647	455,275	317,458	389,095	301	394,290
20	889.00	M & R - GENERAL	13	739,901	367,035	66,954	89,484	62,396	76,476	59	77,497
21	890.00	M & R - INDUSTRIAL	17	58,242	0	973	7,717	20,131	19,453	-	9,969
22	892.00	SERVICES	15	1,585,198	1,443,116	115,577	21,384	3,392	999	-	729
23	893.00	METERS & HOUSE REGULATORS	23	147,525	117,340	20,128	8,937	851	210	15	44
24	894.00	OTHER EQUIPMENT	18	542,742	331,594	47,164	49,341	33,656	40,537	33	40,418
25	902.00	METER READING	6	234,234	214,479	16,720	2,736	241	40	7	12
26	903.00	CUSTOMER RECORDS AND COLLECTION EXPENSE	6	929,008	850,655	66,313	10,851	957	158	28	47
25	920.00	SALARIES	19	2,656,607	1,715,610	227,857	219,622	145,715	174,087	239	173,476
26	921.00	OFFICE SUPPLIES & EXPENSES	19	647,134	417,912	55,505	53,499	35,495	42,407	58	42,258
27	923.00	OUTSIDE SERVICES EMPLOYED	19	3,920	2,531	336	324	215	257	0	256
28		TOTAL		35,732,757	23,538,155	3,046,477	2,801,122	1,887,954	2,245,976	1,960	2,211,114
29		**ALLOCATOR #24**		100.000%	65.873%	8.526%	7.839%	5.284%	6.285%	0.005%	6.188%

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, 2021.

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.

<u>OPERATING EXPENSES – PURCHASED GAS EXPENSES - PAGE 7</u>

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.

<u>OPERATING EXPENSES – UNDER STORAGE EXPENSES - PAGE 7</u>

Accounts 814 through 837

Underground Storage Plant Expense was allocated using Factor No. 25 – Sales and CHOICE Transportation.

<u>DISTRIBUTION EXPENSES – OPERATIONS - PAGE 7</u>

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 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, 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 11.20%
For the 12 Months Ending December 31, 2023

Ln. No.	Item	Total	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	Account 117	3,631,226	2,695,278	430,010	418,789	77,708	3,922	5,519
2	Account 164	40,836,689	30,311,032	4,835,881	4,709,695	873,905	44,104	62,072
3	Allocated Storage Per ACOS Study using Allocation Factor #25	44,467,915	33,006,310	5,265,891	5,128,485	951,613	48,025	67,591
4	Sales & CHOICE Transportation (Dth)	47,284,578.0	35,096,959.7	5,599,367.9	5,453,522.6	1,011,865.2	50,862.6	72,000.0
5	Factor 25 Allocation of Storage	100%	74.225%	11.842%	11.533%	2.140%	0.108%	0.152%
6	Pre-Tax as Filed	10.55%	10.55%	10.55%	10.55%	10.55%	10.55%	10.55%
7	Revenue Requirement related to storage assigned to rate schedule (Ln. 6 * Ln. 7)	4,690,968	3,481,871	555,505	541,009	100,387	5,066	7,130
8	Rate Per Dth	0.0992						

Ln. No.	Item	Total DTH	% of Total	Included In Proposed Rates	Ratio	Redistributed Per Settlement
9						
10						
11						
12						
13	SGSS1 - Subject to Storage	4,107,511.0	69.710%	387,243	0.7336	20,213
14	SCD1 - Subject to Storage	1,491,857.0	25.320%	140,654	0.2664	7,340
15	SGDS1 - Not Subject to Storage	292,513.0	4.960%	27,553		(27,553)
16		5,891,881.0	99.990%	555,449		0
17				Included		
18		Total	% of	In Proposed		Redistributed
19		DTH	Total	Rates	Ratio	Per Settlement
20						
21	SGSS2 - Subject to Storage	3,914,532.0	44.120%	238,693	0.7179	149,686
22	SCD2 - Subject to Storage	1,538,991.0	17.340%	93,811	0.2821	58,819
23	SGDS2 - Not Subject to Storage	3,419,855.0	38.540%	208,505		(208,505)
24		8,873,378.0	100.000%	541,009		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	1.30	1.09	1.09	0.88	0.27	29.29	(0.69)
2	Peak & Average Proposed Rates	1.27	1.06	1.05	0.94	0.40	22.23	(0.52)
3	Customer/Demand Current Rates	0.76	1.14	2.56	2.97	3.05	29.29	(0.14)
4	Customer/Demand Proposed Rates	0.79	1.10	2.33	2.86	2.98	22.23	(0.10)
5	Average of P/A & C/D Current Rates	0.99	1.12	1.62	1.54	0.90	29.29	(0.57)
6	Average of P/A & C/D Proposed Rates	1.00	1.08	1.51	1.55	0.99	22.23	(0.43)

Columbia Gas of Pennsylvania , Inc
Calculation of Gas Procurement Charge

		2021 Rate Case Calculation			2022 Rate Case Calculation		
1	**Labor and Benefits** [(1)]	**Amount**	**Rate**		**Amount**	**Rate**	
2	Accounting Support	$4,531.43			$4,667.37		
3	Gas Supply Support	$203,428.42			$209,531.27		
4	Legal Support	$5,685.68			$5,856.25		
5	Regulatory Support	$84,506.70			$87,041.90		
6	Treasury Support	$11,999.46			$12,359.45		
7	**Total Labor and Benefits (Line 2 + Line 3 + Line 4 + Line 5 + Line 6)**	**$310,151.69**			**$319,456.24**		
8	**Outside Services - Legal Support**	**$61,000.00**			**$61,000.00**		
9	**Information Technology Systems Maintenance**						
10	Gas Source	$49,021.00			$49,021.00		
11	% of customers taking Sales Service	80.00%			87.20%		
12	**Cost allocated to Sales Service Customers (line 10 * Line 11)**	**$39,216.80**			**$42,746.31**		
13	**TOTAL (line 7 + line 8 + line 12)**	**$410,368.49**			**$423,202.55**		
14	Total Sales (Therms)	362,959,766 [(2)]			401,156,955 [(2)]		
15	Gas Procurement Charge (Line 13 / Line 14)		$0.00113	per / therm		$0.00105	per / therm
16	Gas Procurement Charge (Line 15 * 10)		$0.01130	per / Dth		$0.01050	per / Dth

(1) Labor charges include payroll, benefits and taxes.

(2) 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, 2023

Number of Bills

	Residential FPFTY RS	Residential RDS FPFTY	Residential RS Final Bills	Residential RDS Final Bills	New Residential Customers	Residential Customer Attrition	Total
January	338,238.0	46,992.0	3,663.0	310.0	0.0	(1,226.0)	387,977.0
February	338,876.0	46,657.0	3,684.0	285.0	262.0	(1,227.0)	388,537.0
March	339,203.0	46,322.0	3,864.0	281.0	508.0	(1,227.0)	388,951.0
April	338,294.0	45,987.0	4,209.0	304.0	759.0	(1,223.0)	388,330.0
May	336,958.0	45,652.0	5,709.0	398.0	868.0	(1,217.0)	388,368.0
June	335,712.0	45,317.0	6,827.0	495.0	1,140.0	(1,212.0)	388,279.0
July	335,039.0	44,982.0	5,839.0	452.0	1,398.0	(1,209.0)	386,501.0
August	334,894.0	44,647.0	6,127.0	404.0	2,072.0	(1,208.0)	386,936.0
September	335,448.0	44,312.0	4,963.0	348.0	2,672.0	(1,208.0)	386,535.0
October	336,678.0	43,977.0	4,410.0	375.0	4,248.0	(1,211.0)	388,477.0
November	338,964.0	43,642.0	4,557.0	329.0	4,660.0	(1,217.0)	390,935.0
December	341,939.0	43,307.0	4,154.0	370.0	4,466.0	(1,225.0)	393,011.0
Total	4,050,243.0	541,794.0	58,006.0	4,351.0	23,053.0	(14,610.0)	4,662,837.0

Volumes (Dth)

	Residential FPFTY RS	Residential RDS FPFTY	Residential RS Final Bills	Residential RDS Final Bills	New Residential Customers	Residential Customer Attrition	Total
January	5,351,842.6	773,774.7	0.0	0.0	2,803.0	(19,790.0)	6,108,630.3
February	5,504,939.9	777,326.0	0.0	0.0	6,421.0	(20,296.0)	6,268,390.9
March	4,591,664.4	662,865.8	0.0	0.0	10,101.0	(16,976.0)	5,247,655.2
April	2,838,663.1	463,186.2	0.0	0.0	12,933.0	(10,667.0)	3,304,115.3
May	1,421,149.3	182,594.1	0.0	0.0	12,513.0	(5,181.0)	1,611,075.4
June	726,408.1	95,198.8	0.0	0.0	13,891.0	(2,654.0)	832,843.9
July	430,139.3	57,762.4	0.0	0.0	14,602.0	(1,576.0)	500,927.7
August	405,949.4	55,391.1	0.0	0.0	18,922.0	(1,490.0)	478,772.5
September	405,949.5	53,744.0	0.0	0.0	21,758.0	(1,485.0)	479,966.5
October	640,993.0	100,661.0	0.0	0.0	31,507.0	(2,396.0)	770,765.0
November	1,845,068.3	275,966.3	0.0	0.0	32,893.0	(6,853.0)	2,147,074.6
December	3,995,641.0	567,564.0	0.0	0.0	32,264.0	(14,743.0)	4,580,726.0
Total	28,158,407.9	4,066,034.4	0.0	0.0	210,608.0	(104,109.0)	32,330,943.3

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	387,977	$ 25.47	$ 9,881,774	6,108,630.3	$ 8.7254	$ 53,300,243	$ 162.85
February	388,537	$ 25.47	$ 9,896,037	6,268,390.9	$ 8.7254	$ 54,694,218	$ 166.24
March	388,951	$ 25.47	$ 9,906,582	5,247,655.2	$ 8.7254	$ 45,787,891	$ 143.19
April	388,330	$ 25.47	$ 9,890,765	3,304,115.3	$ 8.7254	$ 28,829,728	$ 99.71
May	388,368	$ 25.47	$ 9,891,733	1,611,075.4	$ 8.7254	$ 14,057,277	$ 61.67
June	388,279	$ 25.47	$ 9,889,466	832,843.9	$ 8.7254	$ 7,266,896	$ 44.19
July	386,501	$ 25.47	$ 9,844,180	500,927.7	$ 8.7254	$ 4,370,795	$ 36.78
August	386,936	$ 25.47	$ 9,855,260	478,772.5	$ 8.7254	$ 4,177,482	$ 36.27
September	386,535	$ 25.47	$ 9,845,046	479,966.5	$ 8.7254	$ 4,187,900	$ 36.30
October	388,477	$ 25.47	$ 9,894,509	770,765.0	$ 8.7254	$ 6,725,233	$ 42.78
November	390,935	$ 25.47	$ 9,957,114	2,147,074.6	$ 8.7254	$ 18,734,085	$ 73.39
December	393,011	$ 25.47	$ 10,009,990	4,580,726.0	$ 8.7254	$ 39,968,667	$ 127.17
Total	4,662,837.0		$ 118,762,458	32,330,943.3		$ 282,100,413	$ 1,030.54
BDRBp (Oct-Mar)							$ 715.62
BDRBo (Apr-Sep)							$ 314.92

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAp")
Peak Period RNAp Effective October 2023 through March 2024

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-2022-XXXXXX	$ 42.78	$ 73.39	$ 127.17	$ 162.85	$ 166.24	$ 143.19	$ 472.28
4									
5	**Actual Distribution Revenue per Bill ("ADRBp")**								Three month
6									ADRBp
7	Monthly ADRBp*		NA	NA	NA	$ 162.00	$ 165.00	$ 143.00	$ 470.00
8									Total
9	Monthly BDRBp - Monthly ADRBp	ln 3 - ln 7				$ 0.85	$ 1.24	$ 0.19	$ 2.28
10									
11	**Actual Number of non-CAP residential Bills ("ANBp")**								
12									Average ANBp
13	Monthly ANBp*		NA	NA	NA	386,216	386,576	386,658	386,483
14									
15									
16	**Revenue to be Assigned to RNAp Rate**					$ 328,283.60	$ 479,354.24	$ 73,465.02	$ 881,182.00
17									
18	**Forecast Decatherms (Dth) for Effective RNAp Period (FTp)***		741,654	2,121,035	4,563,205	6,143,740	6,301,971	5,273,115	25,144,720
19									
20	**RNAp Rate Effective October 2023 through March 2024**	ln 16 / ln 18							$ 0.0350

* For illustrative purposes only.

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAo")
Off-Peak Period RNAo Effective April 2024 through September 2024

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-2022-XXXXXXX	$ 99.71	$ 61.67	$ 44.19	$ 36.78	$ 36.27	$ 36.30	$ 314.92
4									
5	**Actual Distribution Revenue per Bill ("ADRBo")**								
6									Total ADRBo
7	Monthly ADRBo*		$ 101.00	$ 62.00	$ 42.00	$ 35.00	$ 38.00	$ 37.50	$ 315.50
8									Total
9	Monthly BDRBo - Monthly ADRBo	ln 3 - ln 7	$ (1.29)	$ (0.33)	$ 2.19	$ 1.78	$ (1.73)	$ (1.20)	$ (0.58)
10									
11	**Actual Number of non-CAP residential Bills ("ANBo")**								
12									Average ANBo
13	Monthly ANBo*		385,507	383,919	382,413	381,460	381,022	381,267	382,598
14									
15									
16	**Revenue to be Assigned to RNAo Rate**		$ (497,304.03)	$ (126,693.27)	$ 837,484.47	$ 678,998.80	$ (659,168.06)	$ (457,520.40)	$ (221,906.84)
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 2024 through September 2024**	ln 16 / ln 18							$ (0.0308)

* For illustrative purposes only.

Columbia Gas of Pennsylvania , Inc
Calculation of Residential Energy Efficiency Rider
For the 12 Months Ended December 31, 2023

		Amount		Rate	
1	Program Costs (2023)	$1,426,860.00			
2	Residential Sales Service (RSS) - Volumes (Dth)	28,264,907	(1)		
3	Residential Distribution Service Choice (RDS) - Volumes (Dth)	4,066,034	(1)		
4	**Total Residential - Volumes (Dth)**	**32,330,941**			
5	**Residential Energy Efficiency Rider Rate (per/ Dth) (Line 1 / Line 4)**			**$0.04410**	per / Dth
6	**Residential Energy Efficiency Rider Rate (per/ Therm)**			**$0.00441**	per / Therm

(1) Fully Projected Future Test Year Residential Sales Volumes per Exhibit 103, Sch. 1

Columbia Gas of Pennsylvania, Inc. — Exhibit KLJ-11
Proposed Customer Charge Impact — Page 1 of 1
For the 12 Months Ending December 31, 2023

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**		$25.47	$28.36	$52.76	$267.11		$1,403.41	
3	**Calculated Monthly Customer Charge (incl. Mains) (Customer / Demand)**					$1,066.31		$7,062.09	
4	**Exhibit 111, Schedule 2, Page 16, Line 43**								
5	**Midpoint**					$666.71		$4,232.75	
6	**Current Customer Charges**		$16.75	$29.92	$57.00	$683.52	1/	$3,694.68	2/
7	**Percent of Calculated Monthly Customer Charge (excl. Mains)**		**66%**	**106%**	**108%**				
8	**Percent of Midpoint @ Current Rates**					**103%**		**87%**	
9	**Proposed Customer Charges**		$25.47	$34.23	$65.36	$823.58	3/	$4,506.14	4/
10	**Percent of Calculated Monthly Customer Charge (excl. Mains)**		**100%**	**121%**	**124%**				
11	**Percent of Midpoint @ Proposed Rates**					**124%**		**106%**	

Footnotes:

		Bills	SDS/LGSS	LDS/LGSS
1/	SDS/LGSS - Current Rates			
	> 64,400 to ≤ 110,00 Therms Annually	2,139	$265.00	
	>110,000 to ≤ 540,000 Therms Annually	2,442	$1,050.11	
	Weighted Average		$683.52	
2/	LDS/LGSS - Current Rates			
	> 540,000 to <= 1,074,000 Therms Annually	493		$2,673.99
	> 1,074,000 to <= 3,400,000 Therms Annually	313		$4,159.15
	> 3,400,000 to <= 7,500,000 Therms Annually	60		$8,020.79
	> 7,500,000 Therms Annually	12		$11,882.42
	Weighted Average			$3,694.68
3/	SDS/LGSS - Proposed Rates			
	> 64,400 to ≤ 110,00 Therms Annually	2,139	$319.30	
	>110,000 to ≤ 540,000 Therms Annually	2,442	$1,265.29	
	Weighted Average		$823.58	
4/	LDS/LGSS - Proposed Rates			
	> 540,000 to <= 1,074,000 Therms Annually	493		$3,261.28
	> 1,074,000 to <= 3,400,000 Therms Annually	313		$5,072.62
	> 3,400,000 to <= 7,500,000 Therms Annually	60		$9,782.40
	> 7,500,000 Therms Annually	12		$14,492.16
	Weighted Average			$4,506.14

COLUMBIA STATEMENT NO. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2022- 3031211
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
RAYMOND A. BRUMLEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

TABLE OF CONTENTS

I. Introduction

Q. Please state your name and business address.

A. My name is Raymond A. Brumley. My business address is 121 Champion Way, 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. I moved into a Field Engineering role in June of 2002 where I designed capital work for the Company and Columbia Gas of Maryland 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 currently began my 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 and collaboration across organizations;
- 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 this regulatory agency in a consumer complaint proceeding and in the Company's 2021 base rate case at Docket No. R-2021-3024296. I have not testified before any other regulatory agencies.

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 (twelve-months ending December 31, 2023) 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 2022 to 2026 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 2021, and the budgeted amount for 2022 and 2023 are provided in the following table.

Table 1

Budget Class - Age and Condition

Description	Total 2021 Actual	Total 2022 Projected	Total 2023 Projected
Measuring and Regulating Station	3,643	0	0
Compressor Stations	275,630	50,000	50,000
Mains - Leakage Elimination	183,266,398	180,661,000	222,623,000
Service Lines – Replaced	55,105,132	50,177,000	56,803,000
Customer Service Lines Replaced	13,890,403	16,726,000	18,934,000
Meters / 998 Int. Co. Meters	1,090,514	950,000	1,000,000
Meter Install – Replace	384,340	1,100,000	1,150,000
House Regulators - Replace	33,008	80,000	90,000
Plant Regulators – Replace	13,798,470	15,649,000	17,150,000
Reg Structures Replace	325,016	885,000	885,000
LV Excess Press Meas Sta	64,666	900,000	900,000
Corrosion Mitigation Ins	173,363	150,000	150,000
Service Regulators - Replacement	6,175	20,000	20,000
In-Line Inspection	0	8,383,000	22,538,000
	268,416,758	275,731,000	342,293,000

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	2021 Actuals	2022 Approved	2023 Projected
Age and Condition	268,457,000	275,831,000	342,392,000
Betterment	19,201,000	15,603,000	6,825,000
Public Improvement	8,941,000	13,750,000	7,100,000

Q. Please explain why the 2022 budget for the Age and Condition budget class is more than the 2021 budget for Age and Condition?

A. Within our 2022 Age & Condition budget, Columbia is projecting increases in expenditures for mainline and service line replacement work, primarily due to increased contractor pricing. Also, unit costs per foot for mainline replacements and unit costs for service line replacements are expected to increase from 2021 to 2022, as well as 2023, 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 over the past year, 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.

Also, within our Age and Condition budget, approximately $8.4 million has been allocated for the preparation of work to be done with regards to In-Line

Inspections (ILI) on our D-10132 Line in State College and our CAT Line in Emigsville (see Table 4 below for further information on these ILI projects).

Table 4

In-Line Inspection Project Name	Length (miles)	HCA (miles)	Diameter (in)	Original Install (year)	MAOP (PSIG)
D-10132 - State College	10.6	1.7	8 & 12	1966	400
CAT - Emigsville	6.2	2.6	12	1958	550

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 retrofit for ILI. The goal is to complete design engineering, land acquisitions, and the purchase of long lead time materials in 2022 with construction execution planned for 2023.

Q. How was the budget for 2023 developed?

A. In addition to what is stated above, within our 2023 Age & Condition Budget, Columbia is projecting even higher expenditures for mainline and service line replacement work due to our current (5 year) construction blanket contract expiring the end of 2021 and a new construction blanket contract taking effect in 2022. Though this is competitively bid, based on the market demand for natural gas contractors, not just across Pennsylvania but other states as well, pricing will increase to the levels shown in our 2023 projections. Budget plans are derived based upon historical trends and known future projects.

For 2023 an allocation of over $298 million has been requested for the replacement of mains and service lines alone, to maintain the company's momentum of replacing its aging infrastructure. This is an increase of over $50 million compared to 2022. Additionally, approximately $22.5 million has been allocated for ILI, an increase of over $14 million compared to 2022, for continued work to be performed on D-10132 in State College and our CAT Line in Emigsville.

III. <u>Columbia's Pipeline Replacement Efforts</u>

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 2021, 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
Total Actual (Through YE 2021)	**6,518,690**	feet

From 2007 – 2021, through 2021, Columbia's replacement program eliminated an average of 434,579 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.

Q. Why does Columbia need to continue to replace its bare steel and cast iron systems?

A. Columbia's Distribution Integrity Management Program ("DIMP") risk scoring continues to rank external corrosion on bare steel and bell joint failure on cast iron pipelines 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 2021. 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 and cast iron, 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 C.J. Anstead's testimony (Columbia Statement No. 14) by our ability to address Type-1 and Type-2 leaks appropriately, as well as all of the other operational improvements including more frequent leakage surveys, 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, cast iron, bare steel, cathodically-protected steel, and plastic pipe. The material initially at risk is generally first-generation bare steel, cast iron, and wrought iron. Evidence further indicates that the corrosion with respect to unprotected coated steel is accelerating, gradually causing more leaks. Also, cast iron pipe is quite old and is in need of replacement due to its age and vulnerability to fractures caused by ground movement. 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" 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.

With all of that stated, while the system is currently safe, Columbia must, as a prudent operator, address the systemic problem of replacing its unprotected steel, cast iron, and wrought iron facilities. And finally, the issues that are manifesting themselves on first generation plastic (though the risks have not yet risen to the level of risk associated with bare steel, cast iron, or wrought iron), also necessitate a measured replacement strategy geared to those locations where Columbia is uncovering this pipe in the course of replacing other facilities. Witness Anstead provides further testimony on the Company's plans 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, and cast iron pipe 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, which 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?

[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.

A. The long term view is that as bare steel, wrought iron, and cast iron pipe is removed from the system, we expect to see a reduction in Type 1 and Type 2 leakage repair caused by corrosion. However, this impact is expected to be gradual over the period of the program. The remaining cast iron, wrought iron, and bare steel pipe to be replaced continues to degrade, which continues to drive Type 1 and Type 2 leakage repair activities. In 2021, our pipe replacements, together with our aggressive leak repair program, allowed Columbia to reduce the total number of Type-2 outstanding leaks in the system to 539, a 90% reduction since 2007.

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 Vortices" 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 2021 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 2021 Columbia had approximately 130 construction crews which employed approximately 1,300 contractor employees and subcontractors (e.g. restoration, flaggers, drillers, plumbers, etc.). For 2022, Columbia will have approximately 140 construction crews with approximately 1400 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?

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 Anstead's testimony, but includes initiating an annual leakage survey on all of its bare steel mains, identification and mitigation of system cross bores, reducing the number of inactive services in the system, reducing its Type-2 leak repair backlog, 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 cast iron pipe that it removes from the system annually.

Having said all of that, however, the system data is clear that as first generation bare steel and cast iron pipe continues to age, Columbia will have to continue to focus on the accelerated replacement of bare steel and cast iron 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 15 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 2021 actuals, is $238.00 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 American's 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 ("NGDCs") in Pennsylvania and across the country undertake main replacement programs, increase training and qualification requirements, and fight 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 will 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 440,000 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.

- 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.

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 projects in 2022.
- 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 district 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, 2021?

A. Yes. In 2021, the Public Affairs team participated in the following proactive outreach discussions:

- **Adams County** – Columbia conducted proactive outreach to McSherrystown Borough on a pipeline replacement project.
- **Allegheny County - CONNECT Utilities Meetings:** Columbia participated virtually in CONNECT Utilities Meetings, which brought together numerous municipalities and utility representatives to discuss planned utility projects and municipal government paving plans.
- **Allegheny County - City of Pittsburgh Utility Coordination:** Throughout the year, Columbia participated with the City of Pittsburgh in its monthly 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 Bellevue Borough, Brentwood Borough, the City of Clairton, Findlay Township, Kennedy Township, Leet Township, Pine Township, City of Pittsburgh, Pleasant Hills Borough, Scott Township, Sewickley Borough, Stowe Township, South Fayette Township and Whitehall Borough regarding 2021 pipeline replacement projects or operational work in those communities.
- **Beaver County –** Columbia conducted proactive outreach with Beaver Borough, the City of Beaver Falls, Brighton Township, Chippewa

Township, Conway Borough and Franklin Township on pipeline replacement projects.

- **Butler County –** Columbia conducted a proactive meeting with Worth Township on a pipeline replacement project.
- **Centre County –** Columbia conducted proactive outreach with State College Borough regarding a pipeline replacement project.
- **Clarion County –** Columbia conducted proactive outreach with Madison Township on a pipeline replacement project.
- **Fayette County –** Columbia conducted proactive outreach s with Brownsville Borough, Dunbar Borough, Georges Township, Luzerne Township, Masontown Borough, Springhill Township and the City of Uniontown on pipeline replacement projects.
- **Franklin County –** Columbia conducted proactive outreach to Greencastle Borough on a pipeline replacement project.
- **Greene County** - Columbia conducted proactive outreach to Richhill Township on restoration for a pipeline replacement project.
- **Lawrence County –** Columbia conducted proactive outreach with the City of New Castle, Ellport Borough and Ellwood City Borough on pipeline replacement projects.
- **McKean County –** Columbia conducted proactive outreach to the City of Bradford on a pipeline replacement project.
- **Somerset County –** Columbia conducted proactive outreach to Somerset Borough on a pipeline replacement project.

- **Washington County –** Columbia conducted proactive outreach with Canonsburg Borough, Canton Township, Charleroi Borough, East Bethlehem Township, East Washington Borough, Independence Township, North Franklin Township, Peters Township and Roscoe Township 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, Glen Rock Township, Hanover Borough, Manchester Township, West York Borough, York Township 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, Bon Air Neighborhood, Allegheny County:** Columbia was in regular contact with City of Pittsburgh officials regarding issues and concerns with the restoration of streets and property associated with the infrastructure replacement projects completed in the Bon Air neighborhood. Columbia was able to reach a co-op agreement with the City on the paving of streets in the neighborhoods and completed the majority of the restoration work by the end of 2019.
- **Beaver Borough, Beaver County:** Columbia conducted several meetings with Beaver Borough officials in late 2018 and 2019 to reach an agreement with Beaver Borough officials to share restoration costs for roadway and sidewalk restorations associated with Columbia's 2019 pipeline replacement projects. These meetings led to an agreement on planned work for 2020, including enhanced communications to affected Beaver Borough residents about the projects.

- **Harmony Township, Beaver County:** Columbia met with the township manager and public works director to discuss 2019 projects and planned restoration work. Columbia was involved in a lengthy dispute with the township over street opening fees and restoration costs that was eventually settled. For the 2019 projects, Columbia and the township reached a settlement on fees and restoration plans, and the process went smoothly throughout the infrastructure replacement project.
- **City of Bradford, McKean County:** Columbia met with City of Bradford officials in early 2019 to address concerns about 2018 restorations and Columbia's planned work in 2019. The group was able to successfully address concerns about past restorations and reached an agreement on coordination of Columbia's work with the City's planned sidewalk improvement plans for 2019.
- **City of Pittsburgh, Allegheny County:** In the Spring of 2020, the City undertook a comprehensive rewrite of its permit policies and procedures related to work in their right-of-way. Columbia worked with the City to explain our concerns with newly proposed rules that were not within the jurisdiction/oversight of local governments and a new permitting fee based on the size of a project and time it took to complete. At the urging of Columbia and other utilities, the City adjusted its policies related to oversight of Commission regulated utilities and capped the permit fee costs related to large projects.

In the Spring of 2021, Columbia Gas led a coalition of utilities working in the City of Pittsburgh against significant changes to road restoration standards as outlined in proposed changes to the City's Right of Way Procedures Manual. The proposed updates to the manual shifted old, unattended, legacy road issues to a utility who "touched" a street to repair or upgrade its facilities.

The 2021 proposed Right of Way Manual provisions would have increased utility restoration costs by hundreds of thousands of dollars or more per year. Because of the concerns expressed by the utility coalition, the proposed changes were not implemented by the City of Pittsburgh.

- **Brownsville Borough, Fayette County:** Columbia continued to engage Borough Council in 2021 regarding its concerns with and opposition to updated permit fee formulas and restoration standards that would increase costs for work Columbia conducts in the borough. Under their ordinance, the permit fees for large pipeline replacement projects are tens of thousands of dollars and paving restoration costs for operational work increase from $800-$1,000 to $8,000-$10,000.
- **West Brownsville Borough, Fayette County:** Columbia met with Borough Council in 2021 to discuss its concerns with an updated paving restoration ordinance requiring curb to curb paving plus ten feet on each side of a road cut. The ordinance will significantly increase restoration costs related to the company's operational and pipeline replacement work.
- **Georges Township and South Union Township, Fayette County:** In 2021, Columbia continued its opposition to the implementation of an

engineering inspection fee based on the square yardage of the road disturbance created by Columbia's work in those townships' right of way. This fee language was included in updates of the townships' road cut ordinances. In 2021, Columbia replaced 5,500 feet of mainline pipe in Georges Township and the Township's engineering firm invoiced Columbia for more than $33,000 in engineering inspection fees for the project. In addition, Columbia requested justification for more than $30,000 of engineering inspection fees from South Union Township for both operational work and pipeline replacement projects. Columbia has objected to the engineering inspection fees.

- **Luzerne Township, Fayette County:** In 2020, Columbia met with the Luzerne Township Supervisors to discuss a proposed permit fee formula change/increase and increased restoration standards. After discussion with the Supervisors, the changes/increases were placed on hold.
- **Rices Landing Borough, Greene County:** Columbia worked with the Mayor and Borough Council in 2020 to prevent the retroactive application of increased permit fee costs in a new road opening ordinance passed by the Council that year. Columbia also expressed concerns with a new "escrow account fee" for new permit requests mandated in the new ordinance. The "escrow fee" language provides few details on what may be charged by the borough against this account. Columbia is monitoring its application to ensure unreasonable charges are not applied against the escrow account.
- **Canton Township, Washington County:** Columbia continues to work

with the township regarding its policy of requiring the signing of a "Road Maintenance Agreement" which forces significant paving restoration (100 feet) on each side of a road opening cut Columbia may make. Columbia negotiated restoration agreements using PennDOT restoration standards for 2020 and 2021 pipeline replacement projects and a new customer pipeline extension reducing restoration costs on the projects.

- **Canonsburg Borough, Oakdale Borough, Stowe Township in Allegheny County and Chippewa Township, Beaver County:** Columbia engaged all four municipalities in 2021 raising concerns with identical permit fee and road restoration ordinances passed in 2020 that will significantly increase costs for Columbia Gas work. The ordinances require 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 and created a linear and square foot fee for larger projects resulting in thousands of dollars in fees per project.
- **Mead Township, Warren County:** Columbia Gas worked with township supervisors in 2021 to reduce permit fees related to a Columbia Gas new business project.

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-2022-3031211

March 18, 2022

Columbia Gas of Pennsylvania, Inc.
Direct Testimony of Paul R. Moul
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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 11.20%. My return on equity includes a provision of 0.25% in recognition of management effectiveness. I have not made an independent evaluation of the Company's management effectiveness. The testimony of witness Mark Kempic, President of the Company (Columbia Statement No. 1) describes the superior performance of its management. 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, 2023 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	43.23%	4.51%	1.95%
Short-Term Debt	2.39%	1.65%	0.04%
Total Debt	45.62%		1.99%
Common Equity	54.38%	11.20%	6.09%
Total	100.00%		8.08%

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. Is the market impact of the COVID-19 Pandemic reflected in your analysis of the cost of equity for the Company?

A. Yes. My cost of equity analysis reflects the impact of the COVID-19 Pandemic ("Pandemic"). These events have had a significant impact on the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the Pandemic. These events led to the end of the record-setting 128-month economic expansion. As we entered a recession in February 2020, extraordinary actions were taken by the Federal Open Market Committee ("FOMC") to address these disruptions. Over the course of the Pandemic, stock prices have rebounded and have reached new highs. Renewed economic growth has produced higher inflation to levels not seen in four (4) decades. Indeed, in January 2022, the rate of inflation spiked upward to 7.5% due to pandemic-related supply side issues, strong consumer demand, and tight labor markets. Energy prices have increased as well, with the commodity cost of natural gas moving up. While short-term interest rates remain at historically low levels, longer term interest rates began to rise in February 2021. At this point, short-term interest rates are poised to increase after the FOMC ends its bond buying program. The FOMC has indicated that several increases in the Fed Funds rate will likely occur in 2022. The first of these increases are expected in March 2022. Recently, the yield on ten-year Treasury notes reached 2.00% for the first time since mid-2019. Stock market performance has reacted to renewed economic growth by reaching new highs. While there has been some pullback in overall market prices in early 2022, the overall market performance in 2021 was stellar i.e., a 26.89% annual price appreciation. I have considered these events as they impact the inputs that I used in the various models of the cost of equity.

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 441,000 customers located in south-central and western Pennsylvania. Throughput to its customers for the twelve-months ended December 31, 2020 was represented by approximately 45% to sales customers and approximately 55% 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 11.20% including 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.

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[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).

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 nine (9) 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 ten 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. I should also note that, prior to this rate case filing, one Gas Group member (South Jersey Industries) entered into an agreement to be acquired by a private equity investor. This action would require the removal of SJI from the Gas Group going forward. However, for this case, my analysis of the members of the Gas Group included market data through December 2021, which predated the acquisition announcement of SJI. Hence, my cost of equity determination in this case is not altered by the inclusion of SJI in the Gas Group, because the proposed acquisition had no impact on the stock prices through December 2021. 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-2021-3030045) approved by the Commission on January 13, 2022.

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	11.42%
Risk Premium	10.50%
CAPM	13.45%
Comparable Earnings	12.45%

From these measures, I recommend a cost of equity of 11.20%, which includes 0.25% in recognition of the Company's exemplary management performance. My determination of the cost of equity focuses on the DCF and Risk Premium approaches that provide a return of 10.96% (11.42% + 10.50% = 21.92% ÷ 2 = 10.96%) and on all of the market-based models, i.e., DCF, Risk Premium and CAPM, that provide a return of 11.79% (11.42% + 10.50% + 13.45% = 35.37% ÷ 3 = 11.79%). My 11.20% cost of equity recommendation includes 25 basis points or 0.25% recognition for the exemplary performance of the Company's management and falls within the range of 10.96% to

11.79% indicated above. Mr. Kempic's testimony in Columbia Statement No. 1 demonstrates that the Company ranks high in customer service and management effectiveness. To obtain new capital to support an expanded construction program and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. Along these lines, the Company is spending considerable amounts of new capital, which are large by historical standards, which will put a strain on financial performance in the short run. In recognition of its performance, the Company should be granted an opportunity to earn an 11.20% rate of return on common equity.

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 profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation. 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 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 2019 and switched to another LDC that provides service in an overlapping service territory to the Company. This clearly demonstrated the high risk faced by the Company to bypass. 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. In addition, with the consolidation of several formerly competing LDCs in western Pennsylvania, CPA could potentially face additional threats from the stronger LDC competitor that remains. 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 Johnson.

Q. Does your cost of equity analysis and recommendation take into account the WNA that the Company has?

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 66 of the Company's major account customers, i.e., those with large volume usage and/or those with competitive alternatives.

This throughput to these 66 customers represents approximately 27% (19,576,533 Dth ÷ 73,420,908 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 1103.9 miles (or approximately 14%) of its distribution mains as of year-end 2020. There are also concerns regarding first generation plastic pipe that may require replacement. The Company also has 40,456 (or approximately 9%) of its services constructed of unprotected steel. For the future, the Company expects its net capital expenditures to be:

Year	Capital Expenditures
2022	$ 379,065,000
2023	$ 423,129,000
2024	$ 432,740,000
2025	$ 461,322,000
2026	$ 487,946,000
Total	$ 2,184,202,000

The Company's total capital expenditures over the next five years will represent approximately 77% ($2,184,202,000 ÷ $2,835,900,000) of the net utility plant in service at December 31, 2021.

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 2021. 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 Company 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., South Jersey Industries, 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 2016-2020. 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 slightly higher for the Gas Group compared to 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 higher 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

[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).

financial risk. The five-year average common equity ratios, based on permanent capital, were 55.3% for CPA, 51.5% for the Gas Group, and 41.3% for the S&P Public Utilities. The Company's common equity ratio was higher than the Gas Group, thereby indicating somewhat lower financial risk. However for the purpose of this case, the Company's common equity ratio is within the range of other gas distribution utilities.

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 0.175 (1.8% ÷ 10.3%) for the Company, 0.079 (0.7% ÷ 8.9%) for the Gas Group, and 0.039 (0.4% ÷ 10.3%) 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 73.7% for the Company, 83.6% for the Gas Group, and 78.8% 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"),

[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.

the five-year average pre-tax interest coverage was 4.20 times for the Company, 4.05 times for the Gas Group, and 3.02 times for the S&P Public Utilities. The interest coverages were fairly similar for the Company and the Gas Group, thereby indicating similar risk.

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. In 2018 and 2019, the effective income tax rate declined from earlier years after implementation of the TCJA.

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 61.1% for the Company, 56.0% for the Gas Group and 69.5% 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 IGF to construction has declined for the Gas Group in 2018 and 2019 with the implementation of the new lower federal income tax rate because of lower marginal rates and lower provision for deferred income taxes. The Company has not been similarly affected because in 2018 and 2019 its revenues increased, while operating expenses decreased, which more than offset the decline in income taxes, including tax deferrals. 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 0.88 as the average for the Gas Group (see page 2 of Schedule 3) and 0.91 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 indicate lower risk for CPA. Its common equity ratio, 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.

[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.

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, 2021 capitalization corresponds with the end of the HTY in this case. The November 30, 2022 capital structure is estimated at the end of the FTY, and the December 31, 2023 capital structure is estimated at the end of the FPFTY. The Company will receive an equity infusion of $25 million in the FTY. The Company expects to issue $90 million of new long-term debt in the FTY and $210 million of new long-term debt in the FPFTY. For the FTY, one issue of $50 million has already occurred and $40 million will take place later in 2022. The issues in the FPFTY will be represented by individual borrowings of $85 million, $30 million, and $95 million. 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 ratesetting 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 43.23% long-term debt, 2.39% short-term debt, and 54.38% common equity at December 31, 2023. The common equity ratio projected for the FPFTY is consistent with the actual common equity ratio for the Company at November 30, 2021. 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, 2021. On page 2 of Schedule 6, I have shown the embedded cost rate of debt estimated at November 30, 2022. In the FTY, the debt issue placed in December 2021 reflects the actual interest rate of 3.2671% on this issue. And on page 3 of Schedule 6, the embedded cost of debt is shown at December 31, 2023. For the new issues of long-term debt, I have used cost rates of 3.80% for the June 2022 issue in the FTY and 3.95%, 4.10% and 4.20% for the issues in the FPFTY (December 2022, June 2023, and December 2023, respectively). In each instance, 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 4.51% embedded cost of long-term debt at December 31, 2023, 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 43.23% 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 1.65%, which represents the Company's estimate for the FPFTY. This forecast reflects the upward move in short-term interest rates now taking place. I should note that the actual short-term debt interest rate in the HTY in this case was well below the forecast interest rate in the FTY in the Company's prior rate case because the FOMC did not increase the Fed Funds rate in 2021 as expected in the forecast last time. 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 3-month LIBOR rate, plus an additional 0.30%, which reflects the recent historical yield differential between the 3-month LIBOR rate and NiSource's commercial paper borrowing rate.

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 4.36% for the FPFTY.

<u>Cost of Equity – General Approach</u>

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 that 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 11.20% for CPA, which includes an increment for exemplary 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 Schedule 1, page 2, for the Gas Group. The DCF return is 11.42% with the leverage adjustment and 10.43% 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

[5] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

model may not fully reflect the true risk of a utility. Other limitations of the DCF include the constant price-earnings 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 twelve (12) months ended December 2021, 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 (2) to three (3) weeks prior to the actual payment).

For the twelve (12) months ended December 2021, the average dividend yield was 3.47% 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 3.55% and 3.58%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.55% 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 (3) different, but generally accepted, manners and used the average of the three

(3) adjusted values as calculated in the lower panel of data presented on Schedule 7.[6] This adjustment adds thirteen (13) basis points to the six-month average historical yield, thus producing the 3.68% 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 price-earnings multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of 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 the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book

[6] Under the 1/2 growth 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 in order 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.

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 where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a “transition” stage where 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 (3) stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three (3) 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 (3) 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, which are those used by investors when pricing common stocks.

Q. How did you determine 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 Schedules 8 and 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 price-earnings multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates were obtained from the Value Line publication that provides this data. While historical data cannot be ignored, it is much less significant in 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 price-earnings ("P-E") multiple. As such, my company-specific growth analysis, which focuses principally upon 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 focuses also 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 (5) 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 in order 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 in order 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 also are 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 (5.17%), Zacks (5.94%), and Value Line (7.61%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While a variety of 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 Myron 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.

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[7] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

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 5.17% to 7.61%. 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 market capital structure ratios are 43.49% long-term debt, 0.46% preferred stock, and 56.06% 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 that 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] provides a return of 7.59% 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 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 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 existed.

[8] Franco Modigliani and Merton H. Miller, The Cost of Capital, Corporation Finance, and the Theory of Investments, American Economic Review, June 1958, at 261-297. Franco Modigliani and Merton H. Miller, Taxes and the Cost of Capital: A Correction, American Economic Review, June 1963, at 433-443.

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 expressed 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 7.59%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 3.81% to compensate investors for the risk of a 51.07% debt ratio and 0.02% for a 0.54% 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 sum to 11.42% (7.59% + 3.81% + 0.02%), 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 summed the 3.68% dividend yield, the 6.75%

growth rate, and 0.99% for the leverage adjustment in order to arrive at the same 11.42% (3.68% + 6.75% + 0.99%) return. I know of no means to mathematically solve for the 0.99% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.99% adjustment is merely a convenient way to compare the 11.42% return computed using the Modigliani & Miller formulas to the 10.43% return generated by the DCF model (i.e., $D_1/P_0 + g$, or the traditional form of the DCF shown on Schedule 7, page 1) based on a market-value capital structure. A 10.43% 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 11.42%, computed as follows:

	D_1/P_0	+	g	+	$lev.$	=	k
Gas Group	3.68%	+	6.75%	+	0.99%	=	11.42%

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 price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market because price-earnings 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 Schedule 1, page 2. That result is 10.50%.

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 3.75% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

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 twelve (12) months ended December 2021, the average monthly yield on Moody's index of A-rated public utility bonds was 3.11%.

For the six- and three-month periods ended December 2021, the yields were 3.02% and 3.08%, respectively. During the twelve (12) months ended December 2021, the range of the yields on A-rated public utility bonds was 2.91% to 3.44%. Page 2 of Schedule 11 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 1.06% on a twelve-month average basis, 1.08% on a six-month average basis, and 1.13% on a three-month average basis. With these data, 1.00% 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 below. Blue Chip is a reliable authority and contains consensus forecasts of a variety of 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 January 1, 2022, and a yield spread of 1.00%, derived from 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 also have 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
2022	First	2.8%	3.6%	2.1%	1.00%	3.10%
2022	Second	3.0%	3.8%	2.2%	1.00%	3.20%
2022	Third	3.2%	4.0%	2.4%	1.00%	3.40%
2022	Fourth	3.4%	4.2%	2.5%	1.00%	3.50%
2023	First	3.6%	4.4%	2.7%	1.00%	3.70%
2023	Second	3.7%	4.6%	2.8%	1.00%	3.80%

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, 2021 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
2023-2027	4.4%	5.2%	3.4%
2028-2032	4.9%	5.7%	3.8%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.75% yield on A-rated public utility bonds represents a reasonable 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. Recent FOMC pronouncements have moved the forecasts of interest rates to higher levels.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2021 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 Schedule 12, page 1.

Common Equity Risk Premiums	
Low Interest Rates	6.63%
Average Across All Interest Rates	5.67%
High Interest Rates	4.69%

Based on my analysis of the historical data, the equity risk premium was 6.63% when the marginal cost of long-term government bonds was low (i.e., 2.85%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.09% on average during periods of high interest rates), the spread narrowed to 4.69%. Over the entire spectrum of interest rates, the equity risk premium was 5.67% when the average government bond yield was 4.95%. I have utilized a 6.75% equity risk premium. The equity risk premium of 6.75% that I employed is near the risk premiums associated with low interest rates.

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., “”") and the equity risk premium (i.e., “RP”). The Risk Premium approach provides a cost of equity of:

	i	**+**	***RP***	**=**	***k***
Gas Group	3.75%	+	6.75%	=	10.50%

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 13.45% for the Gas Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 12.29% (13.45% - (0.12 x 9.68%)). To compute the cost of equity with the CAPM, three (3) 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 0.88 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 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. 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 0.54 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 1.00 for the book value capital structure of the Gas Group.

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 twelve (12) months ended December 2021, the average yield on 30-year Treasury bonds was 2.05%. For the six- and three-months ended December 2021, the yields on 30-year Treasury bonds were 1.94% and 1.95%, respectively. During the twelve (12) months ended December 2021, the range of the yields on 30-year Treasury bonds was 1.82% to 2.34%. The low yields that existed during recent periods can be traced to weakness in business fixed investment and exports due in part to the trade dispute between the United States and China. Thereafter, extraordinary events associated with the Pandemic induced significant turmoil that jolted the capital markets

[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, December 27-29, 1971. (May 1972), pp. 435-452.

in the February-May 2020 time frame. During this period, we saw abrupt reaction to the Pandemic. These events led to the end of the record-setting 128-month economic expansion. As the recession unfolded in February 2020, the FOMC acted to address these disruptions. The FOMC continues to support the money and capital markets during the recovery from the COVID-19 Pandemic. Presently, the Fed Funds rate is near zero. It is expected that a transition in FOMC policy will prospectively produce higher interest rates as the Pandemic nears its end and the FOMC ends its quantitative easing. That program is expected to end in March 2022 and a Fed Funds rate increase is expected at that time. A forward-looking assessment of the capital markets is especially relevant now because the Company's rates will be based on financial conditions in 2023 and beyond. Higher inflation expectations are a contributing factor that points to higher interest rates. Indeed, higher inflation today is revealed by a 5.9% increase in social security payments announced on October 13, 2021, which is the largest one-year increase in nearly four (4) decades. As previously noted, the rate of inflation spiked upward to 7.5% in January 2022, reaching a four (4) decade high. FOMC is in the process of tapering its bond buying program (i.e., quantitative easing) which will be completed in March 2022. The Fed Funds rate is also likely to increase from very low levels that existed during the Pandemic. Higher interest rates clearly point to higher capital costs prospectively. I have already described the forecasts of higher interest rates, including the end of quantitative easing by the FOMC and indications prospectively of several increases in the Fed Funds rate in 2022.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on January 1, 2022 indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.1% to 2.8% during the next six (6) quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.4%

from 2023 through 2027 and 3.8% from 2028 to 2032. 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 2.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on Schedule 13, page 2, 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 Schedule 12, page 1. On that schedule, the market return was 12.06% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.85% when interest rates were low. As such, I carried over to Schedule 13, page 2, the average large common stock returns of 12.06% and the average yield on long-term government bonds of 2.85%. The resulting market premium is 9.21% (12.06% - 2.85%) based on historical data, as shown on Schedule 13, page 2. As also shown on Schedule 13, page 2, I calculated the forecast returns, which show a 12.89% total market return. With this forecast, I calculated a market premium of 10.14% (12.89% - 2.75%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 9.68% (10.14% + 9.21% = 19.35% ÷ 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 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 understate the cost of equity significantly 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. As noted previously, CPA is relatively smaller than the Gas Group. 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.

Q. What does your CAPM analysis show?

A. Using the 2.75% risk-free rate of return, the leverage adjusted beta of 1.00 for the Gas Group, the 9.78% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*
Gas Group	2.75%	+	1.00	x (	9.68%	) +	1.02%	=	13.45%

<u>Comparable Earnings Approach</u>

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 in order 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 (2) 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 vs. 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 (6) 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 Schedule 14, page 3. 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 Schedule 14, page 2, 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 in order 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 in order to cover conditions over an entire business cycle. A ten-year period (five (5) historical years and five (5) 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 12.1% using only the returns that were less than 20%, as shown on Schedule 14, page 2. The average forecasted rate of return as published by Value Line is 12.8% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data, my Comparable Earnings result is 12.45%, as shown on Schedule 1, page 2.

Conclusion On Cost Of Equity

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 11.20% for CPA, which includes 25 basis points in recognition of the exemplary performance of the Company's management. My cost of equity recommendation is within the range of results and should be considered in the context of the Company's risk characteristics relative to the barometer group companies. 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. In summary, the Company should be provided an opportunity to realize an 11.20% rate of return on common equity so that it can compete in the capital markets, attain reasonable credit quality, sustain its cash flow in the context of the its high levels of capital expenditures, and be compensated for its strong management performance.

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.

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).

COLUMBIA STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2022-3031211
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
NICOLE M. PALONEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

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 and 2021 base rate cases at Docket Nos. R-2015- 2468056, R-2016-2529660, R-2018-2647577 and R-2021-3024296. 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 on behalf of Columbia Gas of

Maryland 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 the 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, 2023), that have been incorporated in Columbia witness Miller'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
NCSC OPEB Costs Amortization	Bly

In addition to the information I will be supporting above, I will also be supporting the additional labor and benefits adjustment made by Company Witness Miller at Exhibit 104, Schedule 2, Sheet 18.

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 grass roots Field Operations budget planned at the cost element level. This budget includes all known Field Operations work, 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 grass roots budget is compared to the prior year spend to ensure it is reasonable compared to actual costs incurred in the prior year.

(2) State Financial Planning and Analysis (State FP&A): State FP&A reviews and verifies the Field Operations budget is entered correctly in the budget system, as well as 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 the state.

(3) Corporate Financial Planning & Analysis (Corporate FP&A): Corporate FP&A is responsible for budgeting the NCSC allocation. In addition, Corporate FP&A budgets corporate O&M functions and overhead expenses charged to the state 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 State Leadership to discuss the upcoming budget and answer questions. After everything is complete and there are no further adjustments, the final budget is reviewed and approved by the Company President and Senior VP of Regulatory and Utilities Planning. 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 business unit'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. More detailed labor budgets are developed by projecting the year's labor based on a trend analysis. The projection includes estimates for headcount, gross salary, overtime, vacation and sick time, and labor charges in from other departments. This results in a sub-total for total labor dollars available by month, which will then be allocated between O&M accounts, capital, and charges to other departments. 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 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, consistent with historical results by department, to calculate a net labor amount. 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 782 active full-time employees for 2022 and 2023, and an overall wage increase guideline of 3% for exempt and non-exempt employees. Labor costs for bargaining unit employees are based on the contracts currently in place. The headcount reflects the level of 782 active full-time employees at the end of the Historic Test Year ("HTY").

Q. Please explain the additional labor and benefits adjustment included in Exhibit 104, Schedule 2, page 18.

A. At the time the cost of service for this case was prepared, the Company was in labor negotiations with several unions. The adjustment proposed herein is reflective of the contract that was presented to the unions for ratification before the cost of service was completed. These adjustments were based on the successful negotiations other companies across the NiSource footprint have had with the unions, and is reflective of the increased labor costs included in other contracts that have been ratified. Adjustments in Exhibit 104, Schedule 2, Sheet 18 include an annual wage increase of $.50 cents in 2022 and 2023 (the Future Test Year (FTY) and the FPFTY, respectively), as well as the application of merit increases to the increase in FTY and FPFTY. The company will provide updates to this adjustment during the course of the proceeding.

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 2021 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 based on historical information and inflationary cost increases.

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 22, O&M expense is $166,706,602 for the Historic Test Year ended November 30, 2022, $173,506,000 for the Future Test Year ending November 30, 2022 and $175,295,000 for the Fully Projected Future Test Year ending December 31, 2023, increases of $6,799,398 and $1,789,000, respectively, before pro forma ratemaking adjustments for the FTY and the FPFTY.[1]

Q. Does this complete your direct testimony?

A. Yes, it does.

[1] This testimony compares O&M expenses independent of expense items specifically tracked against revenues as discussed earlier in this testimony.

Exhibit NP-1

Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

							Budget						
CE	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	23,873	23,108	22,910	23,693	25,709	25,251	28,309	29,646	31,181	31,534	32,271	36,572	38,028
Incentive Compensation	293	1,171	1,149	1,249	1,238	1,333	1,584	1,642	1,742	2,150	1,133	2,676	2,946
Pension	2,119	6,005	6,598	-	3	1,137	-	6	549	-	-		-
OPEB	715	1,065	492	(154)	(284)	(550)	(1,378)	(810)	(514)	(1,109)	(730)	(678)	(1,420)
Other Employee Benefits	5,076	6,363	6,509	6,184	6,454	4,584	4,791	5,635	5,975	6,445	6,851	7,302	7,973
Outside Services	15,636	15,175	13,094	12,123	12,104	22,311	26,079	23,977	25,458	22,634	23,453	22,167	29,086
Rent and Leases	1,314	1,374	1,458	1,615	1,887	2,273	4,791	3,607	3,873	3,203	3,296	2,857	2,658
Corporate Insurance	3,116	3,574	3,413	3,048	3,004	3,087	4,516	3,481	3,705	3,495	3,631	5,861	7,860
Injuries and Damages	1,209	944	795	630	630	500	500	400	-	400	400	400	300
Employee Expenses	1,109	1,046	1,163	1,142	1,295	1,305	1,640	1,452	1,501	1,584	1,483	1,642	1,622
Company Memberships	347	345	249	292	262	256	256	332	491	491	563	560	523
Utilities and Fuel Used in Company Operations	675	570	567	503	1,167	1,303	1,310	1,370	1,102	1,709	1,715	2,142	1,959
Advertising	500	185	170	170	470	170	170	170	170	170	174	174	170
Fleet	4,663	4,104	4,421	5,046	5,452	5,708	5,728	5,797	5,879	6,255	5,673	6,671	6,434
Materials & Supplies	4,929	4,767	4,775	4,899	4,649	5,024	5,067	5,962	5,366	5,865	5,568	5,755	6,159
Other O&M	(3,987)	(3,780)	(116)	(783)	60	(1,906)	(434)	393	1,050	646	1,381	193	2,495
PUC, OCA, OSBA Fees	1,673	1,953	1,354	1,454	1,699	1,583	2,161	2,330	2,460	2,262	2,341	2,262	2,262
NCSC Shared Services & NGD Shared Operations	31,889	38,399	37,740	39,742	44,597	47,962	49,533	57,719	67,158	66,049	64,185	59,051	78,913
Amortization	82	75	(243)	(1,446)	(1,455)	185	267	496	511	409	845	935	935
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operation and Maintenance Expense	95,231	106,443	106,498	99,407	108,941	121,516	134,890	143,604	157,656	154,193	154,233	156,541	188,903

Exhibit NP-1

Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

	Actuals												
CE	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	23,153	23,577	22,845	23,996	25,124	25,818	27,980	29,093	30,019	32,461	36,471	36,293	35,828
Incentive Compensation	1,303	1,628	1,649	1,690	1,845	1,816	1,791	1,981	2,590	1,381	1,246	2,137	2,676
Pension	392	5,799	13,088	91	2,489	1,131	14	21	8,538	(8,417)	12	13	(12)
OPEB	1,683	775	(213)	88	(454)	(1,298)	(1,336)	(583)	(410)	(843)	(325)	(693)	(1,459)
Other Employee Benefits	4,995	7,472	6,210	5,880	5,635	5,432	5,992	5,924	6,099	6,015	6,931	9,181	7,311
Outside Services	15,180	15,440	13,244	12,133	14,113	22,070	22,951	25,361	28,246	21,352	22,850	15,615	24,677
Rent and Leases	1,306	1,207	1,348	1,485	1,699	1,699	2,252	2,831	3,453	3,234	3,409	2,592	1,812
Corporate Insurance	3,045	3,241	2,926	2,763	2,734	2,796	2,899	3,024	3,176	3,239	4,363	6,281	6,421
Injuries and Damages	605	545	340	241	305	(185)	381	363	337	270	512	317	260
Employee Expenses	1,405	1,450	1,553	1,465	1,376	1,264	1,415	1,381	1,545	1,383	1,713	1,063	1,701
Company Memberships	295	250	293	262	249	313	479	563	599	527	569	854	711
Utilities and Fuel Used in Company Operations	451	417	487	1,094	1,247	1,244	1,287	1,460	1,679	1,693	1,723	1,871	2,738
Advertising	389	281	167	133	243	236	207	226	283	146	224	719	551
Fleet	4,650	4,726	5,092	5,357	5,780	6,106	5,956	6,206	6,320	6,338	6,906	6,389	6,274
Materials & Supplies	4,741	4,967	4,412	4,353	5,171	5,343	5,873	5,461	6,327	5,627	6,320	6,643	6,832
Other O&M	(3,527)	(3,005)	157	(63)	31	512	306	367	647	1,074	1,242	982	1,353
PUC, OCA, OSBA Fees	1,721	1,539	1,348	1,523	1,585	1,815	2,161	1,960	1,846	1,814	2,113	2,125	2,198
NCSC Shared Services & NGD Shared Operations	34,023	36,457	38,899	40,164	43,374	50,760	53,169	56,264	68,727	63,166	64,147	62,366	68,769
Amortization	82	0	(489)	(1,446)	(594)	185	267	396	511	845	845	935	935
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operation and Maintenance Expense	95,892	106,766	113,356	101,209	111,952	127,057	134,044	142,299	170,532	141,304	161,271	155,683	169,576

Exhibit NP-1

Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

	Variance												
CE	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Labor	(720)	469	(65)	303	(585)	567	(329)	(553)	(1,162)	927	4,200	(279)	(2,200)
Incentive Compensation	1,010	457	500	441	607	484	207	339	848	(769)	113	(539)	(270)
Pension	(1,727)	(206)	6,490	91	2,486	(6)	14	15	7,989	(8,417)	12	13	(12)
OPEB	968	(290)	(705)	242	(170)	(748)	42	227	104	266	405	(15)	(38)
Other Employee Benefits	(81)	1,109	(299)	(304)	(819)	848	1,201	289	124	(429)	80	1,879	(663)
Outside Services	(456)	265	150	10	2,009	(241)	(3,128)	1,384	2,788	(1,282)	(603)	(6,552)	(4,409)
Rent and Leases	(8)	(167)	(110)	(130)	(188)	(574)	(2,539)	(776)	(420)	31	113	(266)	(846)
Corporate Insurance	(71)	(333)	(487)	(285)	(270)	(291)	(1,617)	(457)	(529)	(255)	732	420	(1,439)
Injuries and Damages	(604)	(399)	(455)	(389)	(325)	(685)	(119)	(37)	337	(130)	112	(83)	(40)
Employee Expenses	296	404	390	323	81	(41)	(225)	(71)	44	(202)	230	(578)	80
Company Memberships	(52)	(95)	44	(30)	(13)	57	223	231	108	35	6	294	188
Utilities and Fuel Used in Company Operations	(224)	(153)	(80)	591	80	(59)	(23)	90	577	(16)	8	(272)	778
Advertising	(111)	96	(3)	(37)	(227)	66	37	56	113	(24)	51	546	381
Fleet	(13)	622	671	311	328	398	228	409	441	83	1,233	(283)	(159)
Materials & Supplies	(188)	200	(363)	(546)	522	319	806	(501)	961	(238)	752	889	673
Other O&M	460	774	272	720	(29)	2,418	740	(26)	(403)	428	(139)	788	(1,142)
PUC, OCA, OSBA Fees	48	(413)	(5)	69	(114)	232	-	(370)	(614)	(448)	(228)	(137)	(64)
NCSC Shared Services & NGD Shared Operations	2,134	(1,942)	1,159	422	(1,223)	2,798	3,636	(1,455)	1,569	(2,884)	(38)	3,315	(10,145)
Amortization	(0)	(74)	(246)	(0)	861	-	-	(100)	-	436	-	0	(0)
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Operation and Maintenance Expense	661	324	6,858	1,802	3,011	5,542	(846)	(1,305)	12,876	(12,889)	7,038	(858)	(19,327)

COLUMBIA STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2022-3031211
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
JENNIFER HARDING
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

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 Director, Income Tax Operations at NCSC.

Q. Please briefly describe your professional experience.

A. I began my career with KPMG as a Senior Associate in the tax department 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 income tax audit CAP ("Compliance Assurance Process") program. Constellation was acquired by Exelon Corporation in 2012, and I moved to Chicago, Illinois as the Tax Manager of the electric utility responsible for income tax accounting, forecasting income taxes, and income tax and non-income tax return filings. In 2014, I moved to the Netherlands and worked for Mead Johnson Nutrition BV as the Tax Manager 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 moved to Columbus, Ohio and worked for Cardinal Health 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 in my current position.

Q. Please describe your educational background.

A. I received a bachelor's in business administration with a concentration in Accounting in 2007 from the Notre Dame of Maryland University in Baltimore, Maryland.

Q. What are your responsibilities in your current position?

A. In my current position as Director of Tax Operations, I am responsible for the operational income tax activities for NiSource Inc. and Subsidiaries, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"). My responsibilities include oversight and review of the preparation of the Company's income tax accrual and deferred tax entries, forecasting income taxes, preparation and filing income tax returns, technical income tax research and preparation of income tax data and related testimony for rate proceedings.

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

A. I have previously provided testimony to the Pennsylvania Public Utility Commission ("Commission"), the Maryland Public Service Commission, the Kentucky Public Service Commission, and the Indiana Utility Regulatory 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, 2021) and Exhibit 107 for the Future Test Year (the twelve-month period ending November 30, 2022) and Fully Projected Future Test Year (the twelve-month period ending December 31, 2023). 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. Is the Company monitoring Federal and Pennsylvania legislation that may impact income tax expense?

A. Yes, the Company is monitoring Federal legislative developments that may impact income tax expense, however, there is no significant proposed Federal legislation at this time. With respect to state legislation, H.B. 2300, was introduced in the Pennsylvania House on January 27, 2022. If enacted, H.B. 2300 would reduce the corporate net income tax rate in 2023 to 9.74% and to 9.49% in 2024. If and when legislation is enacted to reduce the Pennsylvania corporate net income tax rate, Columbia would utilize the State Tax Adjustment ("STAS") pursuant to 52 Pa. Code § 69.51 - § 69. The STAS provides for the automatic adjustment of rates for changes in state taxes, including the Pennsylvania Corporate Net Income Tax, Capital Stock Tax, Gross Receipts Tax and Public Utility Realty Tax. Pursuant to Section 69.52 a utility which has a STAS or gross receipts tax rider shall maintain its surcharge and rider rates at 0% unless there has been a change in the applicable tax rates. Procedurally under Section 69.52 Exhibit A, every public utility which has been subjected to new or increased taxes enacted by the General Assembly shall compute the surcharge as prescribed by the Commission and submit the computation to the Commission.

Furthermore, pursuant to Section 69.55(2), the STAS and gross receipts tax rider shall be zeroed, and the tax expenses recovered through application of the surcharge and rider shall be rolled into base rates by filing a tariff or tariff supplement and supporting data on 60-days' statutory notice to the Commission. The transfer of revenues to base rates shall be accomplished so that there will be no effective change in total revenues recovered from each service classification as a result of the roll-in. It is my understanding that many utilities implement this roll-in through the filing of a new base rate case.

To the extent legislation is enacted before the record is closed in this proceeding, Columbia would expect to include the impact to base rates.

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 Pennsylvania Public Utility Commission's ("Commission") 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 $4,305,588 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. How does the 2008 change in method of accounting for repairs impact Columbia's taxable income in the rate-making process?

A. For a period, the repairs deduction is anticipated to exceed deductions if the plant had been capitalized for tax purposes, and thus will continue to result in a reduction to taxable income. However, beginning post October 18, 2011 (the effective date of rates as established in Columbia's 2010 rate case) the federal repairs deduction is being normalized under deferred tax accounting, so there will be no impact on total federal tax expense. However, the repairs deduction has not been normalized, based on prior Commission orders, and is flow-through for state tax purposes and is reflected in the state tax expense.

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 15.

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 adjusts federal 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,

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[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).

Pennsylvania Governor Tom Wolf signed HB542 into law. In response to the 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?

A. The benefit of the Pennsylvania NOL has been included in the revenue gross up factor presented on Exhibit 2, Schedule 3, Page 5, Line 12 by reducing the Pennsylvania state income tax rate of 9.99% to 5.99% (9.99% multiplied by 60%). However, since the Pennsylvania NOL carryforward is fully utilized in the Fully Project Future Test Year, the Pennsylvania state income tax rate included in the revenue gross-up factor on Exhibit 102, Schedule 3, Page 5, Line 12 is 9.99%.

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 2018 to 2020. 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 $65.3 million by the 3-year average of the Federal taxable income of the consolidated group members with taxable income of $589.1 million to determine the percentage of Columbia's of 11%. This percentage was multiplied by the 3-year average of Federal taxable loss of the adjusted consolidated group members with taxable loss of $201.1 million. The consolidated group member Federal taxable loss was adjusted to exclude Federal taxable losses attributed to Bay State Gas Company and Northern Indiana Public Service Company for tax year 2018. The losses were excluded since the assets of Bay State Gas Company were sold in 2020 and losses recognized by Northern Indiana Public Services Company are not expected to continue as they primarily related to accelerated depreciation deductions. Columbia's allocation of Federal taxable loss companies is $22.3 million tax effected at 21% resulting in a Section 1301.1(b) differential of $4.7 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. 7), Columbia's pro forma capital additions for reliability or infrastructure projects are $275.8 million in the FTY and $342.4 million in the FPFTY. This expenditure level is greater than $2.3 million (50% of the $4.7 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 18 and discussed in direct testimony of Columbia Witness Miller, Columbia's pro forma operating and maintenance budget is $228.6 million in the FTY and $246.6 million in the FPFTY. This expenditure level is greater than $2.3 million (50% of the $4.7 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 38 delineates total pro forma tax expense of $41,860,983. This total includes $6,073,605 of state income taxes (Exhibit 7, Page 19, Line 37), which is based on $228,101,380 of operating income (Exhibit 7, Page 19, Line 1) less $45,932,535 of interest expense on debt (Exhibit 7, Page 19, Line 9) for total pre-tax income of $182,168,845 resulting in an effective state income tax rate of 3.33%. The reduced state effective tax rate, as compared to the Pennsylvania statutory rate of 9.99%, 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 $35,787,378 (Exhibit 7, Page 19, Line 36) resulting in an effective tax rate of 19.65%. 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 38 delineates total tax expense of $55,731,526. This total includes $9,531,758 of state income taxes (Exhibit 107, Page 16, Line 37), which is based on $294,540,409 of operating income (Exhibit 107, Page 16, Line 1) less $58,870,071 of interest expense on debt (Exhibit 107, Page 16, Line 9) for total pre-tax income of $235,670,338 resulting in an effective state income tax rate of 4.04%. The reduced state effective tax rate, as compared to the Pennsylvania statutory rate of 9.99%, 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 $7,797,926 (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 $46,199,768 (Exhibit 107, Page 16, Line 36) resulting in an effective tax rate of 19.6%. 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. 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 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 20.

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 $ 33,775,318 as shown in Exhibit 7, Page 9. 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, of $30,466,782 as a deferred tax asset for the unutilized Federal net operating loss carryforward 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 $13,706,611 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 $147,718 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 $56,818 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, 2020. The West Virginia tax for gas stored underground was developed using the December 31, 2018 assessed value and the 2020 tax rate. This annualized level is equal to the Historic Test Year level of $521,924, 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 a downward adjustment of $87,244 from the annualized level as a result of using the December 31, 2019 assessed value and the 2021 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 $231 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. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2022-3031211
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
JULIE COVERT
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

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 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, 2023, which reflects the Fully Projected Future Test Year ("FPFTY") investment level that is utilized within the revenue requirement supported by Witness Miller (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 Ex. 108, Schedule 1 from Docket No. R-2021-3024296 (Updated through Dec. 31, 2021)

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

A. I will be addressing the twelve-month period ending November 30, 2021 as the Historic Test Year (Exhibit 8), the twelve-month period ended November 30, 2022 as the Future Test Year (Exhibit 108), and the twelve-month period ended December 31, 2023 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 and R-2021-3024296. 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 28 of the approved settlement in the Company's prior rate case, at Docket No. R-2021-3024296, Columbia is required to provide the Commission and the statutory parties, on or before April 1, 2022, 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, 2021. This update is attached to my testimony as Exhibit JEC-1.

Q. Please comment on how the Company's actual net capital additions for the 12 month period ending November 30, 2021 (the HTY) compares to the projections made in Columbia's prior rate case at Docket No. R-2021-3024296.

A. The Company was 3.36% under the budget provided in the 2021 Rate Case 2021-3024296 for net additions for the 12 months ending November 30, 2021, as shown in the table below.

Budget per 2021 Rate Case, 2021-3024296 Exhibit 108, Schedule 1				
	Budget	Actual	Over/(Under)	%
Additions	673,668,440	636,927,677	(36,740,764)	-5.45%
Retirements	89,306,266	72,205,111	(17,101,155)	-19.15%
Total	584,362,174	564,722,565	(19,639,609)	-3.36%

Q. Please explain the development of rate base at November 30, 2021 for the Historic Test Year, November 30, 2022 for the Future Test Year and December 31, 2023 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, 2021. 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, 2023, as shown on Exhibit 108, Schedule 1, Page 14, Column 5, was developed beginning from Column 2 of Page 1 with Gas Plant in Service at November 30, 2021 (also shown on Exhibit 8, Page 3, Column 3). For purposes of presenting the FTY and FPFTY, the Account 101 and 106 information is combined in Line 2. Forecasted Plant in Service from December 2021 through December 2023 per the Company's forecasted budget are shown in Exhibit 108, Schedule 1, columns 3-5. The forecasted plant additions were provided based on the Company's current capital plan, Column 3 & 6. Forecasted retirements from December 2021 to December 2023, as supported by Company witness Spanos (Columbia Statement No. 5) are shown in Exhibit 108, Schedule 1, column 4 & 7. By adding forecasted Plant in Service and subtracting forecasted retirements, Exhibit 108, Schedule 1 reflects the net forecasted plant in service included in rate base as of December 31, 2023, column 6. Additional details surrounding the budget is discussed by 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, 2021. 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 6 and Exhibit 108, Page 3, Line 7 Accumulated Provision for Gas Lost – Underground Storage, Account 117, is per books as of November 30, 2021 for the Historic Test Year and December 31, 2023 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 2021 actual balances (most recently available), with January 2022 through November 2022 balances calculated by applying the Gross Domestic Product

("GDP") deflator supported by Company witness Miller (Columbia Statement No. 4) in Exhibit 104, Schedule 2, Page 20, to the actual balances of January 2021 through November 2021. 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 Miller in Exhibit 104, Schedule 2, Page 20 to the January 2021 through November 2021 actual balances to reflect expected new prepayments as of December 2023.

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 include 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 2020 through November 2021 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 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 2021, 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 2021 through December 2023. 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, 2021 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, 2022 and December 31, 2023 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 the 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 2021 through December 2023, with entries for November and December of each year based on actual data for November and December of 2021. The balances for the months of January 2023 through October 2023 are the same as the balances in the month of January 2022 through October 2022 following the trend that deposits gradually go up in the winter and down in the summer. The balances for January 2022 – October 2023 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 account. 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 journalized 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 24 for the HTY and Exhibit 108 Page 3, line 23 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 2021 base rate case in Docket No. R-2021-3024296, the Company would be eligible to include plant additions in the DSIC once eligible account balances exceed the levels projected by Columbia at December 31, 2022.

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.

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Line No.	Description	Account No. (1)	Plant Beginning Balance 11/30/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 1/31/2021 (8)=(5+6+7) $
				Gas Plant in Service					
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	27,732,265	259,968	0	27,992,233	91,403	(404,078)	27,679,558
6	Cloud Software	303.99	1,719,212	3,281		1,722,494			1,722,494
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	3,250,037	0	0	3,250,037	569,214	0	3,819,251
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
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	3,361,100	0	0	3,361,100	0	0	3,361,100
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	3,353,028	72,912	0	3,425,940	2,529	(12)	3,428,456
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	5,521,273	69,554	0	5,590,827	8,296	(1,541)	5,597,581
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,722,082	64,013	0	17,786,096	29,637	0	17,815,732
30	Structures, Other Distribution System, Leased	375.71	5,819,288	79,207	0	5,898,495	0	0	5,898,495
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,904,754,580	23,954,331	(14,053,325)	1,914,655,585	14,175,551	(750,106)	1,928,081,031
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,129,547	162	(313,970)	63,815,739	328	(18,790)	63,797,277
36	Cast Iron	376.80	205,867	0	(8,798)	197,070	0	(993)	196,076
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	110,979,281	2,444,905	(46,370)	113,377,816	306,102	(5,718)	113,678,200
39	Measuring & Regulating Equipment Local Gas	378.30	438,503	0	(1,010)	437,493	0	0	437,493
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	630,460,256	8,297,612	(1,113,401)	637,644,467	4,118,921	(131,133)	641,632,255
43	Meters	381.00	40,743,004	83,612	(34,168)	40,792,448	16,471	(50,889)	40,758,030
44	Auto Meter Reading Devices	381.10	24,645,195	0	0	24,645,195	0	0	24,645,195
45	Meter Installations	382.00	41,270,605	119,516	(11,362)	41,378,759	66,387	(6,576)	41,438,570
46	House Regulators	383.00	14,654,963	120,648	(616)	14,774,996	94,600	(604)	14,868,992
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,960,476	60,570	(29,537)	5,991,509	1,990	(15,414)	5,978,085
49	Industrial M&R Equipment. Large Volume	385.10	1,037,970	0	0	1,037,970	0	(1,298)	1,036,672
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	10,326,335	124,238	(9,553)	10,441,021	239,720	0	10,680,741
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	General Plant			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,305,316	0	(22,490)	2,282,826	0	(109,296)	2,173,531
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	3,270,694	169,701	0	3,440,394	163,963	(281,703)	3,322,654
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	60,884	0	0	60,884	0	0	60,884
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	(179,308)	0
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	17,041,365	24,880	(9,213)	17,057,031	42,167	(5,961)	17,093,237
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	953,270	0	0	953,270	0	0	953,270
80	Total Gas Plant in Service		2,989,253,197	35,949,113	(15,653,812)	3,009,548,498	19,927,277	(1,963,421)	3,027,512,354

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			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 1/31/2021 (2) $	Additions (3) $	Retirements (4) $	Balance as of 2/28/2021 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 3/31/2021 (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	27,679,558	1,243,190	(121,106)	28,801,642	157,993	(269,767)	28,689,868
6	Cloud Software	303.99	1,722,494	151,514	0	1,874,008	7,687	0	1,881,695
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	3,819,251	0	0	3,819,251	59,061	0	3,878,312
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
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	3,361,100	0	0	3,361,100	0	0	3,361,100
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	3,428,456	46,038	(54)	3,474,440	0	0	3,474,440
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	5,597,581	297,918	(8,338)	5,887,161	16,545	(4,446)	5,899,260
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,815,732	0	0	17,815,732	8,192	0	17,823,924
30	Structures, Other Distribution System, Leased	375.71	5,898,495	0	0	5,898,495	0	0	5,898,495
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,928,081,031	6,179,797	(121,193)	1,934,139,635	9,249,480	(372,136)	1,943,016,979
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	63,797,277	(1)	(17,337)	63,779,939	1,090	(64,995)	63,716,034
36	Cast Iron	376.80	196,076	0	(7,791)	188,285	0	(731)	187,554
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	113,678,200	495,768	(50,523)	114,123,445	1,257,222	(124,453)	115,256,214
39	Measuring & Regulating Equipment Local Gas	378.30	437,493	0	0	437,493	0	0	437,493
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	641,632,255	2,662,018	(779,269)	643,515,004	3,748,619	(711,327)	646,552,296
43	Meters	381.00	40,758,030	79,754	0	40,837,784	13,035	(84,563)	40,766,256
44	Auto Meter Reading Devices	381.10	24,645,195	1,487	0	24,646,682	10,433	0	24,657,115
45	Meter Installations	382.00	41,438,570	89,363	(3,322)	41,524,611	91,497	(25,405)	41,590,703
46	House Regulators	383.00	14,868,992	74,229	(274)	14,942,947	98,006	(605)	15,040,348
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,978,085	0	(706)	5,977,379	0	0	5,977,379
49	Industrial M&R Equipment. Large Volume	385.10	1,036,672	0	(806)	1,035,866	0	0	1,035,866
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	10,680,741	26,073	(8,279)	10,698,534	720	(20,578)	10,678,677
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	General Plant			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,173,531	0	0	2,173,531	0	(25,726)	2,147,804
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	3,322,654	0	0	3,322,654	0	0	3,322,654
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	60,884	0	0	60,884	0	0	60,884
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	17,093,237	21,656	0	17,114,893	12,057	0	17,126,950
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	953,270	0	0	953,270	0	0	953,270
80	Total Gas Plant in Service		3,027,512,354	11,368,802	(1,118,998)	3,037,762,159	14,731,636	(1,704,733)	3,050,789,062

Columbia Gas of Pennsylvania, Inc.
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Line No.	Description	Account No. (1)	Plant Beginning Balance 3/31/2021 (2) $	Additions (3) $	Retirements (4) $	Balance as of 4/30/2021 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 5/31/2021 (8)=(5+6+7) $
				Gas Plant in Service					
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	28,689,868	3,170,831	(144,743)	31,715,955	83,796	(478,688)	31,321,064
6	Cloud Software	303.99	1,881,695	145,360		2,027,055	1,311		2,028,366
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	3,878,312	0	0	3,878,312	22,320	0	3,900,632
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
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	3,361,100	0	0	3,361,100	0	0	3,361,100
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	3,474,440	0	0	3,474,440	8	(2,779)	3,471,669
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	5,899,260	0	0	5,899,260	376	(463)	5,899,173
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,823,924	0	0	17,823,924	7	0	17,823,931
30	Structures, Other Distribution System, Leased	375.71	5,898,495	0	0	5,898,495	0	0	5,898,495
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,943,016,979	12,826,824	(201,751)	1,955,642,051	17,136,031	(587,453)	1,972,190,630
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	63,716,034	3,614	(20,758)	63,698,890	1	(36,009)	63,662,881
36	Cast Iron	376.80	187,554	0	0	187,554	0	(2,753)	184,801
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	115,256,214	180,894	(189,912)	115,247,196	218,830	(36,582)	115,429,443
39	Measuring & Regulating Equipment Local Gas	378.30	437,493	0	0	437,493	0	0	437,493
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	646,552,296	6,137,581	(992,233)	651,697,644	5,869,856	(1,814,544)	655,752,956
43	Meters	381.00	40,766,256	397,175	(42,893)	41,120,538	10,345	(59,514)	41,071,369
44	Auto Meter Reading Devices	381.10	24,657,115	0	0	24,657,115	0	0	24,657,115
45	Meter Installations	382.00	41,590,703	102,682	(8,916)	41,684,470	34,931	(10,006)	41,709,394
46	House Regulators	383.00	15,040,348	80,201	(1,526)	15,119,023	44,991	(957)	15,163,057
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,977,379	2,865	(11,935)	5,968,308	3,325	(16,848)	5,954,785
49	Industrial M&R Equipment. Large Volume	385.10	1,035,866	0	0	1,035,866	0	(7,619)	1,028,247
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	10,678,677	0	0	10,678,677	6,776	(1,565)	10,683,888
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	General Plant			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,147,804	0	0	2,147,804	0	0	2,147,804
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	3,322,654	0	0	3,322,654	80	0	3,322,734
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	60,884	0	(1,816)	59,068	0	0	59,068
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
69	Tools, Shop Equipment	394.20	35,454	0	(17,919)	17,534	0	0	17,534
70	Tools, Tools and Other	394.30	17,126,950	19,318	(174,347)	16,971,921	10,430	(270,885)	16,711,467
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	953,270	0	0	953,270	0	0	953,270
80	Total Gas Plant in Service		3,050,789,062	23,067,345	(1,808,751)	3,072,047,657	23,443,414	(3,326,666)	3,092,164,404

Columbia Gas of Pennsylvania, Inc.
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				Gas Plant in Service					
Line No.	Description	Account No. (1)	Plant Beginning Balance 5/31/2021 (2) $	Additions (3) $	Retirements (4) $	Balance as of 6/30/2021 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 7/31/2021 (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	31,321,064	722,810	(83,562)	31,960,312	4,188,252	(28,351)	36,120,212
6	Cloud Software	303.99	2,028,366	616,283	0	2,644,648	1,391,327	0	4,035,976
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	3,900,632	(109,712)	0	3,790,920	211,252	0	4,002,172
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
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	3,361,100	0	0	3,361,100	0	0	3,361,100
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	3,471,669	130,512	0	3,602,181	56,342	(198)	3,658,325
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	5,899,173	33,822	(11,817)	5,921,178	15,201	(13,889)	5,922,490
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,823,931	0	0	17,823,931	0	0	17,823,931
30	Structures, Other Distribution System, Leased	375.71	5,898,495	0	0	5,898,495	0	0	5,898,495
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,972,190,630	13,619,752	(388,604)	1,985,421,778	13,613,737	(329,825)	1,998,705,690
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	63,662,881	0	(18,353)	63,644,529	6	(25,043)	63,619,491
36	Cast Iron	376.80	184,801	0	0	184,801	0	0	184,801
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	115,429,443	713,453	(14,751)	116,128,145	791,136	(29,671)	116,889,610
39	Measuring & Regulating Equipment Local Gas	378.30	437,493	0	0	437,493	0	0	437,493
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	655,752,956	5,113,365	(122,264)	660,744,057	5,375,121	(1,140,787)	664,978,391
43	Meters	381.00	41,071,369	432,175	(34,319)	41,469,225	22,298	(23,139)	41,468,384
44	Auto Meter Reading Devices	381.10	24,657,115	0	0	24,657,115	0	0	24,657,115
45	Meter Installations	382.00	41,709,394	84,142	0	41,793,536	92,541	(12,220)	41,873,857
46	House Regulators	383.00	15,163,057	66,044	0	15,229,101	97,070	(924)	15,325,248
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,954,785	6,197	(26,484)	5,934,498	11,610	(85,074)	5,861,033
49	Industrial M&R Equipment. Large Volume	385.10	1,028,247	0	0	1,028,247	0	0	1,028,247
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	10,683,888	308,502	(47,190)	10,945,200	20,781	(36,753)	10,929,228
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	General Plant			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,147,804	0	0	2,147,804	0	(7,318)	2,140,486
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	3,322,734	0	0	3,322,734	0	0	3,322,734
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	59,068	0	(1,928)	57,140	0	0	57,140
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
69	Tools, Shop Equipment	394.20	17,534	0	0	17,534	0	0	17,534
70	Tools, Tools and Other	394.30	16,711,467	288,371	(29,664)	16,970,174	66,776	0	17,036,950
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	953,270	0	0	953,270	0	0	953,270
80	Total Gas Plant in Service		3,092,164,404	22,025,716	(778,935)	3,113,411,185	25,953,450	(1,733,192)	3,137,631,443

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Line No.	Description	Account No.	Plant Beginning Balance 7/31/2021	Additions	Retirements	Balance as of 8/31/2021	Additions	Retirements	Balance as of 9/30/2021
				Gas Plant in Service					
		(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	36,120,212	1,781,087	(2,971,103)	34,930,196	81,569	(14,812)	34,996,954
6	Cloud Software	303.99	4,035,976	66,786	0	4,102,762	681,474	0	4,784,236
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	4,002,172	540,634	0	4,542,806	0	0	4,542,806
11	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
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	3,361,100	0	0	3,361,100	0	0	3,361,100
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	3,658,325	13,271	(0.07)	3,671,595	2,405	0	3,674,000
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	5,922,490	4,830	(8,163)	5,919,158	46,763	(1,074)	5,964,846
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,823,931	0	0	17,823,931	99,859	0	17,923,790
30	Structures, Other Distribution System, Leased	375.71	5,898,495	0	0	5,898,495	43,329	0	5,941,824
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,998,705,690	17,117,519	(486,959)	2,015,336,250	22,228,866	(567,824)	2,036,997,293
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	63,619,491	0	(21,294)	63,598,198	0	(63,301)	63,534,897
36	Cast Iron	376.80	184,801	0	(3,009)	181,792	0	(3,192)	178,600
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	116,889,610	1,226,516	(278,076)	117,838,050	2,164,653	(254,194)	119,748,510
39	Measuring & Regulating Equipment Local Gas	378.30	437,493	0	0	437,493	0	(1,173)	436,320
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	664,978,391	6,035,393	(942,352)	670,071,432	6,700,415	(357,415)	676,414,432
43	Meters	381.00	41,468,384	0	(41,237)	41,427,147	562,661	(49,109)	41,940,700
44	Auto Meter Reading Devices	381.10	24,657,115	0	0	24,657,115	0	0	24,657,115
45	Meter Installations	382.00	41,873,857	96,287	(7,013)	41,963,130	60,571	(12,965)	42,010,736
46	House Regulators	383.00	15,325,248	72,041	(713)	15,396,577	69,843	(948)	15,465,472
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,861,033	5,462	(26,186)	5,840,310	2,521	(7,276)	5,835,555
49	Industrial M&R Equipment. Large Volume	385.10	1,028,247	0	(4,672)	1,023,574	0	(84)	1,023,490
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	10,929,228	54,548	(26,045)	10,957,731	8,730	(7,888)	10,958,572
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	General Plant			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,140,486	0	(844)	2,139,642	0	0	2,139,642
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	3,322,734	0	0	3,322,734	0	0	3,322,734
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	57,140	0	0	57,140	0	0	57,140
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
69	Tools, Shop Equipment	394.20	17,534	0	0	17,534	0	0	17,534
70	Tools, Tools and Other	394.30	17,036,950	106,491	(1,744)	17,141,696	49,940	0	17,191,636
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	953,270	0	0	953,270	0	0	953,270
80	Total Gas Plant in Service		3,137,631,443	27,120,864	(4,819,407)	3,159,932,899	32,803,598	(1,341,255)	3,191,395,242

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2021-3024296
Updated for Actuals Through December 31, 2021

Line No.	Description	Account No. (1)	Plant Beginning Balance 9/30/2021 (2) $	Gas Plant in Service: Additions (3) $	Retirements (4) $	Balance as of 10/31/2021 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 11/30/2021 (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	34,996,954	44,522	(214,540)	34,826,935	1,520,162	(86,299)	36,260,798
6	Cloud Software	303.99	4,784,236	888,275	0	5,672,511	94,106	0	5,766,616
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 1/	351.20	4,542,806	0	0	4,542,806	(1,292,769)	0	3,250,037
11	Wells Construction 1/	352.01	738,941	0	0	738,941	387,831	0	1,126,772
12	Wells Equipment 1/	352.02	168,032	0	0	168,032	904,938	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	3,361,100	0	0	3,361,100	0	0	3,361,100
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	3,674,000	140	0	3,674,140	42,855	0	3,716,994
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	5,964,846	9,838	(5,652)	5,969,032	36,785	(2,566)	6,003,251
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,923,790	0	0	17,923,790	(8)	0	17,923,782
30	Structures, Other Distribution System, Leased	375.71	5,941,824	701	0	5,942,524	39,119	0	5,981,643
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	2,036,997,293	20,490,954	(713,201)	2,056,775,046	23,950,756	(1,166,407)	2,079,559,395
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	63,534,897	(1,090)	(112,033)	63,421,774	0	(53,502)	63,368,272
36	Cast Iron	376.80	178,600	0	(3,170)	175,430	0	(5,438)	169,992
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	119,748,510	2,847,110	(97,517)	122,498,103	1,724,383	(131,224)	124,091,263
39	Measuring & Regulating Equipment Local Gas	378.30	436,320	3,649	(17,385)	422,584	2	(3,350)	419,236
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
42	Services	380.00	676,414,432	7,790,437	(591,445)	683,613,424	6,322,927	(1,971,936)	687,964,415
43	Meters	381.00	41,940,700	221,265	(45,315)	42,116,650	301,661	(28,757)	42,389,554
44	Auto Meter Reading Devices	381.10	24,657,115	0	0	24,657,115	0	0	24,657,115
45	Meter Installations	382.00	42,010,736	308,900	(11,506)	42,308,131	40,506	(21,757)	42,326,881
46	House Regulators	383.00	15,465,472	102,106	(1,055)	15,566,523	80,642	(2,367)	15,644,797
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,835,555	10,098	(8,491)	5,837,162	2,186	(19,942)	5,819,406
49	Industrial M&R Equipment. Large Volume	385.10	1,023,490	0	(261)	1,023,229	0	(802)	1,022,427
50	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	0	623,932	0	(1,268)	622,664
54	Other Equipment, Telemetering	387.45	10,958,572	15,034	(10,830)	10,962,777	49	(102,958)	10,859,868
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
57	General Plant			0	0		0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,139,642	0	(30,079)	2,109,563	0	0	2,109,563
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	3,322,734	0	(461,606)	2,861,128	(132)	(155,296)	2,705,700
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	57,140	0	0	57,140	0	0	57,140
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
69	Tools, Shop Equipment	394.20	17,534	0	0	17,534	0	0	17,534
70	Tools, Tools and Other	394.30	17,191,636	193,987	(34,324)	17,351,299	204,983	0	17,556,282
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	0	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	953,270	0	(1,205)	952,065	0	0	952,065
80	Total Gas Plant in Service		3,191,395,242	32,925,925	(2,359,612)	3,221,961,555	34,360,982	(3,753,868)	3,252,568,669

1/ November 2021 - Reclass $1,292,769 from 351.20 to 352.01 and 352.02.

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2021-3024296
Updated for Actuals Through December 31, 2021
Gas Plant in Service

	Description	Account No. (1)	Plant Beginning Balance 11/30/2021 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2021 (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	36,260,798	2,508,048	(461,200)	38,307,646
6	Cloud Software	303.99	5,766,616	246,062	0	6,012,679
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 1/	351.20	3,250,037	44,803	0	3,294,840
11	Wells Construction 1/	352.01	1,126,772	0	0	1,126,772
12	Wells Equipment 1/	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	0	389,345
16	Compressor Station Equipment	354.00	948,177	0	0	948,177
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	3,361,100	0	(7)	3,361,093
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,716,994	619,816	0	4,336,810
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171
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	6,003,251	32,288	(10,276)	6,025,262
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,923,782	23,870,674	0	41,794,456
30	Structures, Other Distribution System, Leased	375.71	5,981,643	205	0	5,981,849
31	Structures, Communication	375.80	16,515	0	0	16,515
32	Mains:					
33	Mains	376.00	2,079,559,395	44,637,270	(3,797,042)	2,120,399,623
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	63,368,272	112	(487,417)	62,880,968
36	Cast Iron	376.80	169,992	0	(4,374)	165,619
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	124,091,263	1,166,286	(70,887)	125,186,661
39	Measuring & Regulating Equipment Local Gas	378.30	419,236	(8)	0	419,228
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)
42	Services	380.00	687,964,415	9,023,470	(31,216)	696,956,670
43	Meters	381.00	42,389,554	46,687	(32,472)	42,403,769
44	Auto Meter Reading Devices	381.10	24,657,115	11,113	0	24,668,228
45	Meter Installations	382.00	42,326,881	229,345	0	42,556,225
46	House Regulators	383.00	15,644,797	98,605	0	15,743,402
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,819,406	2,608	(42,773)	5,779,241
49	Industrial M&R Equipment. Large Volume	385.10	1,022,427	0	(3,524)	1,018,904
50	Other Equipment	387.10	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	622,664	0	(33,833)	588,831
54	Other Equipment, Telemetering	387.45	10,859,868	130,710	(67,527)	10,923,052
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372
57	General Plant			0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,109,563	671,699	(77,576)	2,703,685
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	2,705,700	0	(526,834)	2,178,867
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	57,140	0	0	57,140
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	0	0	0	0
69	Tools, Shop Equipment	394.20	17,534	0	0	17,534
70	Tools, Tools and Other	394.30	17,556,282	2,123,576	(9,907)	19,669,951
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	(3,847)	784,069
79	Miscellaneous Equipment	398.00	952,065	5,909	(7,023)	950,951
80	Total Gas Plant in Service		3,252,568,669	85,469,279	(5,667,735)	3,332,370,212

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2021-3024296
Updated for Actuals Through December 31, 2021

SUMMARY

Line No.	Description	Account No.	Plant Beginning Balance 11/30/2020	Additions	Retirements	Balance as of 12/31/2021
		(1)	(2)	(3)	(4)	(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	27,732,265	15,853,630	(5,278,250)	38,307,646
6	Cloud Software	303.99	1,719,212	4,293,467	0	6,012,679
				0	0	
7	Underground Storage Plant			0	0	
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 1/	351.20	3,250,037	44,803	0	3,294,840
11	Wells Construction 1/	352.01	738,941	387,831	0	1,126,772
12	Wells Equipment 1/	352.02	168,032	904,938	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	0	389,345
16	Compressor Station Equipment	354.00	948,177	0	0	948,177
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477
				0	0	
18	Distribution Plant			0	0	
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,100	0	(7)	3,361,093
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,353,028	986,827	(3,044)	4,336,810
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
24	Rights of Way	374.50	3,233,171	0	0	3,233,171
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	5,521,273	572,215	(68,226)	6,025,262
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,722,082	24,072,373	0	41,794,456
30	Structures, Other Distribution System, Leased	375.71	5,819,288	162,561	0	5,981,849
31	Structures, Communication	375.80	16,515	0	0	16,515
32	Mains:			0	0	
33	Mains	376.00	1,904,754,580	239,180,868	(23,535,825)	2,120,399,623
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,129,547	4,223	(1,252,802)	62,880,968
36	Cast Iron	376.80	205,867	0	(40,249)	165,619
37	Measuring & Regulating Equipment General	378.10	1,444,656	0	0	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	110,979,281	15,537,257	(1,329,877)	125,186,661
39	Measuring & Regulating Equipment Local Gas	378.30	438,503	3,643	(22,918)	419,228
40	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417
41	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)
42	Services	380.00	630,460,256	77,195,733	(10,699,320)	696,956,670
43	Meters	381.00	40,743,004	2,187,139	(526,374)	42,403,769
44	Auto Meter Reading Devices	381.10	24,645,195	23,033	0	24,668,228
45	Meter Installations	382.00	41,270,605	1,416,668	(131,048)	42,556,225
46	House Regulators	383.00	14,654,963	1,099,028	(10,589)	15,743,402
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	5,960,476	109,432	(290,667)	5,779,241
49	Industrial M&R Equipment. Large Volume	385.10	1,037,970	0	(19,066)	1,018,904
50	Other Equipment	387.10	19,450	0	0	19,450
51	Other Equipment, Odorization	387.20	117,248	0	0	117,248
52	Other Equipment, Radio	387.42	119,609	0	0	119,609
53	Other Equipment, Other Communications	387.44	623,932	0	(35,101)	588,831
54	Other Equipment, Telemetering	387.45	10,326,335	935,881	(339,165)	10,923,052
55	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
56	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372
				0	0	
57	General Plant			0	0	
58	Structures, Communications	390.10	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,305,316	671,699	(273,330)	2,703,685
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	3,270,694	333,611	(1,425,438)	2,178,867
62	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007
63	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787
64	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
65	Stores Equipment	393.00	0	0	0	0
66	Tools, Garage & Service Equipment	394.10	60,884	0	(3,744)	57,140
67	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476
68	Tools, CNG Equipment, Portable	394.12	179,308	0	(179,308)	0
69	Tools, Shop Equipment	394.20	35,454	0	(17,919)	17,534
70	Tools, Tools and Other	394.30	17,041,365	3,164,631	(536,045)	19,669,951
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	266,039	0	0	266,039
73	Power Operated Equipment	396.00	948,698	0	0	948,698
74	Communication Equipment	397.00	0	0	0	0
75	Communication Equipment, Telephone	397.10	0	0	0	0
76	Communication Equipment, Radio	397.20	0	0	0	0
77	Communication Equipment, Other	397.40	0	0	0	0
78	Communication Equipment, Telemetering	397.50	787,916	0	(3,847)	784,069
79	Miscellaneous Equipment	398.00	953,270	5,909	(8,228)	950,951
80	**Total Gas Plant in Service**		**2,989,253,197**	**389,147,401**	**(46,030,386)**	**3,332,370,212**

COLUMBIA STATEMENT NO. 12

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2022- 3031211
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
RIBEKA DANHIRES
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

I. <u>Introduction</u>

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 September 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 Rate Case, at Docket No. R-2021-3024296, as the Tariff Witness. I also provided direct testimony as the Tariff Witness in Columbia Gas of Maryland's ("CMD's") 2018 and 2021 Rate Case in Case Nos. 9480 and 9664, respectively, before the Maryland Public Service Commission. In addition, I submitted direct testimony and testified in support of CMD's 2016, 2017, 2018, 2019 & 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 in Case No. 9479.

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. <u>Tariff Changes Summary</u>

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. 337 include base rate revisions. In addition to the base rate revisions, Columbia is proposing two new rate riders - the Revenue Normalization Adjustment ("Rider RNA") and the Energy Efficiency Rider ("EE Rider"). All substantive changes reflect a "(C)" in the right margin of the page. Several non-substantive changes, such as formatting, 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. Non-Substantive Tariff Changes

Q. Please explain the formatting changes.

A. The headers on each Tariff page have been updated to reflect Supplement No. 337 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 18, 2022" and "May 17, 2022", respectively.

IV. Substantive Tariff Changes

Q. Please explain the changes to rates within Supplement No. 337 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, whereas the

Distribution System Improvement Charge ("Rider DSIC") has been set as zero. A new column was added to page 16 for the proposed Rider RNA.

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, and the Distribution Charge and Gas Supply Charge. Rider DSIC has been set as 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, the Distribution Charge and the Gas Supply Charge. Rider DSIC has been set to zero, for all rate schedules.

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 not proposing any changes to the Customer Charge and Distribution Charge rates for these customers. Rider DSIC has been set as zero for these customers and the Gas Supply Charge has increased, as reflected on page 19.

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 a decrease to the Price-to-Compare for residential gas supply and an increase for commercial gas supply. The changes are a direct result of the change in the Merchant Function Charge ("Rider MFC") rates. The "Gas Supply Charge Summary" on page 21a and the "Price-to-Compare Summary" on page 21c includes these changes too.

Page 21, which is the "Rider Summary", reflects an increase to the Rider Universal Service Plan ("Rider USP") rate and the Rider MFC rate. This "Rider Summary" page also includes new lines for the two proposed riders: Rider RNA and the EE Rider. These new rider rates are also included on page 21b within the "Total Pass-through" charge.

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 are included on Tariff page 161 which is the tariff pages that describes the rider.

Q. Pages 16 and 21 of the tariff designate a location for Rider RNA, however, a rate is not indicated. Please explain.

A. As indicated in the description of Rider RNA on pages 144 and 145 of the Tariff, the Company is not proposing to bill Rider RNA until the October 2023 billing cycle. Columbia has filed the proposed Tariff with an effective date of May 17, 2022, and at that time a rate for Rider RNA will not be billed. Therefore, it is appropriate that Rider RNA rate is not specified in the Tariff at this time.

Q: Page 21 and 21b designates a location for the Energy Efficiency Rider. Please explain.

A. As proposed on pages 164 through 164a of the Tariff, the Company is proposing the EE Rider which is the cost recovery mechanism associated with the Company's proposed Energy Efficiency Program, discussed below. The charge will appear as its own line item on page 21, however, it will be included in the overall pass-through charge as shown on page 21b. Pass-through charges are then included in each applicable rate schedule's total rate.

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 Rider USP can be found on page 5 within that same exhibit and schedule and Rider MFC rate changes are shown in Exhibit No. 103, Schedule No. 7, pages 7 and 8. The rate design contained in Exhibit No. 103 is also discussed in Company Witness Covert's testimony (Columbia Statement No. 11). The percentages for Rider MFC are identified in Exhibit JS-1 attached to Company witness Siegler's testimony (Columbia Statement No. 3).

Q. The Company's tariff includes a proposal for Rider RNA. Please explain.

A. Company witness Johnson's testimony, Statement No. 6, introduces and explains Rider RNA which Columbia proposes to be applicable to non-CAP residential customers under Rate Schedules RSS and RDS. Rider RNA has been added to the Company's tariff on pages 144 and 145.

Q: The Company's tariff includes a proposal for the Energy Efficiency Rider. Please explain.

A. Company witnesses Love's testimony, Statement No. 16, introduces and explains the Company's proposed Residential Energy Efficiency Program. As explained in Love's testimony, Columbia is proposing two residential energy efficiency programs to help residential customers reduce their energy consumption, improve efficiency, and conserve resources. The Company is proposing this tariff rider to recover the costs of the EE program from the residential customer classes, which is the only class of customer eligible to participate in the proposed EE program. The EE rider rate will not be charged to residential customers participating in the Company's low income Customer Assistance Program. The EE Rider has been added to the Company's tariff on pages 164 and 164a.

Q. Does this complete your Prepared Direct Testimony?

A. Yes.

COLUMBIA STATEMENT NO. 13

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2022-3031211
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
DEBORAH A. DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

TABLE OF CONTENTS

I. Introduction

Q. Please state your name and business address.

A. Deborah Davis, 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 Manager, Universal Services.

Q. What are your responsibilities as Manager, Universal Services?

A. I am responsible for efficient and compliant administration of all programs for low-income customers including the Customer Assistance Program ("CAP"), the Low-Income Usage Reduction Program ("LIURP") and Columbia's Hardship Fund.

Q. What is your educational and professional background?

A. I hold a Bachelor of Arts degree in Social Work from the University of Pittsburgh. Prior to joining Columbia in 1992, I worked at a community-based agency assisting low-income clients with accessing utility service and providing other basic life necessities. I was hired by Columbia as a Community Relations representative and subsequently became Manager of the Customer Programs Department. My titles have changed over the years, but I have remained in a similar function throughout my 29-year career at Columbia.

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

A. I will provide an update on Columbia's Hardship Fund funding. I will also provide a summary of the outreach efforts conducted by the Company to promote the existing programs available to low-income customers over the past year. Finally, I will explain the current funding level LIURP and propose a solution to the large carryover budget that currently exists and will likely continue for the next several years.

II. Hardship Fund Program Update

Q. Please explain Columbia's Hardship Fund program.

A. The Hardship Fund is a Columbia-sponsored fuel fund that provides financial assistance through grants to low-income, payment-troubled residential customers, and is administered by the Dollar Energy Fund ("DEF"). Columbia's Hardship Fund program is a fund of last resort providing cash assistance to eligible customers to reduce arrears, reconnect service or stay a service termination. To be eligible, a customer's household income must be less than 200% of the Federal Poverty Income Guidelines ("FPIG"); the customer must be a residential heat customer and demonstrate an imminent need due to a pending termination notice, overdue arrears or loss of service; and finally, the customer must show that he or she has made a sincere effort to pay at least some of his or her bill in the last 90 days.

The DEF administers the program, which includes developing and maintaining an online application and database system for processing Hardship

Fund applications. DEF contracts with various community-based agencies throughout Columbia's service territory to accept applications, which are then reviewed by the Company and DEF personnel for approval. In 2020 the Company implemented an on-line application for customers to apply to the program, in addition to being able to apply in person or over the phone with agency representatives.

Q. How does Columbia fund its Hardship Fund program?

A. The Hardship Fund is funded by customer donations, shareholder dollars, and pipeline penalty credits and refund proceeds. Specifically, the Company shareholders contribute $150,000 annually; customers and Company sponsored fundraising typically contribute another $100,000 to $150,000 annually; and up to an additional $375,000 is provided from funds retained by the Company from pipeline penalty credits and refund proceeds, for a total yearly budget of approximately $675,000.

For program year 2020/2021, which ran from October 1, 2020 through September 30, 2021, Columbia was authorized to increase the income limit for the Hardship Fund from 200% of the FPIG to 300% and contribute an additional $400,000 in shareholder dollars to cover those additional customers. Any unused funds from program year 2020/2021 carried over to the following program year.

Q. What is the current balance of the Hardship Fund budget?

A. For program year 2021/2022, which is the current program year, the budget at the beginning of the program year was $652,588. As of February 28, 2022, the balance is $615,358.

Q. What is the current balance of the pipeline penalty credits and supplier refunds to be used to supplement the Hardship Fund?

A. Columbia is permitted to maintain a balance of up to $750,000 from pipeline penalty credits and supplier refunds for funding for the Hardship Fund. The current balance, however, is $0. The Company made a transfer of $260,237.65 to the DEF in January 2022. The Company anticipates adding to the fund balance when additional pipeline penalty credits and supplier refunds are received.

Q. What is the primary source of voluntary contributions for the Hardship Fund?

A. The primary source of voluntary contributions for the Hardship Fund is the Company's "Add a Buck" campaign, which solicits voluntary donations from customers via a message on their bills. Columbia's "Add a Buck" campaign has raised the following amounts over the past years:

Year	Total Customer Bill Contribution
2011	$ 76,566
2012	$ 73,095
2013	$ 70,798
2014	$ 63,495
2015	$ 74,002
2016	$ 68,819
2017	$ 68,249
2018	$ 62,282
2019	$ 57,229
2020	$ 68,043
2021	$ 65,248

Q. Please provide a history of the Company's efforts to promote its Hardship Fund and raise donations for the Fund.

A. Columbia has a long history of seeking alternative ways to fund its Hardship Fund, including:

- In 1998, the Company formalized its Gift of Energy Certificate program. The Company incentivizes customers, friends and family to purchase gifts of energy for other Columbia customers to be credited to low-income customer accounts. A total of all Gifts of Energy sold are matched and donated to the DEF by Columbia's shareholders.
- In 1998 and 1999, the Company contracted to sell antique miniature replicas of two different models of company trucks with $5.00 of every purchase donated to the DEF.

- In 2002, the Company sponsored the City of Pittsburgh, Light Up Night Warm Up tent promoting the DEF and soliciting donations.
- In 2002 and 2003, the Company purchased radio ad time to promote donations to the DEF.
- In 2004, the Company partnered with the Punxsutawney Groundhog Club to develop and implement an online donation campaign. The campaign solicited raffle prizes for online donations, while the Groundhog took a vacation throughout Pennsylvania asking people to donate online to the DEF and documenting his travels on the campaign website. Radio ads and web ads were used to promote the campaign and solicit donations.
- In 2006, the Company started a long-standing annual partnership with the Trans-Siberian Orchestra ("TSO"). A donation is made to the DEF for every ticket sold. This sponsorship continues today.
- Also in 2006, the Company was a primary sponsor of the Irish Heritage Festival and negotiated the opportunity to promote the DEF and provide donation opportunities at the two-day event.
- In 2007, the Company sponsored a theatrical performance of *Edward Scissorhands* with a dollar for every ticket purchased going to the DEF.
- During the heating season in 2008 and 2009, Columbia contracted with the Pittsburgh Penguins with the Check the Box campaign. Every time a player was sent to the penalty box, an announcer reminded attendees to check the

box on the gas bill for a monthly pledge to DEF. Additional radio spots were used to promote the program as well.

- In 2012 and 2013, the Company sent thank you letters signed by the DEF Executive Director and Columbia's President to the prior year's Hardship Fund donors.
- In 2015 and 2016, the Company sponsored a hot oatmeal breakfast for employees where donations were requested for the DEF as an avenue to increase funds for the Cool Down for Warmth promotion.
- In 2016, the Company held poverty simulations with operations employees and included DEF personnel asking them to speak about their organization and its mission.
- In 2017, Columbia held a campaign to increase E-Bill participation. An incentive for signing up was a $5.00 contribution to the Dollar Energy Fund. The Company raised $4,900 through this effort with 980 new E-bill participants.
- Also in 2017 and 2018, the Company partnered with Nest Thermostat Labs, to promote Nest thermostat use. For every Nest Thermostat purchased as a result of this campaign, a donation was made to the Dollar Energy Fund. Despite numerous email blasts, web mentions and social media promotions, less than $10,000 was raised over the two years.

- In 2018 Columbia initiated a fundraising opportunity at Top Golf in Bridgeville, PA. Held in the fall, this fundraiser capitalized on existing contacts with Dollar Energy Fund's summer golf outing and brought in new donors that Company employees invite. The event was held in 2018 and in 2019 and raised a combined total of $26,980, resulting from sponsorships, participants and gift baskets generously donated by Company employees.
- In 2020, due to the COVID 19 pandemic restrictions on large gatherings of people, the Tran Siberian Orchestra ("TSO") concert was cancelled and the Top Golf fundraiser was not possible. Columbia reacted to this by doing alternative fundraising and awareness activities. Columbia partnered with Steel City Radio and WQED to sponsor TSO Re-imagined, which broadcasted past concerts and had live interviews and segments to promote the TSO during the holidays. The DEF was provided on-air segments and ads to encourage donations.
- In 2020, Columbia developed and marketed "Digger Dog" craft kits for kids with proceeds of each kit sold going to the DEF. This initiative was promoted on our website, Dollar Energy's website, with social media posts and to our Universal Service Advisory Council.
- In 2021, the Company continued its sponsorship of the Trans Siberian Orchestra, which donated $.50 for every ticket sold to the DEF. This effort provided an extra $8,234 in assistance for Columbia Gas customers.

Q. Does the Company participate in Dollar Energy Fund sponsored/developed fundraisers?

A. Yes. Over the years, the DEF has developed and sponsored various fundraisers. The proceeds of these events are divided among participating utilities. Specific events in which Columbia has participated in during the past five years include:

- Warmathon radio call-in campaign — Columbia provides sponsorship money and volunteers to answer telephone calls.
- Cool Down for Warmth - Historically an individual or group of dedicated employees, participate to raise funds by sitting in a house made of ice until they reach their contribution goal through donations from family, friends and co-workers. In the past two years, the event was held virtually due to the pandemic but funds were still raised.
- DEF Golf Outing - Columbia Gas sponsors this event and sponsors two teams.
- DEF Request a Thon, a partnership with a local radio station has been the newest initiative beginning in 2018. Listeners can call in to the station and make a pledge and hear their song request on the air. Columbia's sponsorship extends to this effort as well.

Q. Are there any other yearly promotions Columbia participates in to promote its Hardship Fund?

A. Yes, the following activities occur annually:

- Bill insert requesting donations;
- Social Media posts on Facebook and Twitter about events and requesting donations;
- E-mail blast requesting donations yearly;
- Coupon on paper bill and E-bill copy to those who have not yet signed up for monthly donations; and
- Website postings which explain how and where to contribute

III. Low Income Usage Reduction Program ("LIURP") Carry Over

Q. How much did the Company carry over from 2021 to fund the LIURP program in 2022?

A. The Company carried over $3,857,244, for a total 2022 budget of $8,932,244. This included unspent funds from 2020 as well.

Q. How much has the Company spent in 2020 and 2021?

A. In 2020, the Company spent $2,510,577 of its goal of $4,955,929. In 2021, the Company spent $3,463,108 of its goal of $7,320,352.

Q. Why did the Company not meet its goals in 2020 and 2021?

A. The Company halted all in-home work for several months in 2020 in response to the Covid 19 pandemic. This resulted in a drop in production which was slow to resume once the in-home suspension was lifted. In addition, the Company ceased to remove customers from the CAP program for not cooperating with weatherization. This has traditionally been the catalyst for many customers agreeing to weatherization.

Without this and the added customer concern of being exposed to COVID even with required safety precautions, customers were less likely to cooperate with weatherization. Finally, contractors began to experience staffing issues as some staff did not return to work while others dealt with fluctuations in staffing levels due to Covid illnesses and exposures among staff. These conditions remained throughout 2021.

Q. Does the Company anticipate spending its projected budget of $8,932,244 in 2022?

A. No. As agreed in the Company's 2021 rate case settlement at Docket No. R-2021-3024296, the Company canvassed participating Community Based Organizations ("CBOs") to determine if they have the capacity to do additional work in 2022. Unfortunately, no CBOs agreed to increase their allocation for 2022. The majority could not commit to a production level higher than what was achieved in 2021 when the Company spent less than half of its current 2022 budget. The Company also canvassed for profit existing contractors as well and is unable to allocate the full funds needed to meet the almost $9 Million target.

Q. Why are contractors and CBOs not willing to increase their allocations for 2022?

A. The Company asked this question during the one-on-one canvassing. The Company was told by most contractors that there is an expected increase in funding from the federal government that will more than double the production levels for the state providers. In addition, there is a shortage of seasoned, knowledgeable workers in the energy efficiency arena in this state which reduces the ability for any contractors to hire additional crews for the additional workload. Finally, some contractors are having difficulty finding general laborers willing to do weatherization work.

Q. What is the Company doing to increase customer participation?

A. The Company conducted an outreach campaign in the fourth quarter of 2021. The outreach campaign consisted of Google Search Engine Marketing (SEM) ads, social media paid ads, ads on Spotify, outdoor billboards, as well as Company social media posts. In addition, the Company is participating in the planning of a statewide outreach initiative with other Pennsylvania utilities to promote energy efficiency which may help to legitimize the program for potential customers. Finally, the Company has been working to develop the processes and vendor relationships to successfully implement the Health and Safety Pilot which will remove prior barriers to facilitate weatherization of high use homes.

Q. What does the Company anticipate spending in 2022?

A. The Company is looking for new contractors to spread the allocations further. The Company did see improved customer engagement in the fourth quarter and early 2022, which may be a result of the outreach campaigns and colder weather. At this time, the Company estimates an aggressive goal of $6.5 Million spend in 2022 if the trends of customer engagement and contractor production levels continue positively.

Q. What will happen if the Company does not spend the full allotment?

A. The Company will carry over the funding into 2023 and gradually chip away at the under spend in the future. The Company continues to project the full allotment in the Rider USP for recovery.

Q. Is the Company proposing any changes?

A. Yes. The Company proposes to spread any carryover from 2022 evenly over the next three calendar years, 2023 through 2025. This will allow the Company to earmark these funds for energy efficiency purposes, without recovering funds from ratepayers that cannot be utilized in a given year while working toward increasing the available resources to install the measures.

IV. Customer Outreach Efforts in 2021

Q. Did the Company expand outreach efforts in 2021 to low income and potentially low-income customers?

A. Yes. The Company increased its grass roots outreach efforts as well as expanded its overall Communications strategy to reach known eligible customers but also create new channels to reach potentially eligible customers.

Q. Please expand on the grass roots component.

A. After sharing its outreach strategy with its Universal Service Advisory Council and gaining feedback, the Company targeted new and previously targeted groups for grass roots efforts. These included, local trunk or treat Halloween events, We Soldier On, Community Baby Showers and new mothers groups, Food Banks, School Districts, Homeless and Housing Coalitions, Vaccination clinics and at home vaccination services for seniors. The Company will continue to invest resources in these grass roots efforts. The Company updated handouts to tailor the messaging to the audience and included a QR code for easy sharing and access.

Q. Please elaborate on the Company's overall Communications Strategy.

A. The Company created a "We're Here For You" campaign focusing on awareness of all available programs and resources offered by Columbia as well as federal resources such as Low Income Home Energy Assistance Program (LIHEAP) and the Emergency Rental Assistance Program (ERAP). Specific campaign activities included:

- Information about the Company's available programs and resources on its website, including printable resources and direct links to application sites;
- Outreach information in Spanish and English disseminated to community partners;
- Community Virtual Roundtable to update partners, including community action agencies, legislative offices, senior advocates and other low-income advocates;
- Emails to known low-income customers and potentially eligible customers targeted based on census and geographical information;
- Written communications to customers about the Company's programs in the form of a newsletters, bill inserts, direct mail letters and post card reminders;

- Press Release issued at the beginning of each program season with updated information;
- Social Media Ads paid and through the Company channels including Facebook, Google ads, Twitter and Next Door;
- Social Media paid ads using the traditional LIHEAP ads to maintain the momentum of prior years' ads;
- Paid audio and banner ads on digital radio platform Spotify targeted to customers in the company's service territory; and
- Opinion Editorial from Company's President on the availability of LIHEAP and other programs that ran in multiple papers.

Q. Did the Company attempt to target the lowest income population (0 – 50% of poverty), as suggested by the Office of Consumer Advocate in the Company's prior rate case?

A. Yes, as part of its grass roots efforts, the Company took several steps to seek opportunities to target this particular demographic. Columbia considered this demographic when identifying the school districts to attempt outreach. In addition, some of the individual events, such as the Community baby showers, Hoops for Scoops, and Halloween trunk or treats were targeted due to the higher percentage of customers within that demographic.

Q. What are the results of these outreach efforts?

A. The Company was able to provide information to families with children in eight school districts in its service territory. Total enrollment for these school districts is more than 19,000 students. This was the most successful new outreach avenue when considering numbers of potential customers reached.

Although the number of customers receiving LIHEAP is fairly consistent with the past year, 23% of the customers that received LIHEAP cash had not received a grant in the prior year. This indicates the Company is reaching new customers that may not have been aware of the program.

To date, the Company has received assistance through the new Emergency Rental Assistance Program for 3,193 customers.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 14

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2022-3031211
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
C.J. ANSTEAD ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

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I. Introduction

Q. Please state your name and business address.

A. C.J. Anstead, 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 professional experience.

A. I have over thirty years of experience in the natural gas industry with a large focus in gas operations and construction. Prior to joining Columbia in 1998, I worked for a natural gas pipeline contractor. During my tenure at Columbia, I have worked in a variety of roles across the NiSource companies and within NiSource Corporate Services. Prior to my current role, I served as the Director of Technical Services for NiSource Corporate Services Company from May of 2017 through June of 2019 where I was responsible for the quality assurance and operator qualifications programs across the NiSource companies. In June of 2019, I moved into the role of Director of Safety, Compliance and Risk Management for Columbia Gas of Ohio, where I was responsible for initiatives to address risk and improve safety. I assumed the role of Vice President of Gas Operations for Columbia Gas of Pennsylvania on April 1, 2021.

Q. Have you testified before this or any other Commission?

A. Yes, I testified before this Commission in the Company's 2021 base rate case at Dockett R-2021-3024296.

Q. Please describe your membership in, or affiliation with, any industry organizations.

A. I served as a member of the American Gas Association Quality Management Committee from 2017 through 2021 and I am currently on the Northeast Gas Associations Operations Committee.

Q. What is the purpose of your direct testimony?

A. I will 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.

Finally, I will testify regarding Columbia's Distribution Integrity Management Program ("DIMP"), the strategic operation and maintenance ("O&M") activities that it has undertaken to improve its system, and the additional O&M activities that Columbia is planning to undertake.

II. <u>Overview of Columbia's Pipeline Distribution System</u>

Q. Please describe Columbia's distribution system.

A. Currently, Columbia serves approximately 440,000 residential, industrial and commercial customers. The Company owns and operates a natural gas distribution system in 26 counties serving 450 communities spread across Pennsylvania. Columbia provides that service through approximately 7,758 miles of distribution and transmission mains and approximately 437,717 services that it owns, operates, and maintains.[1] These facilities (as of January 1, 2022) are composed of approximately 975 miles of bare steel, 23 miles of cathodically protected bare steel, 1 mile of cast iron, 46 miles of wrought iron mains (in total, 1,045 miles of "first generation priority pipe" main), and 38,813 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) mains and services, and 25 miles classified as other.[3]

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

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[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.

[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 25 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.

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 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 corrosion in bare steel?

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 or cast-iron 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 has made significant progress in reducing facility damage rates. In 2007, damages per thousand locates were at 5.39. By 2021, Columbia was able to reduce the damages per thousand locate tickets to 1.69. Locate ticket volumes were up 4% last year. Total number of damages reduced from 278 in 2020 to 239 in 2021. Efforts to improve locator performance and improved techniques for finding difficult to locate facilities have proven to be effective. Excavator negligence remains the highest cause of damages to our facilities, at 49% of total damages in 2021. Columbia continued to intervene and educate excavators – especially the problematic ones – and was able to achieve a 24% reduction to excavator error between 2020 and 2021. 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 (scheduled to be eliminated across the system in 2022) and wrought iron. Those sections identified as higher risk within the system are prioritized for replacement and will be included as priority pipe in the Company's next Long Term Infrastructure Improvement Plan, scheduled to be filed in the second quarter of 2022.

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. <u>Federal Pipeline Safety Rules and Advisories</u>

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.
- Safety of Underground Natural Gas Storage Facilities (85 FR 8164 supersedes 81 FR 91860) – Pursuant to Section 12 of the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016" or the "PIPES Act of 2016", this Federal Department of Transportation final rule ("FR") amends the Federal pipeline safety regulations to establish minimum federal safety standards for underground natural gas storage, including critical safety issues related to downhole facilities--well integrity, wellbore tubing, and casing. The FR incorporates the American Petroleum Institute's ("API") recommended practice 1171 by reference into the pipeline safety regulations. This recommended practice outlines the standard for the functional integrity of

natural gas storage in depleted hydrocarbon reservoirs and aquifer reservoirs. Incorporating these recommendations will provide the Pipeline and Hazardous Materials Administration ("PHMSA") and the states with a minimum federal standard for inspection, enforcement, and training through a federal/state partnership and certification process modeled after the current pipeline safety program. The FR applies to Columbia's Blackhawk underground storage facility located at 115 Felt Lane, Beaver Falls, Pennsylvania. While fulfilling its obligations under this Final Rule, Columbia conducted casing integrity logs on its Blackhawk wells during 2020. The results of the casing integrity logs revealed casing deterioration damage on the top joint of the production casing on two of the wells. To perform the necessary repairs, Columbia safely isolated the wells. Impacted joints were then safely replaced, the plugs removed, and the wells were brought back into service. As part of API 1171, Columbia will continue to manage and maintain protocols associated with the safe operations of the wells. This is a great example of how recommended practices, Integrity Management Programs and SMS identify and bring to light latent risks so that they may be prioritized to protect the distribution system, customers, the communities and employees.

- <u>Pipeline Safety:</u> <u>Gas Pipeline Regulatory Reform</u> (86 FR 2210) PHMSA amended the Federal Pipeline Safety Regulations (PSR) at 49 CFR parts 191 and 192 to ease regulatory burdens on the construction, operation, and maintenance of gas transmission, distribution, and gathering pipeline systems without adversely affecting safety. These amendments include regulatory relief actions identified by internal agency review, petitions for rulemaking, and public comments submitted in response to a Department of Transportation (DOT) regulatory reform notice entitled "Notification of Regulatory Review." Specifically, the changes to the regulations that can impact the Company include the following:

- Amended the definition of an incident (§191.3) by increasing the cost of property damage from $50,000 or more to $122,000 or more. The rule also gives PHMSA the ability to adjust the reporting threshold based on inflation and posted on PHMSA's website.
- Removed the requirement to report mechanical fitting failures by removing §191.12 Distribution Systems: Mechanical Fitting Failure Reports and §192.1009 What must an operator report when a mechanical fitting fails. However, PHMSA revised the Gas Distribution Annual report form (PHMSA Form F 7100.1-1) to identify the number of leaks involving a mechanical joint failure as a separate line item from the count of leaks by cause.
- Gave the Company the choice of managing inspections of pressure regulators serving farm taps under its distribution integrity

management plan (DIMP) (§192.740 Pressure regulating, limiting, and overpressure protection - Individual service lines directly connected to production, gathering, or transmission pipelines).

- Revised § 192.465, External corrosion control: Monitoring, to clarify that operators may remotely inspect rectifier stations for external corrosion.
- Revised the welding process requirement at § 192.229, Limitations on welders and welding operators, to align better with welder requalification requirement to specify that welders or welding operators may not weld with a particular welding process unless they have engaged in welding with that process within the preceding 7½ months. This change provides operators some flexibility in scheduling welding activities to maintain welder requalification.
- Revised atmospheric corrosion monitoring requirements (at §§ 192.481, 192.491, 192.1007, and 192.1015) both to align the inspection interval for atmospheric corrosion on gas distribution service pipelines with leakage survey requirements at § 192.723, and to clarify that consideration of corrosion risks under DIMP explicitly includes atmospheric corrosion.
- Revised requirements governing plastic pipe (at §§ 192.7, 192.121, 192.281, 192.285, and appendix B to part 192) to improve alignment

with, and incorporate by reference, certain updated industry standards.

- Revised test requirements for pressure vessels at § 192.153 to align pressure test factor requirements with industry standards, and to clarify certain other pressure testing requirements.
- Revised language at § 192.507 to extend an existing authorization for pretesting of fabricated units and short segments of steel pipe prior to installation on pipelines with high-stress operating conditions to pipelines operating at lower-stress operating conditions.

- Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (84 FR 52180) – 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. This includes previously untested pipelines, which are commonly referred to as "grandfathered" pipelines, operating at or above 30 percent of specified minimum yield strength ("SMYS"). Records to confirm MAOP include pressure test records or material property records (mechanical properties) that verify the MAOP is appropriate for the class location. Operators with missing records can choose one of six methods to reconfirm their MAOP and must keep the record that is generated by this exercise for the life of the pipeline. PHMSA has also created a framework whereby operators with insufficient material property records can obtain such records. PHMSA considers "insufficient" material property records to be those records where the pipeline's physical material properties and attributes are not documented in traceable, verifiable, and complete records. PHMSA is requiring operators to perform integrity assessments on certain pipelines outside of high consequence areas ("HCAs"), whereas prior to this rule's publication, integrity assessments were only required for pipelines in HCAs. Pipelines in Class 3 locations, Class 4 locations, and in the newly defined moderate consequence areas ("MCAs") must be assessed initially within 14 years of this rule's publication date and then must be reassessed at least once every 10 years thereafter. 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. This action fulfills the section 5 mandate from the 2011 Pipeline Safety Act to expand elements of the IM requirements beyond HCAs where appropriate.

- Pipeline Safety: Inside Meters and Regulators, issuance of advisory bulletin ADB-2020-01 (85 FR 61101) - To further enhance PHMSA's safety efforts and implement NTSB's April 24, 2019, Recommendations P–19–001 and P–19–002, PHMSA issued this advisory bulletin to remind operators of the requirements for inside meters and regulators and of the existing Federal DIMP regulations to reduce the possibility of the failure of inside meter and regulator installations. NTSB Recommendations to the Pipeline and Hazardous Materials Safety Administration:
    - P-19-001: Require that all new service regulators be installed outside occupied structures.
    - P-19-002: Require existing interior service regulators be relocated outside occupied structures whenever the gas service line, meter, or regulator is replaced. In addition, multifamily structures should be prioritized over single-family dwellings.

PHMSA is alerting owners and operators of natural gas distribution pipelines to the consequences of failures of inside meters and regulators and existing Federal regulations covering the installation and maintenance of inside meter and regulators. PHMSA is also reminding operators of their obligation to continually assess risks to their systems and address those risks as required by the DIMP regulations (§ 192.1007). PHMSA reminds pipeline operators of their responsibilities to continuously improve their knowledge of their pipeline systems, identify integrity threats, evaluate and rank risks, and identify, evaluate, and implement preventative and mitigative measures as required by the Federal Pipeline Safety Regulations.

- Pipeline Safety: Overpressure Protection on Low-Pressure Natural Gas Distribution Systems, issuance of advisory bulletin ADB-2020-02 (85 FR 61101) - PHMSA is reminding all owners and operators of low-pressure natural gas distribution systems of the risk of failure of overpressure protection systems. Advisory bulletin ADB-2020-02 is intended to clarify the existing pipeline safety standards and highlight the importance of evaluating and implementing overpressure protection design elements and operational practices within their compliance programs. This advisory reminds pipeline operators of their obligations to comply with the gas DIMP regulations at 49 CFR part 192, subpart P. Under DIMP, gas distribution operators must have knowledge of their pipeline systems; identify threats to their systems; evaluate and rank risks; and identify, evaluate, and implement measures to address those risks. ADB-2020-02 highlights the need for operators of low-pressure systems to review thoroughly their current DIMP for the threat of overpressurization and to make any necessary changes or modifications to become fully compliant with the Federal Pipeline Safety Regulations (§192.1007(f)).

- Pipeline Safety: Statutory Mandate To Update Inspection and Maintenance Plans To Address Eliminating Hazardous Leaks and Minimizing Releases of Natural Gas From Pipeline Facilities, issuance of advisory bulletin ADB-2021-01 (86 FR 31002) - PHMSA issued this advisory bulletin to remind each owner and operator of a pipeline facility that the "Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020" (PIPES Act of 2020) contains a self-executing mandate requiring operators to update their inspection and maintenance plans to address eliminating hazardous leaks and minimizing releases of natural gas (including intentional venting during normal operations) from their pipeline facilities. Operators must also revise their plans to address the replacement or remediation of pipeline facilities that are known to leak based on their material, design, or past operating and maintenance history.

In addition to the FRs and Advisories above, the following proposed rules or recommendations are currently being made by, or are under consideration by PHMSA:

- Valve Installation and Minimum Rupture Detection Standards (PHMSA-2013-0255 RIN 2137-AF06) - PHMSA has issued a notice of proposed rulemaking ("NPRM") proposing regulations for: the installation of remote-control valves ("RCV"), automatic shutoff valves ("ASV"), or equivalent technology, on all newly constructed and fully replaced gas transmission pipelines to meet a congressional mandate (Section 4 of the 2011 Pipeline Safety Act); NTSB safety recommendations that followed the San Bruno incident; U.S. General Accounting Office ("GAO") recommendations on the ability of operators to respond to commodity releases in HCAs; and technical reports commissioned by PHMSA on valves and leak detection from Oak Ridge National Laboratory ("ORNL") and Kiefner and Associates, respectively. Also, the NPRM would establish Federal minimum standards for the identification of ruptures and the initiation of pipeline shutdowns, segment isolation, and other mitigating actions, which are designed to reduce the volume of commodity released due to a pipeline rupture and thereby minimize potential adverse safety and environmental consequences. This NPRM would also establish standards for improving the effectiveness of emergency response.

- Pipeline Safety - Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (PHMSA-2011-0023 RIN 2137–AF39) - This rulemaking would amend the pipeline safety regulations relevant to gas transmission pipelines by adjusting the repair criteria in HCAs and creating new criteria for non-HCAs, requiring the inspection of pipelines following extreme events, requiring safety features on in-line inspection tool launchers and receivers, updating and bolstering pipeline corrosion control, codifying a management of change process, clarifying certain IM provisions, and strengthening IM assessment requirements.

- NTSB Recommendation P-12-17 Pipeline Safety Management Systems (API Recommended Practice 1173) – Conceptually, Pipeline Safety Management Systems are built on the premise that managing the safety of a complex industry requires a system of efforts to address multiple, dynamic, changing activities, and circumstances. It further reflects the PHMSA view that if the industry is to achieve the goal of zero incidents, a highly structured and comprehensive effort is required. The broad components of these plans would include:
    - Demonstrated management commitment
    - Structured pipeline safety risk management decisions
    - Increased confidence in risk prevention and mitigation
    - Providing a platform for shared knowledge and lessons learned
    - Promoting a pipeline safety-oriented culture

  The ultimate purpose of this initiative is intended to produce a continuous pipeline safety improvement cycle among pipeline operators of "Plan-Do-Check-Act."

The API 1173 Standard for Pipeline Safety Management Systems is only a recommended practice, but Columbia and NiSource have chosen to pursue the adoption and implementation of a Safety Management System ("SMS"). As an early adopter of deploying an SMS, Columbia has aggressively educated the entire workforce and key contractor resources on what it is and why we are using API 1173 as our guideline to measure progress. We have implemented a Corrective Action Program ("CAP") with all employees and key contractor resources that enables a more robust and formal process for identifying risks and developing actions to reduce risk. We have also established a new governance model to review and prioritize identified risks. The building of additional capacities within our SMS are underway and will continue, centered in process safety improvements, asset management improvements and safety culture improvements.

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, 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) operates at a hoop stress of 20 percent or more of SMYS [System Minimum Yield Strength]; or (3) transports gas within a storage field." Columbia has 40.2 miles of transmission class pipelines (6.2 miles within

HCAs) per the 2019 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 continues to focus heavily on Transmission Operations with the Gas Transmission Rulemaking (promulgated October 1, 2019) that makes the inspection procedures and safety requirements of the various class locations more rigorous and creates a definition of an MCA in addition to the existing HCA already defined in the rule. Future rulemaking regarding transmission class lines is already being discussed by PHMSA and industry representatives.

IV. <u>Strategic O&M Safety Initiatives</u>

Q. Please discuss Columbia's strategy regarding Operating and Maintenance ("O&M") safety initiatives going forward.

A. The Company continues to focus its efforts and resources on the top risks to the Company's system as enumerated in its DIMP Plan and as modified based on the annual DIMP data review, which sometimes results in risk reprioritizations or other updates to the plan. Columbia is expanding focus in several critical areas to maintain and enhance its operational capabilities:

- **Cross Bore Program:** Columbia began a cross bore program in September of 2013, as a result of identifying cross bores as a potential risk in its DIMP plan. Working with local municipalities, Columbia has inspected over 568.8 miles of sanitary and storm sewer mains, and 36,266 customer laterals since 2013. During this inspection work, 577 cross bores were identified, with 359 of those involving Columbia's system. Given the number of cross bores found through this program, it is identified as a high risk in Columbia's DIMP plan. Consistent with the Company's proposal in its 2020 rate case (Docket No. R-2020-3018835) to accelerate this program by increasing the resources allocated to this work, it is anticipated that the program is currently on pace to be completed in 31 years. The Company is requesting $2,700,000 in incremental funding, as reflected in Exhibit 104, Schedule 2, pg. 18, to further accelerate this program's pace and is anticipated to be completed in 16 years.
- **Abnormal Operating Condition (AOC) Remediation Program**: An AOC is defined as a condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may indicate a condition exceeding design limits; or result in a hazard(s) to persons, property, or the environment. The AOC Program is an initiative identified

through Columbia's SMS. This program is designed to proactively address identified AOCs across Columbia's system. Examples of AOCs that will be addressed through this program include, but are not limited to improper regulator vents, extending regulator vents, regulator vent screen installation, meterset support, paint meterset/repair coating, field assembled risers and buried meter valve remediation. This program will increase the safety and reliability of Columbia's service lines and meter assets that are often closest to customer's homes and will help to prevent potential future failures resulting in hazardous leaks. The Company is requesting $600,000 in funding for this program, as reflected in Exhibit 104, Schedule 2, pg. 18.

- **Natural Gas Detectors for Home Use:** Columbia has worked with New Cosmos, a manufacturer of Natural Gas Detectors for home use to allow Columbia customers a to purchase DeNova Detect ML-310ES model through the Columbia Gas website (Safety Products - Columbia Gas of Pennsylvania (columbiagaspa.com). The device is powered by a 5-year battery which allows for placement at greater elevations within the home to provide earlier and more accurate warnings. When a dangerous threshold of natural gas is reached, it sounds both an 85db alarm and a voice warning "Danger - Gas leak explosion risk - evacuate, then call 911". This technology is especially timely since the odorant used in natural gas may be less effective for customers potentially suffering a persistent loss of smell due to Covid. In addition to the discounts offered through our website, Columbia intends to provide 200-250 Natural Gas Detectors at no cost during low-income home audits in 2023. The Company is requesting $13,000 in funding for this program, as reflected in Exhibit 104, Schedule 2, pg. 18.

- **Picarro Leak Detection Program**. Columbia has employed the Picarro platform system to enhance its process for leak detection and to refine the prioritization of repairs and replacements for its natural gas distribution system. The use of the Picarro Leak Detection System will serve to advance the Company's leak detection capabilities, as well as estimate leak density and methane emissions across its service territory. Additionally, the Picarro system will support the Company's Operations and Construction departments by aiding in the prioritization of system risk for the Company's ongoing infrastructure replacement program, and by providing quality assurance checks following the installation of new infrastructure. As Columbia looks to shift compliance leak survey from traditional walking leakage inspection to advanced mobile leak detection, additional leaks are expected. Through the use of Picarro, Columbia expects to find, and repair, 2 times the number of leaks compared to traditional leakage inspection. After the first full triennial cycle of using Picarro, Columbia expects the number of leaks found to decrease to 1.5 times the number of leaks, when compared to traditional leakage inspection. Columbia plans to use the leak flow rate data gathered from the Picarro program to further its goals to reduce methane emissions. The Company is requesting $10,900,000 in incremental funding to advance the Picarro leak detection program, as reflected in Exhibit 104, Schedule 2, pg. 18.

- **Blackline Safety Devices:** Columbia Gas will be deploying the Blackline Safety Device safety monitor with gas detection capabilities to all frontline working employees in Q3 of 2022. The Blackline device is a wearable personal safety monitor that is intrinsically safe and provides an extra layer of protection for our employees and particularly those working in lone worker scenarios. This device has features that include employee check-in requirements, worker fall and no motion detection, silent and audible SOS communication features, employee location and gas detection (LEL, O2, CO, H2S). The Company is requesting $265,000 in funding for this initiative, as reflected in Exhibit 104, Schedule 2, pg. 18.

- **Safety Management System (SMS).** As previously noted in my testimony, Columbia has implemented Safety Management System (SMS). As an early adopter of deploying an SMS, Columbia has aggressively educated the entire workforce and key contractor resources on what it is and why Columbia is using API 1173 as our guideline to measure progress. The Company has implemented a Corrective Action Program (CAP) with all employees and key contractor resources that enables a more robust and formal process for identifying risks. Columbia also has established a new governance model to review and react to risks identified. The building of additional capacities within the SMS are underway and will continue, centered in process safety improvements, asset management improvements and safety culture improvements.

The O&M safety initiatives identified above, in conjunction with the Company's ongoing accelerated replacement program, are designed to address the key risks identified in Columbia's DIMP Plan and continue to reduce the inherent pipeline safety risks in Columbia's operating system. SMS will continue to mature and strengthen the culture of risk identification and reduction at Columbia.

- **Supplemental Safety Staffing Increase for Enhanced Columbia Safety Support –** Columbia seeks to increase the current levels of safety resources and staffing dedicated to supporting our business operations. Recognized occupational safety and health (OSH) staffing models support increasing our staff of safety professionals. Increased safety resources will result in strengthening our high performing safety programs and initiatives and better enable Columbia to focus on hazard identification and mitigation in the field. Principally, these OSH models are based upon the risks inherent to the types of work that we perform and the number of workers that support our work and projects within Columbia. Increasing our OSH staff will result in numerous benefits by increasing safety resources to support all elements of our collective safety programs. These benefits include more field time by OSH staff resulting in a greater number of safety observations, worker contacts, and coaching opportunities for Columbia employees and contractors. Supplemental safety support related to the elements of our Safety Management Systems (SMS) programs including our Corrective Action Program (CAP) efforts and responding to safety related concerns. Additional safety resources will positively impact on our safety culture including the strengthening of our practices surrounding safe work in the field where our greatest risks are present. Columbia desires to increase safety staffing that includes the addition of four Safety and Health Coordinators and one dedicated Safety Technical Trainer. Columbia is requesting $417,000 for additional safety positions, as reflected in Exhibit 104, Schedule 2, pg. 18.

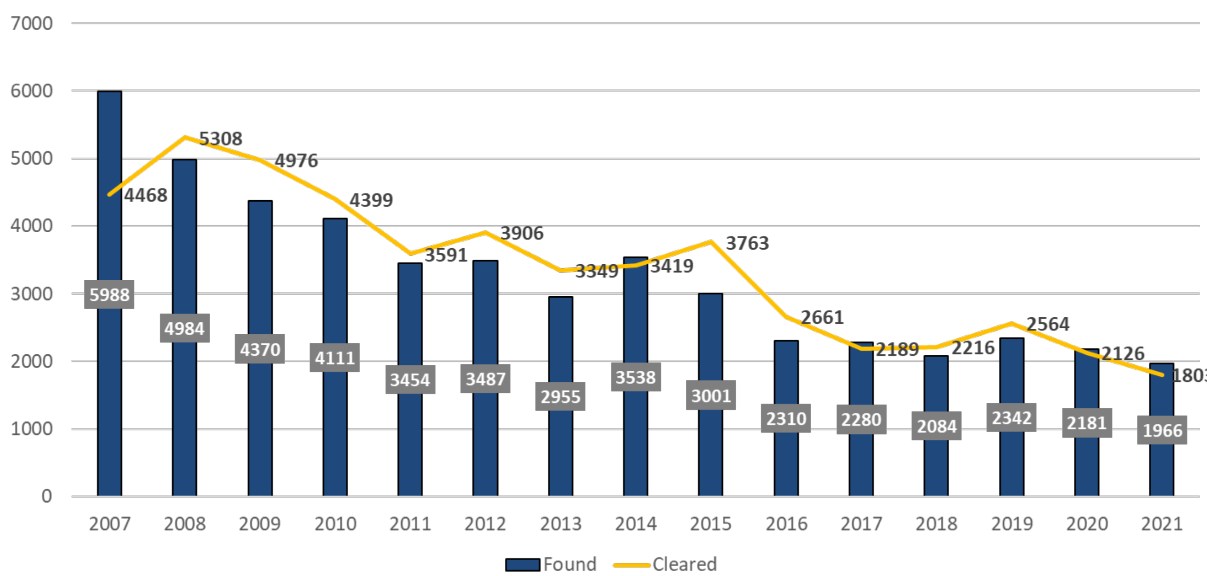
Q. Are there any additional details demonstrating the improvement of Columbia's system operations?

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 4 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 ten years alone, Columbia's pipeline replacement efforts were responsible for cutting the number of leaks found from 4,111 in 2010 to only 1966 in

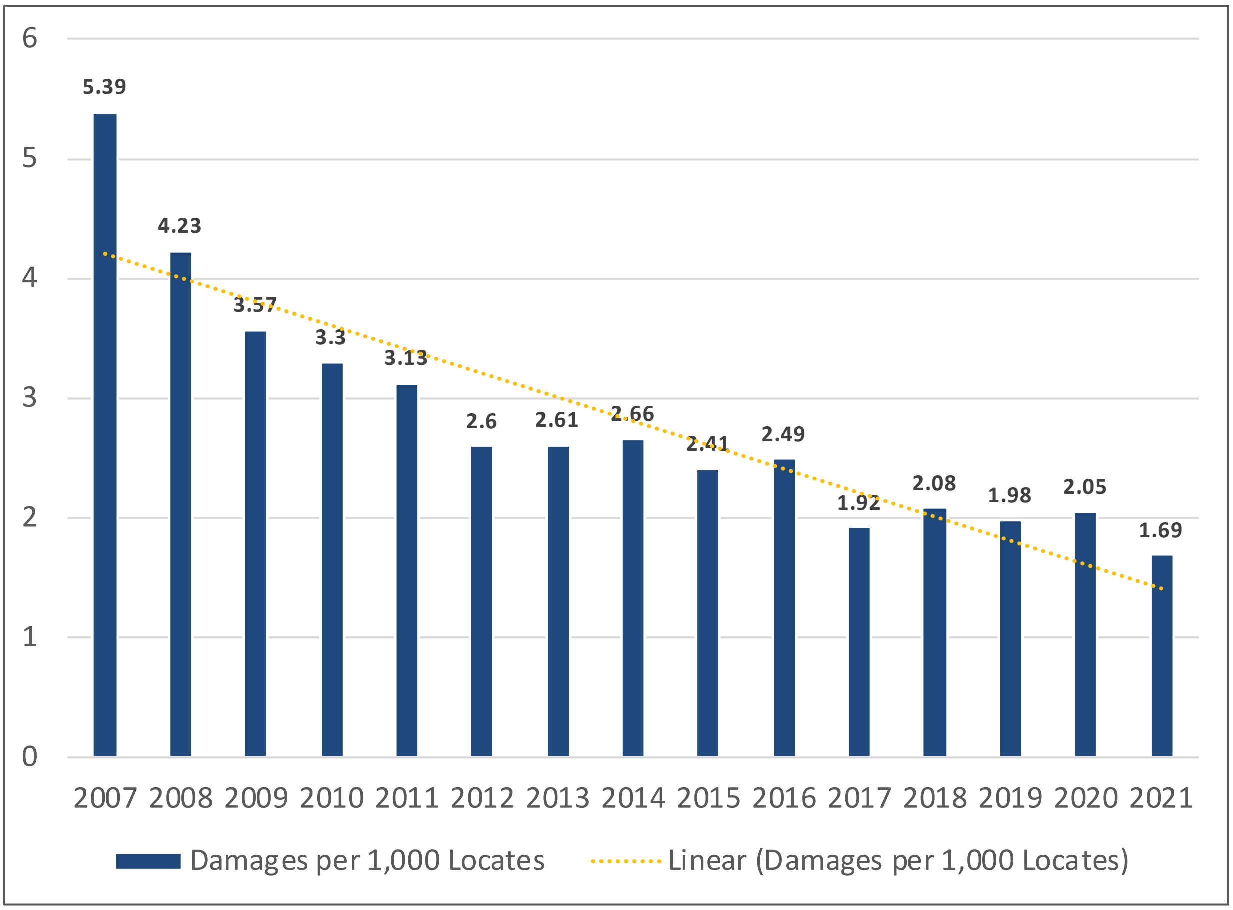
2021. That's over a 50% reduction in leaks. That reduction in leaks improves safety, reduces methane emissions, and even improves service to customers since there are fewer service interruptions due to water offs and leakage repairs. Going forward, reduction of Grade 2 leaks will continue to be a focus.

Figure 4
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 5 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 69% reduction in the damage rate on the Columbia system between 2007 and 2021, from a damage per thousand (locate requests) rate of 5.39 in 2007 to a damage per thousand rate of 1.69 through December 31, 2021, as shown in Figure 5 below.

Figure 5



- *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.

V. <u>Columbia's Operating Performance</u>

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 six 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 2021 as follows:

	2015	2016*	2017	2018	2019	2020	2021
Day	96.79%	99.17%	99.16%	98.70%	98.99%	99.51%	99.5%
Evening	90.95%	95.24%	94.87%	95.61%	97.28%	97.09%	96.1%
Holiday	91.59%	92.11%	85.25%	86.32%	88.79%	95.35%	92.4%
Overnight	85.87%	94.86%	95.19%	92.43%	90.42%	95.62%	95.6%
Weekend	82.76%	91.83%	92.66%	91.72%	93.66%	95.31%	95.1%
Total	**92.68%**	**96.88%**	**96.82%**	**96.40%**	**97.28%**	**98.12%**	**97.8%**
**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-time appointments. It did so by tasking the Integration Center (Columbia's

[4] The percent of customer-generated appointments that are met within the appointment window or according to state regulation, where applicable.

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 97.10% in 2014, to a rate of 99.5% in 2021.

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 2021 that number was 10 OSHA recordable injuries which is a reduction in frequency of 79%. 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:

- Columbia delivers safety training to all employees. This training spans skills from employee safe driver training to office ergonomics.

- Columbia has local and state-wide safety teams made up of engaged front line workers, leaders, contractors and managers. These teams make recommendations on, and implement, safety improvement opportunities.
- Columbia performs a post-incident root cause analysis involving the team of the involved business unit of every OSHA recordable 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 a job site safety observation program in which leaders perform job site safety observations in the field to coach employees on safe working behaviors, field work activities, and to provide feedback to employees on their safety performance. Each Leader in the organization is required to spend time in the field conducting job site observations. Our Leader job site observation data will be tracked, measured and communicated as a safety leading indicator in our overall safety performance metrics for 2022. The job site observation program also includes our executive leadership team.
- Columbia employees evaluate risk and identify the work hazards at each jobsite prior to beginning work and complete a pre-job safety briefing which is reviewed with each employee on the job site or project. A new pre-job safety briefing is required and completed when the personnel, risks, or scope of the work changes so that our teams perform our work as safely as possible. This

process was reviewed and updated in 2022 with the roll out of PC tablets and the implementation of an updated electronic digital pre-job safety briefing form and process. Our pre-job briefing process also reinforces that all of our employees have stop work responsibility.

- Columbia has been administering and utilizing the National Safety Council Safety Barometer survey since 2017 to define our safety culture to support our core values and guiding principles. While surveying every other year, we have been using the NSC safety perception survey process to identify our strengths and opportunities within our safety culture. The NSC Safety Barometer elicits employee responses to 50 statements regarding foundational safety elements. These components are grouped into six performance categories of safety excellence to provide an overall summary of our safety program and culture. Employee responses were compared with 1,420 businesses in the NSC Database. Benchmarking is central to fully understanding survey results. We then use the comprehensive feedback provided in the survey to utilize employee led action planning teams to develop focused and sustainable initiatives to improve performance and strengthen our safety culture.
- Currently, our team of safety professionals consists of a Safety Manager and four Safety Coordinators who each support one of operating areas. As of 2022, three of our safety professionals currently hold the Certified Safety

Professional (CSP) designation accredited by the Board of Certified Safety Professionals.

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 discontinue the annual leak survey for bare steel due to the decreased inventory and reduced risk. 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. 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-2022-3031211
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
NICHOLAS BLY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

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 Manager of Corporate O&M and Consolidation in the Financial Planning and Analysis ("FP&A") department.

Q. What are your responsibilities?

A. As Manager of Corporate O&M and Consolidation, my principal responsibilities include 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 these duties, I am 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.

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 was a partial owner and an Officer of JadeTrack, Inc. serving in a multifunctional finance and operations role. In October 2020, I re-joined NCSC and assumed my current role. Lastly, I'm a Certified Public Accountant and Certified Treasury Professional.

Q. Have you ever testified before a regulatory Commission?

A. I filed testimony before the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company LLC ("NIPSCO") in Cause No. 45621.

<u>Statement of Purpose</u>

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.

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
NCSC OPEB Costs Amortization	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), and health benefits (e.g. vision, medical).

Q. Can you describe the annual budget development process for Corporate O&M and Overheads?

A. The overall NiSource O&M targets are established by the Chief Financial Officer, SVP of Strategy & Chief Risk Officer, and Vice President of Corporate Financial and Regulatory Planning, and approved by the Executive Leadership Team. Department O&M targets are refined and updated as necessary for changes during throughout the Present Estimate process. Material changes to the O&M plan must be approved by the responsible Executive Council leader of the Executive Leadership Team, and Chief Financial Officer. O&M expense budgeting methodology is a combination of a "top down" and "grass roots" approach.

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. Does this complete your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 16

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2022-3031211
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
THEODORE M. LOVE
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2022

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" 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 been advising 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. Most recently, I advised PGW on its most recent energy efficiency plan in 2020. 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 seven dockets. I have also provided written testimony in 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 address Columbia's proposed Three-Year Energy Efficiency Plan ("Plan" or "EE Plan").

Q. Please summarize your testimony.

A. I will provide an overview of the EE Plan and its development. I will then discuss the Plan's projected cost, savings, and cost effectiveness under the Total Resource Cost ("TRC") test. Finally, I will provide a summary of each program followed 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

Q. Would you please describe the Three-Year Energy Efficiency Plan?

A. Columbia is proposing to implement two energy efficiency programs over three years starting January of 2023. These programs are designed to help Columbia's residential customers reduce their energy consumption, improve efficiency, and conserve resources. The Plan is projected to provide lifetime savings of 3.3 million dekatherms ("Dths") of natural gas at a cost of $8.1 million over three years.

Q. Will the Plan, if implemented, benefit the Company's residential customers?

A. Yes, it will. Columbia is proposing an investment that will return a present value of TRC net benefits of $16.2 million, in 2022 dollars, with a TRC benefit-cost ratio

("BCR") of 2.42. 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 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. How was the Plan developed?

A. As described in Section 1.2 of Exhibit TML-2, the Plan was developed as a way to help Columbia's residential customers use natural gas more efficiently. Two programs were identified and developed to address the usage of natural gas in residential buildings.

The Plan has two programs. The first program is the Residential Prescriptive (RP) Program. The RP Program utilizes a very similar program design to other natural gas equipment rebate programs run by two other natural as distribution companies serving Pennsylvania. The second program, the Online Audit Kit ("OAK") Program, is based on a successful program run by Columbia Gas of Virginia for more than ten years. I will explain the RP Program and OAK Program in more detail later in my testimony.

Various market characteristics were gathered for Columbia's 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.

Q. How does the plan address low-income customers?

A. Low-income customers are allowed to participate in any of the programs, but the Plan does not specifically include participation assumptions for this market. The OAK program does provide a free online audit and will mail targeted low-cost energy saving kits to customers at no cost. However, the majority of services offered by the Company for assisting low-income customers with their energy bills are still through existing pathways, such as the Low Income Usage Reduction Program ("LIURP").

Q. Has Columbia provided detailed implementation plans for each of the proposed programs?

A. Yes, Section 2 of Exhibit TML-2 provides a detailed plan for each of the two programs in the plan, including annual budgets by cost category, savings, and participation projections. There is also information on program delivery, incentive design, target markets, marketing, as well as evaluation, measurement, and verification ("EM&V") details.

Q. How much natural gas will Columbia's residential customers save who participate in the EE Plan?

A. The programs are projected to save 189,942 incremental annual Dths of natural gas and 3.3 million Dths over the lifetime of the measures installed. The following tables show the incremental and lifetime natural gas savings by program and are presented as Tables 3 and 4 in Exhibit TML-2.

Portfolio Total Gas Savings by Program (First Year)

Program	2023	2024	2025	2023 - 2025
Residential Prescriptive Program	20,619	61,632	82,196	164,448
Online Audit Kit Program	2,684	9,393	13,418	25,495
Total	**23,303**	**71,025**	**95,614**	**189,942**

Portfolio Total Gas Savings by Program (Lifetime)

Program	2023	2024	2025	2023 - 2025
Residential Prescriptive Program	375,092	1,111,639	1,480,422	2,967,153
Online Audit Kit Program	36,077	126,269	180,384	342,730
Total	**411,169**	**1,237,908**	**1,660,807**	**3,309,883**

Q. What additional benefits are projected to occur from the EE Plan?

A. The Plan is projected to save 8,724 MWh of electricity and 146 million gallons of water over the lifetime of the measures installed. Additionally, reduced emission of over 201,597 short tons of CO2 are expected to occur from program activity, which is equivalent to removing over 7,700 cars from the road permanently. Section 1.4 of Exhibit TML-2 contains additional details on savings projected for the plan.

Q. How much additional employment do you estimate that the EE Plan will generate?

A. The Plan is projected to generate between 99 and 199 net additional new jobs in the broader Pennsylvania economy over the lifetime of the efficiency measures installed. The majority of these jobs will stay close to where savings occurred due to: (1) most of the job creation being a product of the economic "multiplier" effect through the cycle of re-spending energy savings; and (2) the shift away from spending in the less-labor intensive energy sector towards more job-intensive sectors such as food service and production, as explained in Section 1.4.4 of Exhibit TML-2

Q. How much will it cost to achieve these results?

A. The total portfolio is projected to cost \$8.1 million over three years, or an average of \$2.7 million per year. The first year is anticipated to be mainly devoted to the setup and initial ramp up of the program and has anticipated spending of \$1.4 million. Spending rises to \$3.8 million in the third year of the Plan as the programs are projected to be fully ramped up. The following table provides annual spending by program and is Table 1 of Exhibit TML-2.

Portfolio Total Costs by Program

Projected Costs (Nominal)	**2023**	**2024**	**2025**	**2023 - 2025**
Residential Prescriptive Program	\$898,000	\$2,243,000	\$3,021,000	\$6,162,000
Online Audit Kit Program	\$241,860	\$356,510	\$501,300	\$1,099,670
Portfolio Wide Costs	\$300,000	\$254,000	\$258,000	\$812,000
Total	**\$1,439,860**	**\$2,853,510**	**\$3,780,300**	**\$8,073,670**

The following table breaks out the total spending at the portfolio level by budget category and year and is Table 2 in Exhibit TML-2.

Portfolio Total Costs by Category

Category	**2023**	**2024**	**2025**	**2023 - 2025**
Customer Incentives	\$685,860	\$2,058,510	\$2,747,300	\$5,491,670
Administration	\$561,000	\$558,000	\$643,000	\$1,762,000
Marketing	\$140,000	\$120,000	\$151,000	\$411,000
Inspections	\$33,000	\$97,000	\$129,000	\$259,000
Evaluation	\$20,000	\$20,000	\$110,000	\$150,000
Total	**\$1,439,860**	**\$2,853,510**	**\$3,780,300**	**\$8,073,670**

Q. How will these costs be allocated to customers?

A. The programs were designed to specifically target residential customers. As such, the requirement for participation is to have a residential account with the Company. This means that all costs for the program are to be recovered from the residential class, excluding customers participating in the Company's low-income Customer Assistance program, through the rate mechanism described in the testimony of Company Witness Danhires (Columbia St. 12). Columbia Witness Johnson (Columbia St. 11) addresses how the proposed Energy Efficiency Rider rate was calculated.

Q. Is Columbia proposing annual budget caps for individual programs?

A. No. The proposal is an investment over three years of approximately $2.7 million dollars per year. Although the previously described budget levels represent anticipated funding levels, the utility should be allowed to move budget dollars between years and programs depending on market conditions and adoption rates. The total three-year budget is capped at the projected amount and the Plan still needs to be cost effective at a portfolio level.

Q. Why is this flexibility important?

A. The ability to allocate funding effectively is crucial for a portfolio administrator. The ability to adjust budgets ensures that unspent funds from one program can be used to address higher demand in other programs and helps provide continuity for customers, contractors, and suppliers. This flexibility must also extend to program design and implementation, such as increasing or decreasing incentives based on market conditions. Columbia would file a revised EE Plan if a program is added or removed, additional funds over and beyond the three-year cap were required, or material changes were expected for portfolio-level cost-effectiveness projections.

Q. How did you assess the economic benefits and costs of the EE Plan?

A. The TRC Test was used to evaluate the economic impacts of the EE Plan, based on the Act 129 TRC Test with modifications used in other approved voluntary gas programs in Pennsylvania. The TRC test evaluates all resource savings from a portfolio of programs against the costs incurred by program participants and the program administrator, where incentives are considered a transfer from the administrator to participants. Savings under the TRC are monetized using the avoided cost to supply those resources.

Q. What avoided costs values were used to develop the Plan?

A. As described in Section 1.5.2 of Exhibit TML-2, avoided cost of natural gas was developed using a similar approach to what was used by other natural gas distribution companies offering energy efficiency programs in Pennsylvania. Baseload gas costs were based on NYMEX futures adjusted for delivery to Columbia Gas Transmission ("TCO") FTS, which were gradually blended with forecasts from the Annual Energy Outlook from 2022 ("AEO 2022"), until fully switching over to AEO 2022 in 2034. Commodity costs include the commodity charge and gas retention from the TCO tariffs. The avoided costs for heating load were computed from the Columbia Transmission SST rate, plus refill from the Columbia FSS rate, adjusted for load factor over the heating season. The avoided costs also include avoidable load-related distribution investments borrowed from UGI's estimates in its 2018 EE&C filing, at Docket No. R-2018-3006814.

Avoided costs for electricity and peak demand were based on values from the Act 129 Phase IV filings from the electric distribution companies ("EDCs").[1] These

[1] On June 18, 2020, the Commission adopted an Implementation Order, which directed that EDCs to file EE&C plans for Phase IV by November 30, 2020. *See Energy Efficiency and Conservation Program* Implementation Order, at Docket No. M-2020-3015228 (June 18, 2020).

values were translated to annual dollar per kilowatt-hour ("$/kWh") and peak demand kilowatt-year ("$/kW-yr") values and weighted by their overlap with Columbia's service territory. Avoided cost for water are based on the Act 129 Phase IV TRC Test Order.[2]

Q. What are the lifetime TRC benefits and costs projected for the Plan?

A. Under the TRC test, the Plan is projected to provide a present value of benefits in 2022 dollars of $27.6 million with a corresponding cost of $11.4 million. This comes out to $16.2 million in net benefits from the proposed plan with an overall BCR of 2.42. In addition, both the RP and OAK program are cost effective on their own.

Q. Will these net benefits stimulate economic activity?

A. Yes. The present worth of TRC net benefits represents a long-term injection of wealth into the economy. For residential customers, the reduction in the total costs of gas service translates to after-tax disposable income, which can be saved or spent. Moreover, the amount of additional economic activity stimulated by the efficiency investment will end up being several times the net benefits due to re-spending within the local, state, and regional economies. While there is doubtless some "leakage" as some spending takes place outside Pennsylvania, the majority of the economic benefits stay at the state and local levels according to research by the American Council for an Energy Efficient Economy ("ACEEE")[3].

This economic activity generated by the net economic benefits of efficiency investment is in addition to the economic activity generated directly by

[2] *2021 Total Resource Cost (TRC) Test,* Final Order, Docket No. M-2019-3006868 (December 19, 2019).
[3] Energy Efficiency Job Creation: Real World Experiences" Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.

expenditures on the part of both Columbia and program participants to install the efficiency measures.

Q. When does Columbia anticipate programs will be available to customers?

A. The Company anticipates that programs will be available to customers approximately six to nine months after approval of the Plan. This means that the programs are projected to launch midway through 2023. This will give the Company time to finalize program design details, hire vendors to run the programs, and get any initial marketing materials and outreach organized and implemented.

Q. Please describe the RP Program.

A. The RP Program aims to reduce lost opportunities for efficiency improvements during the turnover of natural gas space heating and water heating equipment. The program is expected to cost $6.2 million in nominal dollars over three years and save 2.97 million Dth of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $13.6 million with a BCR of 2.41. The program will also save 8,724 MWh of electricity and approximately 182 thousand tons of CO2 over the lifetime of the installed measures, which is equivalent to permanently removing over 6,935 cars from the road.

The RP program will specifically provide incentives for furnaces, boilers, combination space and water heating boilers ("combi boilers"), tankless water heaters, and WIFI-enabled thermostats. The program will use ENERGY STAR® criteria as a minimum efficiency level, when available. A full list of the measures along with minimum efficiency levels and proposed incentives can be found in the

"Financial Incentive" portion of the RP Program description in Exhibit TML-2.

Q. How will the RP program be administered?

A. Columbia anticipates hiring a third-party implementor to issue rebates through online and paper applications. This may include the setup of an online marketplace for the sale of smaller equipment, such as WIFI-enabled thermostats, with rebates taken out at the time of purchase.

Columbia will also utilize the program implementer for inspections of a portion of installed equipment to make sure that the equipment is installed and matches the details provided in the application. Applications that have been selected for inspection will not receive a rebate until the inspection has been completed.

An evaluator will be retained to provide an impact and process evaluation of the program once sufficient participation levels have been achieved. This activity is anticipated to occur in the third year of the program.

Q. How will the information about the RP Program reach customers?

A. The main way in which customers are expected to hear about the RP program is through trade allies, such as heating ventilation and air conditioning ("HVAC") installers and plumbers. The Company, along with the program implementor, will work closely with these trade allies to ensure that they have the tools needed to help customers understand the benefits of the higher efficiency equipment and are able to easily apply to the program. Trade ally efforts will be supported by general marketing activities through more traditional avenues such as bill inserts, emails, and social media advertisements. In addition, the Company will promote the RP incentives through its OAK Program.

Q. Please describe the OAK Program.

A. The OAK Program provides residential customers with a free online audit that will provide targeted information for customers on how to reduce their energy usage and bills. The program will also provide customers who complete the audit with free, targeted energy savings kits. The program is expected to cost $1.1 million in nominal dollars over three years and save 343 thousand Dth of natural gas over the lifetime of measures installed. The program is projected to provide present value TRC net benefits of $3.28 million with a BCR of 4.32. The program will also save 146.4 million gallons of water and approximately 20 thousand tons of CO2 over the lifetime of the installed measures, which is equivalent to permanently removing over 766 cars from the road.

To participate, customers will go through a web-based audit that collects basic information about a customer's home and energy usage. Based on the information provided, he or she will then receive customized recommendations along with estimated impacts from implementing those recommendations. If the customer uses natural gas to heat his or her home, then they can elect to receive a kit with low-cost measures such as outlet gaskets, caulk, and foam sealant along with instructions on how to install them. If the customer uses natural gas for water heating, they can elect to receive a kit that includes low flow aerators and a high-efficiency showerhead. The OAK Program will be available to all residential customers at no cost.

Q. How will the OAK Program be administered?

A. Columbia expects to hire a third-party implementor to provide the online audit web-based application. For customers who do not have easy access to the internet, a phone version of the audit will be made available. The implementor will also be responsible for sending the free energy saving kits to customers who request them.

The program will be marketed through bill inserts, social media, Columbia's website, and other traditional advertising channels, such as radio or print advertisements. As part of the recommendations from the online audit, customers will be shown information about relevant RP incentives, including a link to apply for rebate through the RP program.

An evaluator will be engaged to provide annual evaluations of customer installation rates. A full program impact and process evaluation will be performed once sufficient participation activity has occurred, which is anticipated for the third program year.

Q. Please explain the portfolio wide costs associated with EE Plan.

A. The portfolio wide costs are not attributable to specific programs such as development, design, tracking, reporting, legal and administrative overhead. This includes amortized costs for plan and portfolio development incurred for the Company's EE Plan filing. Portfolio wide costs are projected to become 7% of the final year's costs, and, over the three-year period, portfolio wide costs represent 10% of the portfolio's expenditures.

Q. How will Columbia report on results of the Plan?

A. As explained in Section 1.6.4 of Exhibit TML-2, the Company will provide an annual report three months after the close of each program year. The program year ends on December 31st, so the annual report will be provided in April of the following year. This annual report will provide results for the previous year, including savings, participation, spending, and cost effectiveness along with descriptions of notable activity and any updates to program design and delivery.

Q. What conclusions do you reach about the proposed EE Plan?

A. I find that the Plan is based on successful energy efficiency efforts by other natural gas distribution companies and will provide important natural gas and other resource savings. Furthermore, the Plan will provide substantial economic benefits to the Company's residential ratepayers, the economy within the Company's territory, and Pennsylvania as a whole.

Q. On the basis of these conclusions, what are your recommendations to the Commission?

A. I recommend that the Commission approve the implementation of the Three-Year Energy Efficiency Plan.

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 M. LOVE

2534 Downingsville Rd. | Lincoln, VT 05443
(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 14 years, Theodore "Theo" Love has been providing economic-based 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.

Alter & Rosen, LLP –New York, NY 2007 to 2010
Consultant
Managed the development of an online database management system for musical copyrights and brought on board paying beta users. Managed data entry, reporting, termination and reversion issues for transactions involving musical copyright catalogues valued at over $100 million.

AllianceBernstein LP –White Plains, NY 2006 to 2007
Client Reporting Analyst
Oversaw the monthly and quarterly report process for clients domiciled outside the United States. Increased by 150% the amount of accounts that met a fifth business day deadline. Transferred firm's quarterly reporting process to new system.

Education

Clark University – Worcester, MA
B.A. Magna cum Laude, *Mathematics and Computer Science*, 2006.

Kansai Gaidai University: Hirakata City, Osaka Japan.
Study Abroad Program, Spring Semester 2005

General Assembly: New York City, NY
Data Science Intensive Course, 2015

Recent Project Experience

Green Energy Economics Group, Inc.

Economic and Policy Analysis
Small Business Utility Advocate - California *(June 2020 – Present)*

- Performing data analysis of underserved small and medium business customers as part of the California Energy Efficiency Coordinating Committee (CAEECC) Underserved Working Group for Small and Medium Business (SMB).
- Prepared report and analysis of arrearages for small businesses due to COVID-19 and assisted with policy recommendations and comments on strategies to address COVID-19 related debt (Do. No. 21-01-014)
- Assisted with analysis and comments for ongoing docket on clean energy financing (Do. No. 20-08-022)
- Provided comments on program design of CleanPowerSF's Food Service Program (Do. No R13-11-05)

Gas Topic Committee Co-chair
Association of Energy Service Professionals (AESP) *(January 2019 – Present)*

- Co-chair of the topic committee that oversees gas energy efficiency activity in North America. Leader of regular member calls and active participant in conference planning.

Benefit Cost Analysis Expert
Public Service Enterprise Group (PSEG) – New Jersey *(October 2021 – Present)*

- Provided assistance with calculation of six economic tests for PSEG's energy efficiency and conservation portfolio, including development of calculation engine and launch as a subcontractor to ANB Enterprises.
- Consulted on forecasting and data analysis for PSEG's internally run commercial Engineered Solutions and Direct Install programs.

Economic and Policy Analysis
Consumer Advocate – Nova Scotia *(March 2019 – Present)*

- 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 in Matter No.
- Provided comments on the 2019 DSM Potential Study's economic analysis and projection assumptions and approach
- Member of DSM Advisory Group (DSMAG) on behalf of the Consumer Advocate of Nova Scotia to provide ongoing support

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

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

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   Analysis of commercial program goals and program design.

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3. **Nova Scotia Utility and Review Board** Matter No. M09096, Efficiency 1 (E1) Application for Approval of 2020 – 2022 Demand Side Management (DSM) Resource Plan; The Consumer Advocate. May 28, 2019.

   DSM Investment Levels and Affordability, Usage of Unspent Ratepayer Funding, Rate and Bill Impacts, Target Setting.

4. **Pennsylvania PUC** R-2018-3006814, UGI Gas Utilities Inc. – Gas Division, Rate Case; UGI Utilities Inc. – Gas Division. January 28, 2019.

   Energy Efficiency & Conservation Plan and Total Resource Cost Implementation.

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6. **Pennsylvania PUC** M-2017-2640306, Petition of Peoples Natural Gas Company LLC for Approval of its Energy Efficiency and Conservation Plan; Peoples Natural Gas – Peoples Division, Peoples Natural Gas – Equitable Division; January 31, 2018.

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7. **Pennsylvania PUC** P-2016-2580030, UGI Penn Natural Gas, Inc. Rate Case; UGI Penn Natural Gas, Inc. January 2017.

   Energy efficiency & conservation plan and total resource cost implementation.

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9. **Pennsylvania Public Utility Commission (PUC)** P-2014-2459362, Philadelphia Gas Works Demand-Side Management Plan for FY 2016-202; Philadelphia Gas Works. May 2015.

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Exhibit TML-2

Columbia Gas of Pennsylvania

Three-Year Energy Efficiency Plan

January 1, 2023 – December 31, 2025

March 18, 2022

Table of Contents

1 Introduction and Background

1.1 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.

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 $8.1 million on the administration and delivery of two residential energy efficiency programs. The programs are projected to save 3.3 million Dth of natural gas over the lifetime of the measures installed. From a total resource perspective, the portfolio present value of benefits is $27.6 million, with $11.4 million in present value of costs, leading to a present value of net benefits of $16.2 million and a TRC BCR of 2.42. Furthermore, the energy efficiency programs are expected to save 8,724 MWh of electricity, 146 million gallons of water, create between 99 and 199 jobs, and avoid the emission of CO_2 equivalent to over 7,700 cars being removed from the road over the lifetime of installed measures.

1.2 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.

1.3 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 $3.8 million in FY 2025, approximately 0.7% 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	$898,000	$2,243,000	$3,021,000	$6,162,000
Online Audit Kit Program	$241,860	$356,510	$501,300	$1,099,670
Portfolio Wide Costs	$300,000	$254,000	$258,000	$812,000
Total	**$1,439,860**	**$2,853,510**	**$3,780,300**	**$8,073,670**

[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).

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 7% of the portfolio total cost, and, over the three-year period, they represent 10% 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	$685,860	$2,058,510	$2,747,300	$5,491,670
Administration	$561,000	$558,000	$643,000	$1,762,000
Marketing	$140,000	$120,000	$151,000	$411,000
Inspections	$33,000	$97,000	$129,000	$259,000
Evaluation	$20,000	$20,000	$110,000	$150,000
Total	**$1,439,860**	**$2,853,510**	**$3,780,300**	**$8,073,670**

1.4 Portfolio Benefits

1.4.1 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	20,619	61,632	82,196	164,448
Online Audit Kit Program	2,684	9,393	13,418	25,495
Total	**23,303**	**71,025**	**95,614**	**189,942**

Table 4. Projected Lifetime Gas Savings by Program (Dth)

Program	2023	2024	2025	2023 - 2025
Residential Prescriptive Program	375,092	1,111,639	1,480,422	2,967,153
Online Audit Kit Program	36,077	126,269	180,384	342,730
Total	**411,169**	**1,237,908**	**1,660,807**	**3,309,883**

1.4.2 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)	95	298	400	793
Demand (kW)	16.9	53.2	71.4	141.4
Water (Million Gallons)	1.5	5.4	7.7	14.6
Lifetime				
Energy (MWh)	1,040	3,282	4,402	8,724
Water (Million Gallons)	15.4	53.9	77.0	146.4

1.4.3 Emission Reductions

This section contains projections for CO_2 emission reductions due to the energy efficiency programs. The total lifetime savings of 202 thousand tons of CO_2 is equivalent to removing over 7,700 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	24,053	72,418	97,157	193,628
Electricity	950	2,997	4,021	7,969
Total	**25,004**	**75,415**	**101,178**	**201,597**

1.4.4 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 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

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[3] "Energy Efficiency Job Creation: Real World Experiences" Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.
[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.

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 99 and 199 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	12	19	25
2024	37	56	74
2025	50	75	100
TOTAL	**99**	**149**	**199**

1.5 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	$23,311,491	$9,685,588	$13,625,903	2.41
Online Audit Kit Program	$4,264,882	$986,750	$3,278,132	4.32
Portfolio Wide Costs	$0	$738,970	($738,970)	-
EE Programs	**$27,576,373**	**$11,411,307**	**$16,165,065**	**2.42**

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

[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.

[7] DRIPE accounts for the suppression effects on wholesale prices from reduced usage due to DSM.

prices for carbon dioxide (“CO_2”) are included, the portfolio would show substantially more benefits.

1.5.1 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 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 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.

[8] Act 129 Phase IV 2021 Total Resource Cost (TRC) Test (Case No. M-2019-3006868). Final Order dated December 19, 2019. P. 20

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.

Avoided costs for water came from the Act 129 Phase IV TRC Test Order.

1.6 Implementation

1.6.1 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 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 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 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 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 Evaluation, Measurement, and Verification

1.7.1 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 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 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 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 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. 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$)***
Savings Projections	***Three-Year Savings Projections***

Cost Effectiveness — *Three-Year Cost-Effectiveness Results (2022$)*

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC Test	$23,311,491	$9,685,588	$13,625,903	2.41
Gas Admin Test	$22,918,272	$5,499,359	$17,418,913	4.17

Savings Projections — *Three-Year Savings Projections*

First Year Savings	2023	2024	2025	2023 - 2025
Natural Gas (Dth)	20,619	61,632	82,196	**164,448**
Electric Energy (MWh)	94.6	298.3	400.2	**793.1**
Peak Demand (kW)	16.9	53.2	71.4	**141.4**
Water (Million Gallons)	0.0	0.0	0.0	**0.0**

	Lifetime Savings | **2023** | **2024** | **2025** | **2023 - 2025**

Lifetime Savings	2023	2024	2025	2023 - 2025
Natural Gas (Dth)	375,092	1,111,639	1,480,422	**2,967,153**
Electric Energy (MWh)	1,040.5	3,281.5	4,402.0	**8,724.0**
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	$660,000	$1,968,000	$2,618,000	**$5,246,000**
Administration	$123,000	$122,000	$146,000	**$391,000**
Marketing	$82,000	$56,000	$68,000	**$206,000**
Inspections	$33,000	$97,000	$129,000	**$259,000**
Evaluation	$0	$0	$60,000	**$60,000**
Total	**$898,000**	**$2,243,000**	**$3,021,000**	**$6,162,000**

Participation Projections

Three-Year Participation Projections

Projected Units	2023	2024	2025	2023 - 2025
Furnace - ENERGY STAR	720	2,100	2,800	**5,620**
Boiler - 94+ AFUE	30	110	140	**280**
Combi Boiler - 94+ AFUE	120	340	450	**910**
Wifi Thermostat - ENERGY STAR	1,300	4,100	5,500	**10,900**
Tankless Water Heater - ENERGY STAR	170	500	670	**1,340**
Total	**2,340**	**7,150**	**9,560**	**19,050**

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 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. 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. 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. The program also addresses water heating savings by offering incentives for ENERGY STAR® tankless water heaters.

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

All equipment besides the Wi-Fi thermostat must be powered by natural gas.

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 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,	<u>Quality Assurance</u>

and Verification	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. <u>Evaluations</u> 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	<u>Rebate Processing and Inspection</u> 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. <u>Marketing and Outreach</u> Columbia Gas and their vendors will handle marketing and outreach for the RP program. <u>Evaluator</u> 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$)***
Savings Projections	***Three-Year Savings Projections***

Three-Year Cost-Effectiveness Results (2022$)

CE Test	PV Benefits	PV Costs	PV Net	BCR
TRC Test	$4,264,882	$986,750	$3,278,132	4.32
Gas Admin Test	$2,669,506	$986,750	$1,682,756	2.71

Three-Year Savings Projections

First Year Savings	2023	2024	2025	2023 - 2025
Natural Gas (Dth)	2,684	9,393	13,418	**25,495**
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)	1.5	5.4	7.7	**14.6**
Lifetime Savings	**2023**	**2024**	**2025**	**2023 - 2025**
Natural Gas (Dth)	36,077	126,269	180,384	**342,730**
Electric Energy (MWh)	0.0	0.0	0.0	**0.0**
Water (Million Gallons)	15.4	53.9	77.0	**146.4**

Budget Projections	***Three-Year Budgets (Nominal)***

Costs by Category	2023	2024	2025	2023 - 2025
Customer Incentives	$25,860	$90,510	$129,300	**$245,670**
Administration	$138,000	$182,000	$239,000	**$559,000**
Marketing	$58,000	$64,000	$83,000	**$205,000**
Inspections	$0	$0	$0	**$0**
Evaluation	$20,000	$20,000	$50,000	**$90,000**
Total	**$241,860**	**$356,510**	**$501,300**	**$1,099,670**

Participation Projections	***Three-Year Participation Projections***

Projected Kits	2023	2024	2025	2023 - 2025
Water Heating Kit	480	1,680	2,400	**4,560**
Space Heating Kit	780	2,730	3,900	**7,410**
Total	**1,260**	**4,410**	**6,300**	**11,970**

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	Quality Assurance 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. Evaluations

	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
Online Audit Kit Program							
Web Faucet Aerator - Kitchen	$2.70	$2.70	10	0.51	0	0	941
Web Faucet Aerator - Bathroom	$0.70	$0.70	10	0.11	0	0	201
Web High Efficiency Showerhead	$4.96	$4.96	10	0.51	0	0	934
Web Switch/Outlet Cover	$2.40	$2.40	15	1.64	0	0	-
Web Caulk	$3.12	$3.12	15	0.37	0	0	-
Web Foam Sealant	$6.21	$6.21	15	0.37	0	0	-
Water Heating Kit	$8.98	$8.98	1	-	0	0	-
Space Heating Kit	$7.27	$7.27	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**	**Cost**	**PV of Net Benefits**	**Present Value Benefit**	**Cost**	**PV of Net Benefits**
Portfolio Total	$27,576,373	$11,411,307	$16,165,065	$25,587,777	$7,225,078	$18,362,699
Non-Measure Costs		$2,331,528			$2,331,528	
Total Measure Costs	$27,576,373	$9,079,779	$18,496,593	$25,587,777	$4,893,550	$20,694,227
Program						
Residential Prescriptive Program						
Program Total	$23,311,491	$9,685,588	$13,625,903	$22,918,272	$5,499,359	$17,418,913
Non-Measure Costs		$824,226			$824,226	
Total Measure Costs	$23,311,491	$8,861,361	$14,450,129	$22,918,272	$4,675,132	$18,243,139
Online Audit Kit Program						
Program Total	$4,264,882	$986,750	$3,278,132	$2,669,506	$986,750	$1,682,756
Non-Measure Costs		$768,332			$768,332	
Total Measure Costs	$4,264,882	$218,418	$4,046,464	$2,669,506	$218,418	$2,451,088
Portfolio Wide Costs						
Program Total	-	$738,970	$(738,970)	-	$738,970	$(738,970)
Non-Measure Costs		$738,970			$738,970	
Total Measure Costs	-	-	-	-	-	-

3.4 Technical Reference Manual (TRM)

Attachment A

Technical Reference Manual

Measure Savings Algorithms

Columbia Gas of Pennsylvania

March 18, 2022

Prepared by:

Green Energy Economics Group

Table of Contents

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: 3/6/22
Effective date: TBD
End date: TBD

Measure Description
This measure applies to residential-sized gas furnaces and boilers 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.

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 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

Source: Lifetime estimates used by Efficiency Vermont, PGW and UGI.

Water Savings

There are no water savings for this measure.

2.1.2 WiFi Thermostat – ENERGY STAR®

Unique Measure Code(s): TBD
Draft date: 3/6/22
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
$\Delta kW = 0$ 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
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.

3.2 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[7].

Water Savings Algorithms
The water savings for low flow showerheads are due to the reduced amount of water being used per shower.

$$\Delta Gallons = \frac{\left(GPM_{base} - GPM_{eff}\right) \times\ N_{persons} \times T_{person-day} \times N_{showers-day} \times 365 \times ISR}{N_{showerheads-home}}$$

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[8]
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 [9]
$T_{person-day}$	=	Average minutes per person per day used for showering. 7.8 min/day [10]
$N_{showers-day}$	=	Average number of showers per person per day. 0.6 showers/person/day [11]
365	=	Days per year
ISR	=	In service rate. Kit Default = 35%. Direct install Default = 100%. [12]
$N_{showerheads-home}$	=	Average number of showers per home. Actual or defaults: SF=1.6, MF=1.1, Unknown=1.5 [13]

[7] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[8] The Energy Policy Act of 1992 established the maximum flow rate for showerheads at 2.5 gallons per minute (GPM)
[9] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[10] Ibid.
[11] Ibid.
[12] Ibid.
[13] 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.

$$\Delta MMBtu = \frac{\left[\Delta Gallons \times 8.3 \times c_p \times (T_{out} - T_{in})\right] / 1{,}000{,}000}{RE_{DHW}}$$

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)
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%[14]

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[15].

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

[14] 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).
[15] 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[16].

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[17]
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[18]
$T_{person-day}$	=	Average minutes per person per day of faucet hot water usage. Kitchen=4.5, Bathroom=1.6, Unknown=6.1[19]
365	=	Days per year
DF	=	Drain rate, the percentage of water flowing down the drain. Kitchen=75%, Bathroom=90%, Unknown=79.5%[20]
ISR	=	In service rate. Kit delivery default = 28%, Direct install default = 100%[21]
$N_{faucets-home}$	=	Average Number of Faucets per home. Actual or for defaults see table below.

Average Number of Faucets per Home[22]

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)

[16] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[17] Ibid
[18] Ibid
[19] Ibid
[20] Ibid
[21] Ibid
[22] Ibid

T_{out}	=	Average mixed water temperature flowing from the faucet (degrees Fahrenheit) Kitchen=93 °F, Bathroom=86 °F, Unknown=87.8 °F [23]
T_{in}	=	Assumed temperature of water entering house (degrees Fahrenheit) 52 °F [24]
RE_{DHW}	=	Recovery efficiency of the domestic hot water heater = 75%[25]

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[26].

[23] Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)
[24] Ibid
[25] See assumption for low flow shower head.
[26] 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."