Columbia Gas of Pennsylvania, Inc.
2021 General Rate Case
Docket No. R-2021-3024296
Standard Filing Requirements
Testimony
Volume 10 of 10

M. KEMPIC

COLUMBIA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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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 initially 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, and R-2016-2529660.

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 2020 and at the outset of 2021, 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 436,000 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.

On October 9, 2020, NiSource Inc. completed the sale of Bay State Gas Company d/b/a Columbia Gas of Massachusetts and thereby finalized the Asset Purchase Agreement entered into with Eversource, a Massachusetts voluntary association, on February 26, 2020. NiSource remains 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 cast iron, bare steel and first generation pipe and its expenditures on 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. Proposed Rate Increase

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. Despite the impact of COVID-19, throughout the pandemic Columbia, its employees, and its contractors continued to provide essential services to our customers with minimal disruption. Indeed, as detailed in the testimony of Columbia witness Brumley (Columbia Statement No. 7), in 2020, even with the global disruption to most business as a result of the pandemic, Columbia nonetheless was able to replace and retire a significant amount of pipe in 2020. In light of the substantial capital investment Columbia has made and the large capital investments that will be made through the end of 2022, 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 $98.3 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 6,078,654 feet (over 1,150 miles) of cast iron and bare steel pipe. In addition, 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 and growing capital program which is necessary to retire and replace aging infrastructure, a rate increase is unavoidable. As explained in Company witness Davis' testimony (Columbia Statement No. 13), the Company has taken - and will continue to take – specific measures to assist those financially insecure customers, especially those customers who find themselves impacted by COVID-19. 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.

b. Other Objectives

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 systems, and is expanding focus in several critical areas to maintain and enhance its operational capabilities. These efforts are supported by NiSource's continued 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.

In the Company's most recent base rate case, the Commission approved a number of SMS driven safety initiatives that were narrowly focused, but will enhance safety for Columbia, its employees, and for the communities we serve. Specifically, the Commission approved the Company's request to: (1) accelerate Columbia's staged approach of identifying and remediating cross bores; (2) accelerate the Company's expanded field assembled riser replacement program to include customer owned facilities; (3) hire fulltime employees to accelerate Columbia's legacy service line record enhancement program to correct inaccurate and/or incomplete data within legacy records; and (4) employ the Picarro analytics system to enhance the Company's process to refine how leak repairs and replacements are prioritized on the natural gas distribution system.

As outlined in the testimony of Columbia witness Anstead (Columbia Statement No. 14), as a result of Columbia's SMS, the Company is implementing two additional programs to improve safety and reduce risk. The first program is the System Pressure Visibility Program, which includes installing digital pressure recording telemetry equipment at natural gas pressure regulator stations across the Columbia operating territory. The new digital devices will transmit real time pressure data to Gas Control Supervisory Control and Data Acquisition (SCADA) systems where pressures and alarms will be monitored by Gas Control personnel and computer systems 24/7. This new technology will improve operational safety through immediate awareness of operating pressures and abnormal operating pressure conditions and ensure more reliable and accurate operating pressure data capture that cannot be matched by traditional analog paper pressure charts primarily due to fewer mechanical parts.

In addition to the System Pressure Visibility, as a result of Columbia's SMS the Company is also updating its red tag procedures applicable to customer-owned appliances to retain more knowledge of the issues with customer owned appliances and to provide inspections at the request of the customer to ensure the gas line downstream from red tagged appliances remains safe.

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 Notestone will discuss the proposed RNA further in Columbia Statement No. 11.

Establishment of a Federal Tax Reform Adjustment ("FTRA") rider: Columbia proposes the FTRA so that the Company will have a Commission approved rider in place to address any changes to the Federal income tax rate should the rate change from the current rate of 21%. Company witness Harding will discuss the proposed FTRA in Columbia Statement No. 10.

Q. Does the Company have any other ongoing initiatives?

A. Yes. NiSource Next is an enterprise-wide initiative focused on leveraging our company's scale, driving efficiencies, improving our cost structure and capabilities, and enhancing our ongoing commitment to safety. The NiSource Next initiative will focus on the following outcomes:

- An unwavering commitment to safety leadership through our ongoing SMS journey.
- Fostering innovation within teams to rethink outdated processes and drive efficiencies.
- Leveraging technology to make meaningful connections to customers and enhance service levels.
- Streamlining cost structures to drive efficiencies across the organization.
- Standardizing operations management supported by modern technology for improved speed and reliability.

This program of work is already underway and has deepened our focus on driving O&M cost savings and transforming our operations to ensure we are well-positioned to deliver on our commitments to operational excellence and customer value. Safety is the first priority of our NiSource Next work and it will build upon the successes we have had in our ongoing SMS journey.

Q. Please describe NiSource Next.

A. 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. NiSource Next is structured to leverage our scale, use technology, define clear roles and accountability with our leaders and employees and standardize our processes to create an organization focused on operational rigor and continuous improvement.

Future Infrastructure Replacement

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 and cast iron facilities as soon as possible. In addition, as Columbia's infrastructure replacement program has been operating for 14 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 juncture where risks beyond bare steel and cast iron now need to be considered. 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 cast iron and bare steel, 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 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, Columbia will include replacing short, non-contiguous segments of plastic pipe that are encountered when analysis shows that it is more cost effective to replace rather than to reuse these segments of pipe while replacing priority pipe.

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

Budgeted Capital Expenditures					
Class	**2021**	**2022**	**2023**	**2024**	**2025**
Growth	$42,952	$42,676	$41,220	$44,893	$48,904
Betterment	$42,615	$8,500	$10,700	$8,500	$5,452
Public Improvement	$9,497	$6,000	$7,500	$7,939	$7,449
Replacement	$260,838	$289,108	$339,809	$348,704	$366,628
Support Services	$2,750	$3,250	$2,700	$2,250	$2,344
Total Gross Capital	**$358,652**	**$349,534**	**$401,928**	**$412,286**	**$430,777**

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 (2019)
Columbia Gas	7,656.40
PGW	3,040.72
PECO	6,928.30
UGI[1]	12,028.00
Peoples[2]	13,081.30
National Fuel	4,842.87

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 16% of Columbia's

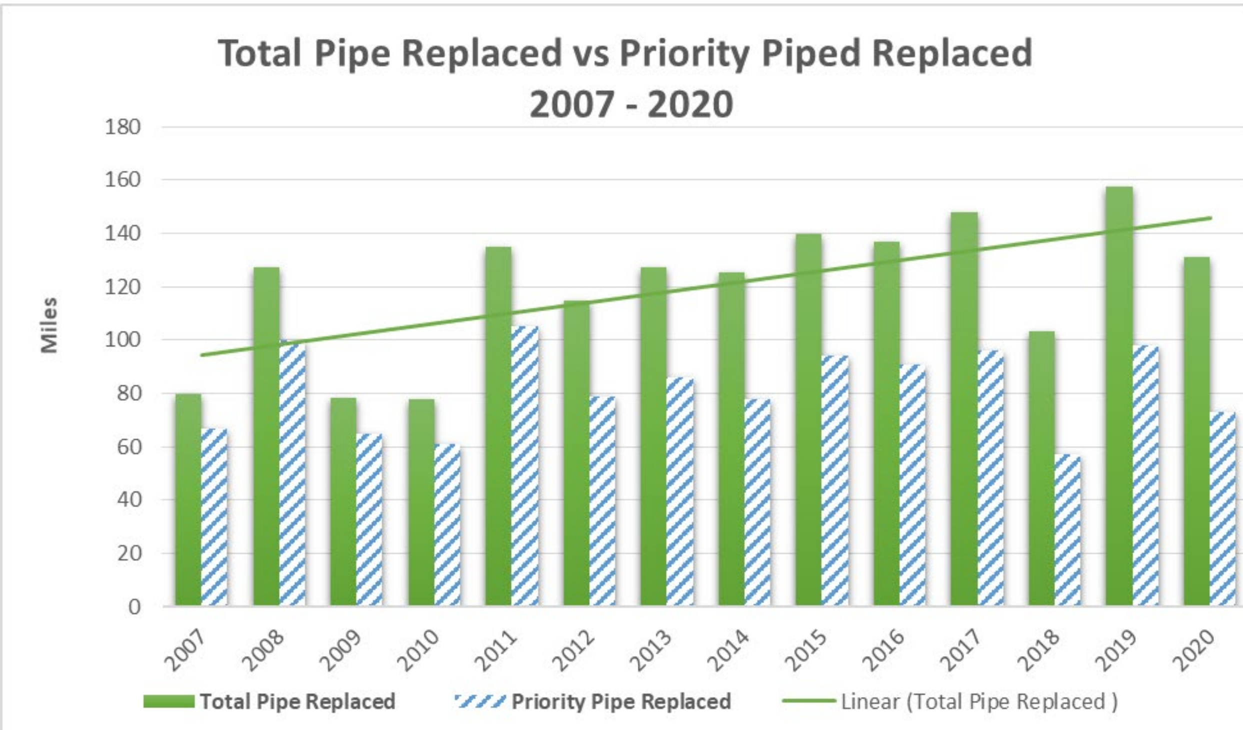
[1] All companies/ divisions combined.
[2] All companies/ divisions combined.

total inventory of pipe is either bare steel or cast iron, approximately 8% is pre-1982 plastic, and approximately 16% is pre-1971 coated pipe, which are nearing the end of their useful life. When the latter two types of pipe border cast iron or bare steel, the Company will include them in the replacement project in order to reduce that risk now while the community is disrupted due to the replacement work. Further, gas prices continue to remain low in Pennsylvania and continuing to invest in pipeline replacement while gas prices are low will aid in mitigating the impact on the customer's total bill.

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

A. See Figure 3 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 3



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

A. As Figure 3 above indicates, following a decrease in 2018, the Company resumed its normal performance levels by replacing 98 miles of bare steel and cast iron in 2019. Unquestionably, 2020 posed new challenges, but, despite the impact of COVID-19 pandemic on our operations, as described in Columbia witness Brumley's testimony, Columbia was able to successfully complete its infrastructure replacement program in 2020 by replacing 73 miles of cast iron and bare steel and 10 miles of pre-1982 plastic and 18 miles of pre-1971 coated steel.

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.

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

A. Today, replacement of bare steel and cast iron mains and services are the priorities that drive infrastructure modernization. SMS is expanding the classes of priorities through identification of risk reduction, in addition to bare steel and cast iron.

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

A. In addition to the 73 miles of bare steel and cast iron pipe replaced in 2020, 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, 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. The Company has identified risks regarding the failure of both pre-1982 plastic pipe and pre-1971 coated steel pipe and replaces them as part of our cast iron and bare steel projects when they are found next to cast iron and bare steel. As we move forward and these facilities continue to age and the Company continues to reduce the inventory of cast iron and bare steel further, the Company will prioritize replacement of pre-1982 plastic and pre-1971 steel in stand-alone situations. Consequently, Columbia will be incorporating pre-1982 plastic and pre-

1971 steel pipe as stand-alone categories 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. It 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, 2022, 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 5.18% 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 7.88%. Company witness Moul (Columbia Statement No. 8) demonstrates that Columbia should be granted an opportunity to earn a 10.95% rate of return on common equity.

IV. MANAGEMENT EFFECTIVENESS

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

A. No. While Columbia believes its performance would otherwise warrant such an upward adjustment, Columbia has opted not to seek an adjustment in this proceeding in light of the COVID-19 pandemic. The Company, and its employees, continue to perform at a high level to the benefit to our customers and the communities we serve.

Q. If Columbia were seeking to adjust the Company's requested rate of return for management effectiveness, what evidence would the Company offer in support?

A. 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, 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 8, below.

Figure 8
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%	27%	50%	33%	0%	33%
Significant Improvement Necessary	0%	18%	0%	8%	0%	0%
Major Improvement Necessary	0%	0%	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 8 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 "Significant Improvement Necessary". A review of the information in Figure 8 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. Recently, the Commission issued its Annual Utility Consumer Report and Evaluation ("UCARE") for 2019. 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 9, 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 9 below. Columbia's consumer complaint rate was also better than any of the seven major natural gas companies, which averages 0.91.

Figure 9

**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 10 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 10

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 lowest score amongst all seven Pennsylvania gas utility companies, as shown in Figure 11 below.

Figure 11

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 of all seven major natural gas companies. Figure 12, below, is illustrative.

Figure 12

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 2019 Quality of Service Performance Report?

A. Yes, Columbia's "Quality of Service Performance Report," which was filed on January 31, 2021, 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 2019 Quality of Service Performance Report.

Columbia continues to hold a firm 0% busy out rate for the last 12 years, while Calls Answered within 30 seconds is at 86%, up from 83% in 2019. Columbia experienced an abandonment rate of 2.04%. Although the abandonment rate was higher than 2019's of 1.94%, it is lower than 2017's abandonment rate of 2.06%. Columbia's abandonment rate is tied for the lowest in the gas industry.

Columbia continues to recruit via NiSource job postings 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 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 2020. In addition, over 1.2 million paperless bills were issued to customers. In July 2020 Columbia enhanced its paperless billing enrollment process to make it easier for customers to enroll. This enhancement has contributed an increase in approximately 200,000 additional paperless bills issued over 2019's number of 1 million.

Approximately 4.5 million payments were posted to customer accounts; of those, 67% were electronic payments.

2. Meter Reading:

In 2020, Columbia obtained over 5.3 million meter readings with 99.92% of meters read on the scheduled meter reading date. Columbia experienced an increase in the number of meters not read monthly in accordance with 56.12 (4)(ii). For 2019, the Company averaged only two (2) meters read outside the 6-month time frame compared to an average of 21 meters not read in 2020. 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. In 2019, the Company remained at only one (1) meter being read outside the 12-month interval to be in compliance with 56.12 (4)(iii). Again, for 2020, the number of meters not read under 56.12 (4) (iii) increased in the later months of 2020 for the same reason as explained above.

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, 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 2020. In 2020, Columbia's "First Contact Resolution" rate was 92.46%. This statistic indicates the success our call center has had in satisfying customers the first time they contact the Company. Figure 13, below, gives more detail on the service results Columbia achieved in this area in 2020

Figure 13

Phone Rep Performance	
	YE 2020
Overall satisfaction	94.15%
Put on hold after speaking with a rep	17.17%
Rep explained reason for hold	91.68%
Being courteous and professional	94.59%
Treated as a respected customer	94.58%
Showing concern for the situation	91.32%
Displaying knowledge in job	91.11%
Adequately answering questions	91.36%
How well rep listened to customer	93.37%
Having authority to make decisions	90.42%
Working quickly and efficiently	90.98%
Clarity of speech, speed, tone, and volume	94.33%
First contact resolution	92.46%

CPA Automated Phone Service	
	YE 2020
Overall satisfaction	81.85%
Offering choices that helped get directly to the information wanted	77.63%
Ease of navigating prompts	77.04%
Ease of getting connected to live representative	77.11%
Number of steps required to complete the transaction	72.50%
IVR first contact resolution	76.35%

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

A. As reflected in Figure 14 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 14

CPA Field Visit Scheduling	
	YE 2020
Willing to accommodate needs	94.97%
Told when work would take place	94.32%
Arrived on time	95.80%
Total time to resolve	95.65%
CPA Field Work Crew Performance Ratings	
	YE 2020
Overall satisfaction with performance	96.19%
Courteous and professional	97.98%
Displayed skill and knowledge	97.82%
Explained work being performed	98.24%
Adequately answered questions	97.23%
Aware of service performed	94.15%
Worked quickly and efficiently	98.26%
Being respectful of your property	97.54%
Left work property as found before work began	98.70%
Work crew identified themselves	98.14%
Work was completed by the work crew	91.70%
Satisfied request on the first visit	91.31%

Q. How did Columbia perform in the 2020 J.D. Power Residential Customer Satisfaction Survey?

A. Columbia achieved an overall Customer Satisfaction Index ("CSI") score of 765 in the annual J.D. Power survey of mid-sized eastern natural gas utilities, ending 2020 in second place. This is an increase of 20 points over the Company's 2019 final survey result of 745. The Company outperformed the mid-sized eastern utility average of 734 by 31 CSI points and gained in all categories. Columbia's overall industry rank also improved by 14 positions.

In addition, Columbia Gas beat the mid-sized eastern utility averages in all seven categories and had the top mid-sized eastern ranking in the Safety & Reliability, Customer Service, and Billing & Payment categories.

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

A. Over the past 15 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 2.06% in 2019. It also reduced its net write-off for the same period from 2.79% to 1.22%.

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 2019 Universal Service and Collections Report, as seen below, Columbia had the most affordable Customer Assistance Program ("CAP") in the Commonwealth. In 2019, Columbia's monthly average CAP bill was $52.00. This was the lowest bill amount of all gas and electric utilities in the state during 2019. Further, as per below, Columbia CAP has the lowest default rates, in each poverty level, than all other gas utilities.

		2019		
Utility	**Average Monthly CAP Bill**	**0 - 50% of FPIG**	**51% - 100% of FPIG**	**101% to 150% of FPIG**
Columbia	$52	19.1%	15.8%	18.5%
NFG	$59	24.4%	24.4%	24.4%
PECO- Gas	$64	28.0%	20.1%	25.4%
Peoples	$77	24.9%	16.1%	34.8%
Peoples/Equitable	$75	23.7%	17.5%	54.7%
PGW	$115	32.8%	16.7%	52.1%
UGI South	$67	31.4%	28.1%	42.0%
UGI North	$72	31.3%	29.6%	41.4%
Total Industry Average	$73	27.0%	21.0%	36.7%

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.

Columbia's LIURP program is the second largest gas program in the state. Columbia's proposal to offer a LIURP pilot program to address the increasing number of jobs deferred for health or safety issues was recently approved in Docket M-2018-2645401. Through this pilot, Columbia will earmark a maximum of $200,000 to be used to remediate those typical obstacles to providing weatherization measures such as the existence of knob and tube wiring and moisture issues, both of which prevent insulation from being installed. The Company is currently seeking eligible customers for this program.

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 2020 includes:

- Implemented the ability for customers to make bill payments via PayPal, PayPal Credit, Amazon Pay, and Venmo.
- Enhancements to Paperless Billing enrollment process to make it easier for to customers to enroll on the website, during online account registration, and on the phone with a Customer Service Representative.
- Launched a new Bill and Payment Alerts program so customers can receive bill reminders and payment confirmations via email or text message.
- Launched a new usage information page to provide customers with more information about their account's energy usage and compare month/month gas usage.

- Various usability enhancements to allow customers to more easily navigate our website platform on mobile devices.
- Ensured pre-login content on Columbia's website was able to be translated into the following languages: Chinese, French, German, Japanese, Korean, Portuguese, Spanish.
- Provided customers frequent communications and updated website content with relevant safety messaging and protocols for COVID-19.
- Implementing a new Interactive Voice Recognition Unit at the Customer Care Center which will enable customers to interact more easily using natural language commands.

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

A. Yes, the Company along with the other operating Companies in NiSource have adopted a Safety Plan for 2021. 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 will include new processes, training, tools and support all of which are designed to improve safety and eliminate high-consequence events. Some of the new processes being implemented under the Safety Plain include:

- "Daily Acknowledgment Process", under which field employees must acknowledge - before they do work each day - that they have completed a pre-job brief to identify risk and hazards associated with the work they are going to perform; that they have all necessary operator qualifications to perform the work they are going to do; and that they are familiar with the applicable gas standards that apply to the work they are going to do. The Daily Acknowledgement serves as a daily reminder and checklist for employees, and employees are expected to stop work if they are not familiar with the gas standards governing the work that needs to be performed or they do not have the appropriate operator qualification.

- "Critical Process Review", under which employees will review and verify their understanding of their comprehension of the policy and procedures, operational notices, and gas standards associated with the most critical processes employees perform every day, including but not limited to: purging gas mains and services, pressure configuration control; work zone setup; locating and marking underground facilities; tie-ins; and customer relights. This Critical Process Review started at the beginning of 2021 and will continue through the middle of the year.
- "Quality Control Audit Plan/Quality Assurance Audit Plan" under which a field quality control audit plan and a quality assurance audit plan will be created based on the selected Critical Processes. The plans will include metrics, reporting and Quality Management System process owners.

- "Process Safety Reviews" under which we will provide resources and plans to perform process safety reviews for all selected critical processes in order to verify the ability to "fail safely" and/or whether we need to add additional layers of protection.

In addition to these new processes, the Company is providing additional support to employees to further promote safe behavior and results. Some of the support for employees under the new Safety Plan includes:

- "Supporting Field Materials" in which we will review, refresh and supplement materials used by employees to support the critical processes, such as Policies and Procedures, Operational Notices, Standard Operating Procedures (SOPs), special instructions and checklists.
- "Refresher Training", in which we will develop, plan and implement refresher training for applicable employees on all critical operations processes.
- "Performance Support Tool Utilization" in which we will provide additional support on the use of the electronic "Performance Support Tool" application which contains all of the necessary policies and procedures, gas standards, operation notices and other important information pertaining to the critical processes and other gas standards. Our goal is to get the right information to the employee at the right time so

that the employee has the information and confidence necessary to do the job right.

The 2021 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, we provide funding to organizations that assist people in meeting their basic needs, such as food, clothing, and shelter. By partnering with community leaders and state, regional, and local economic development organizations, Columbia is working to attract new businesses and support the expansion of existing businesses, while helping to create more jobs across the area. Contributions made to the community by Columbia and its employees in 2020 include the following:

- United Way: Columbia employees pledge over $117,000 of their personal income to the United Way, in support of education, financial stability and community health.

- Community Donations: Columbia also donated[3] to approximately 120 different non-profit organizations throughout the 26-county and 450 community service area, where we deliver natural gas. Donations supported safety, economic and workforce development, environmental stewardship, STEM & energy education, basic needs and hardship assistance. We also provided $18,000 for the purchase of combination carbon monoxide and smoke detectors for a dozen communities throughout our service area, for which a portion of those funds went to first responders.
- Non-Profit Organizations: Columbia donated $430,000 to non-profit organizations, to help support and improve the quality of life for our customers and fellow community members. Examples of donations made in 2020 are as follows:
- American Red Cross: Columbia made a $110,000 donation to the American Red Cross in support emergency first response as a result of COVID-19
- Dollar Energy Fund: We also fundraised and increased our 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

[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.

relied on essential food donations, we donated thousands of dollars to local food banks.

- First Responder Training: When health and safety mattered most, we partnered with the Northeast Gas Association to provide a free, computer-based first responder natural gas safety training program. Through the program, we trained 117 local first responders on how to respond safely to natural gas emergencies

Q. Please explain Columbia's efforts in expanding the availability of natural gas throughout Pennsylvania.

A. In previous base rate proceedings, Columbia has proposed programs to expand the availability of natural gas in Pennsylvania, as follows:

- **Main and Service Extension and House Piping Credit:** In the Company's 2015 Rate Case, Docket No. R-2015-2468056, the Commission authorized three new business proposals to expand access to natural gas service. These new programs consist of the following: 150 foot main allowance per residential applicant; 150 foot service line allowance for residential customers in the geographic areas where the Company owns the service line; and, the house piping reimbursement program, which enables new residential customers to receive a limited reimbursement for gas piping in defined circumstances.
- **Large Customer Incentive Program:** In the Company's 2016 Rate Case, Docket No. R-2016-2529660, the Commission authorized Columbia's Large

Customer Incentive program. This program is available to applicants who are projected to use more than 64,400 therms annually and who are required to pay a deposit under the Company's main extension policy. The program allows for the customer to pay the deposit for the uneconomic portion of the expansion cost over a period of time, up to ten years. For customers who desire a repayment period over ten years, an up-front payment of 30% of the deposit would be required. In addition to the programs to expand natural gas availability noted above, Columbia's Sales and Marketing team is working with economic development agencies throughout our service territory to identify grants that may be available for new business expansion to help offset the costs of extending mains. The Pipeline Investment Program ("PIPE"), established by Governor Wolf in 2016, provides grants to construct natural gas distribution lines to business parks and existing manufacturing and industrial enterprises, which will result in the creation of new economic base jobs in the Commonwealth, while providing access to natural gas for residents. Applicants who are eligible for PIPE funding include businesses, economic development organizations, hospitals, municipalities, and school districts.

To date, Columbia has been an active participant in helping SEDA-COG Natural Gas Cooperative, Inc. obtain approval for a $1 million PIPE grant for the construction of a point of delivery ("POD") station located in Centre Hall Borough, part of Columbia's service territory. As a result of the installation of the POD, approximately 20,000 feet of gas pipeline was constructed through the currently unserved town of Centre Hall, to provide natural gas service to over 100 new customers, including residential and small commercial customers. The savings and efficiencies resulting from this project will allow Hanover Foods Corporation, a local business, to retain its current workforce of 150 full-time jobs. Construction was completed in June of 2020.

In addition, Columbia has worked with Glenn O. Hawbaker, Inc. to utilize their $1,000,000 PIPE grant to provide natural gas to their asphalt manufacturing plant as well as provide gas service to the unserved town of Barkeyville, Pennsylvania. The 35,000 foot pipeline extension is completed and is expected to provide service to at least 26 residential customers along the route.

Columbia will continue to explore opportunities with potential customers and economic development agencies to identify potential projects that may benefit from the PIPE grant program to bring natural gas to their facilities, and the communities in which they operate and we serve.

V. <u>INTRODUCTION OF WITNESSES</u>

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 Bell'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 Melissa Bell is a Lead Regulatory Analyst for NiSource Corporate Services Company ("NCSC"). In Columbia Statement No. 3, Company witness Bell 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, 2021 and for the twelve months ending December 31, 2022 (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 Nicole Shultz 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, 2022).
- 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 the Fully

Projected Future Test Year that are included in Columbia witness Miller's cost of service analysis.

- 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. Witness Harding also addresses the Company's proposed Federal Tax Reform Adjustment ("FTRA") rider.
- Company witness Chad Notestone is a Lead Analyst for NCSC. In Company Statement No. 11, he testifies about Columbia's allocated cost of service studies. Company witness Notestone 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 acceptance of renewable natural gas onto the Columbia system and the establishment of an FTRA 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, as well as Columbia's customer engagement efforts in response to COVID-19.

- 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 2020.

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.

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
Peoples Companies
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 Relationships and Cost Allocations				X	
Financial Management		X			
Gas Operations				X	
Customer Service			X		
Emergency Preparedness	X				
Human Resources		X			
Materials Management		X			
Information Technology	X				
Fleet Management			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 quantified potential annual cost savings of approximately $329,000 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
Peoples Companies
Focused Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Increase third-party line hit damage collection performance by transferring the responsibilities to the General Counsel to actively pursue and litigate damage claims.	**Peoples Gas:** $121,000 **Equitable Division:** $66,000	-
Expedite the implementation of a uniform Theft of Service (TOS) program for the Peoples Companies.	**Peoples Gas:** $54,000	
Study potential solutions to reduce arrearages and minimize write-offs.	**Peoples Gas:** $43,000	-
Implement Automated Meter Reading (AMR)/smart meter technology as planned to minimize meter reading and billing errors.	**Peoples Gas:** $35,000 **Peoples TWP:** $10,000	-
Subtotals by Company Peoples Gas Total Equitable Division Total Peoples TWP Total **Totals for All Companies**	 $253,000 $66,000 $10,000 $329,000	-

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 Peoples Companies 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.

E. Recommendation Summary

Chapters III through XIII 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 Peoples Companies should be able to initiate its implementation efforts given the Peoples Companies' 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 Peoples Companies 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. <u>Benefits</u>

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. <u>Recommendation Summary</u>

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. <u>Benefits</u>

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.

M. BARTOS

COLUMBIA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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I. Introduction

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 have not previously testified before the Pennsylvania Public Utility Commission, but 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, 2020 as the Historic Test Year ("HTY"), the twelve-month period ending November 30, 2021 as the Future Test Year ("FTY"), and the twelve-month period ending December 31, 2022 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 Melissa Bell's testimony (Columbia Statement No. 3) and Exhibit 003, Schedule 04. I will also explain the forecast methodology used to develop forecasted number of customers and usage for the FTY and the FPFTY. The results of the forecast are contained in Exhibit 010, Schedule 02.

II. Weather Normalization of Historical Test Year

Q. Please explain the weather normalization methodology.

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

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

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

Q. How is base usage determined?

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

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

A. The base use per customer per day is multiplied by the number of days ((base use/customer/day)*days in billing cycle) to produce monthly base use per customer. Temperature-sensitive use per customer equals the total use per customer minus the base use per customer. The temperature-sensitive use per customer is normalized for weather by multiplying it by a ratio of normal HDD to actual HDD. Normal use per customer is calculated by adding the base use per customer to the normal temperature-sensitive use per customer. Total monthly normalized usage is generated by multiplying monthly normal use per customer by the monthly customer count. This calculation for the HTY is prepared separately for residential and commercial customers and the results are presented in Exhibit 010, Schedule 08.

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

A. No, the methodology has not changed since Columbia's last rate filing. However, the historical average HDD have been updated to include the most recent 20-year history (i.e., 20 years ended December 31, 2020). The previous base rate case filing defined normal weather as the 20-year average ending in 2019. 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 2020 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 70% of the most recent 37 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 37-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 2020. 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 31 out of the 33 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

	Mean Absolute Error		Frequency of Lowest Absolute Error	
1984-2020	301	330	26	11

	Relative Frequency of Lowest Absolute Error	
1984-2020	70%	30%

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	

	Mean Absolute Error		Frequency of Lowest Error	
1988-2020	-1005	-1355	31	2
2011-2020	-592	-992	10	0

Relative Frequency of Lowest Error

1988-2020	94%	6%
2011-2020	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 1984-2020
Absolute Values
Columbia Gas of Pennsylvania

	20-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	7.0%
Maximum	1.4%	0.8%	19.6%

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

A. Demand Forecast Methodology Overview

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

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

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

A. I use the Company's billing records through November 2020 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 non-manufacturing equipment) 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.

Q. How are the economic effects associated with COVID-19 incorporated into the forecast?

A. Data indicates that COVID-19 had three identifiable impacts on customer counts and usage. First, on a very short-term basis, the shut-downs associated with COVID-19 appear to have affected use per customer for some classes in the spring and early summer of 2020. These short-term impacts are addressed when necessary by including a dummy variable[1] in the econometric model to account for specific months in 2020 in which the use per customer significantly differed from what would have been expected absent the shut-downs. These impacts on use per customer are not expected to persist into the FTY and FPFTY as the most significant shut-downs are largely over. Therefore, it is not necessary to make additional adjustments to the forecast associated with impacts on use per customer associated with the temporary COVID-19 shut-downs.

Second, prohibitions on terminations of customers (i.e., moratoriums on customer shut-offs) due to the economic effects of COVID-19 ("COVID-19 Moratoriums") affected customer counts starting in the spring of 2020 and continue to affect customer counts. As will be described in more detail below, FTY residential and commercial customer counts were adjusted to capture the impacts of the ongoing COVID-19 Moratorium that were not captured by the econometric models, but FPFTY customer counts were not adjusted as it is anticipated that customer counts will return to expected levels before the start of the FPFTY.

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[1] In this case, a dummy variable (or indicator variable) is an independent variable that represents a time-related event. The dummy variable equals 1 when the specific time-related event occurs and equals 0 outside of that specific time. The coefficient on the dummy variable is determined through the econometric modeling process. Statistical results associated with the econometric model identify whether the dummy variable is significant.

Third, shut-downs and changes in consumer activity associated with COVID-19 affected the local and national economy, which in turn affects natural gas customers and usage. For example, unemployment spiked in the spring of 2020, and while unemployment has declined from the peak, it is currently expected to take time for employment levels to return to pre-COVID levels. The economic impacts associated with COVID-19 are incorporated into the FTY and FPFTY forecast through the use of economic independent variable data. Historical and forecasted economic data series used in the econometric models reflect the economic outlook of IHS Global Insight as of December 2020. Therefore, short term and long term COVID-19 economic impacts on customer counts and usage are incorporated in the forecasts produced by the econometric models and the forecasts do not require further adjustment to account for economic conditions related to COVID-19.

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, several monthly variables for shaping, and a trend. As described above, residential customer counts in 2020 were affected by the moratorium on customer shut-offs due to the economic impacts of COVID-19. As shown by the orange line in Figure 4 below, residential customer counts typically are highest in the winter and decrease in the summer as customers are shut-off, (i.e., removed or terminated) for non-payment or other reasons. The prohibition on terminations that the Public Utility Commission ordered in March 2020 resulted in residential customer counts that remained at higher-than-normal levels throughout the remainder of 2020. Termination procedures will resume at the end of this winter (i.e., April 1, 2021) because the Commission has lifted the ban on terminations due to COVID, and the typical winter moratorium will end at that time. From a modeling perspective, dummy variables are added to the residential customer count model for each month of April 2020 through November 2020 (the end of the historical data set) to account for the fact that the customer count data for this period does not reflect normal business conditions. These dummy variables essentially eliminate the impact of the COVID-19 Moratorium on the econometric model and result in a forecast that does not include the effects of the COVID-19 Moratorium, illustrated by the green "Raw Model Output" line on the graph in Figure 4.

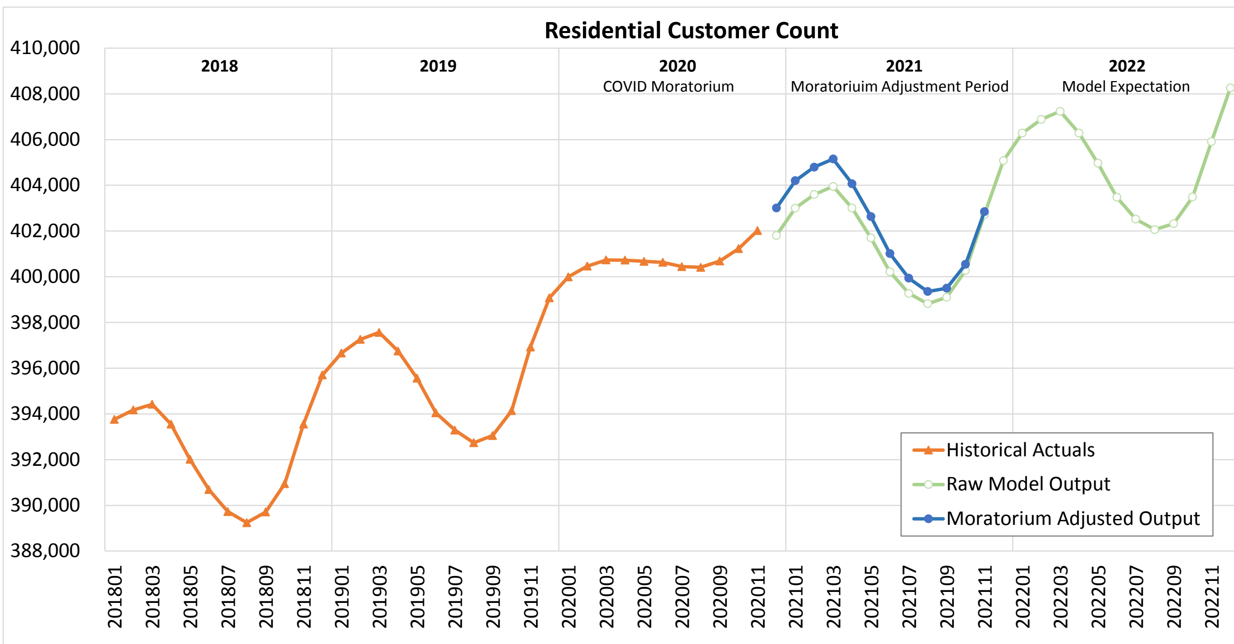
Q. How is the COVID-19 Moratorium accounted for in the residential customer forecast?

A. The residential customer forecast is based on the moratorium on shut-offs remaining in place through March 31, 2021, therefore, the residential customer count forecast produced by the econometric model for the months of December 2020 through March 2021 is increased by 1,200 customers (approximately 0.3%) to account for the additional residential customers that are estimated to be on the system as a result of the COVID-19 Moratorium, as shown by the blue line in the graph in Figure 4. This is not based upon a specification of individual customers that would have been terminated, but represents an estimation of the additional residential customers who currently are being served by Columbia above the customer count that would have been anticipated but for the COVID-19 Moratorium. The level of the residential moratorium adjustment is based on 2020 monthly customer counts compared to previous years, the values of the April 2020-November 2020 dummy variables in the econometric model, and 2017-2019 levels of final terminations at the end of the year (i.e., after restorations related to dormant account survey).

Q. Please explain how the adjustment for the moratorium on shut-offs associated with COVID-19 is phased out of the forecast.

A. The Company will not terminate all qualifying customers effective April 1, 2021. The Company will require several months to communicate with customers who are behind on their bills to work with the customers to develop payment arrangements as required per the order issued on March 18, 2021 at Docket M-2020-3019244 and identify newly-available assistance funding and to execute its termination process and procedures in compliance with Commission-approved processes. It is expected that over time the differential of 1,200 additional residential customers will phase out as termination procedures are reinstated and the normal cycle of customer counts will return. Given the information available at this time, it is estimated that customer counts will return to normal business conditions (i.e., the 1,200 additional residential customers that were assumed to be associated with the COVID-19 moratorium will be addressed) by December 2021. Therefore, adjustments are necessary for the remainder of the FTY to account for the gradual reduction of the 1,200 residential customer differentials resulting from the COVID-19 Moratorium. For the purposes of the customer count forecast for the FTY, it is assumed starting in April 2021 the 1,200 residential customer increase is reduced by an equal proportion, such that by December 2021 no adjustment is made, and the forecast returns to the levels produced by the econometric model as shown in the blue line in Figure 4. The adjustments associated with the COVID-19 moratorium only affect the months of December 2020-November 2021, so only the FTY is impacted. The FPFTY customer count forecast is the unadjusted forecast resulting from the econometric model.

Figure 4



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. As described above, residential use per customer was temporarily affected by the shut-downs associated with COVID-19. From a modeling perspective, a dummy variable was added to the residential use per customer count model for the month of April 2020 because data indicates that residential use per customer was significantly affected in that month. This dummy variable essentially eliminates the impact of the short-term COVID-19 shut-downs on the econometric model and results in a forecast that does not include these short-term effects.

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 is 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.

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 non-manufacturing employment levels and several monthly variables for shaping. As described above, commercial customer counts in 2020 were also significantly affected by the moratorium on customer shut-offs due to the economic impacts of COVID-19. As shown by the orange line in Figure 5 below, commercial customer counts typically are highest in the winter and decrease in the summer as customers are shut-off, (i.e., removed or terminated) for non-payment or other reasons. The prohibition on terminations that was ordered by the Public Utility Commission in March 2020 resulted in commercial customer counts that remained at higher-than-normal levels throughout the remainder of 2020. As I mentioned earlier in my testimony, shut-offs are permitted to resume on April 1, 2021. From a modeling perspective, dummy variables are added to the commercial customer count model for each month of April 2020 through November 2020 (the end of the historical data set) to account for the fact that the customer count data for this period does not reflect normal business conditions. These dummy variables essentially eliminate the impact of the moratorium on shut-offs in the econometric model and result in a forecast that does not include the effects of the moratorium on shut-offs, illustrated by the green "Raw Model Output" line on the graph in Figure 5.

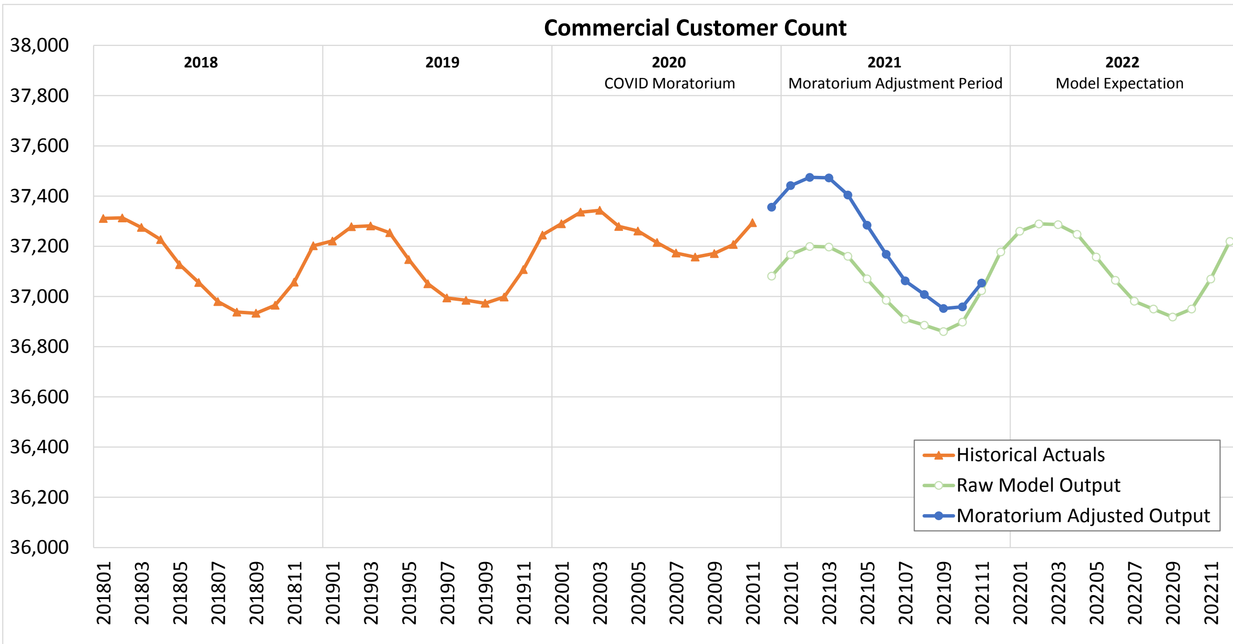
Q. How is the COVID-19 Moratorium accounted for in the commercial customer forecast?

A. Consistent with the residential analysis described above, it was assumed that a moratorium on shut-offs would remain in place through March 31, 2021, therefore, the commercial customer count forecast produced by the econometric model for the months of December 2020 through March 2021 is increased by 275 customers (approximately 0.7%) to account for the customers that are estimated to be on the system as a result of the COVID-19 Moratorium, as shown by the blue line in the graph in Figure 5. Again, this is not based upon a specification of individual customers that would have been terminated, but represents an estimation of the additional commercial customers who currently are being served by Columbia above the customer count that would have been anticipated but for the COVID-19 Moratorium. The level of the moratorium adjustment is estimated by reviewing 2020 monthly customer counts compared to previous years and the values of the April 2020-November 2020 dummy variables in the econometric model.

Q. Please explain how the adjustment for the COVID-19 Moratorium is phased out of the forecast.

A. Consistent with the residential adjustment the COVID-19 Moratorium described above, for the purposes of the customer count forecast for the FTY, it is assumed starting in April 2021 the 275-customer increase is reduced by an equal proportion each month, such that by December 2021 no adjustment is made, and the forecast returns to the levels produced by the econometric model as shown in the blue line in Figure 5. The adjustments associated with the COVID-19 Moratorium only affect the months of December 2020-November 2021, so only the FTY is impacted. The FPFTY customer count forecast is the unadjusted forecast resulting from the econometric model.

Figure 5



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. As described above, commercial use per customer was temporarily affected by the shut-downs associated with COVID-19. From a modeling perspective, a dummy variable is added to the commercial use per customer count model for each of the months of April, May, June, and October 2020 because commercial use per customer was significantly lower than expected during these months. This dummy variable essentially eliminates the impact of the short-term COVID-19 shut-downs on the econometric model and results in a forecast that does not include these short-term effects.

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. Industrial Forecast

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 customers 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.

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.
- 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".
- 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.

Demand Forecasting

- Filed expert testimony regarding the development of demand forecast models and the evaluation of natural gas resource plans for several 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.
- Evaluated demand forecasts and produced alternative demand forecasts in the context of due diligence support for several asset transactions.
- 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 and testified in support of several marginal cost studies filed in rate cases for several 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.

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.A., 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
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
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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				
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

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
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
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

M. BELL

COLUMBIA STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. Melissa J. Bell, 290 West 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"), as a Lead Regulatory Analyst.

Q. What are your responsibilities as Lead Regulatory Analyst?

A. My responsibilities include providing support for regulatory filings for several NiSource Inc. operating companies, including, but not limited to, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"), Columbia Gas of Ohio ("COH"), Columbia Gas of Maryland ("CMD"), Columbia Gas of Kentucky ("CKY"), and Columbia Gas of Virginia ("CVA"). The types of filings include earnings tests, monthly gas cost adjustments, infrastructure replacement, annual uncollectible expense and percentage of income payment plan adjustments, as well as tariff updates. I also provide audit support, rate entry and verification, and other duties as assigned.

Q. What is your educational and professional background?

A. I graduated from The Ohio State University with a Bachelor of Science Degree in Marketing in 1993. I began my career in the energy industry in 1996 when I joined Columbia Gas of Ohio as a Customer Service Representative, before moving on in 1997 to COH's New Business Team as a Project Expediter. In 1999, I left COH for a position at UtiliCorp Energy Solutions as a Commercial Account Executive, until the sale of UtiliCorp Energy Solutions to Exelon Energy was completed in 2000. At that time, I joined CSC Energy Solutions as a Tariff Analyst until February 2003. In March 2003, I was employed by NCSC in the Gas Transportation Services ("GTS") Department as a GTS Analyst II, providing sales support to Major Account Representatives for Columbia, CMD and CVA, as well as support to Natural Gas Suppliers and their customers. In December 2005, I accepted a position as a Senior Regulatory Analyst in NCSC's Regulatory Strategy and Support Department. I was promoted to my current position as Lead Regulatory Analyst in 2010. I have attended ratemaking workshops provided by the Southern Gas Association, Deloitte LLP, Financial Accounting Institute and Regulatory Research Associates.

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

A. Yes. I testified before the Pennsylvania Public Utility Commission ("Commission") in Columbia's previous base rate proceedings, at Docket Nos. R-2020-3018835, R-2016-2529660, R-2014-2406274, and R-2012-2321748, and in a formal complaint proceeding during my tenure as a GTS analyst. I have also submitted testimony in CMD's base rate proceedings, Case Nos. 9644, 9609, 9447, 9417 and 9316; in CKY 2016 base rate proceeding, Case No. 2016-00162; and Columbia Gas of Massachusetts's 2015 base rate proceeding, D.P.U. 15-50.

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 rate base, allocated cost of service, and revenue and rate design proposals.

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 which support Columbia's proposed increase in base rates, as illustrated in Exhibit 102 Schedule 3, Page 3, based on pro forma revenues for the twelve months ending December 31, 2022 (which is the Fully Projected Future Test Year, or "FPFTY"). These exhibits were compiled in accordance with the Commission's regulations under Title 52 Pennsylvania Code Section 53.51 et. seq., regarding Information Furnished With the Filing of Rate Changes. I will also 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 01-04
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 MJB-1	Calculation of the Merchant Function Charge
Exhibit MJB-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, 2020. 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, 2021, which is the most recent available at the time the schedules were developed. The Merchant Function Charge ("MFC") rate (please refer to Exhibit MJB–1, attached to this testimony) was updated to reflect the January 1, 2021 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 MJB-2, attached to this testimony, compares Account 487 revenue to total billed revenue for the three years ending November 2017, November 2018 and November 2019, 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 MJB-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 MJB-2, pages 2 and 3 respectively.

Q. Why is the Company not using data from the Twelve Months Ended November 30, 2020 as a part of the three year average?

A. As stated by Company Witness Miller, the Company determined that 2020 data is highly irregular and should not be used for determining annualized Forfeited Discounts. The irregular results are due to the COVID-19 Pandemic and the associated Emergency Order issued by the PUC on March 13, 2020. In response to the Pandemic and the Emergency Order, the Company suspended billing and collection of forfeited discounts, or late payment charges, on customer's late and unpaid bills. This action has caused the level of forfeited discounts billed during the HTY to be extremely low compared to previous years, and is therefore not appropriate to use in calculation of determining the normal levels of forfeited discunts.

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, 2020. 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, 2021. Column 3 shows a summary of Rider USP at present rates in effect as of January 1, 2021. 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 Chad E. Notestone.

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, 2021

Line No.	Description	Reference		Rate $	
1	PGCC Rate	Exhibit 1-A, Schedule 1, Page 1, Col. 3, Line 5 (1/01/2021 Quarterly GCR Filing)		1.7679	
2	Total Commodity Cost of Gas			**1.7679**	per Dth
3	Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 27, Line 7	0.0152077		
4	Non-Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 27, Line 14	0.0030875		
5	Merchant Function Charge - Residential Sales Service	(Line 4 x Line 5)		0.0269	per Dth
6	Merchant Function Charge - Small General Sales Service	(Line 4 x Line 6)		0.0055	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, 2020

Line No.		12 Mos November 2017	12 Mos November 2018	12 Mos November 2019	Total 3 Year Average	
1	Per Books Acct 487	$ 1,082,094	$ 1,130,923	$ 1,080,703	$ 3,293,720	
2	Per Books Billed Revenue	$ 534,990,949	$ 584,115,062	$ 602,529,915	$ 1,721,635,926	
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2023%	0.1936%	0.1794%	0.1913%	
4	Historic Test Year Sales Revenue (Ex. 3, Page 10, Column 7, Line 6)					$ 464,529,949
5	Historic Test Year Revenue -Transportation Revenue (Ex. 3, Page 10, Column 7, Line 9)					$ 182,170,428
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$ 646,700,377
7	3 Year Average					0.1913%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$ 1,237,138
9	Historic Test Year Acct 487 (Ex. 3, Page 9, Column 1, Line 7)					$ 502,806
10	Annualization Adjustment (Line 8 - Line 9)					$ 734,332

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2021

Line No.		12 Mos November 2017	12 Mos November 2018	12 Mos November 2019	Total 3 Year Average	
1	Per Books Acct 487	$ 1,082,094	$ 1,130,923	$ 1,080,703	$ 3,293,720	
2	Per Books Billed Revenue	$ 534,990,949	$ 584,115,062	$ 602,529,915	$ 1,721,635,926	
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2023%	0.1936%	0.1794%	0.1913%	
4	Future Test Year Sales Revenue (Ex. 103, Page 11, Column 8, Line 5)					$ 475,173,151
5	Future Test Year Transportation Revenue (Ex. 103, Page 11, Column 8, Line 8)					$ 180,251,461
6	Total Sales and Transportation Revenue (Line 4 + Line 5)					$ 655,424,612
7	3 Year Average					0.1913%
8	Annualized Forfeited Discounts (Line 4 * Line 6)					$ 1,253,827
9	Future Test Year Acct 487 (Ex. 103, Page 10, Column 1, Line 6)					$ 1,237,138
10	Annualization Adjustment (Line 7 - Line 8)					$ 16,689

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending December 31, 2022

Line No.		12 Mos November 2017	12 Mos November 2018	12 Mos November 2019	Total 3 Year Average	
1	Per Books Acct 487	$ 1,082,094	$ 1,130,923	$ 1,080,703	$ 3,293,720	
2	Per Books Billed Revenue	$ 534,990,949	$ 584,115,062	$ 602,529,915	$ 1,721,635,926	
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2023%	0.1936%	0.1794%	0.1913%	
4	Fully Projected Future Test Year Sales Revenue (Ex. 103, Page 15, Column 8, Line 5)					$ 483,085,572
5	Fully Projected Future Test Year Transportation Revenue (Ex. 103, Page 15, Column 8, Line 8)					$ 176,847,118
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$ 659,932,690
7	3 Year Average					0.1913%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$ 1,262,451
9	Fully Projected Future Test Year Acct 487 (Ex. 103, Page 14, Column 1, Line 6)					$ 1,253,827
10	Annualization Adjustment (Line 8 - Line 9)					$ 8,624

K. MILLER

COLUMBIA STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

March 30, 2021

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 and R-2020-3018835, 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, 2022 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, 2020 as the "historic test year" or "HTY", the twelve month period ending November 30, 2021 as the "future test year" or "FTY" and the twelve month period ending December 31, 2022 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, 2022 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 $98,278,240 based upon pro forma revenue requirement for the twelve months ending December 31, 2022. Columbia's computation of the revenue deficiency reflects total rate base of $2,673,012,065. 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. <u>HTY – Exhibit 2 – Statement of Income</u>

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, 2020. 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 Bell (Columbia Statement No. 3) and are included on lines 1 through 12. Company witness Bell 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 Shultz (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 7.88% 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 $183,197,648 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, 2018) and Column 2 (twelve months ended November 30, 2019).

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 767 active Columbia employees as of November 2020. 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 $1,634,532 as calculated in Schedule 2, Page 1, Line 5, and a downward lobbying adjustment of $5,827 to remove labor relating to lobbying on Line 6, resulting in a total labor annualization and normalization adjustment of $1,628,705 is added to the actual HTY labor expense level of $36,383,823 in Schedule 1, Page 2. Total Pro Forma HTY labor expense level is $38,012,528 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 $260,629 was increased by $1,640,296 to reflect the actual level of expense associated with incentive compensation paid in 2020. 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. <u>OPEB – Other Post Employment Benefits</u>

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 $665,789 to reflect an adjusted expense level of $0, which matches the amount recovered in revenues. It is important to note that the OPEB credit amount is an accounting calculation, and the Company did not actually receive a credit payment.

E. <u>Outside Services</u>

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

Q. Please describe the ratemaking adjustment for Outside Services.

A. Ratemaking adjustments have been made to Outside Services to remove non-recoverable consulting costs associated with Lobbying and to remove non-recurring outside consultant and legal fees associated with Columbia's previous base rate case, Docket No. R-2020-3018835.

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

Exhibit 4: *Schedule 1, Page 2, Lines 8 & 9; Schedule 2, Page 9*

Q. How were Rents and Leases adjusted for the HTY?

A. Rents and leases were first separated into a) rents and leases related to buildings, and b) other rents and leases including communications equipment and lines, office machines and furnishings. Rents and leases attributable to contractual levels for buildings were annualized on Exhibit 4, Schedule 2, Page 9 for a total of $2,475,857. This amount was then reconciled with the per book test year level of $2,406,373. The resulting adjustment is an increase of $95,067. 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 $473,846 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. Injuries and Damages

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 $403,860 represents an amount including both actual experience and adjustments to an injury and damages accrual account. A downward adjustment of $45,689 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. Employee Expenses

Exhibit 4: *Schedule 1, Page 2, Line 12; Schedule 2, Page 12*

Q. Was an adjustment made for employee expenses?

A. Yes. Downward adjustments of $81,759 and $5,827 were made to the HTY to remove certain employee expenses which Columbia is not seeking to include for recovery in this proceeding. Detail supporting this adjustment is shown on Exhibit 4, Schedule 2, Page 12.

J. Company Memberships

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 $13,547 were made to first remove expenses inadvertently recorded in the historic test year for Columbia related to another NiSource affiliate. Next, annualization adjustments were made for the American Gas Association dues reflective of the payments made relating to calendar year 2020. Column 2, Line 31 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. Utilities and Fuel Used in Company Operations

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 $310,995 is made to recognize inclusion of this amount as both recovery of gas cost and gas purchase expense by Company witness Bell. Columbia includes the expenses associated with gas used in company operations when establishing its gas cost recovery rates. The purchased gas is recorded as system supply and then reclassified from gas purchase to O&M expense. Therefore, it is necessary to remove the amount above from O&M for the purposes of calculating base rates and appropriately show this same level of expense in gas purchase expense along with an offsetting gas recovery level. The remaining historic test year level of $2,207,819 represents other utility costs, such as electric and telecommunications (internet service, cell phones, land lines, etc.), not recovered through the 1307(f) process.

L. Advertising

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

Q. Was advertising adjusted?

A. Yes. Columbia has made an adjustment to remove the expenses associated with its advertising that do not represent a recoverable operating expense. The Company has removed $189,502 of brand advertising from HTY costs. Please see Exhibit 4, Schedule 2, page 15 for details.

M. Materials and Supplies

Exhibit 4: *Schedule 1, Page 2, Line 17; Schedule 2, Page 16*

Q. Was material and supplies adjusted?

A. Yes. Columbia has made an adjustment to remove lobbying-related materials and supply expenses $4,107. Please see Exhibit 4, Schedule 2, page 16 for details.

N. Other O&M

Exhibit 4: *Schedule 1, Page 2, Line 18; Schedule 2, Page 17*

Q. Was other O&M adjusted?

A. Yes. Columbia has made an adjustment to HTY Other O&M Expenses to remove non-recurring costs relating to NiSource Next totaling $2,239,070. Please see the testimony of Company witness Mark Kempic for further details for NiSource Next. Please see Exhibit 4, Schedule 2, page 17 for details.

O. Commission, OCA and OSBA Assessments

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

Q. Please explain the $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 $2,008,792 reflects the most recent invoice amount (September 10, 2020) received as of the submission of this base rate filing.

P. NiSource Corporate Services Company ("NCSC")

Exhibit 4: *Schedule 1, page 2, Line 20; Schedule 2, pages 19-22*

Q. Please explain the structure and role of NCSC.

A. NCSC is a subsidiary of NiSource and an affiliate of Columbia within the NiSource corporate organization. NCSC 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 2020;

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 $60,507,456.

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 15 reflect adjustments made to the actual HTY O&M expense as follows:

Line 4 – Adjusts the NCSC Incentive Compensation to the level paid in 2020 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 15.

Lines 6 – 11 – Non-Recoverable Items that were included in the HTY are removed in the pro forma HTY expense claim.

Lines 12 - 15 – Non-Recurring Items that were included in the HTY are removed in the pro forma HTY expense claim.

Q. <u>NCSC OPEB Amortization</u>

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 in June 2023.

R. <u>Charitable Contributions</u>

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. Rate Case Expense Normalization

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. The approved rates from the Company's last base rate case include an amount for recovery of rate case expenses. Actual rate case expense incurred during the HTY for the Company's prior base rate case has been removed from the pro forma HTY expense and are detailed in lines 1 through 4. 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 4, Schedule 2, and Page 25. The Company is using a one year normalization period due to prior base rate case filing experience and the expectation of future base rate case filings.

T. Uncollectible Accounts Expense

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 has been developed on Exhibit 4, Schedule 2, Page 26 for the HTY. 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. Has the Company made any changes to these two major categories of expense since its last base rate case?

A. Yes. The Company has determined that charge offs for CAP customers who failed to pay the expected payment amount and were no longer eligible for CAP were not being included in normal uncollectible expense and were not picked up in the calculation for the three year average write-off rate used for determining uncollectible expense. Therefore, these uncollectible amounts were not included in the normalized level of uncollectible expense in the Company's prior base rate cases causing the Company to understate the actual level of uncollectible expense.

Q. Please define "CAP expected payment".

A. The "CAP expected payment" is the total billed amount a CAP customer must pay in order to remain a participant in the CAP Program. If a CAP customer fails to make the required expected payment, then they no longer qualify to participate in the CAP Program. Subsequent to default of a CAP customer's expected payment and termination of eligibility in the CAP Program, their total cumulative expected payment amount (Accounts Receivable balance) is written-off as normal uncollectible expense.

Q. Aren't these costs being recovered through Rider USP?

A. No. Rider USP recovers CAP Program costs which include program application and administration costs, CAP pre-program arrearages forgiveness, and the portion of arrearages quantified as the CAP Shortfall (the difference between the total bill, excluding Rider CC and Rider USP, and the customer's CAP expected payment). Rider USP costs do not include recovery of charge-offs (uncollectible expense) related to a customer's default on their CAP expected payment. If a CAP customer fails to make the required expected payment, they no longer qualify to be in the CAP program and their expected payment amount, which includes the remaining balance of preprogram arrearages not yet forgiven, is written off as normal uncollectible expense.

Q. Has the Company missed picking up these amounts when determining the adjustment to Uncollectible Account Expense on Exhibit 4, Schedule 2 in past base rate proceedings?

A. Yes. The Company uses a three year average of the ratio of net charge-offs as compared to billed revenues. The charge-off process for CAP customers who fail to make their expected payment is different that the process for non-CAP customers and utilizes slightly different accounting. The key identifiers utilized for ratemaking are expense Account and Cost Element. FERC Expense Account 904 is the account used for booking all uncollectible expense. Cost Element 3250 is utilized for non-CAP customers and is included in line 25 of Exhibit 4, Schedule 1, labeled as "Uncollectible Accounts" and Cost Element 3251 is utilized for CAP customers and is included in line 28 of Exhibit 4, Schedule 1, labeled as "Total USP Rider". Prior to the discovery of this issue, when these specific CAP customers failed to pay their expected payment and were no longer eligible to be classified as a CAP customer, their unpaid "expected pay" amount was written-off by inadvertently using Cost Element 3251, Total USP Rider. Consequently, these write-offs were not included in the three year average of net charge-offs as a percentage of billed revenues.

Q. In previous base rate cases, what happened to these expenses from a rate making perspective?

A. From a ratemaking perspective, these costs were totally eliminated from the Company's Cost of Service.

Q. Please explain.

A. The "Per Books" expense for these costs rolled to the line labeled as "Total USP Rider". For ratemaking purposes, this line is adjusted to match the Revenues for Rider USP so that the impact to the Cost of Service for base rates is zero, however, since the revenue for these expected payments are not included in Rider USP, the associated costs are simply eliminated. Also, as explained above, since they were not included in the process for determining the three year average experience for uncollectible expense, they were never included for recovery through either base rates or Rider USP.

Q. How is the Company proposing to fix this issue?

A. The Company has started to use Cost Element 3250 for writing-off these receivables and has updated the data that is used to determine the three-year average uncollectible expense ratio to now include the write-offs for these type of customers.

Q. Please can you provide the impact of this change to Normalized Uncollectible Expense for the HTY?

A. Yes. The three year average write-off rate is 0.0129153 and includes the write-offs of expected payments that were determined to be uncollectible. The rate without these write-offs would have been 0.0113537. When applying the difference in rates to FPFTY Annualized DIS Revenues adjusted of $583,380,065 (Exhibit 104, Schedule 2, Page 17, and Line 16) the result is $911,026.

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 data from the Twelve Months Ended November 30, 2017, 2018 and 2019 to determine an uncollectible experience factor to produce normalized uncollectible expense for this the HTY, FTY and FPFTY.

Q. Why is the Company not using data from the Twelve Months Ended November 30, 2020 as a part of the three year average?

A. The Company has determined that 2020 data is highly irregular and should not be used for determining normalized uncollectible expense. The irregular results are due to the COVID-19 Pandemic and the associated Emergency Order issued by the Pennsylvania Public Utility Commission "Commission" on March 13, 2020, at Docket No. M-2020-3019244, which prohibited regulated utilities from terminating service during the pendency of the Pandemic. The action of this Order, to prohibit terminations, and their subsequent write-off of customer accounts due to non-payment, has caused the level of net charge offs during the HTY to be extremely low compared to previous years, and is therefore not appropriate to use in a calculation for determining normal levels of uncollectible Expense.

Q. Has Columbia been deferring incremental Uncollectible Expense relating to COVID-19 as permitted by the Commission's March 13th Order?

A. Yes. During the HTY, Columbia deferred $2,282,078 of incremental Uncollectible Expense to a Regulatory Asset.

Q. Has Columbia filed a notice as required by the Secretarial Letter?

A. Yes, Columbia file this notice on July 10, 2020.

Q. How has the Company determined incremental Uncollectible Expense?

A. The Company used data from R-2018-2647577, and attached as Exhibit KKM-1, to determine a baseline level of recovery for Uncollectible Expense as the FPFTY level of Uncollectible Expense per Ex. 104, Sch. 2, Page 21, $4,733,676, plus Uncollectible Expense Associated with the Settled Revenue Increase of $26 million, using the three year average write-off rate of 0.01191, or $309,539, for a total of $5,043,215 assumed to be recovered annually through base rates. Uncollectible amount in excess of this were deferred to a regulatory asset for future recovery.

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

A. Yes. I discuss this further in my testimony in section labeled as "Other Adjustments".

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, 2017, 2018 and 2019 for this proceeding for reasons explained above. 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 Bell (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 Bell 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 $1,213,673 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, 20. 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. Rider USP Costs

(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 $25,955,332 for the normalized HTY as determined by Company witness Bell. Consequently, the adjustment reflects changes that are necessary to match the expense with the revenues supported by Company witness Bell. As a result, the Rider USP net impact to operating income is zero with the expense offsetting revenues. Therefore, Rider USP costs do not impact the base rate increase requested in this case.

W. Interest on Customer Deposits

Exhibit 4: *Schedule 1, Page 2, Line 29; Schedule 2, Page 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. <u>FTY/FPFTY – Exhibit 102 – Statement of Income</u>

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

$98,278,240 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 $98,278,240 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 has been recalculated and reflects differences in the tax net operating loss positions. The Federal Income Tax rate is applies 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). 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 Adjustments" and "Rate Making Adjustments" for both the FTY and the FPFTY. Company witness Paloney is supporting all budget adjustments, 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 budget adjustments 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 Budget Adjustments & References (Columns 2 and 3) that adjust from the Normalized HTY to the Budgeted FTY (Column 4) which is supported by Company witness Paloney. Columns 5 and 6 provide Rate Making Adjustments and References, followed by the Normalized FTY (Column 7). Similarly, Page 4 provides the details for the FPFTY, starting with the Normalized FTY (Column 1; from Page 3) followed by the Budget Adjustments & References (Columns 2 and 3) that adjust from the Normalized FTY to the Budgeted FPFTY (Column 4) which is also supported by Company witness Paloney. Columns 5 and 6 provide Rate Making Adjustments and References followed by the Normalized FPFTY (Column 7).

Pages 5 and 6 provide the monthly Budget Data for FTY (Page 5) and FPFTY (Page 6); supported by Company witness Paloney.

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 4, 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 28 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 Bell.
- 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 Bell.
- Line 27 – Interest on Customer Deposits – this item is not included in the O&M budget.
- Line 28 – Other Adjustments to the FPFTY O&M not in the budget.

Q. What types of adjustments are you proposing to O&M expense for the FTY and FPFTY?

A. I am proposing the following ratemaking adjustments to determine Pro Forma O&M Expense for the FTY and FPFTY, which I will explain in detail later on in my testimony:

a) Annualization of Company Labor;
b) Amortization of deferred non-recurring pension contribution;
c) Removal of the negative OPEB expense;
d) Outside Services adjustments;
e) Annualization of building rents and leases;
f) Injuries and Damages adjusted to reflect HTY plus inflation;
g) Removal of Employee Expenses;
h) Removal of fuel used in company operations;
i) Advertising adjusted to a normalized level of recoverable expense;
j) Removal of non-recurring expense for NiSource Next from Other O&M;
k) NCSC costs adjusted to annualize labor and remove non-recoverable items;
l) Removal of other lobbying expenses;
m) Normalization of rate case expense;
n) Adjust Uncollectible expense;
o) Adjust Rider USP expense to match revenue; 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 $504,421 and for the FPFTY of $430,280. 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 52.64% and 52.01%, respectively, which is the same percentage as used in the Budget for items that have been adjusted from gross amounts to net O&M expense. 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 $1,358,000 and $439,000, 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. Outside Services

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 includes a lobbying adjustment and an adjustment to remove non-recurring incremental expenses relating to COVID-19 (not relating to Uncollectible Expense). FPFTY only includes a lobbying adjustment.

E. Rents and Leases

Exhibit 104: *Schedule 1, Page 2, Line 8; Schedule 2, Pages 5 & 6*

Q. Please explain the adjustment to rents and leases for the FTY and FPFTY.

A. Known changes to building leases attributable to contractual levels were included on Exhibit 104, Schedule 2, Page 5 and 6 resulting in an increase of $137,855 for the FTY claim and an increase of $77,457 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 FPFTY includes the elimination of rents for Uniontown and Connellsville to reflect the construction of a new Company-owned facility for the Uniontown Operation Center.

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 $358,171 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, 2020.

G. <u>Employee Expenses</u>

Exhibit 104: *Schedule 1, Page 2, Line 12; Schedule 2, Page 8*

Q. Was an adjustment made for employee expenses?

A. Yes. The FTY and FPFTY expense levels for employee expenses were adjusted to remove non-recoverable employee expenses and lobbying by using the pro forma HTY adjustment of $87,586 plus applicable inflationary adjustments.

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

Exhibit 104: *Schedule 1, Page 2, Line 14; Schedule 2, Page 9*

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.

I. <u>Advertising</u>

Exhibit 104: *Schedule 1, Page 2, Line 15; Schedule 2, Page 10*

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 level of 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.

J. <u>NiSource Next Adjustment</u>

Exhibit 104: *Schedule 1, Page 2, Line 18; Schedule 2, Pages 11*

Q. Are you sponsoring an adjustment to Other O&M for NiSource Next?

A. Yes, Exhibit 104, Schedule 2, Page 11 includes an adjustment to remove non-recurring consulting fees for NiSource Next, that have been included in Other O&M budget for the FTY.

Q. Is a similar adjustment needed for the FPFTY?

A. No, Other O&M for the FPFTY does not include any non-recurring costs.

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

Exhibit 104: *Schedule 1, Page 2, Line 20; Schedule 2, Pages 12-14*

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, the FTY also includes an adjustment for a non-recurring item. Page 13 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 2020 through February 2021, 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 2022 through February 2022.

Page 14 determines adjustments for the removal of non-recoverable and non-recurring items. The non-recoverable adjustments are based upon the HTY level of expense, plus incremental adjustments that are produced by using inflation factors. The non-recurring adjustment removes costs for the FTY only (the FPFTY does not include non-recurring costs).

Q. Please explain the non-recurring costs that are being adjusted out of the FTY budget for NCSC.

A. I have proposed rate making adjustments to remove from the FTY budget, non-recurring expenses relating to NiSource Next and Incremental COVID-19 (non-uncollectible expense) in order to normalize the level of FTY expenses for NCSC.

L. <u>Other Lobbying Expense</u>

Exhibit 104: *Schedule 1, Page 2, Lines 13 & 17; Schedule 2, Page 15*

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.

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

Exhibit 104: *Schedule 1, Page 2, Line 23; Schedule 2, Page 16*

Q. Has Columbia included an adjustment for rate case expense?

A. Yes. Exhibit 104, Schedule 2, Page 16 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, outside counsel, and incremental costs associated with legal notices, employee expenses and materials & supplies. The entire rate case expense included for normalization is $1,060,000. Columbia proposes to normalize these costs over twelve months.

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

(Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

Exhibit 104: *Schedule 1, Page 2, Line 24 & 25; Schedule 2, Page 17*

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 $782,615 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 Bell. As a result, the net impact to operating income is zero and does not impact the base rate increase requested in this case.

O. Total Rider USP Costs

Exhibit 104: *Schedule 1, Page 2, Line 26; Schedule 2, Page 18*

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 $26,273,684 for the FTY and $26,432,574 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 Bell computes the increase to Rider USP resulting from the proposed rate increase.

P. Other Adjustments

Exhibit 104: *Schedule 1, Page 2, Line 28; Schedule 2, Page 19*

Q. Please explain the FPFTY other adjustments.

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

- Lines 1 through 10 – Amortization of Deferred COVID-19 Uncollectible Expense.
- Line 11 – Additional O&M Expense for Safety Management System (SMS) (supported by Company witness Curtis Anstead, Columbia Statement No. 14).

Q. Please describe the Company's proposal for recovering deferred Uncollectible Expense.

A. As explained earlier in my testimony, Columbia has been deferring incremental uncollectible expense as a result of the COVID-19 Pandemic, in accordance with the Secretarial Letter issued on May 13, 2020 at Docket No. M-2020-3019775. Columbia exceeded the baseline of annual recoveries for Uncollectible Expense in June of 2020 and made deferrals starting in June, through December 2020, totaling $5,579,245. Columbia is proposing to recover these deferrals over a 5 year period starting January 1, 2022, the beginning of the FPFTY. The resulting annual Amortization included in the FPFTY is $1,115,849.

Q. Is the Company planning on continuing to defer incremental Uncollectible Expense as the Pandemic and associated Emergency Orders continue to be in effect?

A. Yes. Currently, the Company plans to continue to defer incremental expense and plans to update the amount of amortization for this Regulatory Asset in a future base rate case proceeding, however, the Company is also evaluating when the appropriate time to cease this deferral is, based on the Commission's Order entered on March 18, 2020 in Docket M-2020-3019244.

Q. Is the Company planning on updating the deferral amounts to account for related recoveries or other true-up?

A. Yes. Columbia proposes that the Company be permitted to update this Regulatory Asset until the final impacts to customer accounts have been determined.

Q. Does this complete your direct testimony?

A. Yes, it does.

Exhibit No. 104
Schedule No. 2
Page 21 of 25
Witness : K.K. Miller

Columbia Gas of Pennsylvania, Inc.
FTY = Future Test Year TME 11/30/18, FPFTY = Fully Projected Future Test Year TME 12/31/19
Adjustment To Uncollectible Accounts Expense

Line No.	Description	Detail (1) $	Adjustment (2) $	Base Rate Uncoll (3) $	Unbundled Uncoll (4) $	
	FTY Adjustment					
1	**Normal Charge-Offs Recovered Through Base Rates (DIS Billed)**					
2	Total Annualized DIS Revenue	530,005,734				
3	Adjustments to Annualized Revenue:					
4	CAP Revenue Exh. 103, Sch. 1, Pg. 1, Ln. 24	29,093,389				
5	Annualized DIS Revenue adjusted (Ln 2 - Ln 4)	500,912,345				
6	Uncollectible Accounts Average Write-off Rate (Exh. 4, Sch. 2, Pg. 30)	0.0119054				
7	Total Annualized DIS Uncollectible Accounts	5,963,537	**5,963,537**			
8	Total Annualized GMB/GTS Revenue	38,876,217				
9	GMB/GTS 3 Year Average Write-off - Exh. 4, Sch. 2, Pg. 30, Ln. 22		**(66,153)**			
10	**Total FTY Annualized DIS & GMB/GTS Uncollectible Expense**		**5,897,384**	**4,688,161**	**1,209,223**	[1]
11	Total Per Budget			4,750,566	1,196,405	
12	Total FTY Adjustments for Uncollectible Expense			**(62,405)**	**12,818**	
	FPFTY Adjustment					
13	**Normal Charge-Offs Recovered Through Base Rates (DIS Billed)**					
14	Total Annualized DIS Revenue	534,561,779				
15	Adjustments to Annualized Revenue:					
16	CAP Revenue Exh. 103, Sch. 1, Pg. 11, Ln. 24	29,242,574				
17	Annualized DIS Revenue adjusted (Ln 14 - Ln 16)	505,319,205				
18	Uncollectible Accounts Average Write-off Rate (Exh. 4, Sch. 2, Pg. 30)	0.0119054				
19	Total Annualized DIS Uncollectible Accounts	6,016,003	**6,016,003**			
20	Total Annualized GMB/GTS Revenue	39,195,616				
21	GMB/GTS 3 Year Average Write-off - Exh. 4, Sch. 2, Pg. 30, Ln. 22		**(66,153)**			
22	**Total FPFTY Annualized DIS & GMB/GTS Uncollectible Expense**		**5,949,850**	**4,733,676**	**1,216,174**	[2]
23	Total Per Budget			4,688,161	1,209,223	
24	Total FPFTY Adjustments for Uncollectible Expense			**45,515**	**6,951**	

[1] Total Proposed Uncollectible Expense to be recovered in Exhibit 103, Page 11, Line 15, Col 5
[2] Total Proposed Uncollectible Expense to be recovered in Exhibit 103, Page 15, Line 15, Col 5

Assumed Recovery in Base Rate Only

FPFTY	4,733,676
Uncollectible Relating to Revenue Increase 1_/	309,539
	5,043,215
1_/ :	
Revenue Increase	26,000,000
Uncollectible Accounts Average Write-off Rate (Exh. 4, Sch. 2, Pg. 30)	0.01191
Uncollectible Relating to Revenue Increase	309,539

J. SPANOS

COLUMBIA STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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 34 years of depreciation experience which includes expert testimony in over 350 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, 2020. Exhibit No. 109, Schedule No. 1, Attachment A presents the results of the depreciation study as of November 30, 2021. Exhibit No. 109, Schedule No. 1, Attachment B presents the results of the depreciation study as of December 31, 2022. 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 "2020 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2020," includes the results of the depreciation study as related to the original cost at November 30, 2020. The report also includes the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment A, 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 estimated original cost at November 30, 2021. 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 "2022 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2022," includes the results of the depreciation study as related to the estimated original cost at December 31, 2022.

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, 2021, and December 31, 2022.

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 at November 30, 2021, estimated?

A. The book reserve at November 30, 2021, 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 at November 30, 2020. Annual accruals were estimated using the annual accruals calculated as of November 30, 2020. 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 at November 30, 2021.

Q. Was the book reserve at December 31, 2022, 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 2016 through 2020.

Table 1, pages V-4 through V-6 presents the estimated survivor curve, the original cost at November 30, 2021, and the book reserve and calculated annual depreciation for each account or subaccount of Gas Plant. Table 2, pages V-7 and V-8 presents the bringforward to November 30, 2021, of the book depreciation reserve as of November 30, 2020. Table 3 on pages V-9 and V-10 sets forth the calculation of the annual accruals used in the bringforward. Table 4, page V-11, presents the experienced and estimated net salvage during the five-year period, 2016 through 2020.

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-67 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, 2022. 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, 2022, are organized and presented in the same manner as those as of November 30, 2021.

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, 2020. 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, 2020, are organized and presented in the same manner as those as of November 30, 2021.

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 68 percent of the original cost of depreciable gas plant as of November 30, 2021.

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 at November 30, 2020, 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 at November 30, 2021, are presented by type main on pages VII-32 through VII-36 of Exhibit No. 109, Schedule No. 1, Attachment A and are based in part on the bringforward of the book reserve. Also, the calculations at December 31, 2022 are presented by type main on pages II-32 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-11 of Exhibit No. 109, Schedule No. 1, Attachment A and on page I-10 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 2015 through 2019 for the calculation as of November 30, 2020, and on experience during the period 2016 through November 30, 2020, plus estimates for the last month of 2020 for the calculation as of November 30, 2021.

The amortization for the December 31, 2022 calculation is based on experience during the period 2016 through November 30, 2020, plus estimates for the period December 2020 through December 2021. 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-10 of Exhibit No. 109, Schedule No. 1, Attachment B.

Q. Have you provided a monthly bringforward to December 31, 2022, of the plant and book depreciation reserve as of November 30, 2021?

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 inAugust 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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

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	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

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	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.		IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-19 / UG-19	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util. 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

	2021	2021			2022		
	NOV 30	DECEMBER			JANUARY		
Account	Begin. Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	1,932.08			1,932.08			1,932.08
351.00	3,250,036.96			3,250,036.96			3,250,036.96
352.01	738,941.36			738,941.36			738,941.36
352.02	168,031.87			168,031.87			168,031.87
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	3,691,925.24	44,898.43	2,721.18	3,734,102.49	6,881.30	1,088.47	3,739,895.32
374.50	3,233,171.42			3,233,171.42			3,233,171.42
375.34	5,935,978.81	87,926.10	5,328.99	6,018,575.92	13,475.87	2,131.59	6,029,920.20
375.60	86,227.87			86,227.87			86,227.87
375.70	27,196,440.89	5,057,623.57	64,078.65	32,189,985.81		5,092.16	32,184,893.65
375.80	16,515.17			16,515.17			16,515.17
376.00	2,181,044,480.41	47,219,010.84	2,434,993.00	2,225,828,498.25	6,892,778.46	2,021,695.60	2,230,699,581.11
378.00	126,103,757.33	1,750,661.72	55,397.83	127,799,021.22	206,725.60	31,198.45	127,974,548.37
379.10	135,966.90			135,966.90			135,966.90
380.00	695,122,581.39	15,183,268.78	702,974.78	709,602,875.39	2,614,466.98	562,474.46	711,654,867.91
381.00	41,638,535.60	228,445.69	16,288.87	41,850,692.42	37,015.67	6,888.34	41,880,819.75
381.10	24,820,375.62	40,313.95		24,860,689.57	6,532.18		24,867,221.75
382.00	42,452,170.64	282,482.01	17,120.55	42,717,532.10	45,519.13	7,200.15	42,755,851.08
383.00	18,993,073.78	192,974.61	11,695.72	19,174,352.67	26,701.25	4,223.57	19,196,830.35
385.00	7,811,445.82	205,784.48	12,472.10	8,004,758.20	31,539.27	4,988.84	8,031,308.63
387.00	136,698.14			136,698.14			136,698.14
387.40	11,443,998.08			11,443,998.08			11,443,998.08
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	2,285,833.24		168,329.10	2,117,504.14			2,117,504.14
391.11	91,303.67			91,303.67			91,303.67
391.12	2,692,531.12		747,863.29	1,944,667.83			1,944,667.83
392.00	25,616.89			25,616.89			25,616.89
394.00	18,382,788.16	280,428.13	2,741,889.36	15,921,326.93	60,067.97		15,981,394.90
394.12				0.00			0.00
395.00	266,039.42			266,039.42			266,039.42
396.00	948,698.04			948,698.04			948,698.04
397.50	1,677,225.06	234,033.08	14,184.17	1,897,073.97	33,116.24	5,238.28	1,924,951.93
398.00	953,269.70		8,228.13	945,041.57			945,041.57
303.00	32,302,002.60	2,010,695.67	461,200.23	33,851,498.04		55,010.40	33,796,487.64
303.60	9,051,102.42	3,664,304.33		12,715,406.75			12,715,406.75
375.71	5,607,225.91	192,958.91	61,565.77	5,738,619.05		4,892.46	5,733,726.59
Total Plant	**3,272,206,054.51**	**76,675,810.30**	**7,526,331.72**	**3,341,355,533.09**	**9,974,819.92**	**2,712,122.77**	**3,348,618,230.24**

Account	2022 FEBRUARY Additions	Retirements	Ending Balance	2022 MARCH Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
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	9,341.86	1,088.47	3,748,148.71	9,706.35	1,360.59	3,756,494.47
374.50			3,233,171.42			3,233,171.42
375.34	18,294.48	2,131.59	6,046,083.09	19,008.26	2,664.49	6,062,426.86
375.60			86,227.87			86,227.87
375.70		5,092.16	32,179,801.49		5,092.16	32,174,709.33
375.80			16,515.17			16,515.17
376.00	9,357,448.81	2,396,512.32	2,237,660,517.60	9,722,544.03	2,359,422.89	2,245,023,638.74
378.00	280,645.05	31,198.45	128,223,994.97	291,594.85	33,704.21	128,481,885.61
379.10			135,966.90			135,966.90
380.00	3,549,329.36	650,684.81	714,553,512.46	3,687,811.89	811,927.68	717,429,396.67
381.00	50,251.47	6,888.34	41,924,182.88	52,212.11	8,610.42	41,967,784.57
381.10	8,867.91		24,876,089.66	9,213.90		24,885,303.56
382.00	61,795.53	7,200.15	42,810,446.46	64,206.58	9,000.19	42,865,652.85
383.00	36,248.88	4,223.57	19,228,855.66	37,663.19	5,279.46	19,261,239.39
385.00	42,816.86	4,988.84	8,069,136.65	44,487.42	6,236.05	8,107,388.02
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	81,546.66		16,062,941.56	84,728.32		16,147,669.88
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	44,957.70	5,238.28	1,964,671.35	46,711.80	6,547.85	2,004,835.30
398.00			945,041.57			945,041.57
303.00		41,003.43	33,755,484.21		72,705.03	33,682,779.18
303.60			12,715,406.75			12,715,406.75
375.71		4,892.46	5,728,834.13		4,892.46	5,723,941.67
Total Plant	**13,541,544.57**	**3,161,142.87**	**3,358,998,631.94**	**14,069,888.70**	**3,327,443.48**	**3,369,741,077.16**

	2022			2022		
	APRIL			MAY		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
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	15,560.10	1,904.83	3,770,149.74	14,367.41	2,721.18	3,781,795.97
374.50			3,233,171.42			3,233,171.42
375.34	30,471.87	3,730.29	6,089,168.44	28,136.17	5,328.99	6,111,975.62
375.60			86,227.87			86,227.87
375.70		5,092.16	32,169,617.17		5,092.16	32,164,525.01
375.80			16,515.17			16,515.17
376.00	15,586,064.99	2,074,846.67	2,258,534,857.06	14,391,379.72	2,351,977.19	2,270,574,259.59
378.00	467,451.35	81,617.88	128,867,719.08	431,620.80	89,135.15	129,210,204.73
379.10			135,966.90			135,966.90
380.00	5,911,876.12	708,539.49	722,632,733.30	5,458,725.74	811,927.68	727,279,531.36
381.00	83,700.44	12,054.59	42,039,430.42	77,284.73	17,220.85	42,099,494.30
381.10	14,770.67		24,900,074.23	13,638.49		24,913,712.72
382.00	102,928.61	12,600.27	42,955,981.19	95,039.04	18,000.39	43,033,019.84
383.00	60,377.31	7,391.24	19,314,225.46	55,749.33	10,558.91	19,359,415.88
385.00	71,317.13	8,730.47	8,169,974.68	65,850.61	12,472.10	8,223,353.19
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	135,826.71		16,283,496.59	125,415.47		16,408,912.06
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	74,882.98	9,166.99	2,070,551.29	69,143.14	13,095.70	2,126,598.73
398.00			945,041.57			945,041.57
303.00		93,231.22	33,589,547.96		390,039.51	33,199,508.45
303.60			12,715,406.75			12,715,406.75
375.71		4,892.46	5,719,049.21		4,892.46	5,714,156.75
Total Plant	**22,555,228.28**	**3,023,798.56**	**3,389,272,506.88**	**20,826,350.65**	**3,732,462.27**	**3,406,366,395.26**

	2022			2022		
	JUNE			JULY		
Account	**Additions**	**Retirements**	**Ending Balance**	**Additions**	**Retirements**	**Ending Balance**
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
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	17,209.98	2,721.18	3,796,284.77	16,752.41	2,721.18	3,810,316.00
374.50			3,233,171.42			3,233,171.42
375.34	33,702.87	5,328.99	6,140,349.50	32,806.81	5,328.99	6,167,827.32
375.60			86,227.87			86,227.87
375.70	212,797.06	5,092.16	32,372,229.91		5,092.16	32,367,137.75
375.80			16,515.17			16,515.17
376.00	17,238,694.69	2,613,018.70	2,285,199,935.58	16,780,368.19	2,676,375.58	2,299,303,928.19
378.00	517,016.39	89,135.15	129,638,085.97	503,270.43	98,229.28	130,043,127.12
379.10			135,966.90			135,966.90
380.00	6,538,727.22	988,348.39	732,829,910.19	6,364,881.58	988,348.39	738,206,443.38
381.00	92,575.43	17,220.85	42,174,848.88	90,114.11	17,220.85	42,247,742.14
381.10	16,336.83		24,930,049.55	15,902.49		24,945,952.04
382.00	113,842.39	18,000.39	43,128,861.84	110,815.65	18,000.39	43,221,677.10
383.00	66,779.25	10,558.91	19,415,636.22	65,003.79	10,558.91	19,470,081.10
385.00	78,879.06	12,472.10	8,289,760.15	76,781.89	12,472.10	8,354,069.94
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	150,228.76		16,559,140.82	146,234.61		16,705,375.43
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	82,823.01	13,095.70	2,196,326.04	80,620.99	13,095.70	2,263,851.33
398.00			945,041.57			945,041.57
303.00	4,010,480.67	1,831,442.30	35,378,546.82			35,378,546.82
303.60	3,026,519.33		15,741,926.08			15,741,926.08
375.71	204,452.08	4,892.46	5,913,716.37		4,892.46	5,908,823.91
Total Plant	**32,401,065.02**	**5,611,327.28**	**3,433,156,133.00**	**24,283,552.95**	**3,852,335.99**	**3,453,587,349.96**

Account	2022 AUGUST Additions	Retirements	Ending Balance	2022 SEPTEMBER Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
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	19,245.79	2,721.18	3,826,840.61	21,768.94	2,721.18	3,845,888.37
374.50			3,233,171.42			3,233,171.42
375.34	37,689.66	5,328.99	6,200,187.99	42,630.85	5,328.99	6,237,489.85
375.60			86,227.87			86,227.87
375.70		5,092.16	32,362,045.59	212,797.06	5,092.16	32,569,750.49
375.80			16,515.17			16,515.17
376.00	19,277,901.79	2,472,118.06	2,316,109,711.92	21,805,268.82	2,485,746.67	2,335,429,234.07
378.00	578,175.51	98,229.28	130,523,073.35	653,975.35	98,229.28	131,078,819.42
379.10			135,966.90			135,966.90
380.00	7,312,209.15	1,106,914.41	744,411,738.12	8,270,852.72	915,315.87	751,767,274.97
381.00	103,526.38	17,220.85	42,334,047.67	117,098.88	17,220.85	42,433,925.70
381.10	18,269.37		24,964,221.41	20,664.51		24,984,885.92
382.00	127,309.08	18,000.39	43,330,985.79	143,999.52	18,000.39	43,456,984.92
383.00	74,678.74	10,558.91	19,534,200.93	84,469.25	10,558.91	19,608,111.27
385.00	88,209.86	12,472.10	8,429,807.70	99,774.33	12,472.10	8,517,109.93
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	167,999.68		16,873,375.11	190,024.74		17,063,399.85
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	92,620.35	13,095.70	2,343,375.98	104,763.04	13,095.70	2,435,043.32
398.00			945,041.57			945,041.57
303.00		1,077,849.96	34,300,696.86	4,010,480.67	127,354.98	38,183,822.55
303.60			15,741,926.08	3,026,519.33		18,768,445.41
375.71		4,892.46	5,903,931.45	204,452.08	4,892.46	6,103,491.07
Total Plant	**27,897,835.36**	**4,844,494.45**	**3,476,640,690.87**	**39,009,540.09**	**3,716,029.54**	**3,511,934,201.42**

	2022			2022		
	OCTOBER			NOVEMBER		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,250,036.96			3,250,036.96
352.01			738,941.36			738,941.36
352.02			168,031.87			168,031.87
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	42,878.64	2,721.18	3,886,045.83	21,388.80	2,721.18	3,904,713.45
374.50			3,233,171.42			3,233,171.42
375.34	83,970.67	5,328.99	6,316,131.53	41,886.40	5,328.99	6,352,688.94
375.60			86,227.87			86,227.87
375.70		5,092.16	32,564,658.33		5,092.16	32,559,566.17
375.80			16,515.17			16,515.17
376.00	42,950,189.74	2,484,603.61	2,375,894,820.20	21,424,489.15	1,787,994.94	2,395,531,314.41
378.00	1,288,145.78	55,604.02	132,311,361.18	642,555.15	55,604.02	132,898,312.31
379.10			135,966.90			135,966.90
380.00	16,291,232.02	1,049,059.73	767,009,447.26	8,126,420.99	976,027.22	774,159,841.03
381.00	230,651.57	17,220.85	42,647,356.42	115,054.01	17,220.85	42,745,189.58
381.10	40,703.21		25,025,589.13	20,303.65		25,045,892.78
382.00	283,638.19	18,000.39	43,722,622.72	141,484.90	18,000.39	43,846,107.23
383.00	166,380.45	10,558.91	19,763,932.81	82,994.18	10,558.91	19,836,368.08
385.00	196,527.10	12,472.10	8,701,164.93	98,031.99	12,472.10	8,786,724.82
387.00			136,698.14			136,698.14
387.40			11,443,998.08			11,443,998.08
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,117,504.14			2,117,504.14
391.11			91,303.67			91,303.67
391.12			1,944,667.83			1,944,667.83
392.00			25,616.89			25,616.89
394.00	374,294.79		17,437,694.64	186,706.38		17,624,401.02
394.12			0.00			0.00
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	206,353.45	13,095.70	2,628,301.07	102,933.59	13,095.70	2,718,138.96
398.00			945,041.57			945,041.57
303.00		15,375.98	38,168,446.57		252,323.23	37,916,123.34
303.60			18,768,445.41			18,768,445.41
375.71		4,892.46	6,098,598.61		4,892.46	6,093,706.15
Total Plant	**62,154,965.61**	**3,694,026.08**	**3,570,395,140.95**	**31,004,249.19**	**3,161,332.15**	**3,598,238,057.99**

	2022		
	DECEMBER		
Account	Additions	Retirements	Ending Balance
350.20			1,932.08
351.00			3,250,036.96
352.01			738,941.36
352.02			168,031.87
352.10			206,940.78
353.00			389,345.13
354.00			948,176.70
355.00			104,476.92
374.40	44,898.43	2,721.18	3,946,890.70
374.50			3,233,171.42
375.34	87,926.10	5,328.99	6,435,286.05
375.60			86,227.87
375.70	212,797.06	5,092.16	32,767,271.07
375.80			16,515.17
376.00	44,973,353.38	1,532,941.10	2,438,971,726.69
378.00	1,348,823.74	55,604.02	134,191,532.03
379.10			135,966.90
380.00	17,058,628.59	769,250.88	790,449,218.74
381.00	241,516.38	17,220.84	42,969,485.12
381.10	42,620.53		25,088,513.31
382.00	296,998.93	18,000.34	44,125,105.82
383.00	174,217.78	10,558.95	20,000,026.91
385.00	205,784.48	12,472.10	8,980,037.20
387.00			136,698.14
387.40			11,443,998.08
387.50			2,201,371.95
390.10			49,821.42
391.10		94,356.55	2,023,147.59
391.11			91,303.67
391.12		1,577,540.60	367,127.23
392.00			25,616.89
394.00	391,925.90	303,527.92	17,712,799.00
394.12			0.00
395.00		1,118.18	264,921.24
396.00			948,698.04
397.50	216,073.71	13,095.70	2,921,116.97
398.00		136.82	944,904.75
303.00	4,010,480.67	459,807.81	41,466,796.20
303.60	3,026,519.33		21,794,964.74
375.71	204,452.08	4,892.46	6,293,265.77
Total Plant	**72,537,017.09**	**4,883,666.60**	**3,665,891,408.48**

RESERVE BRINGFORWARD

Iumber of months for accrual calculation = 12 mber of months in FFTY = 13

			PROJECTED 21			PROJECTED 2022										
	2021	Accrual			5-yr			5-yr	2021							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	DECEMBER							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,337,386
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,884
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	823,271
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,167	769	5,936	2,721	218	0	0	848,597
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,795,044
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	10,958	2,752	13,710	5,329	1,972	0	0	1,450,670
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,498
375.70	3,781,479	2.98	0.00		1	0.00		1	73,738	0	73,738	64,079	0	0	0	3,791,139
375.80	8,259	2.17							30	0	30	0	0	0	0	8,289
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,057,996	104,954	4,162,950	2,434,993	219,149	0	0	293,873,938
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	403,071	16,939	420,010	55,398	14,403	0	0	20,931,749
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	56,236
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,773,466	259,908	2,033,374	702,975	231,982	0	0	139,505,967
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,141	(5,076)	78,065	16,289	0	1,792	0	17,909,540
381.10	17,041,116	5.62							116,336	0	116,336	0	0	0	0	17,157,452
382.00	15,035,037	1.88			2			2	66,716	0	66,716	17,121	0	0	0	15,084,633
383.00	7,831,229	2.04			185			653	32,442	15	32,458	11,696	0	0	0	7,851,991
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	34,532	9,551	44,083	12,472	4,490	0	0	2,449,624
387.00	78,374	3.02							344	0	344	0	0	0	0	78,718
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	187	45,581	0	0	0	0	2,854,226
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,568,717
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,917	0	6,917	168,329	0	0	0	976,331
391.11	47,228	6.39							486	0	486	0	0	0	0	47,714
391.12	2,174,689	14.57							28,152	0	28,152	747,863	0	0	0	1,454,977
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,931
394.00	7,626,712	3.49			(437)			(923)	49,884	(36)	49,847	2,741,889	0	0	54	4,934,724
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	84,376
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,935)	(1,536)	0	0	0	0	894,482
397.50	659,240	4.37	0.00		51	0.00		51	6,508	4	6,512	14,184	0	0	0	651,568
398.00	478,581	6.08							4,809	0	4,809	8,228	0	0	0	475,162
303.00	17,029,312								558,100	0	558,100	461,200	0	0	0	17,126,212
303.60	1,291,101								273,111	0	273,111	0	0	0	0	1,564,212
362.10	(151,290)				67,200			61,646	0	5,600	5,600	0	0	0	0	(145,690)
375.71	2,501,391								190,151	0	190,151	61,566	0	0	0	2,629,977
Total	**562,561,344**				**4,729,256**			**5,159,700**	**7,869,972**	**394,105**	**8,264,077**	**7,526,332**	**472,214**	**1,792**	**0**	**562,828,667**

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 mber of months in FFTY = 13

	2021	Accrual	PROJECTED 21			PROJECTED 2022			2022							
	NOV 30	Rates	COR	Salvage	5-yr Amort of NS	COR	Salvage	5-yr Amort of NS	JANUARY							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,359,599
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,911
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	826,282
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,201	805	6,005	1,088	87	0	0	853,427
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,797,954
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,044	2,631	13,676	2,132	789	0	0	1,461,426
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,551
375.70	3,781,479	2.98	0.00		1	0.00		1	79,932	0	79,932	5,092	0	0	0	3,865,979
375.80	8,259	2.17							30	0	30	0	0	0	0	8,319
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,103,720	129,307	4,233,026	2,021,696	181,953	0	0	295,903,316
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	406,041	22,144	428,184	31,198	8,112	0	0	21,320,623
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	58,258
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,794,338	262,967	2,057,305	562,474	185,617	0	0	140,815,181
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,383	(1,797)	81,586	6,888	0	758	0	17,984,995
381.10	17,041,116	5.62							116,446	0	116,446	0	0	0	0	17,273,899
382.00	15,035,037	1.88			2			2	66,954	0	66,954	7,200	0	0	0	15,144,387
383.00	7,831,229	2.04			185			653	32,616	54	32,670	4,224	0	0	0	7,880,437
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,012	9,230	44,242	4,989	1,796	0	0	2,487,081
387.00	78,374	3.02							344	0	344	0	0	0	0	79,062
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	2,899,777
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,586,071
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	982,983
391.11	47,228	6.39							486	0	486	0	0	0	0	48,200
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,478,589
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,727
394.00	7,626,712	3.49			(437)			(923)	46,392	(77)	46,315	0	0	0	54	4,981,093
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	85,531
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	893,821
397.50	659,240	4.37	0.00		51	0.00		51	6,959	4	6,964	5,238	0	0	0	653,294
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	479,950
303.00	17,029,312								558,100	0	558,100	55,010	0	0	0	17,629,301
303.60	1,291,101								273,111	0	273,111	0	0	0	0	1,837,324
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(140,553)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	2,815,236
Total	**562,561,344**				**4,729,256**			**5,159,700**	**7,939,227**	**429,975**	**8,369,202**	**2,712,123**	**378,353**	**758**	**0**	**568,108,152**

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 mber of months in FFTY = 13

PROJECTED 21 PROJECTED 2022

	2021	Accrual			5-yr			5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	FEBRUARY							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,381,813
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,939
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	829,292
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,210	805	6,015	1,088	87	0	0	858,266
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,800,864
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,070	2,631	13,701	2,132	789	0	0	1,472,206
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,603
375.70	3,781,479	2.98	0.00		1	0.00		1	79,919	0	79,920	5,092	0	0	0	3,940,806
375.80	8,259	2.17							30	0	30	0	0	0	0	8,349
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,114,615	129,307	4,243,922	2,396,512	215,686	0	0	297,535,040
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	406,715	22,144	428,859	31,198	8,112	0	0	21,710,172
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	60,280
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,800,588	262,967	2,063,555	650,685	214,726	0	0	142,013,326
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,456	(1,797)	81,659	6,888	0	758	0	18,060,523
381.10	17,041,116	5.62							116,482	0	116,482	0	0	0	0	17,390,381
382.00	15,035,037	1.88			2			2	67,027	0	67,027	7,200	0	0	0	15,204,214
383.00	7,831,229	2.04			185			653	32,662	54	32,716	4,224	0	0	0	7,908,930
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,153	9,230	44,383	4,989	1,796	0	0	2,524,679
387.00	78,374	3.02							344	0	344	0	0	0	0	79,406
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	2,945,328
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,603,425
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	989,636
391.11	47,228	6.39							486	0	486	0	0	0	0	48,687
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,502,200
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,523
394.00	7,626,712	3.49			(437)			(923)	46,598	(77)	46,521	0	0	0	54	5,027,668
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	86,686
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	893,159
397.50	659,240	4.37	0.00		51	0.00		51	7,082	4	7,087	5,238	0	0	0	655,142
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	484,738
303.00	17,029,312								558,100	0	558,100	41,003	0	0	0	18,146,397
303.60	1,291,101								273,111	0	273,111	0	0	0	0	2,110,435
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(135,416)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,000,494
Total	**562,561,344**				**4,729,256**			**5,159,700**	**7,957,768**	**429,975**	**8,387,743**	**3,161,143**	**441,195**	**758**	**0**	**572,894,314**

RESERVE BRINGFORWARD

umber of months for accrual calculation = 12 mber of months in FFTY = 13

PROJECTED 21 PROJECTED 2022

Account	2021 NOV 30 Begin. Balance	Accrual Rates 2020	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2016-2020	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2017-2021	2022 MARCH 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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,404,027
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,966
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	832,303
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,222	805	6,027	1,361	109	0	0	862,823
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,803,773
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,099	2,631	13,731	2,664	986	0	0	1,482,286
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,656
375.70	3,781,479	2.98	0.00		1	0.00		1	79,907	0	79,907	5,092	0	0	0	4,015,621
375.80	8,259	2.17							30	0	30	0	0	0	0	8,378
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,127,805	129,307	4,257,112	2,359,423	212,348	0	0	299,220,380
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	407,521	22,144	429,664	33,704	8,763	0	0	22,097,369
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	62,302
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,807,878	262,967	2,070,846	811,928	267,936	0	0	143,004,308
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,542	(1,797)	81,746	8,610	0	947	0	18,134,606
381.10	17,041,116	5.62							116,525	0	116,525	0	0	0	0	17,506,906
382.00	15,035,037	1.88			2			2	67,113	0	67,113	9,000	0	0	0	15,262,327
383.00	7,831,229	2.04			185			653	32,717	54	32,771	5,279	0	0	0	7,936,422
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,319	9,230	44,549	6,236	2,245	0	0	2,560,747
387.00	78,374	3.02							344	0	344	0	0	0	0	79,750
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	2,990,879
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,620,780
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	996,288
391.11	47,228	6.39							486	0	486	0	0	0	0	49,173
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,525,812
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,319
394.00	7,626,712	3.49			(437)			(923)	46,840	(77)	46,763	0	0	0	54	5,074,485
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	87,841
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	892,498
397.50	659,240	4.37	0.00		51	0.00		51	7,228	4	7,232	6,548	0	0	0	655,826
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	489,527
303.00	17,029,312								558,100	0	558,100	72,705	0	0	0	18,631,792
303.60	1,291,101								273,111	0	273,111	0	0	0	0	2,383,547
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(130,279)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,185,753
Total	**562,561,344**				**4,729,256**			**5,159,700**	**7,979,905**	**429,975**	**8,409,880**	**3,327,443**	**492,387**	**947**	**0**	**577,485,310**

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 mber of months in FFTY = 13

PROJECTED 21 PROJECTED 2022

Account	2021 NOV 30 Begin. Balance	Accrual Rates 2020	COR % of Rets (Projected 21)	Salvage % of Rets (Projected 21)	5-yr Amort of NS 2016-2020	COR % of Rets (Projected 2022)	Salvage % of Rets (Projected 2022)	5-yr Amort of NS 2017-2021	2022 APRIL 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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,426,241
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	388,993
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	835,313
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,237	805	6,042	1,905	152	0	0	866,808
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,806,683
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,139	2,631	13,770	3,730	1,380	0	0	1,490,946
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,708
375.70	3,781,479	2.98	0.00		1	0.00		1	79,894	0	79,894	5,092	0	0	0	4,090,423
375.80	8,259	2.17							30	0	30	0	0	0	0	8,408
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,147,027	129,307	4,276,333	2,074,847	186,736	0	0	301,235,131
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	408,542	22,144	430,686	81,618	21,221	0	0	22,425,217
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	64,324
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,818,078	262,967	2,081,046	708,539	233,818	0	0	144,142,996
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,657	(1,797)	81,860	12,055	0	1,326	0	18,205,738
381.10	17,041,116	5.62							116,581	0	116,581	0	0	0	0	17,623,486
382.00	15,035,037	1.88			2			2	67,227	0	67,227	12,600	0	0	0	15,316,954
383.00	7,831,229	2.04			185			653	32,789	54	32,844	7,391	0	0	0	7,961,874
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,539	9,230	44,769	8,730	3,143	0	0	2,593,643
387.00	78,374	3.02							344	0	344	0	0	0	0	80,094
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,036,430
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,638,134
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,002,941
391.11	47,228	6.39							486	0	486	0	0	0	0	49,659
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,549,423
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	22,115
394.00	7,626,712	3.49			(437)			(923)	47,160	(77)	47,083	0	0	0	54	5,121,622
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	88,996
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	891,836
397.50	659,240	4.37	0.00		51	0.00		51	7,421	4	7,425	9,167	0	0	0	654,084
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	494,315
303.00	17,029,312								558,100	0	558,100	93,231	0	0	0	19,096,661
303.60	1,291,101								273,111	0	273,111	0	0	0	0	2,656,658
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(125,141)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,371,012
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,011,482**	**429,975**	**8,441,457**	**3,023,799**	**446,450**	**1,326**	**0**	**582,457,845**

RESERVE BRINGFORWARD

lumber of months for accrual calculation = 12 mber of months in FFTY = 13

PROJECTED 21 PROJECTED 2022

	2021	Accrual			5-yr			5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	MAY							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,448,454
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,020
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	838,324
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,255	805	6,059	2,721	218	0	0	869,929
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,809,593
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,184	2,631	13,815	5,329	1,972	0	0	1,497,461
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,761
375.70	3,781,479	2.98	0.00		1	0.00		1	79,882	0	79,882	5,092	0	0	0	4,165,212
375.80	8,259	2.17							30	0	30	0	0	0	0	8,438
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,170,555	129,307	4,299,861	2,351,977	211,678	0	0	302,971,337
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	409,699	22,144	431,842	89,135	23,175	0	0	22,744,749
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	66,347
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,830,514	262,967	2,093,482	811,928	267,936	0	0	145,156,614
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,788	(1,797)	81,992	17,221	0	1,894	0	18,272,402
381.10	17,041,116	5.62							116,647	0	116,647	0	0	0	0	17,740,134
382.00	15,035,037	1.88			2			2	67,358	0	67,358	18,000	0	0	0	15,366,312
383.00	7,831,229	2.04			185			653	32,873	54	32,927	10,559	0	0	0	7,984,242
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	35,792	9,230	45,022	12,472	4,490	0	0	2,621,703
387.00	78,374	3.02							344	0	344	0	0	0	0	80,438
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,081,981
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,655,488
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,009,593
391.11	47,228	6.39							486	0	486	0	0	0	0	50,145
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,573,035
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,911
394.00	7,626,712	3.49			(437)			(923)	47,540	(77)	47,463	0	0	0	54	5,169,139
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	90,151
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	891,175
397.50	659,240	4.37	0.00		51	0.00		51	7,642	4	7,647	13,096	0	0	0	648,634
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	499,103
303.00	17,029,312								558,100	0	558,100	390,040	0	0	0	19,264,721
303.60	1,291,101								273,111	0	273,111	0	0	0	0	2,929,769
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(120,004)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,556,271
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,049,920**	**429,975**	**8,479,895**	**3,732,462**	**509,469**	**1,894**	**0**	**586,697,702**

RESERVE BRINGFORWARD

umber of months for accrual calculation = 12 **mber of months in FFTY =** 13

			PROJECTED 21			PROJECTED 2022										
	2021	Accrual			5-yr			5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	JUNE							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,470,668
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,048
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	841,334
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,273	805	6,078	2,721	218	0	0	873,067
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,812,503
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,231	2,631	13,862	5,329	1,972	0	0	1,504,023
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,813
375.70	3,781,479	2.98	0.00		1	0.00		1	80,133	0	80,133	5,092	0	0	0	4,240,254
375.80	8,259	2.17							30	0	30	0	0	0	0	8,468
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,195,109	129,307	4,324,415	2,613,019	235,172	0	0	304,447,562
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	410,922	22,144	433,065	89,135	23,175	0	0	23,065,503
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	68,369
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,843,388	262,967	2,106,356	988,348	326,155	0	0	145,948,466
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	83,923	(1,797)	82,126	17,221	0	1,894	0	18,339,202
381.10	17,041,116	5.62							116,717	0	116,717	0	0	0	0	17,856,851
382.00	15,035,037	1.88			2			2	67,493	0	67,494	18,000	0	0	0	15,415,805
383.00	7,831,229	2.04			185			653	32,959	54	33,013	10,559	0	0	0	8,006,696
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	36,054	9,230	45,284	12,472	4,490	0	0	2,650,025
387.00	78,374	3.02							344	0	344	0	0	0	0	80,782
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,127,532
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,672,842
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,016,246
391.11	47,228	6.39							486	0	486	0	0	0	0	50,631
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,596,646
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,707
394.00	7,626,712	3.49			(437)			(923)	47,941	(77)	47,864	0	0	0	54	5,217,057
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	91,306
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	890,513
397.50	659,240	4.37	0.00		51	0.00		51	7,871	4	7,876	13,096	0	0	0	643,414
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	503,891
303.00	17,029,312								558,100	0	558,100	1,831,442	0	0	0	17,991,378
303.60	1,291,101								273,111	0	273,111	0	0	0	0	3,202,881
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(114,867)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,741,530
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,090,205**	**429,975**	**8,520,180**	**5,611,327**	**591,181**	**1,894**	**0**	**589,017,269**

RESERVE BRINGFORWARD

lumber of months for accrual calculation = 12 mber of months in FFTY = 13

			PROJECTED 21			PROJECTED 2022										
	2021	Accrual			5-yr			5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	JULY							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,492,882
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,075
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	844,345
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,293	805	6,098	2,721	218	0	0	876,226
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,815,413
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,282	2,631	13,914	5,329	1,972	0	0	1,510,636
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,867
375.70	3,781,479	2.98	0.00		1	0.00		1	80,385	0	80,385	5,092	0	0	0	4,315,546
375.80	8,259	2.17							30	0	30	0	0	0	0	8,498
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,221,564	129,307	4,350,871	2,676,376	240,874	0	0	305,881,183
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	412,244	22,144	434,388	98,229	25,540	0	0	23,376,122
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	70,391
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,857,183	262,967	2,120,151	988,348	326,155	0	0	146,754,113
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	84,071	(1,797)	82,274	17,221	0	1,894	0	18,406,150
381.10	17,041,116	5.62							116,793	0	116,793	0	0	0	0	17,973,644
382.00	15,035,037	1.88			2			2	67,641	0	67,641	18,000	0	0	0	15,465,446
383.00	7,831,229	2.04			185			653	33,053	54	33,107	10,559	0	0	0	8,029,245
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	36,339	9,230	45,569	12,472	4,490	0	0	2,678,633
387.00	78,374	3.02							344	0	344	0	0	0	0	81,126
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,173,083
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,690,196
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,022,898
391.11	47,228	6.39							486	0	486	0	0	0	0	51,118
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,620,258
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,503
394.00	7,626,712	3.49			(437)			(923)	48,372	(77)	48,295	0	0	0	54	5,265,407
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	92,461
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	889,852
397.50	659,240	4.37	0.00		51	0.00		51	8,121	4	8,125	13,096	0	0	0	638,443
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	508,679
303.00	17,029,312								558,100	0	558,100	0	0	0	0	18,549,478
303.60	1,291,101								273,111	0	273,111	0	0	0	0	3,475,992
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(109,730)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	3,926,789
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,133,532**	**429,975**	**8,563,507**	**3,852,336**	**599,248**	**1,894**	**0**	**593,131,087**

RESERVE BRINGFORWARD

lumber of months for accrual calculation = 12 mber of months in FFTY = 13

PROJECTED 21 PROJECTED 2022

	2021	Accrual			5-yr			5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	AUGUST							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,515,096
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,102
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	847,355
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,314	805	6,119	2,721	218	0	0	879,406
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,818,323
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,337	2,631	13,968	5,329	1,972	0	0	1,517,304
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,919
375.70	3,781,479	2.98	0.00		1	0.00		1	80,372	0	80,372	5,092	0	0	0	4,390,826
375.80	8,259	2.17							30	0	30	0	0	0	0	8,528
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,250,027	129,307	4,379,333	2,472,118	222,491	0	0	307,565,908
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	413,649	22,144	435,792	98,229	25,540	0	0	23,688,146
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	72,413
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,871,805	262,967	2,134,773	1,106,914	365,282	0	0	147,416,690
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	84,229	(1,797)	82,433	17,221	0	1,894	0	18,473,257
381.10	17,041,116	5.62							116,873	0	116,873	0	0	0	0	18,090,517
382.00	15,035,037	1.88			2			2	67,800	0	67,800	18,000	0	0	0	15,515,245
383.00	7,831,229	2.04			185			653	33,154	54	33,208	10,559	0	0	0	8,051,894
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	36,645	9,230	45,875	12,472	4,490	0	0	2,707,546
387.00	78,374	3.02							344	0	344	0	0	0	0	81,470
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,218,634
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,707,550
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,029,551
391.11	47,228	6.39							486	0	486	0	0	0	0	51,604
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,643,869
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,299
394.00	7,626,712	3.49			(437)			(923)	48,829	(77)	48,752	0	0	0	54	5,314,213
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	93,616
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	889,190
397.50	659,240	4.37	0.00		51	0.00		51	8,389	4	8,393	13,096	0	0	0	633,741
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	513,468
303.00	17,029,312								558,100	0	558,100	1,077,850	0	0	0	18,029,728
303.60	1,291,101								273,111	0	273,111	0	0	0	0	3,749,103
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(104,593)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,112,048
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,179,613**	**429,975**	**8,609,588**	**4,844,494**	**619,991**	**1,894**	**0**	**596,278,085**

RESERVE BRINGFORWARD

umber of months for accrual calculation = 12 mber of months in FFTY = 13

PROJECTED 21 PROJECTED 2022

Account	2021 NOV 30 Begin. Balance	Accrual Rates 2020	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2016-2020	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2017-2021	2022 SEPTEMBER 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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,537,309
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,129
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	850,366
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,339	805	6,144	2,721	218	0	0	882,611
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,821,233
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,401	2,631	14,032	5,329	1,972	0	0	1,524,036
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	75,972
375.70	3,781,479	2.98	0.00		1	0.00		1	80,624	0	80,624	5,092	0	0	0	4,466,358
375.80	8,259	2.17							30	0	30	0	0	0	0	8,558
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,283,292	129,307	4,412,599	2,485,747	223,717	0	0	309,269,042
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	415,293	22,144	437,437	98,229	25,540	0	0	24,001,813
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	74,435
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,888,926	262,967	2,151,893	915,316	302,054	0	0	148,351,213
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	84,415	(1,797)	82,618	17,221	0	1,894	0	18,540,548
381.10	17,041,116	5.62							116,964	0	116,964	0	0	0	0	18,207,481
382.00	15,035,037	1.88			2			2	67,984	0	67,984	18,000	0	0	0	15,565,229
383.00	7,831,229	2.04			185			653	33,271	54	33,325	10,559	0	0	0	8,074,660
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	37,001	9,230	46,231	12,472	4,490	0	0	2,736,814
387.00	78,374	3.02							344	0	344	0	0	0	0	81,814
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,264,185
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,724,904
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,036,203
391.11	47,228	6.39							486	0	486	0	0	0	0	52,090
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,667,481
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	21,095
394.00	7,626,712	3.49			(437)			(923)	49,350	(77)	49,273	0	0	0	54	5,363,540
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	94,772
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	888,529
397.50	659,240	4.37	0.00		51	0.00		51	8,701	4	8,705	13,096	0	0	0	629,350
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	518,256
303.00	17,029,312								558,100	0	558,100	127,355	0	0	0	18,460,473
303.60	1,291,101								273,111	0	273,111	0	0	0	0	4,022,215
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(99,456)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,297,307
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,233,750**	**429,975**	**8,663,725**	**3,716,030**	**557,990**	**1,894**	**0**	**600,669,684**

RESERVE BRINGFORWARD

lumber of months for accrual calculation = 12 mber of months in FFTY = 13

			PROJECTED 21			PROJECTED 2022										
	2021	Accrual			5-yr			5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	OCTOBER							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,559,522
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,157
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	853,376
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,380	805	6,185	2,721	218	0	0	885,856
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,824,142
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,507	2,631	14,139	5,329	1,972	0	0	1,530,873
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	76,024
375.70	3,781,479	2.98	0.00		1	0.00		1	80,875	0	80,875	5,092	0	0	0	4,542,141
375.80	8,259	2.17							30	0	30	0	0	0	0	8,588
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,338,344	129,307	4,467,651	2,484,604	223,614	0	0	311,028,475
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	418,132	22,144	440,275	55,604	14,457	0	0	24,372,028
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	76,457
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,917,456	262,967	2,180,423	1,049,060	346,190	0	0	149,136,387
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	84,727	(1,797)	82,930	17,221	0	1,894	0	18,608,151
381.10	17,041,116	5.62							117,108	0	117,108	0	0	0	0	18,324,589
382.00	15,035,037	1.88			2			2	68,291	0	68,291	18,000	0	0	0	15,615,519
383.00	7,831,229	2.04			185			653	33,466	54	33,521	10,559	0	0	0	8,097,622
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	37,593	9,230	46,823	12,472	4,490	0	0	2,766,676
387.00	78,374	3.02							344	0	344	0	0	0	0	82,158
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,309,736
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,742,259
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,042,856
391.11	47,228	6.39							486	0	486	0	0	0	0	52,576
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,691,092
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	20,891
394.00	7,626,712	3.49			(437)			(923)	50,170	(77)	50,093	0	0	0	54	5,413,687
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	95,927
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	887,867
397.50	659,240	4.37	0.00		51	0.00		51	9,220	4	9,224	13,096	0	0	0	625,478
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	523,044
303.00	17,029,312								558,100	0	558,100	15,376	0	0	0	19,003,196
303.60	1,291,101								273,111	0	273,111	0	0	0	0	4,295,326
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(94,318)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,482,566
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,323,459**	**429,975**	**8,753,434**	**3,694,026**	**590,940**	**1,894**	**0**	**605,140,046**

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 mber of months in FFTY = 13

			PROJECTED 21			PROJECTED 2022										
	2021	Accrual			5-yr			5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	NOVEMBER							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,581,736
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,184
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	856,387
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,421	805	6,226	2,721	218	0	0	889,143
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,827,052
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,613	2,631	14,244	5,329	1,972	0	0	1,537,817
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	76,077
375.70	3,781,479	2.98	0.00		1	0.00		1	80,863	0	80,863	5,092	0	0	0	4,617,911
375.80	8,259	2.17							30	0	30	0	0	0	0	8,617
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,393,688	129,307	4,522,995	1,787,995	160,920	0	0	313,602,556
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	421,020	22,144	443,164	55,604	14,457	0	0	24,745,131
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	78,479
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,945,726	262,967	2,208,694	976,027	322,089	0	0	150,046,964
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	85,037	(1,797)	83,240	17,221	0	1,894	0	18,676,065
381.10	17,041,116	5.62							117,251	0	117,251	0	0	0	0	18,441,840
382.00	15,035,037	1.88			2			2	68,596	0	68,596	18,000	0	0	0	15,666,115
383.00	7,831,229	2.04			185			653	33,660	54	33,715	10,559	0	0	0	8,120,778
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	38,182	9,230	47,412	12,472	4,490	0	0	2,797,126
387.00	78,374	3.02							344	0	344	0	0	0	0	82,502
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,355,287
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,759,613
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,652	0	6,652	0	0	0	0	1,049,508
391.11	47,228	6.39							486	0	486	0	0	0	0	53,062
391.12	2,174,689	14.57							23,612	0	23,612	0	0	0	0	1,714,704
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	20,687
394.00	7,626,712	3.49			(437)			(923)	50,986	(77)	50,909	0	0	0	54	5,464,650
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,155	0	1,155	0	0	0	0	97,082
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	887,206
397.50	659,240	4.37	0.00		51	0.00		51	9,735	4	9,739	13,096	0	0	0	622,122
398.00	478,581	6.08							4,788	0	4,788	0	0	0	0	527,832
303.00	17,029,312								558,100	0	558,100	252,323	0	0	0	19,308,973
303.60	1,291,101								273,111	0	273,111	0	0	0	0	4,568,438
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(89,181)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,667,825
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,412,968**	**429,975**	**8,842,943**	**3,161,332**	**504,145**	**1,894**	**0**	**610,319,406**

RESERVE BRINGFORWARD

Number of months for accrual calculation = 12 Number of months in FFTY = 13

PROJECTED 21 PROJECTED 2022

	2021	Accrual			5-yr			5-yr	2022							
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	DECEMBER							
Account	Begin. Balance	2020	% of Rets	% of Rets	2016-2020	% of Rets	% of Rets	2017-2021	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	0	1,931
351.20	2,315,172	8.07			4,287			4,287	21,856	357	22,214	0	0	0	0	2,603,950
352.01	738,926	0.00							0	0	0	0	0	0	0	738,926
352.02	168,032	0.00							0	0	0	0	0	0	0	168,032
352.10	206,932	0.00							0	0	0	0	0	0	0	206,932
353.00	388,857	0.04			171			171	13	14	27	0	0	0	0	389,211
354.00	820,261	3.81							3,010	0	3,010	0	0	0	0	859,397
355.00	104,477	0.00							0	0	0	0	0	0	0	104,477
374.40	845,600	1.67	0.08		9,223	0.08		9,655	5,463	805	6,268	2,721	218	0	0	892,472
374.50	1,792,134	1.08							2,910	0	2,910	0	0	0	0	1,829,962
375.34	1,444,261	2.20	0.37		33,022	0.37		31,573	11,722	2,631	14,353	5,329	1,972	0	0	1,544,869
375.60	75,446	0.61			104			104	44	9	52	0	0	0	0	76,129
375.70	3,781,479	2.98	0.00		1	0.00		1	81,114	0	81,114	5,092	0	0	0	4,693,933
375.80	8,259	2.17							30	0	30	0	0	0	0	8,647
376.00	292,365,131	2.21	0.09		1,259,452	0.09		1,551,679	4,451,772	129,307	4,581,078	1,532,941	137,965	0	0	316,512,728
378.00	20,581,541	3.81	0.26		203,267	0.26		265,723	424,005	22,144	446,149	55,604	14,457	0	0	25,121,218
379.10	54,214	6.62			15,264			15,264	750	1,272	2,022	0	0	0	0	80,501
380.00	138,407,550	3.03	0.33		3,118,893	0.33		3,155,608	1,975,319	262,967	2,238,286	769,251	253,853	0	0	151,262,147
381.00	17,845,972	2.39		0.11	(60,916)		0.11	(21,562)	85,358	(1,797)	83,561	17,221	0	1,894	0	18,744,299
381.10	17,041,116	5.62							117,398	0	117,398	0	0	0	0	18,559,238
382.00	15,035,037	1.88			2			2	68,911	0	68,911	18,000	0	0	0	15,717,025
383.00	7,831,229	2.04			185			653	33,861	54	33,915	10,559	0	0	0	8,144,134
385.00	2,422,503	5.24	0.36		114,611	0.36		110,763	38,791	9,230	48,021	12,472	4,490	0	0	2,828,185
387.00	78,374	3.02							344	0	344	0	0	0	0	82,846
387.40	2,808,645	4.76	0.03		2,240	0.03		1,878	45,395	157	45,551	0	0	0	0	3,400,839
387.50	1,551,363	9.46							17,354	0	17,354	0	0	0	0	1,776,967
390.10	49,821	0.00							0	0	0	0	0	0	0	49,821
391.10	1,137,743	3.77							6,504	0	6,504	94,357	0	0	0	961,656
391.11	47,228	6.39							486	0	486	0	0	0	0	53,548
391.12	2,174,689	14.57							14,035	0	14,035	1,577,541	0	0	0	151,198
392.00	23,135	1.34		0.13	(2,791)		0.13	(2,791)	29	(233)	(204)	0	0	0	0	20,483
394.00	7,626,712	3.49			(437)			(923)	51,386	(77)	51,309	303,528	0	0	54	5,212,486
394.12	0	0.00			648			648	0	54	54	0	0	0	(54)	0
395.00	83,221	5.21							1,153	0	1,153	1,118	0	0	0	97,116
396.00	896,018	1.77		0.36	(35,221)		0.36	(24,730)	1,399	(2,061)	(662)	0	0	0	0	886,544
397.50	659,240	4.37	0.00		51	0.00		51	10,268	4	10,272	13,096	0	0	0	619,299
398.00	478,581	6.08							4,788	0	4,788	137	0	0	0	532,483
303.00	17,029,312								558,100	0	558,100	459,808	0	0	0	19,407,265
303.60	1,291,101								273,111	0	273,111	0	0	0	0	4,841,549
362.10	(151,290)				67,200			61,646	0	5,137	5,137	0	0	0	0	(84,044)
375.71	2,501,391								190,151	0	190,151	4,892	0	0	0	4,853,084
Total	**562,561,344**				**4,729,256**			**5,159,700**	**8,496,830**	**429,975**	**8,926,805**	**4,883,667**	**412,954**	**1,894**	**0**	**613,951,483**

N. SHULTZ

COLUMBIA STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Nicole M. Shultz 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 a 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 Bachelors of Business Administration in Accounting and Financial Economics from Lincoln Memorial University, and a Master of Business Administration from Otterbein University. My career began at NiSource in 2001 providing General Accounting support for the various Columbia Gas Distribution Companies. In 2005, I worked for the Financial and Fraud Audit Divisions for the State of Ohio. Since rejoining NCSC in 2011, I've worked on General Accounting and Asset Accounting matters for NCSC and Columbia Distribution Companies, which includes Columbia Gas of Pennsylvania, Inc. ("Columbia" and the "Company") before transferring into my current Lead Regulatory Analyst role in 2019.

Q. Have you ever testified before a regulatory Commission?

A. I have provided direct testimony in Columbia's previous base rate proceeding at Docket No. R-2020-3018835.

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, 2022, 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 NMS-1 (Attached hereto)	Update of Ex. 108, Schedule 1 from Docket No. R-2020-3018835 (Updated through Dec. 31, 2020)

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

A. I will be addressing the twelve month period ending November 30, 2020 as the Historic Test Year (Exhibit 8), the twelve month period ended November 30, 2021 as the Future Test Year (Exhibit 108), and the twelve month period ended December 31, 2022 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 and R-2020-3018835. 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. Please describe Exhibit NMS-1.

A. Exhibit NMS-1 provides an update of Columbia Exhibit 108, Schedule 1, from Columbia's prior rate case at Docket No. R-2020-3018835. This exhibit includes actual capital expenditures, plant additions and retirements by month for the twelve months ending December 31, 2020. See Exhibit NMS-1.

Q. Please comment on how the Company's actual capital additions for the 12 month period ending November 30, 2020 (the HTY) compares to the projections made in Columbia's prior rate case at Docket No. R-2020-3018835.

A. The Company has exceeded the budget provided in the 2020 Rate Case 2020-3018835 for additions for the 12 months ending November 30, 2020, as shown in the table below.

Budget per 2020 Rate Case, 2020-3018835 Exhibit 108, Schedule 1				
	Budget	Actual	Over/(Under)	%
Additions	305,016,151	333,249,554	28,233,403	9.26%
Retirements	50,211,838	31,842,460	(18,379,377)	-36.60%
Total	254,794,313	301,407,094	46,612,780	18.29%

Q. Please explain the development of rate base at November 30, 2020 for the Historic Test Year, November 30, 2021 for the Future Test Year and December 31, 2022 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, 2020. 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, 2022, 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, 2020 (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 2020 through December 2022 per the Company's forecasted budget are shown in Exhibit 108, Schedule 1, columns 3-85. The forecasted plant additions were provided based on the Company's current capital plan, Column 3 & 6. Forecasted retirements from December 2020 to December 2022, 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, 2022, 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, 2020. The Company is making no claim for CWIP in the FPFTY.

Q. Please explain the credits to Gas Plant in Service on Exhibit 8, Page 3, Lines 7-8 and Exhibit 108, Page 3, Lines 6-7.

A. Line 7, Depreciation Reserve, Accounts 108-111 in Exhibit 8, Page 3 for the Historic Test Year and Line 6, Exhibit 108, Page 3 for the FPFTY are detailed and supplied by Company witness Spanos, by plant account, in Exhibit 5 for the Historic Test Year and Exhibit 105 in the FPFTY. Exhibit 8, Page 3, Line 8 and Exhibit 108, Page 3, Line 7 Accumulated Provision for Gas Lost – Underground Storage, Account 117, is per books as of November 30, 2020 for the Historic Test Year and December 31, 2022 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 2020 actual balances (most recently available), with January 2021 through November 2021 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 2020 through November 2020. 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 2020 through November 2020 actual balances to reflect expected new prepayments as of December 2022.

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 2019 through November 2020 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 2020, as shown in Exhibit 8, Schedule 7. Exhibit 8, Schedule 7, Line 15 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 2020 through December 2022. 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, 2020 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, 2021 and December 31, 2022 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 2020 through December 2022, with entries for November and December of each year based on actual data for November and December of 2020. The balances for the months of January 2022 through October 2022 are the same as the balances in the month of January 2021 through October 2021 following the trend that deposits gradually go up in the winter and down in the summer. The balances for January 2021 – October 2022 are based on Historic Test Year balances.

Q. Please explain the Company's account for the 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 reset its DSIC to 0% when the Company made its compliance filing for the 2020 rate case at Docket No. 2020-3018835. However, Columbia filed Tariff Supplement No. 324 on March 19, 2021, to become effective April 1, 2021, to update the DSIC rate to recover the under collection from the Rider DSIC for the 12 months ended December 31, 2020.

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 approved base rate increase in Docket No. R-2020-301885, the Company's base rates and rate base included projected balances (FPFTY) at December 31, 2021. The Company would be eligible to include plant additions in the DSIC once net plant additions of $261.78 million from the approved 2020 Rate Case, R-2020-301885 as of December 31, 2021 are exceeded.

V. Other Exhibits

Q. Please explain the purpose of Page 2 of Exhibit 8.

A. This page satisfies 52 Pennsylvania Code Section 53.53 I.A, item 2 of the Commission's standard filing requirements, which provides that Exhibit 8, Page 4, shows the Company's rate base claim from its last base rate proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
Updated for Actuals Through December 31, 2020

			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 11/30/2019 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2019 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 1/31/2020 (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	24,574,424	708,668	(132,678)	25,150,414	12,546	0	25,162,960
6	Cloud Software	303.99	0	0	0	0	0	0	0
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	3,220,858	0	0	3,220,858	0	0	3,220,858
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	948,272	0	0	948,272	0	0	948,272
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	477,100	2,884,000	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	3,082,273	92,478	(1,195)	3,173,555	0	(15)	3,173,540
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,161	10	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	5,184,456	45,984	(3,897)	5,226,544	16,580	(25)	5,243,099
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	9,917,104	7,792,012	(177,785)	17,531,331	0	0	17,531,331
30	Structures, Other Distribution System, Leased	375.71	5,487,917	298,012	(12,476)	5,773,453	8,461	0	5,781,914
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,688,863,735	33,297,345	*(5,884,107)*	1,716,276,974	12,190,430	*(740,000)*	1,727,727,404
34	Mains - CSL Replacements	376.08	23,574,504	0	0	23,574,504	0	(12,999)	23,561,505
35	Bare Steel	376.30	64,933,670	0	(334,938)	64,598,732	0	(797)	64,597,935
36	Cast Iron	376.80	263,240	0	(30,851)	232,389	0	0	232,389
37	Measuring & Regulating Equipment General	378.10	1,451,939	0	(4,347)	1,447,592	0	0	1,447,592
38	Measuring & Regulating Equipment Regulating	378.20	93,245,433	2,144,924	(233,777)	95,156,580	569,521	(25,026)	95,701,076
39	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	0	454,917	0	0	454,917
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	580,788,003	6,117,091	(2,320,491)	584,584,603	3,633,995	(14,172)	588,204,426
43	Meters	381.00	39,176,296	207,905	(64,825)	39,319,377	98,407	0	39,417,784
44	Auto Meter Reading Devices	381.10	24,570,547	2,044	0	24,572,591	0	0	24,572,591
45	Meter Installations	382.00	40,589,166	110,292	(29,106)	40,670,352	39,888	0	40,710,240
46	House Regulators	383.00	13,686,795	96,958	(1,248)	13,782,505	77,854	0	13,860,358
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	6,362,985	14	(9,683)	6,353,316	57	(31,185)	6,322,188
49	Industrial M&R Equipment. Large Volume	385.10	1,579,956	(531,978)	(3,683)	1,044,295	40	0	1,044,335
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	627,560	0	(3,628)	623,932	0	0	623,932
54	Other Equipment, Telemetering	387.45	9,519,187	7,436	(3,258)	9,523,365	8,300	0	9,531,665
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**								
58	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,380,973	0	(2,000)	2,378,973	0	0	2,378,973
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	4,498,635	12,140	(319,479)	4,191,295	512	0	4,191,807
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	57,458	0	(686)	56,772	0	0	56,772
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	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,345,764	289,521	(89,303)	16,545,982	63,090	(71,865)	16,537,208
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	269,030	0	0	269,030	0	0	269,030
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	792,133	0	(4,217)	787,916	0	0	787,916
79	Miscellaneous Equipment	398.00	971,183	0	0	971,183	0	0	971,183
80	**Total Gas Plant in Service**		**2,687,846,103**	**53,574,856**	**(9,667,656)**	**2,731,753,304**	**16,719,682**	**(896,084)**	**2,747,576,901**

1/ In December 2019 an over retirement of $9.5 million was made in GPA 376-Mains. A correction was made in January 2020 to reflect the proper activity for December 2019, which was (9,667,656).

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
Updated for Actuals Through December 31, 2020

			Gas Plant in Service						
Line No.	**Description**	**Account No. (1)**	**Plant Beginning Balance 1/31/2020 (2) $**	**Additions (3) $**	**Retirements (4) $**	**Balance as of 2/28/2020 (5 = 2+3+4) $**	**Additions (6) $**	**Retirements (7) $**	**Balance as of 3/31/2020 (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	25,162,960	765,624	0	25,928,584	37,570	(12,330)	25,953,825
6	Cloud Software	303.99	0			0	1,408,697	0	1,408,697
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	3,220,858	0	0	3,220,858	0	0	3,220,858
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	948,272	0	0	948,272	0	0	948,272
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	3,173,540	20,845	0	3,194,385	0	0	3,194,385
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	5,243,099	35,161	0	5,278,260	76,801	(25,320)	5,329,741
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	17,531,331	0	0	17,531,331	73,458	0	17,604,788
30	Structures, Other Distribution System, Leased	375.71	5,781,914	0	0	5,781,914	0	0	5,781,914
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,727,727,404	23,476,727	(267,135)	1,750,936,996	15,261,993	(394,769)	1,765,804,219
34	Mains - CSL Replacements	376.08	23,561,505	0	(46,024)	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,597,935	0	(41,790)	64,556,145	6	(51,398)	64,504,753
36	Cast Iron	376.80	232,389	0	(3,758)	228,631	0	(7,828)	220,803
37	Measuring & Regulating Equipment General	378.10	1,447,592	0	0	1,447,592	0	0	1,447,592
38	Measuring & Regulating Equipment Regulating	378.20	95,701,076	369,478	(4,931)	96,065,622	490,974	(7,307)	96,549,289
39	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	0	454,917	0	0	454,917
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	588,204,426	4,153,899	(740,823)	591,617,502	5,587,865	(1,868,751)	595,336,616
43	Meters	381.00	39,417,784	202,977	(78,018)	39,542,742	153,114	(126,876)	39,568,980
44	Auto Meter Reading Devices	381.10	24,572,591	30,355	0	24,602,946	881	0	24,603,826
45	Meter Installations	382.00	40,710,240	38,711	(5,018)	40,743,934	79,589	(9,354)	40,814,168
46	House Regulators	383.00	13,860,358	88,375	(442)	13,948,291	81,534	(1,319)	14,028,506
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	6,322,188	0	(30,853)	6,291,335	13,064	(36,174)	6,268,225
49	Industrial M&R Equipment. Large Volume	385.10	1,044,335	2,682	(1,297)	1,045,720	1,022	(4,534)	1,042,209
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	9,531,665	32,139	(5,940)	9,557,864	300	(9,552)	9,548,612
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	2,378,973	0	(1,062)	2,377,912	0	(53,063)	2,324,849
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	4,191,807	0	0	4,191,807	1,024	0	4,192,831
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	56,772	0	0	56,772	0	0	56,772
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	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,537,208	77,155	0	16,614,363	56,238	0	16,670,600
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	269,030	0	0	269,030	0	0	269,030
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	971,183	0	(6,911)	964,272	0	0	964,272
80	**Total Gas Plant in Service**		**2,747,576,901**	**29,294,128**	**(1,234,003)**	**2,775,637,027**	**23,324,128**	**(2,608,576)**	**2,796,352,579**

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
Updated for Actuals Through December 31, 2020

Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 3/31/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 4/30/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 5/31/2020 (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	25,953,825	70,696	(142,874)	25,881,646	742,550.76	0	26,624,197
6	Cloud Software	303.99	1,408,697	20,594	0	1,429,291	1,181.97	0	1,430,473
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	3,220,858	0	0	3,220,858	0	0	3,220,858
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	948,272	0	0	948,272	0	0	948,272
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	3,194,385	1,500	(73)	3,195,813	6,107.73	0	3,201,920
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	5,329,741	5,022	(7,920)	5,326,843	94,704.80	(40,908.81)	5,380,639
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	17,604,788	74,849	0	17,679,637	52.86	0	17,679,690
30	Structures, Other Distribution System, Leased	375.71	5,781,914	35,382	0	5,817,296	0	0	5,817,296
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,765,804,219	1,041,544	(519,097)	1,766,326,666	9,154,194.45	(391,248.38)	1,775,089,612
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,504,753	3	(20,445)	64,484,310	0.28	(10,117.08)	64,474,194
36	Cast Iron	376.80	220,803	0	0	220,803	0	0	220,803
37	Measuring & Regulating Equipment General	378.10	1,447,592	0	0	1,447,592	0	0	1,447,592
38	Measuring & Regulating Equipment Regulating	378.20	96,549,289	1,418,087	(9,344)	97,958,033	2,390,448.69	(20,571.55)	100,327,910
39	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	(4,967)	449,950	0	0	449,950
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	595,336,616	522,565	(507,663)	595,351,518	2,982,666.50	(733,150.84)	597,601,033
43	Meters	381.00	39,568,980	41,745	(55,228)	39,555,497	0	(55,550.83)	39,499,946
44	Auto Meter Reading Devices	381.10	24,603,826	0	0	24,603,826	11,943.71	0	24,615,770
45	Meter Installations	382.00	40,814,168	31,103	(1,835)	40,843,437	63,540.64	(4,197.81)	40,902,779
46	House Regulators	383.00	14,028,506	27,712	(207)	14,056,011	86,841.90	(295.37)	14,142,557
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	6,268,225	51,956	(20,913)	6,299,268	18,419.58	(10,555.28)	6,307,132
49	Industrial M&R Equipment. Large Volume	385.10	1,042,209	2,697	0	1,044,906	(0.94)	(2,068.73)	1,042,836
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	9,548,612	(551)	0	9,548,061	126,175.04	0	9,674,236
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	2,324,849	0	(804)	2,324,045	0	0	2,324,045
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	4,192,831	(254)	0	4,192,577	0	0	4,192,577
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	56,772	0	0	56,772	0	0	56,772
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	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,670,600	158,689	0	16,829,289	25,476.99	(9,794.42)	16,844,972
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	269,030	0	(2,990)	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	964,272	0	(1,206)	963,066	0	0	963,066
80	**Total Gas Plant in Service**		**2,796,352,579**	**3,503,338**	**(1,295,565)**	**2,798,560,352**	**15,704,305**	**(1,278,459)**	**2,812,986,198**

Columns Gas of Pennsylvania, Inc.

Schedule 108 R-2020-3018835

Updated for Actuals Through December 31, 2020

			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 5/31/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 6/30/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 7/31/2020 (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	26,624,197	310,345	(51,696)	26,882,845	149,949	(234,933)	26,797,861
6	Cloud Software	303.99	1,430,473	111	0	1,430,584	27,578	0	1,458,162
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	3,220,858	0	0	3,220,858	0	0	3,220,858
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	948,272	0	0	948,272	0	0	948,272
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	3,201,920	2,000	0	3,203,920	0	(4)	3,203,917
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	5,380,639	22,120	0	5,402,759	7,277	0	5,410,035
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	17,679,690	16,650	0	17,696,340	0	0	17,696,340
30	Structures, Other Distribution System, Leased	375.71	5,817,296	0	0	5,817,296	0	0	5,817,296
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,775,089,612	22,097,400	(404,099)	1,796,782,914	9,462,913	(498,666)	1,805,747,161
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,474,194	6	(34,045)	64,440,155	386	(63,406)	64,377,134
36	Cast Iron	376.80	220,803	0	0	220,803	0	0	220,803
37	Measuring & Regulating Equipment General	378.10	1,447,592	0	0	1,447,592	0	(2,936)	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	100,327,910	(221,239)	(1,127)	100,105,544	933,769	(7,914)	101,031,399
39	Measuring & Regulating Equipment Local Gas	378.30	449,950	0	0	449,950	0	(9,589)	440,361
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	597,601,033	5,823,181	(1,106,108)	602,318,107	4,738,744	(942,271)	606,114,580
43	Meters	381.00	39,499,946	122,741	(47,631)	39,575,057	424,665	(41,624)	39,958,099
44	Auto Meter Reading Devices	381.10	24,615,770	4,431	0	24,620,201	0	0	24,620,201
45	Meter Installations	382.00	40,902,779	44,786	(7,706)	40,939,860	84,312	(9,917)	41,014,254
46	House Regulators	383.00	14,142,557	63,214	(698)	14,205,074	77,416	(1,461)	14,281,029
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	6,307,132	4,866	(60,970)	6,251,028	8,032	(92,486)	6,166,574
49	Industrial M&R Equipment. Large Volume	385.10	1,042,836	(40)	(314)	1,042,482	0	(1,401)	1,041,080
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	9,674,236	124,468	0	9,798,703	181,003	(9,105)	9,970,600
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	2,324,045	0	(636)	2,323,409	0	(12,937)	2,310,472
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	4,192,577	128	0	4,192,705	7,076	0	4,199,781
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	56,772	0	0	56,772	0	0	56,772
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	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,844,972	11,361	(9,829)	16,846,504	45,870	(16,826)	16,875,548
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	963,066	0	0	963,066	0	(9,796)	953,270
80	**Total Gas Plant in Service**		2,812,986,198	28,426,528	(1,724,857)	2,839,687,869	16,148,989	(1,955,272)	2,853,881,586

Columns Gas of Pennsylvania, Inc.

Schedule 108 R-2020-3018835

Updated for Actuals Through December 31, 2020

Line No.	Description	Account No. (1)	Plant Beginning Balance 7/31/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 8/31/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 9/30/2020 (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	26,797,861	731,835	0	27,529,696	58,059	(174,258)	27,413,496
6	Cloud Software	303.99	1,458,162	235,528	0	1,693,690	269	0	1,693,959
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	3,220,858	29,179	0	3,250,037	0	0	3,250,037
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	948,272	0	0	948,272	0	0	948,272
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	3,203,917	0	0	3,203,917	0	(1,079)	3,202,837
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	5,410,035	229	0	5,410,265	17,714	0	5,427,979
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	17,696,340	0	0	17,696,340	25,742	0	17,722,082
30	Structures, Other Distribution System, Leased	375.71	5,817,296	0	0	5,817,296	939	0	5,818,235
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,805,747,161	41,604,399	(365,519)	1,846,986,041	15,565,000	(1,064,488)	1,861,486,553
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,377,134	1	(43,571)	64,333,564	30	(56,929)	64,276,666
36	Cast Iron	376.80	220,803	0	(629)	220,174	0	(3,594)	216,579
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	101,031,399	1,972,310	(39,499)	102,964,209	4,085,360	(32,329)	107,017,241
39	Measuring & Regulating Equipment Local Gas	378.30	440,361	0	0	440,361	0	(1,858)	438,503
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	606,114,580	7,094,850	(123,885)	613,085,545	6,685,635	(2,369,393)	617,401,788
43	Meters	381.00	39,958,099	225,050	(18,104)	40,165,045	9,786	(19,317)	40,155,515
44	Auto Meter Reading Devices	381.10	24,620,201	1,533	0	24,621,734	1,073	0	24,622,807
45	Meter Installations	382.00	41,014,254	39,805	(7,544)	41,046,516	58,267	(8,183)	41,096,599
46	House Regulators	383.00	14,281,029	69,673	(775)	14,349,927	99,880	(780)	14,449,027
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	6,166,574	7,084	(203,714)	5,969,944	37,932	(91,557)	5,916,319
49	Industrial M&R Equipment. Large Volume	385.10	1,041,080	0	0	1,041,080	0	0	1,041,080
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	9,970,600	14,432	(6,699)	9,978,334	335,736	(8,071)	10,305,999
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	2,310,472	0	0	2,310,472	0	0	2,310,472
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	4,199,781	0	0	4,199,781	12,828	0	4,212,609
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	56,772	0	0	56,772	0	0	56,772
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	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,875,548	49,451	(5,290)	16,919,709	37,254	(50,994)	16,905,970
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**		**2,853,881,586**	**52,075,360**	**(815,228)**	**2,905,141,718**	**27,031,505**	**(3,882,831)**	**2,928,290,392**

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
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			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 9/30/2020 (2) $	Additions (3) $	Retirements (4) $	Balance as of 10/31/2020 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 11/30/2020 (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	27,413,496	345,284	(11,749)	27,747,031	599,681	(614,447)	27,732,265
6	Cloud Software	303.99	1,693,959	24,314		1,718,273	940		1,719,212
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	0	0	3,250,037
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	948,272	0	(96)	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	3,202,837	95,036	0	3,297,873	56,209	(1,054)	3,353,028
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	5,427,979	8,395	(3,465)	5,432,909	93,323	(4,960)	5,521,273
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	0	0	17,722,082	0	0	17,722,082
30	Structures, Other Distribution System, Leased	375.71	5,818,235	1,090	0	5,819,325	(37)	0	5,819,288
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains:								
33	Mains	376.00	1,861,486,553	21,829,002	(1,236,378)	1,882,079,177	23,325,250	(649,848)	1,904,754,580
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,276,666	1	(91,723)	64,184,944	1	(55,398)	64,129,547
36	Cast Iron	376.80	216,579	0	(10,712)	205,867	0	0	205,867
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	107,017,241	1,068,841	(105,989)	107,980,092	3,029,067	(29,878)	110,979,281
39	Measuring & Regulating Equipment Local Gas	378.30	438,503	0	0	438,503	0	0	438,503
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	617,401,788	8,364,696	(1,294,502)	624,471,982	7,224,762	(1,236,488)	630,460,256
43	Meters	381.00	40,155,515	7,652	(42,067)	40,121,101	644,660	(22,757)	40,743,004
44	Auto Meter Reading Devices	381.10	24,622,807	0	0	24,622,807	22,389	0	24,645,195
45	Meter Installations	382.00	41,096,599	110,479	(8,392)	41,198,687	80,382	(8,464)	41,270,605
46	House Regulators	383.00	14,449,027	103,035	(825)	14,551,237	104,398	(672)	14,654,963
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	5,916,319	36,445	(25,432)	5,927,333	80,877	(47,735)	5,960,476
49	Industrial M&R Equipment. Large Volume	385.10	1,041,080	0	0	1,041,080	1	(3,111)	1,037,970
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	10,305,999	691	0	10,306,690	50,361	(30,716)	10,326,335
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	2,310,472	0	(1,178)	2,309,294	0	(3,978)	2,305,316
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	4,212,609	0	0	4,212,609	3	(941,918)	3,270,694
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	56,772	4,112	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	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,905,970	90,183	0	16,996,153	45,212	0	17,041,365
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**		2,928,290,392	32,089,257	(2,832,507)	2,957,547,142	35,357,479	(3,651,423)	2,989,253,197

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
Updated for Actuals Through December 31, 2020

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) $
			Gas Plant in Service			
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	259,968	0	27,992,233
6	Cloud Software	303.99	1,719,212	3,281		1,722,494
7	**Underground Storage Plant**					
8	Land	350.10	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,250,037	0	0	3,250,037
11	Wells Construction	352.01	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032
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	0	3,361,100
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	72,912	0	3,425,940
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	69,554	0	5,590,827
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	17,722,082	64,013	0	17,786,096
30	Structures, Other Distribution System, Leased	375.71	5,819,288	79,207	0	5,898,495
31	Structures, Communication	375.80	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
34	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481
35	Bare Steel	376.30	64,129,547	162	(313,970)	63,815,739
36	Cast Iron	376.80	205,867	0	(8,798)	197,070
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	2,444,905	(46,370)	113,377,816
39	Measuring & Regulating Equipment Local Gas	378.30	438,503	0	(1,010)	437,493
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	8,297,612	(1,113,401)	637,644,467
43	Meters	381.00	40,743,004	83,612	(34,168)	40,792,448
44	Auto Meter Reading Devices	381.10	24,645,195	0	0	24,645,195
45	Meter Installations	382.00	41,270,605	119,516	(11,362)	41,378,759
46	House Regulators	383.00	14,654,963	120,648	(616)	14,774,996
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	60,570	(29,537)	5,991,509
49	Industrial M&R Equipment. Large Volume	385.10	1,037,970	0	0	1,037,970
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	0	623,932
54	Other Equipment, Telemetering	387.45	10,326,335	124,238	(9,553)	10,441,021
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	2,305,316	0	(22,490)	2,282,826
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	169,701	0	3,440,394
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	0	60,884
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	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	17,041,365	24,880	(9,213)	17,057,031
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	0	787,916
79	Miscellaneous Equipment	398.00	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**

Columbia Gas of Pennsylvania, Inc.
Schedule 108 R-2020-3018835
Updated for Actuals Through December 31, 2020

	SUMMARY		Gas Plant in Service			
Line No.	**Description**	**Account No. (1)**	**Plant Beginning Balance 11/30/2019 (2) $**	**Additions (3) $**	**Retirements (4) $**	**Balance as of 12/31/2020 (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	24,574,424	4,792,775	(1,374,966)	27,992,233
6	Cloud Software	303.99	0	1,722,494	0	1,722,494
7	Underground Storage Plant					
8	Land	350.10	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,220,858	29,179	0	3,250,037
11	Wells Construction	352.01	738,941	0	0	738,941
12	Wells Equipment	352.02	168,032	0	0	168,032
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	948,272	0	(96)	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	477,100	2,884,000	0	3,361,100
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	3,082,273	347,087	(3,419)	3,425,940
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
24	Rights of Way	374.50	3,233,161	10	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	5,184,456	492,866	(86,495)	5,590,827
28	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228
29	Structures, Other Distribution System	375.70	9,917,104	8,046,776	(177,785)	17,786,096
30	Structures, Other Distribution System, Leased	375.71	5,487,917	423,054	(12,476)	5,898,495
31	Structures, Communication	375.80	16,515	0	0	16,515
32	Mains:					
33	Mains	376.00	1,688,863,735	252,260,528	(26,468,678)	1,914,655,585
34	Mains - CSL Replacements	376.08	23,574,504	0	(59,023)	23,515,481
35	Bare Steel	376.30	64,933,670	596	(1,118,527)	63,815,739
36	Cast Iron	376.80	263,240	0	(66,170)	197,070
37	Measuring & Regulating Equipment General	378.10	1,451,939	0	(7,283)	1,444,656
38	Measuring & Regulating Equipment Regulating	378.20	93,245,433	20,696,447	(564,064)	113,377,816
39	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	(17,424)	437,493
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	580,788,003	71,227,562	(14,371,098)	637,644,467
43	Meters	381.00	39,176,296	2,222,315	(606,164)	40,792,448
44	Auto Meter Reading Devices	381.10	24,570,547	74,648	0	24,645,195
45	Meter Installations	382.00	40,589,166	900,670	(111,078)	41,378,759
46	House Regulators	383.00	13,686,795	1,097,539	(9,339)	14,774,996
47	House Regulators Installations	384.00	3,484,788	0	0	3,484,788
48	Industrial M&R Equipment. Station Equipment	385.00	6,362,985	319,318	(690,794)	5,991,509
49	Industrial M&R Equipment. Large Volume	385.10	1,579,956	(525,576)	(16,410)	1,037,970
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	627,560	0	(3,628)	623,932
54	Other Equipment, Telemetering	387.45	9,519,187	1,004,728	(82,894)	10,441,021
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					
58	Structures, Communications	390.10	49,821	0	0	49,821
59	Office Furniture & Equipment, Unspecified	391.10	2,380,973	0	(98,147)	2,282,826
60	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304
61	Office Furniture & Equipment, Information Systems	391.12	4,498,635	203,157	(1,261,397)	3,440,394
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	57,458	4,112	(686)	60,884
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	0	179,308
69	Tools, Shop Equipment	394.20	35,454	0	0	35,454
70	Tools, Tools and Other	394.30	16,345,764	974,381	(263,114)	17,057,031
71	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
72	Laboratory Equipment Gas	395.00	269,030	0	(2,990)	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	792,133	0	(4,217)	787,916
79	Miscellaneous Equipment	398.00	971,183	0	(17,913)	953,270
80	Total Gas Plant in Service		**2,687,846,103**	**369,198,667**	**(47,496,273)**	**3,009,548,498**

1/ In December 2019 an over retirement of $9.5 million was made in GPA 376-Mains. A correction was made in January 2020 to reflect the proper activity for December 2019, which was (9,667,656).

R. BRUMLEY

COLUMBIA STATEMENT NO. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

TABLE OF CONTENTS

I. Introduction

Q. Please state your name and business address.

A. My name is Raymond A. Brumley. My business address is 2787 Memorial Boulevard, Connellsville, Pennsylvania 15425.

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 once before this regulatory agency in a consumer complaint proceeding. 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, 2022) 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 2021 to 2025 timeframe, with a planned spending program of over $290 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 2020, and the budgeted amount for 2021 and 2022 are provided in the following table.

Table 1

Budget Class - Age and Condition

Gas Plant Account "GPA"	**Description**	**Total 2020 Actual**	**Total 2021 Projected**	**Total 2022 Projected**
354	Compressor Stations	1,036,577	0	0
376	Mains - Leakage Elimination	159,527,477	176,347,000	200,890,000
380	Service Lines – Replaced	54,198,681	51,143,000	58,349,000
376	Customer Service Lines Replaced	14,441,958	17,048,000	19,450,000
381	Meters / 998 Int. Co. Meters	1,224,509	900,000	950,000
382	Meter Install – Replace	99,006	1,050,000	1,100,000
383	House Regulators - Replace	24,072	70,000	80,000
378	Plant Regulators – Replace	19,659,403	12,810,000	6,820,000
375	Reg Structures Replace	192,860	300,000	300,000
385	LV Excess Press Meas Sta	154,004	900,000	900,000
376	Corrosion Mitigation Ins	128,842	150,000	150,000
383	Service Regulators - Replacement	7,550	20,000	20,000
		250,694,939	260,738,000	289,009,000

The table below (Table 2) depicts the three budget classes, Age and Condition, Betterment, and Public Improvement (rounded to the thousands). Please note – 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	2020 Actuals	2021 Approved	2022 Projected
Age and Conditon	250,763,000	260,838,000	289,109,000
Betterment	9,743,000	42,615,000	8,500,000
Public Improvement	7,710,000	8,997,000	5,500,000

Q. How does Columbia's actual spend for 2020 compare to the projected budget for 2020 that was provided in the Company's last rate case, filed in 2020?

A. The projected 2020 budget for plant additions related to distribution plant was $250,633,759, which was included in a table similar to the one above on page 15 of Columbia Statement No. 14, in Docket No. R-2020-3018835. The actual spend for 2020 was $250,694,939, so the actual spend was right in line with the projected budget.

Q. Please explain why the 2021 budget is more than the 2020 budget?

A. Within our 2021 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 2020 to 2021, as well as 2022, 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.

Within our 2021 Betterment budget, approximately $10 million has been slated for the New Castle odorization project, and $23 million for the Airport/Southern Beltway Corridor modernization project. Within the New Castle operating area, the Company plans to strategically install odorization equipment at certain points of delivery. Columbia is also planning to tie some of its distribution systems together, to more efficiently manage odorization and to enhance safe and reliable service to our customers. The Airport/Southern Beltway Corridor project will involve a modernization of essential infrastructure to boost delivery capability to accommodate industrial manufacturing, commercial and residential markets near the Pittsburgh Airport. The project involves a new point of delivery, two new district regulator stations and a high pressure trunk line.

Q. How was the budget for 2022 developed?

A. In addition to what is stated above, within our 2022 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 and a new construction blanket contract taking effect. Though this is competitively bid, based on the market demand for natural gas contractors, not just across

Pennsylvania but other states as well, it is anticipated that their pricing will increase to the levels shown in our 2022 projections. Budget plans are derived based upon historical trends, known future projects, and any commitments made in conjunction with the PA PUC (e.g. over pressure protection program).

III. Columbia's Pipeline Replacement Efforts

Q. How many feet of bare steel, wrought iron, and cast iron main have been eliminated from Columbia's system during its accelerated program, and how does that trend compare with the previous years?

A. Columbia began an accelerated replacement of bare steel, wrought iron, and cast iron pipe in 2007. Between 2007 and the end of 2020, 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
Total Actual (Through YE 2020)	**6,078,654**	feet

From 2007 through 2020, Columbia's replacement program eliminated an average of 434,190 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. As discussed in witness Kempic's testimony (Columbia Statement No. 1), Columbia was unable to complete all of its projected 2020 replacement work as a result of the COVID-19 Pandemic. Prior to the COVID-19 pandemic, Columbia had 140 crews working on pipeline replacement projects across its service territory. In response to COVID-19, starting March 23, 2020, Columbia took a two week work pause throughout the state where only essential projects were worked. Columbia averaged only 12 crews working during this two week period.

Per the Governor's order, Columbia continued to work only essential projects throughout the month of April, averaging 25 crews. With the release on restrictions starting May 4, 2020, Columbia began to ramp up its crews throughout the month of May, as follows:

May 4th - 49 crews

May 11th - 76 crews

May 18th - 104 crews

By June 8, 2020 Columbia was up to 121 crews and continued to add crews to return to pre COVID-19 levels. It should be noted that not all crews were able to return for various reasons as a result of COVID-19. Some contractor employees were laid off during the work pause.

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 49% of all hazardous or potentially hazardous leakage cleared on mains in the Columbia distribution system as of year ending 2020. 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.

[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.

Q. How will main replacements affect the Company's leak repair experience?

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 2020, 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 388, 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, this massive and structural 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 2020 Columbia had approximately 113 construction crews (2020 average is down due to COVID) which employed approximately 1,130 contractor employees and subcontractors (e.g. restoration, flaggers, drillers, plumbers, etc.). For 2021, Columbia will have approximately 145 construction crews with approximately 1,450 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 2020 actuals, is $227.00 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 436,000 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 Communications, Municipal Affairs and Community Relations 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.

In addition, most recently, Columbia hired two new Public Affairs Specialists to work with its Manager of Municipal Affairs to work 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 2021.
- 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, 2020?

A. Yes. In 2020, the Communications, Municipal Affairs and Community Relations team participated in the following discussions:

- **Allegheny County - CONNECT Utilities Meetings:** Columbia participated virtually in CONNECT Spring and Fall 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 with road restoration and repaving efforts. In addition, Columbia and other utilities met with the Mayor's Chief of Staff early in 2020 to discuss improved utility coordination.
- **Allegheny County –** Columbia hosted proactive meetings or discussions with Baldwin Borough, Bellevue Borough, Findlay Township, Mt. Lebanon Township, Peters Township, Pleasant Hills Township, Scott Township, South Fayette Township and Whitehall Borough regarding 2020 pipeline replacement projects or operational work in those communities.
- **Beaver County –** Columbia hosted proactive meetings or discussions with

Beaver Borough and Franklin Township on proposed pipeline replacement projects.

- **Centre County –** Columbia hosted proactive meetings with State College Borough regarding operational work and planned pipeline replacement projects in addition to the borough's permit process and expectations.
- **Fayette County –** Columbia hosted proactive meetings with Springhill Township and Stockdale Borough on pipeline replacement projects.
- **Lawrence County –** Columbia hosted proactive meetings with Wampum Borough on a pipeline replacement project and permitting in the borough's right-of-way.
- **Washington County –** Columbia hosted proactive meetings with Canonsburg Borough to discuss paving restoration concerns and East Washington Borough regarding a pipeline replacement project, permitting and reasonable restoration requirements.
- **Cross Creek Township, Washington County:** Columbia met with township officials to discuss the PA One Call law, Commission enforcement and the AVR (alleged violation report) process. The township was upset it had been cited for PA One Call law violations outside its municipal boundaries. Columbia explained the law, how it works and what is required and worked with the township and the PA One Call Board to address concerns about compliance with the PA One Call law.
- **Westmoreland County –** Columbia hosted discussions with the City of Jeannette regarding restoration requirements for operational work in the

City.

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 in 2019.
- **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.
- **Brownsville Borough, Fayette County:** Columbia continued to work with Borough Council in 2020 regarding its concerns with updated permit fee formulas and restoration standards that would increase costs for work Columbia conducts in the borough. Borough Council has agreed to review the issue and Columbia provided the borough with examples of reasonable permit fee and restoration ordinances in other nearby municipalities.
- **Georges Township, Fayette County:** Columbia has engaged the township's supervisors in opposition to the implementation of an engineering inspection fee based on the square yardage of the road disturbance created by Columbia's work in the right of way. This fee language was included in an update of the township's road cut ordinance. When seeking a permit to replace 5,500 feet of mainline pipe in 2020, the

township's engineering firm informed Columbia the engineering inspection fees were estimated to be between $82,000 and $85,000 for the project. Columbia has objected to those fees.

- **Luzerne Township, Fayette County:** 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 to prevent the retroactive application of increased permit fee costs in a new road opening ordinance passed by the Council in 2020. 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 oppose the township's policy of requiring the signing of a "Road Maintenance Agreement" which forces significant paving restoration (100 yards) on each side of a road opening cut Columbia may make. In 2020, Columbia negotiated a restoration agreement using PennDOT restoration standards for both a 2020 and 2021 pipeline replacement project reducing restoration costs on the project.

Q. Does this conclude your direct testimony?

A. Yes, it does.

P. MOUL

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-2021-3024296

March 30, 2021

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 10.95%. Although my 10.95% return on equity does not make a specific provision for 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, 2022 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	41.77%	4.54%	1.90%
Short-Term Debt	3.89%	0.85%	0.03%
Total Debt	45.66%		1.93%
Common Equity	54.34%	10.95%	5.95%
Total	100.00%		7.88%

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. Are there unusual factors that you included in your analysis of the cost of equity for CPA that make this case unique?

A. Yes. My cost of equity analysis reflects the impact of the coronavirus pandemic. This event had a significant impact on the capital markets -- both debt and equity. Extraordinary events around the COVID-19 pandemic have produced significant turmoil that has rocked the stock and bond markets beginning in the February-March 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As a recession began in February 2020, extraordinary actions were taken by the Federal Open Market Committee ("FOMC") to address these disruptions. That is to say, I have considered these events as they impact the inputs that I used in the various models of the cost of equity. I have applied the cost of equity models using input data that follows the beginning of the economic recession.

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 436,000 customers located in south-central and western Pennsylvania. Throughput to its customers for the twelve-months ended December 31, 2019 was represented by approximately 46% to sales customers and approximately 54% 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 10.95%.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. How have you measured the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of 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. 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

[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).

models in the recent Quarterly Earnings Report (Docket No. M-2020-3023406) approved by the Commission on January 14, 2021.

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	13.46%
Risk Premium	10.00%
CAPM	12.67%
Comparable Earnings	12.00%

From these measures, I recommend a cost of equity of 10.95%. My equity return of 10.95% is amply supported by the market models (i.e., DCF, Risk Premium and CAPM) whose results are in the range of 10.00% to 13.46%. To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements.

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 mechanism applicable only to residential customers. Description of the Company's RNA is contained in the testimony of Company witness Notestone.

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 24% (18,568,998 Dth ÷ 78,965,406 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 1181.2 miles (or approximately 15%) of its distribution mains as of year-end 2019. The Company also has 42,695 (or approximately 10%) of its services constructed of unprotected steel. For the future, the Company expects its net capital expenditures to be:

Year	Capital Expenditures
2021	$ 388,813,000
2022	$ 370,256,000
2023	$ 423,110,000
2024	$ 433,468,000
2025	$ 451,959,000
Total	$ 2,067,606,000

The Company's total capital expenditures over the next five years will represent approximately 82% ($2,067,606,000 ÷ $2,533,660,000) of the net utility plant in service at December 31, 2020.

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 2020. 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 A2 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 2015-2019. The important categories of relative risk may be summarized as follows:

<u>Size.</u> 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 financial risk. The five-year average common equity ratios, based on permanent capital, were 55.1% for CPA, 52.6% for the Gas Group, and 42.2% for the S&P Public Utilities. The Company's common equity ratio was fairly similar to the Gas Group, thereby indicating similar financial risk.

[2]For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.119 (1.3% ÷ 10.9%) for the Company, 0.089 (0.8% ÷ 9.0%) for the Gas Group, and 0.049 (0.5% ÷ 10.2%) 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 74.3% for the Company, 84.1% 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"), the five-year average pre-tax interest coverage was 4.43 times for the Company, 4.23 times for the Gas Group, and 3.22 times for the S&P Public Utilities. The interest coverages were fairly similar for the Company and the Gas Group, thereby indicating similar risk.

[3]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

<u>Quality of Earnings.</u> 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.

<u>Internally Generated Funds.</u> 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 64.5% for the Company, 59.5% for the Gas Group and 74.1% 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 will increase.

<u>Betas.</u> The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated

with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.87 as the average for the 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.

Q. Does Schedule 5 provide the Company's capitalization and capital structure ratios?

[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.

A. Yes. Schedule 5 presents the Company's capitalization and related capital structure ratios. The November 30, 2020 capitalization corresponds with the end of the HTY in this case. The November 30, 2021 capital structure is estimated at the end of the FTY, and the December 31, 2022 capital structure is estimated at the end of the FPFTY. The Company will receive equity infusions of $60 million in the FTY and $5 million in the FPFTY. The Company expects to issue $110 million of new long-term debt in the FTY and $125 million of new long-term debt in the FPFTY. A projection on retained earnings has been reflected in the FTY and FPFTY including an assumption of no dividend payments in either case.

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 41.77% long-term debt, 3.89% short-term debt, and 54.34% common equity at December 31, 2022. 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, 2020. On page 2 of

Schedule 6, I have shown the embedded cost rate of debt estimated at November 30, 2021. And on page 3 of Schedule 6, the embedded cost of debt is shown at December 31, 2022. For the new issues of long-term debt, I have used a cost of 3.25% for the issue in the FTY and 3.67% for the issue in the FPFTY. 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 4.54% embedded cost of long-term debt at December 31, 2021, 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 41.77% 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 0.85%, which represents the Company's estimate for the FPFTY. The Company obtains its short-term debt from the NiSource money pool, which has as its source commercial paper. 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 4.23% 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 10.95% for CPA.

Discounted Cash Flow

Q. Please describe the Discounted Cash Flow 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 13.46% with the leverage adjustment and 11.29% without the leverage adjustment for the Gas Group.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

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 months ended December 2020, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended December 2020 the average dividend yield was 3.36% for the Gas Group based upon a calculation using annualized dividend payments

[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.

and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.65% for both periods. For applying the DCF model, I have used the six-month average dividend yield of 3.65% for the Gas Group. The use of this dividend yield will reflect current capital costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds fourteen basis points to the six-month average historical yield, thus producing the 3.79% 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 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" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle, but rather to rely upon analysts' growth forecasts, 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 those 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 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 (6.83%), Zacks (9.16%), and Value Line (9.89%).

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.[6] Consistent with Professor Gordon's findings, projections of

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

earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts shown on Schedule 9 for the Gas Group exhibit a range of average earnings per share growth rates from 6.83% to 9.89%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 7.50% 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 and is below the midpoint of that data set. 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 33.04% long-term debt, 0.00% preferred stock, and 66.96% 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 rate setting 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 rate-setting 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," provides a return of 8.91% 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.

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 8.91%, which is the return for the Gas Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 4.55% to compensate investors for the risk of a 48.57% debt ratio. Under this approach, the parts sum to 13.46% (8.91% + 4.55%), 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 3.79% dividend yield, the 7.50% growth rate, and 2.17% for the leverage adjustment in order to arrive at the same 13.46% (3.79% + 7.50% + 2.17%) return. I know of no means to mathematically solve for the 2.17% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 2.17% adjustment is merely a convenient way to compare the 13.46% return computed using the Modigliani & Miller formulas to the 11.29% 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

11.29% 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 rate-setting process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 13.46%, computed as follows:

	D_1/P_0	+	g	+	$lev.$	=	K
Gas Group	3.79%	+	7.50%	+	2.17%	=	13.46%

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 10.00%.

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 3.25% 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 months ended December 2020, the average monthly yield on Moody's index of A-rated public utility bonds was 3.02%. For the six and three-month periods ended December 2020, the yields were 2.81% and 2.86%, respectively. During the twelve-months ended December 2020, the range of the yields on A-rated public utility bonds was 2.73% to 3.50%. 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 1.45% on a twelve-month average basis, 1.32% on a six-month average basis, and 1.24% on a three-month average basis. Giving greater emphasis to the three-month average spread, which reflects the downtrend, 1.25% represents a reasonable 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, 2021, and a yield spread of 1.25%, 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
2021	First	2.5%	3.5%	1.7%	1.25%	2.95%
2021	Second	2.5%	3.6%	1.8%	1.25%	3.05%
2021	Third	2.6%	3.7%	1.9%	1.25%	3.15%
2021	Fourth	2.7%	3.8%	2.0%	1.25%	3.25%
2022	First	2.8%	3.8%	2.1%	1.25%	3.35%
2022	Second	2.8%	3.8%	2.1%	1.25%	3.35%

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, 2020 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
2022-2026	3.6%	4.6%	2.8%
2027-2031	4.5%	5.4%	3.6%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 3.25% 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 those data to make investment decisions.

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

A. To develop an appropriate equity risk premium, I analyzed the results from 2020 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	6.70%
Average Across All Interest Rates	5.69%
High Interest Rates	4.69%

Based on my analysis of the historical data, the equity risk premium was 6.70% when the marginal cost of long-term government bonds was low (i.e., 2.88%, 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 5.69% when the average government bond yield was 4.99%. 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., "i"), and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of 10.00%, computed as follows:

	i	+	RP	=	k
Gas Group	3.25%	+	6.75%	=	10.00%

<u>Capital Asset Pricing Model</u>

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 12.67% for the Gas Group. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.87 for the Gas Group.

Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The betas must be reflective of the financial risk associated with the rate-setting 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,[7] as follows:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

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[7] 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.

where 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 0.63 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled “Hamada,” who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.10 for the book value capital structure of the Gas Group.

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 months ended December 2020, the average yield on 30-year Treasury bonds was 1.56%. For the six- and three-months ended December 2020, the yields on 30-year Treasury bonds were 1.49% and 1.62%, respectively. During the twelve-months ended December 2020, the range of the yields on 30-year Treasury bonds was 1.27% to 2.22%. The low yields that existed during recent periods can be traced to weakness in business fixed investment and exports due in part to the U.S.’s trade war with China. Thereafter, extraordinary events associated with the COVID-19 pandemic induced significant turmoil that jolted the capital markets in the February-May 2020 time frame. During this period, we saw abrupt reaction to the coronavirus pandemic and significant declines in the price of crude oil. These events led to the end of the record-setting 128-month economic expansion. As the recession unfolded in February 2020, a historic rout in stock prices took place and the Federal Open Market Committee (“FOMC”) acted to address these disruptions. Presently, the Fed Funds rate is near zero. The

FOMC continues to support the money and capital markets during the coronavirus pandemic.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on January 1, 2021 indicate that the yields on long-term Treasury bonds are expected to be in the range of 1.7% to 2.1% during the next six quarters. The forecast for the FPFTY is 2.1% for 30-year Treasury Bonds. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 2.8% from 2022 through 2026 and 3.6% from 2027 to 2031. 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 2.00% 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 11.92% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.88% when interest rates were low. As such, I carried over to Schedule 13, page 2, the average large common stock returns of 11.92% and the average yield on long-term government bonds of 2.88%. The resulting market premium is 9.04% (11.92% - 2.88%) 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 10.50% total market return. With this forecast, I calculated a market premium of 8.50% (10.50% - 2.00%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 8.77% (8.50% + 9.04% = 17.54% ÷ 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 2.00% risk-free rate of return, the leverage adjusted beta of 1.10 for the Gas Group, the 8.77% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	**+**	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	***=***	***k***
Gas Group	2.00%	+	1.10	x (	8.77%	) +	1.02%	=	12.67%

Comparable Earnings Approach

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risks 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 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 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 they provide 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 historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 11.9% 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 12.1% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data my Comparable Earnings result is 12.00%, 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 10.95% for CPA. 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 10.95% rate of return on common equity so that it can compete in the capital markets, attain reasonable credit quality, and sustain its cash flow in the context of the its high levels of capital expenditures.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-two years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

N. PALONEY

COLUMBIA STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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, and 2018 base rate cases at Docket Nos. R-2015- 2468056, R-2016-2529660, and R-2018-2647577. 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). 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. My testimony supports Columbia's projected Operations and Maintenance ("O&M") expenses for the Fully Projected Future Test Year ("FPFTY") (through December 31,2021), that have been incorporated in Columbia witness Miller's cost of service analysis (Columbia Statement No. 4).

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 Fully Projected Future Test Year test period is derived from the Company's most recent O&M budget.

Q. What is Columbia's O&M expense budget methodology?

The O&M expense budgeting methodology used by Columbia is a combination of a "top down" and "grass roots" approaches. The O&M expense budget serves as a key component of the overall Columbia budget and as a cost management tool for both NCSC and Columbia management.

Q. Please explain.

A. The NCSC management team, including Columbia's management team, first identifies general O&M requirements and planning objectives in conjunction with NiSource's senior management. These requirements and objectives are then communicated to each successive layer of management and employees, as well as the NCSC Financial Planning team, which is responsible for the development of all NCSC budgets. It is the responsibility of these groups, working together, to ensure: (1) that Columbia's budgets, including O&M expenses, are developed in accordance with overall financial goals and objectives; and (2), that individual company operational and administrative requirements and regulatory commitments are addressed.

Q. How is the O&M budget developed?

A. The O&M budget for Columbia is based on a grass roots concept in which individuals who are responsible for approving expenditures are also responsible for budgeting the expenditures. The process generally follows organizational responsibility. Department heads are responsible for overseeing the development of O&M budgets for all cost centers under their control. Budgets originate in operating center locations in the field and other departments representing Columbia's major business functions; these budgets are then combined with a corporate-level budget to arrive at a total company budget. I will discuss the corporate-level budget later in my testimony.

The Company's O&M budget is developed by department and by cost element, with the assistance of the NCSC Financial Planning department. Each department's budget is reviewed with and approved by the Vice President of Financial Planning and Analysis, Chief Operating Officer and the Company President. 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. Does that conclude the development of the O&M expense budgeting process?

A. No. Upon agreement and sign-off on the departmental O&M expense budget, the current year O&M budget is then developed in more detail (i.e., at the individual cost center level) beginning in the preceding fourth quarter for the current year. The process concludes in the first quarter.

The current year detailed O&M budget is reviewed against actual results each month throughout the year to determine the reasons for variances and to take appropriate action. If known variances are the result of timing that will be resolved within the year, then those variances are monitored closely but no further action is taken, unless it is deemed, at some point during the year, that the variance will result in a true budget variance at the end of the year. When the review of monthly budget versus actual reveals variances that are expected to last throughout the year, the Financial Planning department will work with Columbia management to determine the drivers of the variances and steps to be taken to reduce the variance to the overall budget. In certain cases, budget variances will occur to address or take advantage of unforeseen general or operational conditions. In cases where a variance is driven by unforeseen general or operational conditions, the variance may not be reduced or mitigated, but may result in a departmental overrun. In this case, documentation of the drivers of the variance is maintained and evaluated in future planning cycles to ensure proper consideration of new and developing forecast items.

Q. Does the O&M expense budgeting methodology and process described in your testimony result in an accurate estimate of expenses to be incurred during the Fully Projected Future Test Year?

A. Yes. Notwithstanding all of the challenges that resulted from COVID in 2020, Columbia underspent the original O&M budgets by a margin of one half of one percent. Please refer to Exhibit NP-1 accompanying this testimony for a comparison of actual results versus the annual original O&M budget for the years 2009 through 2020. Overall, Exhibit NP-1 indicates a high level of O&M budgeting accuracy by Columbia and, accordingly, provides a high level of confidence as to the accuracy of the O&M expenses included in the Fully Projected Future Test Year.

Notably, in eight of the last twelve years, Columbia has actually overspent the original O&M budget in the ranges noted, which supports the fact that the O&M budget is a conservative approach for ratemaking purposes. In 2015 and 2016, Columbia underspent the original O&M budgets by margins of 0.63% and 0.91%, respectively.

Columbia has experienced a variance of less than 5% to the original O&M budget in eight of the last eleven years, with the only exceptions being 2011, 2017 and 2018, when the variances were approximately 6.44%, 8.17% and (8.36%), respectively. Specifically, in 2011, Columbia experienced larger than budgeted pension contributions. When that factor was normalized, the remaining budget variance for the year was well below 1%.

In 2017, three factors drove the variance. The first was the O&M portion of a large one-time prepayment to the Pension Plan in the amount of $8.45 million. The second driver was a $1.8 million overspend in Gas Operations. The last driver was an incentive compensation payout greater than budgeted, due to positive business results. Adjusting for those three items, the total O&M variance in 2017 was 0.43%.

The budget variance in 2018 was driven by two factors. First, as a result of the Company's rate case settlement, the Commission allowed the Company to amortize the 2017 prepayment over a period of ten years. This resulted in an unbudgeted credit to pension expense in 2018. Secondly, the engagement of NCSC employees in the Merrimack Valley event's recovery efforts contributed to the variance. The Company estimates that the NCSC billings it received were reduced by approximately $2.7 - $3.1 million during the last four months of 2018. Adjusting for those two items, the total O&M variance in 2018 was approximately (1.0%).

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.

Q. What is meant by the term corporate-level budget?

A. Earlier in my testimony I explained that Columbia's budget for field operating centers and other major business functions is combined with a corporate-level budget to arrive at a total company budget. The corporate-level budget represents categories that are budgeted at a NiSource-level, and not an individual Columbia department level. This allows for each corporate-level department to focus exclusively on the expenditures for which they are directly responsible. Examples of O&M expenses included at the corporate level are employee benefits, benefits administration fees, audit fees, financial planning and accounting, in-house legal, human resources, corporate insurance, and regulatory amortizations.

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.

Q. Does your budgeting analysis include any projections regarding Columbia headcount?

Yes, Columbia is projecting 798 active full-time employees for 2021 and 2022, 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 an increase above the ending Historic Test Year ("HTY") level of 767 active full-time employees.

Q. What is the primary drivers for the Company's increased headcount?

A. The primary driver for the Company's increase headcount is to provide support to the Company's ongoing operational activities to provide safe, reliable service to customers.

Positions supporting ongoing operations are most often filled from within the Company's existing employee ranks, and bargaining unit agreement provisions can affect the bidding and selection process so that vacancies are held open for certain periods while applicants temporarily occupy a position before making a final decision. Once the new positions are filled by existing employees, the employees' former positions are then filled by new hires.

Q. Please explain the Company's hiring process to fill field positions.

A. For hiring of field employees, the company utilizes a "wave hiring" process. Wave hiring is built upon creating "pools" of applicants, and then offering a job to an applicant in the "pool". Pools typically consist of 20 applicant**s.** The Company has plans for wave hiring in April, June and October of 2021. The Company will provide updates sharing the results of the wave hiring as requested.

Q. Please explain the increase in the budgeted labor from the HTY to the FTY.

A. See the Company's response to Standard Data Request GAS RR-26 for a summary of labor increases. The adjustments to get to the FTY budget include adjustments for filled vacancies, headcount reductions related to NiSource Next, wage increases and adjustments to the allocation of labor dollars to capital and expense. Please see

Company Witness Kempic's testimony at Columbia Statement No. 1 for further discussion on NiSource Next.

Q. Are filled vacancies included in the normalized labor expense for the FTY?

A. Yes, they are. Included in normalized test year costs are costs associated with 31 vacancies. Total vacancies were reduced to 31 as the Company has also included a headcount reduction of 16 resulting from NiSource Next.

Q. Is the Company projecting any changes to headcounts from the FTY to the FPFTY?

A. No. The headcount remains at 798 for the FPFTY and reflects increases relating only to an average annual wage increase of 3%.

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 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.

Corporate Level Budgets

Q. Please describe the basis for the corporate-level budgets described on page 7 and included in Columbia's overall O&M budget.

A. Corporate-level budgets provided to Columbia include several major categories. Employee benefits expenses are based on information provided by NiSource's independent actuary, AON Hewitt. Corporate insurance expenses are based on estimated property and casualty premium costs developed by NCSC's Insurance Department. Audit fees are based on estimates developed by NCSC Accounting. Telecommunications expenses are based on estimates developed by NCSC Information Technology. NCSC expenses are based on estimates of services to be performed by NCSC, NiSource's shared services company, for Columbia, and are included in the NCSC budget. Benefits administration fees and incentive plan expenses are based on estimates developed by NCSC's Human Resources.

Q. Can you describe the NCSC annual budget development process?

The NCSC budget development process, with regard to timing and duration, is consistent with the Columbia planning process. The NCSC budget process used to develop the FTY and FPFTY was initiated in the fall of 2020 and completed in the first quarter of January 2021.

Targets for the NCSC functions are grounded in a trailing 12 month historical spend with merit and inflation adjusted for each year thereafter. The 12 month historical spend is adjusted to account for one-time items, future planned work, or strategic initiatives to develop final targets. Once targets are established, budgeted expenses are delineated by cost categories such as labor, materials, outside services, and other expenses.

NCSC's Vice President of Planning and Analysis reviews the completed budgets for reasonableness and an understanding of material changes for both the whole of the budgets and the allocation to each of the operating companies. The NCSC Service Fee is distributed to each operating company as an input to their planning process upon approval from NCSC's Vice President of Financial Planning and Analysis.

Q. What allocation bases are available to each NCSC department for allocating their budgets to NiSource companies?

A. The direct costs from NCSC departments, as mentioned above, such as labor, materials, outside services, and other expenses are allocated based on historical distributions to each operating company and adjusted as necessary for any one-time items, future planned work, or strategic initiatives as noted above. The resulting allocation is used to distribute costs by operating company in the financial plan.

In addition to the expenses mentioned above, each department is allocated a portion of NCSC's indirect costs, such as benefits, taxes, depreciation, and other expenses to arrive at a total cost. Labor is the primary driver of how the overhead costs are distributed to the departments. Please refer to Exhibit 4, Schedule 11, Attachment B's Exhibit A, for the description of the Direct Billing and Bases of Allocation for NCSC costs.

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/department leaders that provide forecast updates for the current year and any impact to future years.

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 $155,861,629 for the Historic Test Year ended November 30, 2020, $185,363,000 for the Future Test Year ending November 30, 2021 and $188,548,000 for the Fully Projected Future Test Year ending December 31, 2022, increases of $29,501,371 and $3,185,000, 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.

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

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7	**CE**		**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
8	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
9	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
10	Pension		2,119	6,005	6,598	-	3	1,137	-	6	549	-	-	
11	OPEB		715	1,065	492	(154)	(284)	(550)	(1,378)	(810)	(514)	(1,109)	(730)	(678)
12	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
13	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
14	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
15	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
16	Injuries and Damages		1,209	944	795	630	630	500	500	400	-	400	400	400
17	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
18	Company Memberships		347	345	249	292	262	256	256	332	491	491	563	560
19	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
20	Advertising		500	185	170	170	470	170	170	170	170	170	174	174
21	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
22	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
23	Other O&M		(3,987)	(3,780)	(116)	(783)	60	(1,906)	(434)	393	1,050	646	1,381	193
24	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
25	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
26	Amortization		82	75	(243)	(1,446)	(1,455)	185	267	496	511	409	845	935
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**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
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Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

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7	**CE**		**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
8	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
9	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
10	Pension		392	5,799	13,088	91	2,489	1,131	14	21	8,538	(8,417)	12	13
11	OPEB		1,683	775	(213)	88	(454)	(1,298)	(1,336)	(583)	(410)	(843)	(325)	(693)
12	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
13	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
14	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
15	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
16	Injuries and Damages		605	545	340	241	305	(185)	381	363	337	270	512	317
17	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
18	Company Memberships		295	250	293	262	249	313	479	563	599	527	569	854
19	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
20	Advertising		389	281	167	133	243	236	207	226	283	146	224	719
21	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
22	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
23	Other O&M		(3,527)	(3,005)	157	(63)	31	512	306	367	647	1,074	1,242	982
24	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
25	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
26	Amortization		82	0	(489)	(1,446)	(594)	185	267	396	511	845	845	935
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**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
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Columbia Gas of Pennsylvania
Statement of Operations and Maitntenance Expense
Budget Vs. Actual

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7	**CE**		**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
8	Labor		(720)	469	(65)	303	(585)	567	(329)	(553)	(1,162)	927	4,200	(279)
9	Incentive Compensation		1,010	457	500	441	607	484	207	339	848	(769)	113	(539)
10	Pension		(1,727)	(206)	6,490	91	2,486	(6)	14	15	7,989	(8,417)	12	13
11	OPEB		968	(290)	(705)	242	(170)	(748)	42	227	104	266	405	(15)
12	Other Employee Benefits		(81)	1,109	(299)	(304)	(819)	848	1,201	289	124	(429)	80	1,879
13	Outside Services		(456)	265	150	10	2,009	(241)	(3,128)	1,384	2,788	(1,282)	(603)	(6,552)
14	Rent and Leases		(8)	(167)	(110)	(130)	(188)	(574)	(2,539)	(776)	(420)	31	113	(266)
15	Corporate Insurance		(71)	(333)	(487)	(285)	(270)	(291)	(1,617)	(457)	(529)	(255)	732	420
16	Injuries and Damages		(604)	(399)	(455)	(389)	(325)	(685)	(119)	(37)	337	(130)	112	(83)
17	Employee Expenses		296	404	390	323	81	(41)	(225)	(71)	44	(202)	230	(578)
18	Company Memberships		(52)	(95)	44	(30)	(13)	57	223	231	108	35	6	294
19	Utilities and Fuel Used in Company Operations		(224)	(153)	(80)	591	80	(59)	(23)	90	577	(16)	8	(272)
20	Advertising		(111)	96	(3)	(37)	(227)	66	37	56	113	(24)	51	546
21	Fleet		(13)	622	671	311	328	398	228	409	441	83	1,233	(283)
22	Materials & Supplies		(188)	200	(363)	(546)	522	319	806	(501)	961	(238)	752	889
23	Other O&M		460	774	272	720	(29)	2,418	740	(26)	(403)	428	(139)	788
24	PUC, OCA, OSBA Fees		48	(413)	(5)	69	(114)	232	-	(370)	(614)	(448)	(228)	(137)
25	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
26	Amortization		(0)	(74)	(246)	(0)	861	-	-	(100)	-	436	-	0
27	Lobbying (Amount included in above Cost Elements)		-	-	-	-	-	-	-	-	-	-	-	-
28	**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)
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J. HARDING

COLUMBIA STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021- 3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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 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 ("Columbia" or "the Company"). My responsibilities include oversight and review of the preparation of 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") and the Public Service Commission of Maryland.

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, 2020) and Exhibit 107 for the Future Test Year (the twelve month period ending November 30, 2021) and Fully Projected Future Test Year (the twelve-month period ending December 31, 2022). Taxes other than income tax are included in Exhibit 6 and Exhibit 106.

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. I acknowledge that the Biden Administration is anticipated to offer a proposal to increase federal corporate income tax rates. Columbia has not reflected any assumption of an increase in federal income tax rates in this case. However, later in my testimony I explain a proposed rider mechanism to adjust rates for changes in federal income tax 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 corporate income tax rate of 21%, a result of the enactment of TCJA of 2017, that are being refunded in rates under the Average Rate Assumption Method ("ARAM"). ARAM is the method under which the excess in the reserve for deferred income taxes is reduced over the remaining lives of the property as used in its books of account that gave rise to the reserve for deferred income taxes and flow-through the amortization of the excess accumulated deferred income taxes. Because most of the book versus tax differences related to assets that were 15 or 20 year property for federal tax purposes and there were multiple years of bonus depreciation since

2001, the excess is in a turnaround situation. There is a variable nature inherent in ARAM, which does not result in an amount that is fixed in every period due to factors such as changes in capital additions, depreciation rates, future retirements and the vintages of those retirements. The Company projects to record lower tax expense of $3,841,826 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 a net deficient deferred taxes as a result 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 of time, 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 as a result of being non-deductible include expenses for a portion of business meals and employee stock purchase plan compensation reflected 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 is 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 disallowed bonus depreciation.

Q. Did the Company receive a refund from Pennsylvania for the change in method?

A. No. The Company had a $144,975,996 net operating loss for 2008 that was carried forward to future years. The Company reduced its Pennsylvania taxable income by 15% of taxable income in 2009. The Company also had a $3,663,502 net operating loss for 2010 and a $69,764,304 net operating loss for 2011 that were carried forward to future years. For tax years in 2015 and 2016, the Company was permitted to use the loss carryforward as a state income tax deduction equal to the higher of $5,000,000 or 30% of taxable income. 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

[1] *Nextel Communications of the Mid-Atlantic, Inc. v. Commonwealth*, 171 A.3d 682 (Pa. 2017).

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 removes the $5 million cap on NOL deductions and increases the current cap of 30% of taxable income to 35% for tax year 2018 and 40% for tax year 2019 and future years. On October 30, 2017, Pennsylvania Governor Tom Wolf signed HB542 into law. In response to the decision, the Pennsylvania Department of Revenue has revised its forms and procedures to eliminate the $5 million flat-dollar cap. The Company's claimed tax expense takes into account the increased NOL limitation of 40% of state taxable income in the Future Test Year and the Fully Projected Future Test Year (Exhibit 107, Page 17, Line 6). The Pennsylvania NOL carryforward is reflected on Exhibit 7, Page 23.

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

[2] *Nextel Communications of the Mid-Atlantic, Inc., v. Commonwealth*, 129 A.3d 1 (Pa. Commw. 2015).

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 2017 to 2019. 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 $19.8 million by the 3-year average of the Federal taxable income of the consolidated group members with taxable income of $269.8 million to determine the percentage of Columbia's of 7%. This percentage was multiplied by the 3-year average of Federal taxable loss of the adjusted consolidated group members with taxable loss of $280.5 million. 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 years 2017 and 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 $20.6 million tax effected at 21% resulting in a 1301.1(b) differential of $4.3 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 and discussed in the direct testimony of Witness R. Brumley (Columbia St. No. 7), Columbia's pro forma capital additions for reliability or infrastructure projects are $260.8 million in the FTY and $289.1 million in the FPFTY. This expenditure level is greater than 50% of the amount of $4.3 million 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 Witness K.K. Miller, Columbia's pro forma operating and maintenance budget is $217.5 million in the FTY and $224.7 million in the FPFTY. This expenditure level is greater than 50% of the amount of $4.3 million 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 $39,377,172. This total includes $6,001,345 of state income taxes (Exhibit 7, Page 19, Line 37), which is based on $213,676,833 of operating income (Exhibit 7, Page 19, Line 1) less $40,323,744 of interest expense on debt (Exhibit 7, Page 19, Line 9) for total pre-tax income of $173,353,089 resulting in an effective state income tax rate of 3.46%. 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 loss carryforward deductions for state income tax purposes. The expense for federal income taxes is $33,375,827 (Exhibit 7, Page 19, Line 36) resulting in an effective tax rate of 19.25%. 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 $23,206,708. This total includes $1,275,726 of state income taxes (Exhibit 107, Page 16, Line 37), which is based on $161,439,628 of operating income (Exhibit 107, Page 16, Line 1) less $51,589,133 of interest expense on debt (Exhibit 107, Page 16, Line 9) for total pre-tax income of $109,850,495 resulting in an effective state income tax rate of 1.16%. 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 loss carryforward deductions for state income tax purposes. The expense for federal income taxes is $21,930,982 (Exhibit 107, Page 16, Line 36) resulting in an effective tax rate of 19.96%. 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 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 has been given permission 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 $ 34,637,164 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 $31,978,769 as a deferred tax asset for the amount of unutilized net operating loss 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 $10,523,251 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 and 106.

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). An increase in payroll taxes of $232,939 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 $29,562 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, 2019. The West Virginia tax for gas stored underground was developed using the December 31, 2019 assessed value and the 2019 tax rate. This annualized level is equal to the Historic Test Year level of $523,822, 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 $59,918 from the annualized level as a result of using the December 31, 2019 assessed value and the 2019 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 $625 was not adjusted for the Historic Test Year. The pro forma Fully Projected Future Test Year was also not adjusted from this level.

Q. Are you sponsoring any other tax matters?

A. Yes. I am also sponsoring the illustrative calculations, methodology and mechanism developed for a Federal Tax Reform Adjustment (FTRA) tariff that is referenced in Witness R. Danhires testimony to prospectively apply a positive or negative percentage adjustment for the impact of a future increase or decrease of the Federal income tax rate to customer bills as a result of future Federal Tax Reform.

Q. Why are you requesting the new FTRA tariff?

A. The enactment of the TCJA taught us that Federal income tax rate changes can be very material and take effect abruptly resulting in volatility that is completely outside of the Company's control. Accordingly, the Company's is taking a proactive approach to account for the impact of future increase or decrease in Federal income tax rates based on "lessons learned" from the enactment of the TCJA.

Q. How does the Company expect to compute the impact of future increase or decrease in the Federal income tax rate and what is the mechanism developed by the Company?

A. The Company notes that an increase or decrease in the Federal income tax rate based on tax reform would result in a recovery from customers or pass back to customers related to the increase of income tax expense or reduction of income tax expense, respectively. Currently, the Company does not have an indication of the timing of enactment or confirmation of changes in the Federal income tax rate that have been proposed by the Biden Administration. However, to alleviate the administrative burden and lag in timing, the Company is proposing a Federal Tax Reform Adjustment (FTRA) rider to prospectively apply a positive or negative percentage adjustment for the impact of a future increase or decrease of the Federal income tax rate to customer bills as a result of Federal Tax Reform.

The Company has prepared illustrative schedules utilizing a scenario of a 7% increase in the Federal income tax rate from 21% to 28% proposed by the Biden administration using an effective date of January 1, 2022 for illustrative purposes. These schedules are provided with my testimony as Exhibit JH-1. There are two components of tax expense impacted from a change in the Federal income tax rate that the Company has captured in illustrative schedules based on computations of the fully projected future test year ended December 31, 2022: 1) total current and deferred tax expense included in the cost of service and 2) accumulated deferred income taxes (ADIT) included in the rate base which represent future deductible or taxable statutory book/tax temporary differences.

The total Federal income tax expense is comprised of current Federal income tax expense, deferred Federal income tax expense, excess ADIT amortization, deficient ADIT amortization and Federal investment tax credits. The current Federal income tax expense is computed based on Federal taxable income which is the product of pre-tax income, plus statutory permanent and flow-through book/tax differences, plus statutory temporary book/tax differences, less the state tax deduction, multiplied by the Federal income tax rate (See Exhibit JH-1, Attachment A, Page 1, Lines 1 through 17). The deferred Federal income tax expense is computed based on the future deductible or taxable statutory temporary book/tax differences multiplied by the Federal income tax rate (See Exhibit JH-1, Attachment A, Page 1, Line 18). As depicted in the illustrative schedule Attachment A, Page 1, Column H, Lines 17 and 18, the proposed increase in the tax rate results in an increase of Federal income tax expense of approximately $14.6 million. Additionally, the annual amortization of the deficient ADIT for the fully projected future test year of approximately $2.13 million is included to arrive at total tax expense (Exhibit JH-1, Attachment B, Page 2, Column 2 through 7, Lines 1 through Lines 15 and discussion below) resulting in an increase in total Federal income tax expense of $16.7 million.

The ADIT included in rate base which represent future deductible or taxable statutory book/tax temporary differences are required to be remeasured at the new Federal income tax rate as of the ending balance sheet date prior to the enactment of the new Federal income tax rate. The Company established a Regulatory Liability for the excess ADIT related to the TCJA decrease of the

Federal income tax rate from 35% to 21% effective January 1, 2018 that continues to be passed back to customers (10-years for non-property, 42-years for Federal NOL and ARAM for property). As mentioned above, for illustrative purposes, the Company used an effective date of January 1, 2022 of the increase in the Federal income tax rate which requires ADIT to be remeasured at 28% based on the 2021 ending balance sheet. The Company remeasured the statutory temporary difference for the future test year ended November 30, 2020 on Attachment B, Page 2, Column 2 through 7, Lines 1 through Lines 15 by dividing the deferred tax balance at the current income tax rates to compute the gross balances, then tax effecting the gross balances at the new Federal income tax rate resulting in deficient ADIT of approximately $91.5 million. The Company has presented the amount as a Regulatory Asset that is included in rate base on Attachment B, Page 1, Lines 11-14 to illustrate that the remeasurement of ADIT does not have an immediate impact on rate base as of the balance sheet remeasurement date. Consistent with amortization periods agreed to under the TCJA Federal rate change in 2017, the Company has applied the same amortization periods (10-years for non-property, 42-years for Federal NOL and ARAM for property which is estimated at 39.2-years based on the book depreciation composite rate). The estimated annual amortization of the deficient ADIT is approximately $2.1 million (See Attachment B, Page 2, Lines 2 through 15 for the illustrative computation of the annual amortization based on the FTY remeasurement date and Attachment A, Page 1, Line 23, Column 6 for the amount of the estimated annual amortization included in the computation of the FPFTY Federal income tax expense. This annual amortization of the deficient ADIT is included in total Federal tax expense in the cost of service on Attachment A, Page 1, Line 23. The increase in ADIT for the fully projected future test year is approximately $7.1 million. The Company multiplied the increase by the % Rate of Return computed for the fully projected future test year of 7.88% resulting in decrease in the revenue requirement of approximately ($557k).

The Company notes that the illustrative impact of increased tax expense of $16.7 million and ADIT of ($557k) is approximately $16.2 million, net. The Company applied the statutory tax rate gross up factor of 1.4774 (See computation on Exhibit JH-1, Attachment A, Page 1, Lines 49 through 56) resulting in a gross revenue requirement of approximately $23.9 million. To determine the percentage adjustment to apply prospectively to customer bills, the Company divided the gross revenue requirement of $23.7 million by the fully projected future test year revenue of $758 million at proposed rates to arrive at positive percentage adjustment of 3.15% to prospectively implement the illustrative impact of a new Federal income tax rate. The Company notes that the illustrative schedules and computation of the positive percentage adjustment is subject to the Commission approval of the final revenue requirement for the fully project future test year ended December 31, 2022.

Q. Does this conclude your testimony?

A. Yes.

Attachment A
Witness: J. Harding
Page 1 of 1

COLUMBIA GAS OF PENNSYLVANIA, INC.
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
CURRENT FEDERAL TAX EXPENSE
PRO FORMA AT PROPOSED BASE RATES
HTY = HISTORIC TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2020 /
FTY = FUTURE TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2021 / FPFTY = FULLY PROJECTED FUTURE TEST YEAR PERIOD ENDED DECEMBER 31, 2022

Line No	Description	Ref	Federal Tax Expense at 21% Pro Forma At Forecasted HTY Present Base Rates	Federal Tax Expense at 21% Pro Forma At Forecasted FTY Proposed Base Rates	Federal Tax Expense at 21% Pro Forma At Forecasted FPFTY Proposed Base Rates	/ 1 Federal Tax Expense at 28% Pro Forma At Forecasted FPFTY Proposed Base Rates	Change in Federal Tax Pro Forma At Forecasted FPFTY Proposed Base Rates	
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	
1	Total Sales and Transportation Revenue	Exh 102, Sch 3, Pg 3, Ln 9	646,700,377	655,424,612	758,023,283	758,023,283	-	
2	Late Payment Fees	Exh 102, Sch 3, Pg 3, Ln 10	1,237,138	1,253,827	1,450,098	1,450,098	-	
3	Other Operating Revenues (Excl. Transportation)	Exh 102, Sch 3, Pg 3, Ln 11	11,582	11,582	11,582	11,582	-	
4	Total Operating Revenue Deductions	Exh 102, Sch 3, Pg 3, Ln 9	434,272,263	476,823,840	500,882,916	500,882,916	-	
5	Operating Income Before Income Taxes	Exh 102, Sch 3, Pg 3, Ln 9	213,676,833	179,866,180	258,602,047	258,602,047	-	
6	Statutory Permanent Adjustments	Exh 107, Pg 16, Ln 15	(32,258,807)	(39,140,025)	(43,142,698)	(43,142,698)	-	
7	Statutory Temporary (Deferred) Adjustments	Exh 107, Pg 16, Ln 29	(56,620,879)	(62,103,254)	(87,369,535)	(87,369,535)	-	
8	Pennsylvania Bonus Depreciation Adj	Exh 106, Pg 17, Ln 4	(26,402,313)	(12,707,746)	(11,100,575)	(11,100,575)	-	
9	State Taxable Income (Before NOL)	= Sum Ln 5,6,7,8	98,394,835	65,915,156	116,989,239	116,989,239	-	
10	Net Operating Loss Deduction	= Ln 9 * 40%	39,357,934	26,366,062	46,795,696	46,795,696	-	
11	State Taxable Income (After NOL)	= Ln 9 - Ln 10	59,036,901	39,549,094	70,193,543	70,193,543	-	
12	State Tax Rate		9.99%	9.99%	9.99%	9.99%	0.00%	
13	State Income Tax Payable	= Ln 11 * Ln 12	5,897,786	3,950,954	7,012,335	7,012,335	-	
14								
15	Federal Taxable Income	= Sum Ln 5,6,7 Less Ln 13	118,899,361	74,671,947	121,077,479	121,077,479	-	
16	Federal Tax Rate		21%	21%	21%	28%	7.00%	
17	Current Federal Tax	= Ln 15 * Ln 16	24,968,866	15,681,109	25,426,271	33,901,694	8,475,424	
18	Deferred Federal Tax	= (Ln 7) * Ln 16	11,890,385	13,041,683	18,347,602	24,463,470	6,115,867	
19	Federal Benefit of State Deferred Taxes	Exh 107, Pg 16, Ln 35	(21,747)	(9,501)	(18,334)	(24,445)	(6,111)	
20	Federal Investment Tax Credit	Exh 107, Pg 8, Ln 23	(287,111)	(259,687)	(243,013)	(243,013)	-	
21	Total Current and Deferred Federal Tax Expense		36,550,392	28,453,604	43,512,526	58,097,706	14,585,180	
22	TCJA Excess Amortization	Exh 107, Pg 16, Ln 34	(3,461,677)	(2,467,702)	(2,643,471)	(2,643,471)	-	/ 2
23	FTRA Deficient Amortization	Att B, Pg 2, Cl 9, Ln 28				2,132,389	2,132,389	/ 3
24	Total Current and Deferred State Tax Expense		6,001,345	3,996,198	7,099,641	7,099,641	-	
25	Total Tax Expense		39,090,061	29,982,100	47,968,696	64,686,265	16,717,569	
26								
27								
28	**Rate Base**							
29	Property Plant and Equipment	Exh 108, Pg 3, Ln 6	2,451,787,100	2,716,574,439	3,058,869,624	3,058,869,624	-	
30	Working Capital	Exh 108, Pg 3, Ln 6	36,919,306	41,724,172	39,774,628	39,774,628	-	
31	Deferred Income Taxes	Att B, Pg 1, Ln 16	(395,942,233)	(410,075,527)	(422,195,373)	(429,266,067)	(7,070,694)	
32	Customer Deposits	Exh 108, Pg 3, Ln 6	(3,454,041)	(3,457,993)	(3,456,339)	(3,456,339)	-	
33	Customer Advances for Construction	Exh 108, Pg 3, Ln 6	3,034	19,525	19,525	19,525	-	
34	Total Rate Base	Exh 108, Pg 3, Ln 6	2,089,313,166	2,344,784,616	2,673,012,065	2,665,941,371	(7,070,694)	
35	% Rate of Return Earned on Rate Base	Exh 102, Sch 3, Ln 28	8.36%	6.39%	7.88%	7.88%	7.88%	/ 4
36	Revenue Requirement	= Ln 34 * Ln 35	174,586,773	149,884,080	210,633,351	210,076,180	(557,171)	
37								
38	**Illustrative Impact of Increased Tax Expense and ADIT, net**	**= Sum Ln 25, Ln 36**					**16,160,398**	
39								
40	Statutory Tax Rate Gross-Up Factor	= Ln 37					1.47744707	/ 5
41								
42	**Gross Revenue Requirement**	**= Ln 38 * Ln 40**					**23,876,133**	
43								
44	Total Sales and Transportation Revenue adjusted	= Ln 1					758,023,283	/ 6
45								
46	**Base Distribution Percent Increase Per Bill**	**= Ln 42 / Ln 44**					**3.150%**	
47								
48								
49	**Computation of Statutory Tax Rate Gross-Up Factor**							
50	Federal Rate						28.00%	
51	State Rate						9.99%	
52	State Rate after State NOL (40% Limitation)						5.99%	
53	Federal Benefit of State Rate						-1.68%	
54	Total Statutory Rate						32.32%	
55								
56	Statutory Tax Rate Gross-Up Factor						1.47744707	

NOTES

/ 1 - Illustrative schedule prepared based on a scenario of an increase in the Federal tax rate for FPFTY 2022

/ 2 - Illustrative schedule prepared reflects no change in the pass back of Excess ADIT related to TCJA of 2017. The permanent benefit will continue to be passed back to customers over the respective amortization periods.
However, the 254 Regulatory Liability balance and 190 Deferred Tax (Gross-Up) will be remeasured based on the new Statutory Tax Rate Gross-Up Factor due to the new Federal tax rate. The entry would result in net zero deferred tax expense
DR 254 Regulatory Liability and CR 411 Deferred Tax Benefit / CR 190 Deferred Tax (Gross-Up) and DR 410 Deferred Tax Expense

/ 3 - Illustrative schedule prepared FPFTY Deficient ADIT annual amortization consistent with the amortization periods agreed to for Excess ADIT from TCJA decrease in Federal tax rate (See Attachment B, Page 2, Column 9, Lines 15-28 for computation)

/ 4 - Illustrative schedule prepared applies 7.88% rate of return which represents the rate of return fro the 2021 Rate Case FPFTY at Proposed Rates. The Company would update based on the final rate of return approved by the commission.

/ 5 - Illustrative schedule prepared applies a statutory tax rate gross-up factor based on the new Federal income tax rate (See computation on rows 49-54)

/ 6 - Illustrative schedule prepared applies the total sales and transportation revenue which represent revenue for the 2021 Rate Case FPFTY at Proposed Rates. The Company would updated based on the final revenue approved by the commission.

COLUMBIA GAS OF PENNSYLVANIA, INC.
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
ACCUMULATED DEFERRED INCOME TAX (ADIT) / (EXCESS) DEFICIENT ADIT
PRO FORMA AT PROPOSED BASE RATES
HTY = HISTORIC TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2020 / FTY = FUTURE TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2021 / FPFTY = FULLY PROJECTED FUTURE TEST YEAR PERIOD ENDED DECEMBER 31, 2022

Line No	Description	Ref	ADIT at 21% Pro Forma At Forecasted HTY Present Base Rates	ADIT at 21% Pro Forma At Forecasted FTY Proposed Base Rates	ADIT at 28% Pro Forma At Forecasted FTY Proposed Base Rates	Change in ADIT Pro Forma At Forecasted FTY Proposed Base Rates	ADIT at 28% Pro Forma At Forecasted FPFTY Proposed Base Rates
	(1)	(2)	(3)	(4)	(5)	(6) = (5 - 4)	(8)
					/ 1		
1	Accumulated Deferred Income Taxes (ADIT)						
2	Account 190 - Deferred Income Taxes	Att C, Pg 1, Ln 9	46,585,707	46,597,345	60,622,600	14,025,255	58,089,507
3	Account 282 - Deferred Income Taxes-Depreciation	Att C, Pg 1, Ln 12	(298,978,832)	(315,591,465)	(420,788,620)	(105,197,155)	(438,168,881)
4	Total ADIT		(252,393,125)	(268,994,120)	(360,166,021)	(91,171,900)	(380,079,375)
5					/ 2		/ 5
6	Excess ADIT (TCJA)						
7	Account 190 - Deferred Income Taxes	Att C, Pg 1, Ln 18	27,899,349	26,700,994	26,700,994	-	25,402,776
8	Account 282 - Deferred Income Taxes-Depreciation	Att C, Pg 1, Ln 19	(171,448,457)	(167,782,401)	(167,782,401)	-	(163,628,980)
9	Total Excess ADIT		(143,549,108)	(141,081,407)	(141,081,407)	-	(138,226,203)
10					/ 3		
11	Deficient ADIT (FTRA)	/ 7					
12	Account 190 - Deferred Income Taxes				(14,025,255)	(14,025,255)	(13,474,043)
13	Account 282 - Deferred Income Taxes-Depreciation				105,197,155	105,197,155	102,513,554
14	Total Deficient ADIT				91,171,900	91,171,900	89,039,511
15							/ 6
16	Total ADIT & (Excess)/Deficient ADIT	Att C, Pg 1, Ln 21	(395,942,232)	(410,075,527)	(410,075,527)	-	(429,266,067)
					/ 4		

NOTES
/ 1 - Illustrative schedule prepared based on a scenario of an increase in the Federal tax rate for FPFTY 2022 resulting in remeasurement of ADIT at the new Federal tax rate as of the end of FTY balance sheet date
/ 2 - Illustrative schedule prepared reflects FTY ADIT remeasured at new Federal tax rate (See Attachment B, Page 2, Lines 15-28 for computation of the remeasurement)
/ 3 - Illustrative schedule prepared reflects no change in the pass back of Excess ADIT related to TCJA of 2017. The permanent benefit will continue to be passed back to customers over the respective amortization periods
/ 4 - Illustrative schedule prepared reflects no change in total ADIT & (Excess) / Deficient ADIT as of the balance sheet date when deferred taxes are remeasured at the new Federal tax rate as the permanent difference is recorded as a Regulatory Asset to be amortized over respective periods
/ 5 - Illustrative schedule prepared reflects FPFTY ADIT remeasured at new Federal tax rate (See Attachment B, Page 2, Lines 38-51 for computation of the remeasurement)
/ 6 - Illustrative schedule prepared reflects decrease in Deficient ADIT from FTY to FPFTY based on estimated annual amortization (See Attachment B, Page 2, Column 9, Lines 15-28)
/ 7 - Illustrative schedule prepared reflects FTY and FPFTY Deficient ADIT as a balance separate from Excess ADIT attributed to TCJA of 2017 for illustrative purposes only (actual accounting may be presented as a net balance)

COLUMBIA GAS OF PENNSYLVANIA, INC.
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
ACCUMULATED DEFERRED INCOME TAX (ADIT) / (EXCESS) DEFICIENT ADIT
PRO FORMA AT PROPOSED BASE RATES

HTY = HISTORIC TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2020 / FTY = FUTURE TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2021 / FPFTY = FULLY PROJECTED FUTURE TEST YEAR PERIOD ENDED DECEMBER 31, 2022

Line No	Description	Ref	ADIT at 21% Pro Forma At Forecasted FTY Proposed Base Rates	Current Tax Rates Pro Forma At Forecasted FTY Proposed Base Rates	Gross ADIT Pro Forma At Forecasted FTY Proposed Base Rates	Illustrative Tax Rates Pro Forma At Forecasted FTY Proposed Base Rates	ADIT at 28% Pro Forma At Forecasted FTY Proposed Base Rates	/ 1 (Excess)/Deficient ADIT Pro Forma At Forecasted FTY Proposed Base Rates	/ 2 Amortizable Period Pro Forma At Forecasted FTY Proposed Base Rates	(Excess)/Deficient ADIT Amort Pro Forma At Forecasted FTY Proposed Base Rates
		(1)	(2)	(3)	(4) = (2 / 3)	(5)	(6) = (4 X 5)	(7) = (2 - 6)	(8)	(9) = (7 / 8)
1	Account 190 - Deferred Income Taxes									
2	LIFO Inventory Adj - Federal	Att C, Pg 1, Ln 2	6,973,737	18.90%	36,893,980	25.20%	9,298,316	(2,324,579)	10.00	(232,458)
3	LIFO Inventory Adj - State	Att C, Pg 1, Ln 3	3,685,709	9.99%	36,893,984	9.99%	3,685,709	0	10.00	-
4	Capitalized Inventory - Fed	Att C, Pg 1, Ln 4	1,015,878	18.90%	5,374,419	25.20%	1,354,504	(338,626)	10.00	(33,863)
5	Capitalized Inventory - St	Att C, Pg 1, Ln 5	536,904	9.99%	5,374,414	9.99%	536,904	0	10.00	-
6	Cust. Advances - Fed	Att C, Pg 1, Ln 6	565,678	18.90%	2,992,673	25.20%	754,237	(188,559)	10.00	(18,856)
7	Cust. Advances - St	Att C, Pg 1, Ln 7	298,968	9.99%	2,992,673	9.99%	298,968	0	10.00	-
8	Federal Net Operating Loss	Att C, Pg 1, Ln 8	33,520,471	21.00%	159,621,290	28.00%	44,693,961	(11,173,490)	42.00	(266,035)
9	Total Account 190	Att C, Pg 1, Ln 9	46,597,345		250,143,433		60,622,600	(14,025,255)		(551,212)
10										
11	Account 282 - Deferred Income Taxes-Depreciation									
12	Excess Accelerated Tax Depreciation - Fed	Att C, Pg 1, Ln 11	(315,591,465)	21.00%	(1,502,816,501)	28.00%	(420,788,620)	105,197,155	39.20	2,683,601
13	Total Account 282	Att C, Pg 1, Ln 12	(315,591,465)		(1,502,816,501)		(420,788,620)	105,197,155		2,683,601
14										
15	Total ADIT		(268,994,120)		(1,252,673,068)		(360,166,021)	91,171,900		2,132,389
16										
17										

Line No	Description	Ref	ADIT at 21% Pro Forma At Forecasted FPFTY Proposed Base Rates	Current Tax Rates Pro Forma At Forecasted FPFTY Proposed Base Rates	Gross ADIT Pro Forma At Forecasted FPFTY Proposed Base Rates	Illustrative Tax Rates Pro Forma At Forecasted FPFTY Proposed Base Rates	ADIT at 28% Pro Forma At Forecasted FPFTY Proposed Base Rates
18-22							
23		(1)	(2)	(3)	(4) = (2 / 3)	(5)	(6) = (4 X 5)
24	Account 190 - Deferred Income Taxes						
25	LIFO Inventory Adj - Federal	Att C, Pg 1, Ln 2	6,973,737	18.90%	36,893,980	25.20%	9,298,316
26	LIFO Inventory Adj - State	Att C, Pg 1, Ln 3	3,685,709	9.99%	36,893,984	9.99%	3,685,709
27	Capitalized Inventory - Fed	Att C, Pg 1, Ln 4	1,015,878	18.90%	5,374,419	25.20%	1,354,504
28	Capitalized Inventory - St	Att C, Pg 1, Ln 5	536,904	9.99%	5,374,414	9.99%	536,904
29	Cust. Advances - Fed	Att C, Pg 1, Ln 6	327,660	18.90%	1,733,458	25.20%	436,880
30	Cust. Advances - St	Att C, Pg 1, Ln 7	138,835	9.99%	1,389,740	9.99%	138,835
31	Federal Net Operating Loss	Att C, Pg 1, Ln 8	31,978,769	21.00%	152,279,852	28.00%	42,638,359
32	Total Account 190	Att C, Pg 1, Ln 9	44,657,492		239,939,847		58,089,507
33							
34	Account 282 - Deferred Income Taxes-Depreciation						
35	Excess Accelerated Tax Depreciation - Fed	Att C, Pg 1, Ln 11	(328,626,661)	21.00%	(1,564,888,862)	28.00%	(438,168,881)
36	Total Account 282	Att C, Pg 1, Ln 12	(328,626,661)		(1,564,888,862)		(438,168,881)
37							
38	Total ADIT		(283,969,169)		(1,324,949,015)		(380,079,375)
39							
40							

Line No	Statutory Tax Rates	Current Tax Rates	Illustrative Tax Rates
42	Federal Rate	21.000%	28.000%
43	State Rate	9.990%	9.990%
44	Federal Benefit of State Rate	-2.098%	-2.797%
45	Federal Rate, net of State Benefit	18.902%	25.203%
46	Total Statutory Rate	28.892%	35.193%

NOTES

/ 1 - Illustrative schedule prepared based on a scenario of an increase in the Federal tax rate for FPFTY 2022 resulting in remeasurement of ADIT at the new Federal tax rate as of the end of FTY balance sheet date

/ 2 - Illustrative schedule prepared FPFTY Deficient ADIT estimated annual amortization consistent with the amortization periods agreed to for Excess ADIT from TCJA decrease in Federal tax rate (See Attachment B, Page 2, Column 9, Lines 15-28 for computation)

Non-Property - 10-yr
Federal NOL - 42-yr
Property - ARAM (Illustrative example reflects 39.20 yr which represents the FTY book depre composite rate - Actuals will be based on ARAM computed in PowerTax)

COLUMBIA GAS OF PENNSYLVANIA, INC.
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
RATE BASE ACCUMULATED DEFERRED INCOME TAX (ADIT) / (EXCESS) DEFICIENT ADIT
PRO FORMA AT PROPOSED BASE RATES
HTY = HISTORIC TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2020 /
FTY = FUTURE TEST YEAR TWELVE MONTHS ENDED NOVEMBER 30, 2021 / FPFTY = FULLY PROJECTED FUTURE TEST YEAR PERIOD ENDED DECEMBER 31, 2022

Line No.	Acct		Pro Forma Balance 11/30/20 (1)	Pro Forma Balance 11/30/2021 (2)	Pro Forma Balance 12/31/2022 (3)
1		Account 190 - Deferred Income Taxes			
2	19001000	LIFO Inventory Adj - Federal	6,130,528	6,973,737	6,973,737
3	19002000	LIFO Inventory Adj - State	3,240,062	3,685,709	3,685,709
4	19001000	Capitalized Inventory - Fed	960,030	1,015,878	1,015,878
5	19002000	Capitalized Inventory - St	507,388	536,904	536,904
6	19005000	Cust. Advances - Fed	726,546	565,678	327,660
7	19006000	Cust. Advances - St	383,989	298,968	138,835
8	19005000	Federal Net Operating Loss	34,637,164	33,520,471	31,978,769
9		Total Account 190	46,585,707	46,597,345	44,657,492
10		Account 282 - Deferred Income Taxes-Depreciation			
11	28205000	Excess Accelerated Tax Depreciation - Fed	(298,978,832)	(315,591,465)	(328,626,661)
12		Total Account 282	(298,978,832)	(315,591,465)	(328,626,661)
13		Account 283 - Deferred Income Taxes - Other			
14	28305000	Legal Liability-Lease on G.O. Bldg. - Fed	0	0	0
15	28306000	Legal Liability-Lease on G.O. Bldg. - St	0	0	0
16		Total Account 283	0	0	0
17		Account 254 - Regulatory Liability (Before Gross-up)			
18	25401000 / 25405000	Deficient Deferred Taxes 190- NOL, Inventory & Customer Advances	27,899,349	26,700,994	25,402,776
19	25401000 / 25405000	Excess Accelerated Tax Depreciation - Fed	(171,448,457)	(167,782,401)	(163,628,980)
20		Total Account 254	(143,549,108)	(141,081,407)	(138,226,203)
21		Total Accumulated Deferred Income Taxes (ADIT) and Excess ADIT	(395,942,232)	(410,075,527)	(422,195,373)

Note /1 Attachment C breaks out ADIT from Excess ADIT presented in total ADIT in Exhibit 108, Schedule 8 balances

C. NOTESTONE

COLUMBIA STATEMENT NO. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2021-3024296
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
CHAD NOTESTONE
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 30, 2021

Q. Please state your name and business address.

A. Chad Notestone, my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

A. I am a Lead Regulatory Analyst for NiSource Corporate Services Company ("NCSC"). NCSC provides, among other services, accounting and regulatory-related services for the subsidiaries of NiSource Inc. ("NiSource"). I am testifying on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"), which is one of the NiSource local distribution companies.

Q. What are your responsibilities?

A. I am responsible for the preparation and support of various rate related regulatory studies, such as allocated cost of service ("ACOS") studies, lead lag studies, and the development of revenue used in support of rate proceedings for the subsidiary companies of NiSource.

Q. What is your educational and professional background?

A. I attended Ohio University and received a Bachelor of Business Administration degree in Finance in 2006 and a Master of Business Administration degree in 2013. I began my career with NCSC in 2007 as a Regulatory Analyst. I was promoted to Senior Regulatory Analyst in 2009 and then to Lead Regulatory Analyst in 2013. I became a Manager of Regulatory Studies in 2015. I began my current role in 2021. In addition to my work experience, I have attended a variety of public utility accounting and ratemaking seminars.

Q. Have you previously testified before this Commission?

A. Yes. I provided testimony in Docket No. R-2020-3018835. I have also provided testimony before the State Corporation Commission of Virginia, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, and the Kentucky Public Service Commission.

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

[1] 52 Pa Code § 53.51, et. seq.

included in this testimony. The ACOS studies are based on the fully projected future test year ending December 31, 2022.

Q. Are you responsible for the ACOS studies presented in Exhibit No. 111?

A. Yes, I am.

Q. Three ACOS studies are included in Exhibit No. 111. Is that correct?

A. Yes.

Q. Why did you conduct three ACOS studies?

A. Columbia has filed two studies in its base rate proceedings since the early 1980s that provide the outside limits of the possible allocations of mains to the various classes of service. The customer-demand study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class, while the peak and average study (Exhibit No. 111, Schedule 2) produces results that are generally more favorable to the residential class. Columbia has in the past submitted that the results of two such studies provided a reasonable range of returns for use as a guide in establishing appropriate rates. Columbia continues to believe that the two studies provide the reasonable range of returns for use in revenue allocation. However, Columbia recognizes this Commission's preference for the use of the peak and average study, and therefore used the peak and average study as the primary guide for the allocation of the revenue increase in this case.

Q. What is the basis of the third study and why did Columbia file it?

A. The third study, as presented in Exhibit No. 111, Schedule 3, is an average of the customer-demand study and the peak and average study. The average study with its equal weighting of the two studies, provides the Company, the parties and the Commission with another set of returns that can be used as a guide in revenue allocation. In other words, the average study serves as another tool that can be used by the parties to inform the revenue allocation in setting cost based rates.

Q. Could you provide a list of the schedules, and attachments you are sponsoring through your testimony?

A. Yes. 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. 11, Exhibit CEN-1	Development of Allocation Factors
Statement No. 11, Exhibit CEN-2	Calculation of Allocation Factors
Statement No. 11, Exhibit CEN-3	Factor Selection and Rationale
Statement No. 11, Exhibit CEN-4	Intra-Class Adjustment of Storage Carrying Costs
Statement No. 11, Exhibit CEN-5	ACOS Study Return Results
Statement No. 11, Exhibit CEN-6	Gas Procurement Charge Calc.
Statement No. 11, Exhibit CEN-7	Benchmark Distribution Revenue per Bill
Statement No. 11, Exhibit CEN-8	Revenue Normalization Adjustment for Peak Period
Statement No. 11, Exhibit CEN-9	Revenue Normalization Adjustment for Off Peak Period

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 customer-demand study, Schedule No. 1. It contains 30 pages, while the peak and average study in Schedule 2 and the average study in Schedule 3 both contain 13 pages. The customer-demand 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. 1. 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].

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, 2020).

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

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

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. No. 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 Bell (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 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, 2020 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 CEN-1 attached to this testimony, entitled "Development of Allocation Factors", I provided a description for all allocation factors used for the studies. In Exhibit CEN-2, I included all calculations of all allocation factors. And in Exhibit CEN-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 1, pages 14 through 30.

Q. Please describe the two studies.

A. The study included in Exhibit 111, Schedule No. 1, 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. 1 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.

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 CEN-4, supporting the intra-class adjustment of storage costs from the SGDS1 and SGDS2 classes to the SGSS1, SGSS2, SCD1 and SCD2 classes. This adjustment is made because SGDS1 and SGDS2 customers are not Priority customers for whom Columbia purchases gas in storage to serve.

Q. Please describe this study.

A. The study calculates the storage carrying costs, by rate class, by applying the proposed pre-tax rate of return (Line 6) to the allocated storage balances (Line 3), and utilizing Allocation Factor No. 25. The resulting storage carrying costs for the SGS1/SGDS1 class and the SGS2/SGDS2 class (Line 7) includes costs that would, without an adjustment, be assigned entirely to the SGDS1 class (Line 15) and SGDS2 class (Line 22). These costs are assigned to the SGSS1 and SCD1 classes and the SGSS2 and SCD2 classes ratably, using a factor derived from their projected throughput (Lines 13 & 14 under the heading "Ratio" for the SGSS1 and SCD1 classes and Lines 20 & 21 for the SGSS2 and SCD2 classes). No other intra-class adjustments are being supported or shown on this exhibit.

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 study 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 (Columbia Statement No. 7) provides information about class cost relationships and helps 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 CEN-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 0.72 under the Customer/Demand study to 1.26 under the Peak & Average study. The average ACOS study produces a residential return index of 0.95.

The SGS1/SCD1/SGD1 return indices are 1.08 for the Peak & Average study, 1.14 for the Customer/Demand study and 1.11 for the average ACOS study.

The SGS2/SCD2/SGD2 return indices are 1.14 for the Peak & Average study, 2.87 for the Customer/Demand study and 1.77 for the average ACOS study.

The SDS/LGSS return indices are 0.95 for the Peak & Average study, 3.92 for the Customer/Demand study and 1.81 for the average ACOS study.

The LDS/LGSS return indices are 0.17 for the Peak & Average study, 3.60 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 30.41.

The FLEX return indices are -0.84 for the Peak & Average study, -0.31 for the Customer/Demand study, and -0.72 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 19.91% (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: 68.93% of the overall increase is applied to the residential class; 8.61% of the overall increase is applied to the SGS1/SCD1/SGDS1 class; 9.29% of the overall increase is applied to the SGS2/SCD2/SGDS2 class; 7.14% of the overall increase is applied to the SDS/LGS class; 6.01% of the overall increase is applied to the LDS/LGS class; 0.00% of the overall increase is applied to MLDS customers; and 0.02% 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 7.88%)

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[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 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 proposed residential customer charge does not fully recover the ACOS determined level of customer costs.

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 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 $19.33. The remaining residential revenue increase was assigned to the volumetric charge for a resulting rate of $8.8796 per Dth.

Q. How did Columbia determine a residential customer charge of $19.33?

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 $24.23. 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 43%, but the customer charge has not increased. Columbia's proposed monthly customer charge of $19.33 reflects the $16.75 established in 2012 adjusted for inflation. The proposed charge of $19.33 is well below the minimum cost justified rate of $24.23 supported by the customer charge study excluding mains costs.

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 $26.00 to $31.50. 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 $27.03 (excluding mains) to $69.08 (including mains). Columbia's customer charge proposal of $31.50 falls near the bottom end of the range of customer based costs. The remaining revenue is recovered through the volumetric base rates of $6.5197/Dth for SGSS1/SCD1 service and $6.4348/Dth for SGDS1 service.

Q. What are the customer based costs for the Small General Service customers using between 6,440 and 64,400 therms annually?

A. The proposed SGSS2/SCD2/SGDS2 customer charge for customers whose usage is between 6,440 therms and 64,400 therms is $66.00. 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 $5.4799/Dth for SGSS/SCD service and $5.3949/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, the 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 CEN-4, Columbia has re-allocated $202,594 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 7 and 8. 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 $335.00 and the proposed customer charge for customers whose usage is between 110,000 therms and 540,000 therms is $1,104.00. 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 $4.1250/Dth for SDS/LGSS customers whose usage is between 64,400 therms and 110,000 therms and $3.8566/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	$2,919.00
> 1,074,000 to ≤ 3,400,000 Therms	$4,540.00
> 3,400,000 to ≤ 7,500,000 Therms	$8,755.00
> 7,500,000 Therms	$12,971.00

Q. How is the LDS/LGSS volumetric based rate revenue requirement shown in Exhibit 103, Schedule 8, Page 9, Line 26 spread among the LDS/LGSS annual usage groups?

A. The volumetric base revenue requirement is split among the LDS/LGSS annual usage groups proportionately based on revenue produced from current volumetric base rates. (See Exhibit 103, Schedule 8, Page 9, Lines 28 through 31).

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 1-10. Residential Sales Service is shown on page 1, and pages 2-10 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 2-10. These pages provide monthly bill impacts for Small General Sales Service and Large General Sales Service customers at various usage levels.

Q. Is the Company proposing any changes to the Rider WNA – Weather Normalization Adjustment?

A. Not changes, per se, but the Company is proposing to continue the Rider WNA until a final order is entered in the Company's first rate case filed after May 31, 2026.

Q. Please describe the WNA and explain why the Company is proposing to extend it in this proceeding.

A. Rider WNA adjusts a residential customer's monthly charges based on the actual temperature experienced during the month. Under the WNA, the Company and customers are protected, in part, from usage variations due to weather. The WNA adjusts only the temperature-sensitive portion of customers' bills to reflect normal weather levels. By distinguishing between base load and temperature-sensitive load, each customer's bill is calculated to mitigate the undesirable impacts of warmer than normal or colder than normal weather. Rider WNA was approved in the Company's 2012 base rate proceeding as a pilot program, and is set to expire upon the issuance of a final order in the Company's first rate case filed after May 31, 2020, which will be the order issued in this proceeding, unless the Company obtains Commission approval to continue the WNA. Columbia's nearly eight years of experience with the WNA demonstrates that this rate design mechanism provides stability by adjusting bills for colder and warmer than normal weather, and that the WNA is effective at providing customer-specific billing adjustments in a timely manner. As such, the Company seeks to continue the Rider WNA until a final order is entered in the Company's first rate case filed after May 31, 2026.

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 support 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 2022 billing cycles and ending with March 2023 billing cycles would be applied to residential customers' bills for the period beginning with October 2023 billing cycles and ending with March 2024 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 CEN-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 CEN-7 shows the following BDRB levels for Rider RNA:

	Peak BDRB		Off-Peak BDRB
January	$162.08	April	$98.31
February	$162.18	May	$53.41
March	$140.73	June	$36.78
October	$36.10	July	$28.79
November	$67.94	August	$27.97
December	$121.46	September	$29.94
6-Month Total	$690.49		$275.20

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 (Columbia Statement No. 12).

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 2022 billing cycles. This initial Peak Period RNA ("RNAp") would become effective with October 2022 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.

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

FT is the Forecast Therms for residential non-CAP customers for the six-month period that the RNA will be applied.

Q. Is the calculation of the Off-Peak Period RNA similar to the Peak Period RNA?

A. Yes. The equations are the same for the six-month Off-Peak RNA ("RNAo") calculations.

Q. Does Columbia propose to apply interest to the RNA balances?

A. Yes. Refunds to customers shall be made with interest and recoveries from customers shall include interest at the prime rate for commercial borrowing in effect 60 days prior to the tariff filing and as reported in a publicly available source identified by the Commission or at an interest rate which may be established by the Commission by regulation.

Q. How does the Company plan to implement the RNA in the middle of the Peak Period?

A. For the initial Peak Period RNA, the Company will 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 2022.

Q. Please provide sample RNA calculations for the initial Peak and Off-Peak periods.

A. Please refer to Exhibits CEN-8 and CEN-9 for sample RNA calculations for the initial Peak and Off-Peak Periods. Exhibit CEN-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 2022. Line 3 of Exhibit CEN-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 2022 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 2022 through March 2023. The RNAp rate effective for October 2022 billing cycles through March 2023 billing cycles is calculated on line 20. Exhibit CEN-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 2023 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. Does this complete your 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 CEN-2, Page 1.

Factor No. 2- Throughput Excluding Transportation

Throughput quantities, excluding transportation, for the twelve months ending December 31, 2022 are the basis for Factor No. 2. See Exhibit CEN-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, 2022. See Exhibit CEN-2, Page 2.

Factor No. 4- Gas Purchase Expense

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 4 is based on gas cost assigned to each rate schedule for the twelve months ending December 31, 2022 using the applicable Gas Cost Recovery ("GCR") rates. See Exhibit CEN-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, 2020 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 CEN-2 Pages 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, 2022 were averaged and used to develop Factor No. 6. See Exhibit CEN-2, Page 5.

Factor No. 7 – Current DIS Revenue

Factor No. 7 reflects gross charge-offs recorded during the twelve months ending November 30, 2020 to small usage customers through the Company's Distributive Information System ("DIS"). See Exhibit CEN-2, Page 6.

Factor No. 8 – Current GMB/GTS

Factor No. 8 reflects revenue to be billed during the twelve months ending December 31, 2022 to larger sales usage and transportation customers through the Company's Gas Measurement Billing and General Transportation Systems. See Exhibit CEN-2, Page 7.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 9 – Customer Deposits

Factor No. 9 represents customer security deposits collected from customers by class as of November 30, 2020. See Exhibit CEN-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, 2020. See Exhibit CEN-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 CEN-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 account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 12. See Exhibit CEN-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

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

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 CEN-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 CEN-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 CEN-2, Page 19.

Factor No. 16 – Direct Assignment – Meters

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

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 CEN-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 CEN-2 Page 29.

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

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

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 CEN-2, Page 30.

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 35) 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 CEN-2, Page 31.

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 CEN-2, Page 32.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Aminimum 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.

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 CEN-2, Page 33.

Factor No. 22 –Average Factor Nos. 5 & 20

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

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 CEN-2, Page 34.

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 CEN-2, Page 35.

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 CEN-2, Page 36.

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, 2022. See Exhibit CEN-2, Page 2.

Factor No. 26 – Other Automated Metering Devices

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 26 is developed based on customers eligible for telemetry metering services pursuant to Tariff Supplement 296, which includes customers taking service under rate schedules SDS, LDS and MLDS. See Exhibit CEN-2, Page 37.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 1
DESIGN DAY [1] (2020-2021)

LINE NO.	Rate	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX [2]	Total
1	RCC/RC2	30,900	0	0	0	0	0	30,900
2	RS	328,600	0	0	0	0	0	328,600
3	RTC	105,500	0	0	0	0	0	105,500
4	LG1	0	0	0	4,800	0	0	4,800
5	LG2	0	0	0	7,500	0	0	7,500
6	LG3	0	0	0	0	200	0	200
6	SC2	0	0	17,000	0	0	0	17,000
7	SCC	0	20,700	0	0	0	0	20,700
8	SG2	0	0	51,600	0	0	0	51,600
9	SGS	0	54,500	0	0	0	0	54,500
10	SG4	0	0	800	0	0	0	800
11	TAG1	0	400	0	0	0	0	400
12	TAG2	0	0	5,900	0	0	0	5,900
13	TAG5	0	2,100	0	0	0	0	2,100
14	TAG6	0	0	25,700	0	0	0	25,700
15	TI4	0	0	0	13,000	0	0	13,000
16	TI8	0	0	0	0	14,600	0	14,600
17	TIB	0	0	0	30,600	0	0	30,600
18	TIF	0	0	0	0	21,800	0	21,800
19	TIG	0	0	0	0	9,100	0	9,100
20	FLEX	0	0	0	0	0	45,200	45,200
21	Total	465,000	77,700	101,000	55,900	45,700	45,200	790,500
22	MDS							18,400
23	Other (Co. Used)							2,500
24	Total							811,400
25	**ALLOCATOR #1**	**58.824%**	**9.829%**	**12.777%**	**7.071%**	**5.781%**	**5.718%**	**100.000%**

[1] Includes Firm and Non-Firm Service. Volumes in MDth/Day.
[2] Excludes MDS FLEX

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS 2, 3, & 25
THROUGHPUT EXCLUDING TRANSPORTATION, THROUGHPUT EXCLUDING MDS

LINE NO.		RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX	TOTAL
	Sales								
1	RSS	27,497,571	-	-	-	-	-	-	27,497,571
2	RDGSS	-	-	-	-	-	-	-	-
3	RCC 1/	-	-	-	-	-	-	-	-
4	SGSS1	-	3,901,994	-	-	-	-	-	3,901,994
5	SGSS2	-	-	3,903,397	-	-	-	-	3,903,397
6	NSS/MLSS-1	-	-	-	-	-	69,600	-	69,600
7	LGSS1 & 2	-	-	-	993,014	-	-	-	993,014
8	LGSS3 & greater	-	-	-	-	-	-	-	-
	Transportation								
8	RDS	7,145,892	-	-	-	-	-	-	7,145,892
9	RDGDS	-	-	-	-	-	-	-	-
10	SCD1	-	1,491,506	-	-	-	-	-	1,491,506
11	SCD2	-	-	1,611,987	-	-	-	-	1,611,987
12	SGDS1	-	262,006	-	-	-	-	-	262,006
13	SGDS2	-	-	3,477,755	-	-	-	-	3,477,755
14	SDS	-	-	-	6,501,837	-	-	-	6,501,837
15	LDS	-	-	-	-	11,116,014	-	-	11,116,014
16	FLEX							8,720,420	8,720,420
17	MLDS	-	-	-	-	-	2,326,000	-	2,326,000
18	Total Throughput Excl. Trans. (Allocator 2)	27,497,571	3,901,994	3,903,397	993,014	-	69,600	-	36,365,577
19	**ALLOCATOR #2**	75.614%	10.730%	10.734%	2.731%	0.000%	0.191%	0.000%	
20	Total Throughput Excl. MDS (Allocator 3)	34,643,463	5,655,506	8,993,139	7,494,851	11,116,014		8,720,420	76,623,393
21	**ALLOCATOR # 3**	45.213%	7.381%	11.737%	9.781%	14.507%		11.381%	
22	**Sales and Choice Volume**	34,643,463	5,393,499	5,515,384	993,014	-	69,600	-	46,614,961
23	**ALLOCATOR #25**	74.319%	11.570%	11.832%	2.130%	0.000%	0.149%	0.000%	

NOTE: **1/ RCC rate schedule is for CAP customers. They can be either CHOICE or Sales.**

SOURCE: Exhibit No. 103, Schedule 3.

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	MDS GAS COST	FLEX GAS COST	TOTAL
1	RSS	105,898,647	-	-			-	-	105,898,647
2	RCC	4,419,163	-	-			-	-	4,419,163
3	RDS	9,298,091	-	-			-	-	9,298,091
4	SGSS	-	15,027,359	15,032,763			-	-	30,060,122
5	NSS	-	-	-			220,393	-	220,393
6	SCD	-	2,863,094	3,094,370			-	-	5,957,464
7	SGDS	-	107,731	1,582,399			-	-	1,690,130
8	LGS	-	-	-	3,655,831	168,466	-	-	3,824,297
9	TOTAL	119,615,901	17,998,184	19,709,532	3,655,831	168,466	220,393	-	161,368,307
10	**ALLOCATOR #4**	74.126%	11.153%	12.214%	2.266%	0.104%	0.137%	0.000%	

SOURCE: Exhibit No. 103, Schedule 1.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2020

ALLOCATED COST OF SERVICE — PAGE 1
PEAK & AVERAGE — WITNESS: C. E. Notestone

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 MDS)		76,623,393	34,643,463	5,655,506	8,993,139	7,494,851	11,116,014	8,720,420
2	Percent Throughput		100.000%	45.213%	7.381%	11.737%	9.781%	14.507%	11.381%
3	Throughput Component		50.000%	22.604%	3.691%	5.869%	4.891%	7.254%	5.691%
4	Design Day Volumes (Total Company excl MDS)		790,500	465,000	77,700	101,000	55,900	45,700	45,200
5	Percent Design Day Volumes		100.000%	58.824%	9.829%	12.777%	7.071%	5.781%	5.718%
6	Demand Component		50.000%	29.410%	4.915%	6.389%	3.536%	2.891%	2.859%
7	Demand/Commodity Factor		100.000%	52.014%	8.606%	12.258%	8.427%	10.145%	8.550%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 6
AVERAGE NO. OF CUSTOMERS

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
RSS	3,971,707	0	0	0	0	0	0	4,023,298	51,591
RCC	249,497	0	0	0	0	0	0	252,488	2,991
RDS	657,985	0	0	0	0	0	0	662,355	4,370
RDGDS	0	0	0	0	0	0	0	0	0
SGSS1	0	265,279	0	0	0	0	0	266,855	1,576
SGSS2	0	0	34,745	0	0	0	0	34,842	97
NSS	0	0	0	0	0	12	0	12	0
SCD1	0	97,259	0	0	0	0	0	97,598	339
SCD2	0	0	14,809	0	0	0	0	14,843	34
SGDS1	0	11,227	0	0	0	0	0	11,250	23
SGDS2	0	0	18,574	0	0	0	0	18,642	68
LGSS1 & 2	0	0	0	1,032	0	0	0	1,035	3
LGSS3 & greater	0	0	0	0	24	0	0	24	0
SDS	0	0	0	4,872	0	0	0	4,884	12
LDS	0	0	0	0	864	0	0	864	0
FLEX	0	0	0	0	0	0	276	276	0
MLDS	0	0	0	0	0	84	0	84	0
Total Number of Bills	4,879,189	373,765	68,128	5,904	888	96	276	5,389,350	61,104
Average Number of Customers	406,599	31,147	5,677	492	74	8	23		
ALLOCATOR #6	91.571%	7.015%	1.279%	0.111%	0.017%	0.002%	0.005%		

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	3,896,308.30	3,665,123.95	231,184.35					
2	DIS Billed Revenue - Comm/Ind Sales Only	76,780,323		43,057,756	33,722,567	0	0	0	0
3	Percent	100.000%		56.079%	43.921%	0.000%	0.000%	0.000%	0.000%
4	Allocated DIS Billed Sales Net Charge-offs	3,896,308.30	3,665,123.95	129,645.87	101,538.48	0.00	0.00	0.00	0.00
		Total	Residential	Commercial					
5	DIS Billed Net Charge-offs - Choice Only	390,688.60	323,130.63	67,557.97					
6	DIS Billed Revenue - Comm/Ind Choice Only	44,372,178		15,227,231	29,144,947	0	0	0	0
7	Percent	100.000%		34.317%	65.683%	0.000%	0.000%	0.000%	0.000%
8	Allocated DIS Billed Choice Net Charge-offs	390,688.60	323,130.63	23,183.87	44,374.10	0.00	0.00	0.00	0.00
9	Total DIS Billed Net Charge-offs	4,286,996.90	3,988,254.58	152,829.74	145,912.58	0.00	0.00	0.00	0.00
10	**ALLOCATOR #7**	100.000%	93.031%	3.565%	3.404%	0.000%	0.000%	0.000%	0.000%

EXHIBIT CEN-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	51,107,511	-	21,264	1,299,102	23,877,893	21,202,603	1,329,287	3,377,362
2	**ALLOCATOR #8**	100.000%	0.000%	0.042%	2.542%	46.721%	41.486%	2.601%	6.608%

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	33,701	-	-	-	-	33,701
2	RS	1,614,229	-	-	-	-	1,614,229
3	RTC	119,037	-	-	-	-	119,037
4	Commercial Unlisted	-	22,086	-	-	-	22,086
5	SCC	-	26,310	-	-	-	26,310
	LG1	-	-	-	-		-
	LG2	-	-	-	-	-	-
6	SC2	-	-	5,716	-	-	5,716
7	SGS	-	611,745	-	-	-	611,745
8	SGT	-	15,327	-	-	-	15,327
	SG3		-		-	-	-
9	SG2	-	-	42,668	-	-	42,668
10	TOTAL	1,766,967	675,468	48,384	-	-	2,490,819
11	**ALLOCATOR #9**	70.940%	27.118%	1.942%	0.000%	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	950,984	753,791	91,041	98,199	3,284	4,646	-	23
2	487.00	FORFEITED DISCOUNTS - GMB & GTS	79,828	-	33	2,029	37,297	33,118	2,076	5,275
3		TOTAL CURRENT SALES AND TRANSPORTATION REVENUE	1,030,812	753,791	91,074	100,228	40,581	37,764	2,076	5,298
4		**ALLOCATOR #10**	100.000%	73.126%	8.835%	9.723%	3.937%	3.664%	0.201%	0.514%

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	16,803	1,822	1,436	724	583	-	575
2	374.20	LAND - OTHER DISTRIBUTION	3,361,100	2,573,695	279,106	219,984	110,883	89,304	-	88,128
3	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	73,021	7,919	6,241	3,146	2,534	-	2,500
4	374.40	LAND RIGHTS - OTHER DISTRIBUTION	3,851,518	2,949,223	319,830	252,082	127,062	102,335	-	100,987
5	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBU	-	-	-	-	-	-	-	-
6	374.41	LAND RIGHTS - OTHER DISTRIBUTION LO	13	10	1	1	0	0	-	0
7	374.50	RIGHTS OF WAY	3,233,171	2,475,736	268,483	211,611	106,662	85,905	-	84,774
8	374.50	DIRECT - RIGHTS OF WAY	-	-	-	-	-	-	-	-
9	375.20	M & R STRUCTURES - CITY GATE	7,026	5,380	584	460	232	187	-	184
10	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	3,072	333	263	132	107	-	105
11	375.40	M & R STRUCTURES - REGULATING	6,397,121	4,898,468	531,217	418,692	211,041	169,972	-	167,733
12	375.40	DIRECT - M & R STRUCTURES - REGULAT	27,126	-	-	-	-	-	24,324	2,802
13	375.60	M & R STRUCTURES - DIST. IND. M & R	86,228	-	1,376	11,962	29,251	29,297	-	14,342
14	375.80	M & R STRUCTURES - COMMUNICATION	16,515	12,646	1,371	1,081	545	439	-	433
15	376.00	MAINS	2,376,689,964	1,819,902,806	197,360,335	155,554,358	78,407,002	63,148,652	-	62,316,811
16	376.00	DIRECT - MAINS - MDS	142,006	-	-	-	-	-	71,014	70,992
17	376.08	MAINS-CSL REPLACEMENTS	23,515,481	18,006,509	1,952,726	1,539,088	775,776	624,806	-	616,576
18	376.30	MAINS-BARE STEEL	38,446,622	29,439,732	3,192,608	2,516,331	1,268,354	1,021,527	-	1,008,070
19	376.30	DIRECT - MAINS-BARE STEEL	80,803	-	-	-	-	-	80,803	-
20	376.80	MAINS-CAST IRON	96,846	74,158	8,042	6,339	3,195	2,573	-	2,539
21	378.10	M & R EQUIP - GENERAL	1,444,656	1,106,217	119,964	94,553	47,659	38,385	-	37,879
22	378.20	M & R EQUIP - GENERAL - REGULATING	131,630,413	100,793,356	10,930,590	8,615,211	4,342,487	3,497,420	-	3,451,349
23	378.20	DIRECT - M & R EQUIP-GEN-REG	678,970	-	-	-	-	-	-	678,970
24	378.30	M & R EQUIP - LOCAL GAS PURCHASES	437,493	335,002	36,329	28,634	14,433	11,624	-	11,471
25	379.10	M & R EQUIP - CITY GATE	136,417	104,458	11,328	8,929	4,500	3,625	-	3,577
26	379.11	M & R EQUIP - EXCHANGE GAS	(450)	(345)	(37)	(29)	(15)	(12)	-	(12)
27	380.00	SERVICES	790,447,259	719,915,650	56,912,203	11,145,306	1,659,939	482,173	-	331,988
28	380.00	DIRECT - SERVICES	1,966	-	-	-	-	-	561	1,405
29	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
30	381.00	METERS	42,969,482	32,988,531	6,144,636	3,405,331	333,443	78,205	3,008	16,328
31	381.10	AUTOMATIC METER READING	24,684,074	18,950,457	3,529,823	1,956,213	191,548	44,925	1,728	9,380
32	381.10	AUTOMATIC METER READING - OTHER	404,440	-	-	-	333,307	50,130	5,420	15,583
33	382.00	METER INSTALLATIONS	44,125,107	33,875,727	6,309,890	3,496,915	342,411	80,308	3,089	16,768
34	383.00	HOUSE REGULATORS	16,515,236	15,106,816	1,122,871	252,518	27,085	4,294	496	1,156
35	384.00	HOUSE REG INSTALLATIONS	3,484,788	3,187,606	236,931	53,282	5,715	906	105	244
36	385.00	IND M&R EQUIPMENT	7,448,547	-	118,879	1,033,262	2,526,771	2,530,718	-	1,238,917
37	385.00	DIRECT - IND M&R EQUIPMENT	493,521	-	-	-	-	-	434,968	58,553
38	385.10	IND M&R EQUIPMENT - LG VOLUME	1,037,970	-	16,566	143,987	352,111	352,661	-	172,646
39		TOTAL	3,522,012,747	2,806,794,736	289,415,723	190,974,040	91,225,400	72,453,581	625,514	70,523,754
40		**ALLOCATOR #11**	100.000%	79.694%	8.217%	5.422%	2.590%	2.057%	0.018%	2.002%

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	58,452,700							
5	305.00	Structures & Improvements	0							
6	301-303	TOTAL INTANGIBLE PLANT	63,388,078	50,516,495	5,208,598	3,436,902	1,641,751	1,303,893	11,410	1,269,029
7	350.10	Land	23,882							
8	350.20	Rights of Way	1,932							
9	351.20	Compressor Station Structures	3,250,037							
10	352.01	Wells Construction	738,941							
11	352.02	Wells Equipment	168,032							
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	5,831,763	4,334,108	674,735	690,014	124,217	0	8,689	0
19	374.10	LAND - CITY GATE & M/L IND M&R	21,944	16,803	1,822	1,436	724	583	0	575
20	374.20	LAND - OTHER DISTRIBUTION	3,361,100	2,573,695	279,106	219,984	110,883	89,304	0	88,128
21	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	73,021	7,919	6,241	3,146	2,534	0	2,500
22	374.40	LAND RIGHTS - OTHER DISTRIBUTION	3,851,518	2,949,223	319,830	252,082	127,062	102,335	0	100,987
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	10	1	1	0	0	0	0
25	374.50	RIGHTS OF WAY	3,233,171	2,475,736	268,483	211,611	106,662	85,905	0	84,774
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	5,380	584	460	232	187	0	184
28	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	3,072	333	263	132	107	0	105
29	375.40	M & R STRUCTURES - REGULATING	6,397,121	4,898,468	531,217	418,692	211,041	169,972	0	167,733
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	1,376	11,962	29,251	29,297	0	14,342
32	375.70	M & R STRUCTURES - OTHER	32,767,270	26,113,548	2,692,487	1,776,641	848,672	674,023	5,898	656,001
33	375.71	M & R STRUCTURES - OTHER LEASED	6,293,269	5,015,358	517,118	341,221	162,996	129,453	1,133	125,991
34	375.80	M & R STRUCTURES - COMMUNICATION	16,515	12,646	1,371	1,081	545	439	0	433
35	376.00	MAINS	2,376,689,964	1,819,902,806	197,360,335	155,554,358	78,407,002	63,148,652	0	62,316,811
36	376.00	DIRECT - MAINS - MDS	142,006	0	0	0	0	0	71,014	70,992
37	376.08	MAINS-CSL REPLACEMENTS	23,515,481	18,006,509	1,952,726	1,539,088	775,776	624,806	0	616,576

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

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
		DISTRIBUTION PLANT								
1	376.30	MAINS-BARE STEEL	38,446,622	29,439,732	3,192,608	2,516,331	1,268,354	1,021,527	0	1,008,070
2	376.30	DIRECT - MAINS-BARE STEEL	80,803	0	0	0	0	0	80,803	0
3	376.80	MAINS-CAST IRON	96,846	74,158	8,042	6,339	3,195	2,573	0	2,539
4	378.10	M & R EQUIP - GENERAL	1,444,656	1,106,217	119,964	94,553	47,659	38,385	0	37,879
5	378.20	M & R EQUIP - GENERAL - REGULATING	131,630,413	100,793,356	10,930,590	8,615,211	4,342,487	3,497,420	0	3,451,349
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	437,493	335,002	36,329	28,634	14,433	11,624	0	11,471
8	379.10	M & R EQUIP - CITY GATE	136,417	104,458	11,328	8,929	4,500	3,625	0	3,577
9	379.11	M & R EQUIP - EXCHANGE GAS	(450)	(345)	(37)	(29)	(15)	(12)	0	(12)
10	380.00	SERVICES	790,447,259	719,915,650	56,912,203	11,145,306	1,659,939	482,173	0	331,988
11	380.00	DIRECT - SERVICES	1,966	0	0	0	0	0	561	1,405
12	380.12	CSL REPLACEMENT	0	0	0	0	0	0	0	0
13	381.00	METERS	42,969,482	32,988,531	6,144,636	3,405,331	333,443	78,205	3,008	16,328
14	381.10	AUTOMATIC METER READING	24,684,074	18,950,457	3,529,823	1,956,213	191,548	44,925	1,728	9,380
15	381.10	AUTOMATIC METER READING - OTHER	404,440	0	0	0	333,307	50,130	5,420	15,583
16	382.00	METER INSTALLATIONS	44,125,107	33,875,727	6,309,890	3,496,915	342,411	80,308	3,089	16,768
17	383.00	HOUSE REGULATORS	16,515,236	15,106,816	1,122,871	252,518	27,085	4,294	496	1,156
18	384.00	HOUSE REG INSTALLATIONS	3,484,788	3,187,606	236,931	53,282	5,715	906	105	244
19	385.00	IND M&R EQUIPMENT	7,448,547	0	118,879	1,033,262	2,526,771	2,530,718	0	1,238,917
20	385.00	DIRECT - IND M&R EQUIPMENT	493,521	0	0	0	0	0	434,968	58,553
21	385.10	IND M&R EQUIPMENT - LG VOLUME	1,037,970	0	16,566	143,987	352,111	352,661	0	172,646
22	387.10	OTHER EQUIP DISTRIBUTION	19,450	15,501	1,598	1,055	504	400	4	389
23	387.20	OTHER EQUIP ODORIZATION	117,248	93,439	9,634	6,357	3,037	2,412	21	2,347
24	387.42	OTHER EQUIP RADIO	119,609	95,321	9,828	6,485	3,098	2,460	22	2,395
25	387.44	OTHER EQUIP COMMUNICATION	623,932	497,237	51,269	33,830	16,160	12,834	112	12,491
26	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	10,630,871	8,472,167	873,539	576,406	275,340	218,677	1,914	212,830
27	387.45	DIRECT - OTHER EQUIP CUSTOMER INFO SER	69,585	0	0	0	0	0	69,585	0
28	387.50	GPS EQUIPMENT	2,201,372	1,754,362	180,887	119,358	57,016	45,282	396	44,072
29	374-387	TOTAL DISTRIBUTION	3,574,855,354	2,848,851,668	293,752,082	193,835,393	92,592,221	73,539,122	704,598	71,580,270

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	2,020,141							
4	391.11	OF&E Data Handling Equipment	91,304							
5	391.12	OF&E Information Systems	367,128							
6	391.20	OF&E Air Cond Equip	3,007							
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	60,884							
11	394.11	CNG Equip - Stationary	(26,345)							
12	394.12	CNG Equip - Portable	179,308							
13	394.20	Shop Equipment	35,454							
14	394.30	Tools & Other	17,452,652							
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	2,921,116							
23	398.00	Miscellaneous Equipment	944,905							
24	389-398	TOTAL GENERAL PLANT	25,349,458	20,201,997	2,082,965	1,374,448	656,551	521,438	4,563	507,496
25		TOTAL	3,669,424,654	2,923,904,268	301,718,381	199,336,757	95,014,740	75,364,453	729,260	73,356,795
		ALLOCATOR #12		79.684%	8.222%	5.432%	2.589%	2.054%	0.020%	1.999%

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	2,376,689,964	1,819,902,806	197,360,335	155,554,358	78,407,002	63,148,652	-	62,316,811
2	376.00	DIRECT - MAINS - MDS	142,006	-	-	-	-	-	71,014	70,992
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	18,006,509	1,952,726	1,539,088	775,776	624,806	-	616,576
4	376.30	MAINS-BARE STEEL	38,446,622	29,439,732	3,192,608	2,516,331	1,268,354	1,021,527	-	1,008,070
5	376.30	DIRECT - MAINS-BARE STEE	80,803	-	-	-	-	-	80,803	-
6	376.80	MAINS-CAST IRON	96,846	74,158	8,042	6,339	3,195	2,573	-	2,539
7		TOTAL	2,438,971,723	1,867,423,206	202,513,710	159,616,116	80,454,327	64,797,559	151,817	64,014,988
		ALLOCATOR #13	100.000%	76.566%	8.303%	6.544%	3.299%	2.657%	0.006%	2.625%

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	2,376,689,964	1,819,902,806	197,360,335	155,554,358	78,407,002	63,148,652	-	62,316,811
2	376.00	DIRECT - MAINS - MDS	142,006	-	-	-	-	-	71,014	70,992
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	18,006,509	1,952,726	1,539,088	775,776	624,806	-	616,576
4	376.30	MAINS-BARE STEEL	38,446,622	29,439,732	3,192,608	2,516,331	1,268,354	1,021,527	-	1,008,070
5	376.30	DIRECT - MAINS-BARE STEEL	80,803	-	-	-	-	-	80,803	-
6	376.80	MAINS-CAST IRON	96,846	74,158	8,042	6,339	3,195	2,573	-	2,539
7	380.00	SERVICES	790,447,259	719,915,650	56,912,203	11,145,306	1,659,939	482,173	-	331,988
8	380.00	DIRECT - SERVICES	1,966	-	-	-	-	-	561	1,405
9	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
10		TOTAL	3,229,420,948	2,587,338,856	259,425,912	170,761,423	82,114,266	65,279,731	152,378	64,348,381
11		**ALLOCATOR #14**	100.000%	80.117%	8.033%	5.288%	2.543%	2.021%	0.005%	1.993%

Columbia Gas of Pennsylvania, Inc.
Services Allocation Factor
As of November 30, 2020

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	7,771.80	15,543.60	8028"
808	FLEX	4"	0	0	0	1	0	1	3,882.87	3,882.87	8084"
809	FLEX	6"	1	0	0	0	0	1	4,996.93	4,996.93	8096"
809	FLEX	8"	0	0	0	1	0	1	7,771.80	7,771.80	8098"
810	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8104"
810	FLEX	6"	1	0	0	0	0	1	4,996.93	4,996.93	8106"
816	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	816UNDER 3"
831	FLEX MDS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	831UNDER 3"
833	FLEX	8"	0	0	0	0	1	1	7,771.80	7,771.80	8338"
840	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8404"
840	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	840UNDER 3"
845	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8454"
846	FLEX	6"	0	0	0	0	1	1	4,996.93	4,996.93	8466"
846	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	846UNDER 3"
847	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8474"
848	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	848UNDER 3"
857	FLEX	3"	1	0	0	0	0	1	583.46	583.46	8573"
868	FLEX	UNDER 3"	0	0	0	1	1	2	1,216.88	2,433.76	868UNDER 3"
873	FLEX	6"	1	0	0	0	0	1	4,996.93	4,996.93	8736"
875	FLEX	12"	1	0	0	0	0	1	69,826.82	69,826.82	87512"
875	FLEX	6"	1	0	0	0	0	1	4,996.93	4,996.93	8756"
875	FLEX	8"	0	0	0	1	0	1	7,771.80	7,771.80	8758"
876	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	876UNDER 3"
877	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	877UNDER 3"
879	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	879UNDER 3"
880	FLEX	12"	1	0	0	0	0	1	69,826.82	69,826.82	88012"
881	FLEX	4"	1	0	0	0	0	1	3,882.87	3,882.87	8814"
881	FLEX	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	881UNDER 3"
EDSTIB1	SDS/LGSS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	EDSTIB1UNDER 3"
LG1	SDS/LGSS	3"	4	0	0	2	0	6	583.46	3,500.76	LG13"
LG1	SDS/LGSS	4"	7	0	0	0	1	8	3,882.87	31,062.96	LG14"
LG1	SDS/LGSS	6"	0	0	0	1	0	1	4,996.93	4,996.93	LG16"
LG1	SDS/LGSS	UNDER 3"	24	0	0	3	3	30	1,216.88	36,506.40	LG1UNDER 3"
LG2	SDS/LGSS	3"	8	0	0	1	0	9	583.46	5,251.14	LG23"
LG2	SDS/LGSS	4"	10	0	0	4	1	15	3,882.87	58,243.05	LG24"
LG2	SDS/LGSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	LG26"
LG2	SDS/LGSS	8"	1	0	0	0	0	1	7,771.80	7,771.80	LG28"
LG2	SDS/LGSS	UNDER 3"	46	0	1	7	0	54	1,216.88	65,711.52	LG2UNDER 3"
LG3	LDS/LGSS	4"	1	0	0	0	0	1	3,882.87	3,882.87	LG34"
NSI	MDS/NSS	3"	1	0	0	0	0	1	583.46	583.46	NSI3"

RC2	RSS/RTS	UNDER 3"	1	0	0	1	0	2	1,216.88	2,433.76	RC2UNDER 3"
RCC	RSS/RTS	UNDER 3"	17,471	133	90	2,555	2,703	22,952	1,216.88	27,929,829.76	RCCUNDER 3"
RCC	RSS/RTS	3"	0	1	0	0	0	1	583.46	583.46	RCC3"
RCC	RSS/RTS	4"	3	0	0	0	1	4	3,882.87	15,531.48	RCC4"
RCC	RSS/RTS	6"	1	0	0	0	0	1	4,996.93	4,996.93	RCC6"
RCC	RSS/RTS	10"	1	0	0	0	0	1	111.64	111.64	RCC10"
RS	RSS/RTS	10"	3	0	0	0	2	5	111.64	558.20	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	58	75	583.46	43,759.50	RS3"
RS	RSS/RTS	4"	11	1	1	4	66	83	3,882.87	322,278.21	RS4"
RS	RSS/RTS	5"	2	0	0	0	0	2	1,020.80	2,041.60	RS5"
RS	RSS/RTS	6"	6	0	0	2	3	11	4,996.93	54,966.23	RS6"
RS	RSS/RTS	8"	9	0	0	0	0	9	7,771.80	69,946.20	RS8"
RS	RSS/RTS	UNDER 3"	263,223	1,547	1,349	21,671	31,273	319,063	1,216.88	388,261,383.44	RSUNDER 3"
RTC	RSS/RTS	3"	1	0	0	0	8	9	583.46	5,251.14	RTC3"
RTC	RSS/RTS	4"	2	0	0	0	4	6	3,882.87	23,297.22	RTC4"
RTC	RSS/RTS	UNDER 3"	51,151	268	221	2,829	3,006	57,475	1,216.88	69,940,178.00	RTCUNDER 3"
SC2	SGSS2/SCD2/SGDS2	3"	25	0	0	5	2	32	583.46	18,670.72	SC23"
SC2	SGSS2/SCD2/SGDS2	4"	30	0	0	1	2	33	3,882.87	128,134.71	SC24"
SC2	SGSS2/SCD2/SGDS2	6"	1	0	0	2	0	3	4,996.93	14,990.79	SC26"
SC2	SGSS2/SCD2/SGDS2	UNDER 3"	881	7	5	133	86	1,112	1,216.88	1,353,170.56	SC2UNDER 3"
SCC	SGSS1/SCD1/SGDS1	3"	13	1	0	8	18	40	583.46	23,338.40	SCC3"
SCC	SGSS1/SCD1/SGDS1	4"	11	0	0	4	3	18	3,882.87	69,891.66	SCC4"
SCC	SGSS1/SCD1/SGDS1	5"	1	0	0	0	0	1	1,020.80	1,020.80	SCC5"
SCC	SGSS1/SCD1/SGDS1	UNDER 3"	4,756	54	40	1,488	1,653	7,991	1,216.88	9,724,088.08	SCCUNDER 3"
SG2	SGSS2/SCD2/SGDS2	12"	1	0	0	0	0	1	69,826.82	69,826.82	SG212"
SG2	SGSS2/SCD2/SGDS2	3"	46	0	0	8	6	60	583.46	35,007.60	SG23"
SG2	SGSS2/SCD2/SGDS2	4"	56	0	0	10	7	73	3,882.87	283,449.51	SG24"
SG2	SGSS2/SCD2/SGDS2	5"	0	0	0	0	1	1	1,020.80	1,020.80	SG25"
SG2	SGSS2/SCD2/SGDS2	6"	5	0	0	3	1	9	4,996.93	44,972.37	SG26"
SG2	SGSS2/SCD2/SGDS2	8"	1	0	0	0	0	1	7,771.80	7,771.80	SG28"
SG2	SGSS2/SCD2/SGDS2	10"	1	0	0	0	0	1	111.64	111.64	SG210"
SG2	SGSS2/SCD2/SGDS2	UNDER 3"	2,124	12	8	311	252	2,707	1,216.88	3,294,094.16	SG2UNDER 3"
SG3	SGSS1/SCD1/SGDS1	3"	1	0	0	0	0	1	583.46	583.46	SG33"
SG3	SGSS1/SCD1/SGDS1	4"	1	0	0	3	0	4	3,882.87	15,531.48	SG34"
SG3	SGSS1/SCD1/SGDS1	6"	1	0	0	1	0	2	4,996.93	9,993.86	SG36"
SG3	SGSS1/SCD1/SGDS1	10"	1	0	0	0	0	1	111.64	111.64	SG310"
SG3	SGSS1/SCD1/SGDS1	UNDER 3"	15	1	0	0	0	16	1,216.88	19,470.08	SG3UNDER 3"
SG4	SGSS2/SCD2/SGDS2	3"	3	0	0	1	0	4	583.46	2,333.84	SG43"
SG4	SGSS2/SCD2/SGDS2	4"	3	0	0	1	0	4	3,882.87	15,531.48	SG44"
SG4	SGSS2/SCD2/SGDS2	6"	1	0	0	0	0	1	4,996.93	4,996.93	SG46"
SG4	SGSS2/SCD2/SGDS2	UNDER 3"	23	0	0	5	1	29	1,216.88	35,289.52	SG4UNDER 3"
SGS	SGSS1/SCD1/SGDS1	10"	1	0	0	0	0	1	111.64	111.64	SGS10"
SGS	SGSS1/SCD1/SGDS1	12"	1	0	0	0	0	1	69,826.82	69,826.82	SGS12"
SGS	SGSS1/SCD1/SGDS1	16"	0	0	0	1	0	1	0.00	0.00	SGS16"
SGS	SGSS1/SCD1/SGDS1	3"	20	0	0	20	61	101	583.46	58,929.46	SGS3"

SGS	SGSS1/SCD1/SGDS1	4"	39	0	0	13	45	97	3,882.87	376,638.39	SGS4"
SGS	SGSS1/SCD1/SGDS1	5"	0	0	0	1	0	1	1,020.80	1,020.80	SGS5"
SGS	SGSS1/SCD1/SGDS1	6"	3	0	0	0	2	5	4,996.93	24,984.65	SGS6"
SGS	SGSS1/SCD1/SGDS1	8"	1	0	0	0	0	1	7,771.80	7,771.80	SGS8"
SGS	SGSS1/SCD1/SGDS1	UNDER 3"	11,966	107	84	4,339	5,616	22,112	1,216.88	26,907,650.56	SGSUNDER 3"
SGT	INACTIVE	3"	2	0	0	0	0	2	583.46	1,166.92	SGT3"
SGT	INACTIVE	4"	1	0	0	1	0	2	3,882.87	7,765.74	SGT4"
SGT	INACTIVE	UNDER 3"	14	0	0	3	1	18	1,216.88	21,903.84	SGTUNDER 3"
TAG1	SGSS1/SCD1/SGDS1	3"	4	0	0	0	1	5	583.46	2,917.30	TAG13"
TAG1	SGSS1/SCD1/SGDS1	UNDER 3"	123	0	0	36	22	181	1,216.88	220,255.28	TAG1UNDER 3"
TAG2	SGSS2/SCD2/SGDS2	3"	15	0	0	1	0	16	583.46	9,335.36	TAG23"
TAG2	SGSS2/SCD2/SGDS2	4"	23	0	0	3	1	27	3,882.87	104,837.49	TAG24"
TAG2	SGSS2/SCD2/SGDS2	6"	1	0	0	0	0	1	4,996.93	4,996.93	TAG26"
TAG2	SGSS2/SCD2/SGDS2	UNDER 3"	283	0	0	24	16	323	1,216.88	393,052.24	TAG2UNDER 3"
TAG5	SGSS1/SCD1/SGDS1	3"	6	0	0	1	4	11	583.46	6,418.06	TAG53"
TAG5	SGSS1/SCD1/SGDS1	4"	7	0	0	2	2	11	3,882.87	42,711.57	TAG54"
TAG5	SGSS1/SCD1/SGDS1	UNDER 3"	534	2	0	73	125	734	1,216.88	893,189.92	TAG5UNDER 3"
TAG6	SGSS2/SCD2/SGDS2	3"	53	0	0	4	1	58	583.46	33,840.68	TAG63"
TAG6	SGSS2/SCD2/SGDS2	4"	53	1	0	7	7	68	3,882.87	264,035.16	TAG64"
TAG6	SGSS2/SCD2/SGDS2	6"	5	0	0	1	0	6	4,996.93	29,981.58	TAG66"
TAG6	SGSS2/SCD2/SGDS2	UNDER 3"	979	8	3	97	53	1,140	1,216.88	1,387,243.20	TAG6UNDER 3"
TI4	SDS/LGSS	12"	1	0	0	0	0	1	69,826.82	69,826.82	TI412"
TI4	SDS/LGSS	3"	19	0	0	2	1	22	583.46	12,836.12	TI43"
TI4	SDS/LGSS	4"	25	0	0	2	0	27	3,882.87	104,837.49	TI44"
TI4	SDS/LGSS	6"	5	0	0	2	1	8	4,996.93	39,975.44	TI46"
TI4	SDS/LGSS	UNDER 3"	133	1	0	15	6	155	1,216.88	188,616.40	TI4UNDER 3"
TI8	LDS/LGSS	3"	4	0	0	0	0	4	583.46	2,333.84	TI83"
TI8	LDS/LGSS	4"	16	0	0	3	0	19	3,882.87	73,774.53	TI84"
TI8	LDS/LGSS	6"	3	0	0	1	0	4	4,996.93	19,987.72	TI86"
TI8	LDS/LGSS	8"	0	1	1	0	0	2	7,771.80	15,543.60	TI88"
TI8	LDS/LGSS	UNDER 3"	21	0	0	3	2	26	1,216.88	31,638.88	TI8UNDER 3"
TIB	SDS/LGSS	3"	25	0	0	1	0	26	583.46	15,169.96	TIB3"
TIB	SDS/LGSS	4"	54	0	0	9	1	64	3,882.87	248,503.68	TIB4"
TIB	SDS/LGSS	6"	5	0	0	0	1	6	4,996.93	29,981.58	TIB6"
TIB	SDS/LGSS	8"	1	0	0	0	0	1	7,771.80	7,771.80	TIB8"
TIB	SDS/LGSS	UNDER 3"	132	1	0	15	5	153	1,216.88	186,182.64	TIBUNDER 3"
TIF	LDS/LGSS	3"	8	0	0	1	0	9	583.46	5,251.14	TIF3"
TIF	LDS/LGSS	4"	12	0	0	1	1	14	3,882.87	54,360.18	TIF4"
TIF	LDS/LGSS	6"	3	0	0	0	0	3	4,996.93	14,990.79	TIF6"
TIF	LDS/LGSS	8"	1	0	0	0	0	1	7,771.80	7,771.80	TIF8"
TIF	LDS/LGSS	UNDER 3"	50	1	1	4	1	57	1,216.88	69,362.16	TIFUNDER 3"
TIG	LDS/LGSS	3"	2	0	0	0	0	2	583.46	1,166.92	TIG3"
TIG	LDS/LGSS	4"	1	0	0	0	0	1	3,882.87	3,882.87	TIG4"
TIG	LDS/LGSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	TIG6"
TIG	LDS/LGSS	8"	0	0	0	1	0	1	7,771.80	7,771.80	TIG8"
TIG	LDS/LGSS	UNDER 3"	2	0	0	1	0	3	1,216.88	3,650.64	TIGUNDER 3"

TIH	LDS/LGSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	TIH6"
TM1	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	TM1UNDER 3"
TM1	MDS/NSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	TM16"
TM3	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	TM3UNDER 3"
TMB	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,216.88	1,216.88	TMBUNDER 3"
TMB	MDS/NSS	4"	1	0	0	0	0	1	3,882.87	3,882.87	TMB4"
TMB	MDS/NSS	6"	0	0	0	1	0	1	4,996.93	4,996.93	TMB6"
TMB	MDS/NSS	8"	1	0	0	0	0	1	7,771.80	7,771.80	TMB8"
TMC	MDS/NSS	6"	1	0	0	0	0	1	4,996.93	4,996.93	TMC6"
UNKNOWN			2,301	9	11	432	781	3,534	UNKNOWN	UNKNOWN	UNKNOWN
			356,992	2,156	1,815	34,194	45,922	441,079		534,436,105.05	
Check Total			0	0	0	0	0	0			

		Total Cost	Percent
	RSS/RTS	**486,677,146.77**	**91.077%**
	SGSS1/SCD1/SGDS1	**38,476,455.71**	**7.200%**
	SGSS2/SCD2/SGDS2	**7,536,695.89**	**1.410%**
	SDS/LGSS	**1,122,960.30**	**0.210%**
	LDS/LGSS	**325,363.60**	**0.061%**
	FLEX	**224,003.17**	**0.042%**
	TOTAL BEFORE MDS/NSS	**534,362,625.44**	**100.000%**
	MDS/NSS	**25,882.63**	
	FLEX MDS	**16,760.48**	
	TOTAL	**534,405,268.55**	
	UNKNOWN	**96,948,763.85**	
101-1000	**TOTAL ACCOUNT 380**	**631,354,032.40**	
101-2000	**CIAC**	**(1,108,063.83)**	
101-4000	**Relocation Reimbursements**	**(17,664.36)**	
106	**Completed Construction not Classifie**	**226,649.97**	
Total	**Per Exhibit 8, Schedule 1**	**630,454,954.18**	

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	859.62	0.00	859.62
2	803	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	806	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	808	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
5	809	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
6	810	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
7	816	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
8	819	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
9	820	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10	830	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11	831	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
12	833	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
13	838	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14	840	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
15	845	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
16	846	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
17	847	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
18	848	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
19	856	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	857	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
21	868	0.00	0.00	0.00	0.00	0.00	859.63	0.00	859.63
22	872	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	873	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
24	875	0.00	0.00	0.00	0.00	0.00	859.62	0.00	859.62
25	876	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
26	877	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
27	879	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
28	880	0.00	0.00	0.00	0.00	0.00	429.81	0.00	429.81
29	881	0.00	0.00	0.00	0.00	0.00	981.93	0.00	981.93
30	LG1	0.00	0.00	0.00	24,455.23	0.00	0.00	0.00	24,455.23
31	LG2	0.00	0.00	0.00	42,298.44	0.00	0.00	0.00	42,298.44
32	LG3	0.00	0.00	0.00	0.00	1,289.43	0.00	0.00	1,289.43
33	LG4	0.00	0.00	0.00	0.00	1,289.43	0.00	0.00	1,289.43
34	LG5	0.00	0.00	0.00	0.00	429.81	0.00	0.00	429.81
35	NSI	0.00	0.00	0.00	0.00	0.00	0.00	56.54	56.54
36	RCC	1,378,601.56	0.00	0.00	0.00	0.00	0.00	0.00	1,378,601.56
37	RC2	17,473.25	0.00	0.00	0.00	0.00	0.00	0.00	17,473.25
38	RS	19,724,428.18	0.00	0.00	0.00	0.00	0.00	0.00	19,724,428.18
39	RTC	3,549,108.68	0.00	0.00	0.00	0.00	0.00	0.00	3,549,108.68
40	SCC	0.00	1,159,605.07	0.00	0.00	0.00	0.00	0.00	1,159,605.07
41	SC2	0.00	0.00	537,923.32	0.00	0.00	0.00	0.00	537,923.32
42	SG2	0.00	0.00	1,282,896.24	0.00	0.00	0.00	0.00	1,282,896.24
43	SG3	0.00	10,403.65	0.00	0.00	0.00	0.00	0.00	10,403.65
44	SG4	0.00	0.00	17,571.68	0.00	0.00	0.00	0.00	17,571.68
45	SGS	0.00	3,176,551.15	0.00	0.00	0.00	0.00	0.00	3,176,551.15
46	TAG1	0.00	42,034.90	0.00	0.00	0.00	0.00	0.00	42,034.90
47	TAG2	0.00	0.00	160,610.52	0.00	0.00	0.00	0.00	160,610.52
48	TAG5	0.00	206,474.49	0.00	0.00	0.00	0.00	0.00	206,474.49
49	TAG6	0.00	0.00	547,406.87	0.00	0.00	0.00	0.00	547,406.87
50	TI4	0.00	0.00	0.00	66,216.81	0.00	0.00	0.00	66,216.81
51	TI8	0.00	0.00	0.00	0.00	21,446.58	0.00	0.00	21,446.58
52	TIB	0.00	0.00	0.00	116,253.39	0.00	0.00	0.00	116,253.39
53	TIF	0.00	0.00	0.00	0.00	30,691.60	0.00	0.00	30,691.60
54	TIG	0.00	0.00	0.00	0.00	3,008.68	0.00	0.00	3,008.68
55	TIH	0.00	0.00	0.00	0.00	429.81	0.00	0.00	429.81
56	TMB	0.00	0.00	0.00	0.00	0.00	0.00	1,289.44	1,289.44
57	TMC	0.00	0.00	0.00	0.00	0.00	0.00	429.81	429.81
58	TM1	0.00	0.00	0.00	0.00	0.00	0.00	263.45	263.45
59	TM2	0.00	0.00	0.00	0.00	0.00	0.00	263.45	263.45
60	TOTAL	24,669,611.67	4,595,069.26	2,546,408.63	249,223.87	58,585.34	12,157.00	2,302.69	32,133,358.46
61	**OR #16**	76.772%	14.300%	7.925%	0.776%	0.182%	0.038%	0.007%	100.000%

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurment Stations
As of November 30, 2020

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	LG1		49394	732195	41,114.02	LG1	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	11,290.77	TIB	SDS/LGSS
37	10379912006	400498094	SC2		14628	1333032	4,546.21	SC2	SGSS2/SCD2/SGDS2
37	10405620001	400044475	SGT	TAG6	45746	1333095	14,904.77	TAG6	SGSS2/SCD2/SGDS2
37	10416756005	500065176	SC2		47085	1333063	708.65	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	12983111001	400473518	SGT		661	1232704	20,610.83	SGT	INACTIVE
37	12983117003	400473502	LG2		49426	1232718	2,233.40	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	12983156001	800800458	SGT	TAG6	1268	1292906	1,708.84	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	6,156.09	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	11,015.12	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	TI4	1423	1112553	2,575.48	TI4	SDS/LGSS
37	12983276001	400473401	SGT	TIB	3382	1112553	13,360.04	TIB	SDS/LGSS
37	12983281001	400473412	SG2		1432	1112521	3,135.76	SG2	SGSS2/SCD2/SGDS2
37	12983282001	400473411	SGT	TIB	1431	1112569	2,375.82	TIB	SDS/LGSS
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	9,980.77	TIB	SDS/LGSS
37	12983298001	400473267	SGT	TAG6	1305	1112569	1,771.37	TAG6	SGSS2/SCD2/SGDS2
37	12983301001	400473229	SGT	TI4	4252	1112553	1,853.55	TI4	SDS/LGSS
37	12983302001	400502918	SC2		4492	1112521	1,179.62	SC2	SGSS2/SCD2/SGDS2
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	SDS/LGSS
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	SGT	TIB	4469	1252855	2,953.96	TIB	SDS/LGSS
37	12983355011	400484838	SGT	TIB	14322	1252855	5,698.48	TIB	SDS/LGSS
37	12983355011	500163677	SGT	TIB	47388	1252855	663.83	TIB	SDS/LGSS
37	12983355011	500287938	SGT	TIB	47386	1252855	663.83	TIB	SDS/LGSS
37	12983359001	400473342	SGT	TIB	1364	1252858	1,868.32	TIB	SDS/LGSS
37	12983370001	400495171	SG2		3323	1252863	4,538.11	SG2	SGSS2/SCD2/SGDS2
37	12983403001	400472841	SGT	TI8	718	732195	8,285.78	TI8	LDS/LGSS
37	12983415001	400473189	SGT	TI8	1005	732158	9,302.44	TI8	LDS/LGSS
37	12983428003	400502425	SGT	816	14126	732153	(2,300.48)	816	FLEX
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	TI8	856	70409	6,293.59	TI8	LDS/LGSS
37	12983474002	400472983	SGT	TI8	832	732195	14,328.04	TI8	LDS/LGSS
37	12983477001	400472975	SGT	TAG2	826	732195	2,722.41	TAG2	SGSS2/SCD2/SGDS2
37	12983480002	400472971	SGT	TAG2	746	732195	2,473.69	TAG2	SGSS2/SCD2/SGDS2
37	12983498005	800800442	SGT	TIB	4410	70458	1,250.67	TIB	SDS/LGSS
37	12983504001	400473099	SGT	TIB	924	70451	10,408.46	TIB	SDS/LGSS
37	12983508002	400508899	SGT	TI8	871	70424	9,181.24	TI8	LDS/LGSS
37	12983513001	400472886	SGT	TIB	760	70471	2,467.02	TIB	SDS/LGSS
37	12983515001	400472854	SGT	TI4	733	70471	2,053.49	TI4	SDS/LGSS
37	12983517002	400505175	SGT	TIG	14699	70468	23,377.51	TIG	LDS/LGSS
37	12983537001	400473198	LG2		1013	70453	2,943.45	LG2	SDS/LGSS
37	12983540001	400473178	SGT	TAG6	995	70471	1,041.40	TAG6	SGSS2/SCD2/SGDS2
37	12983543001	400473167	SGT	TI4	986	70402	2,443.06	TI4	SDS/LGSS
37	12983545001	400473135	SGT	TAG6	960	70454	975.58	TAG6	SGSS2/SCD2/SGDS2
37	12983554002	400510507	SGT	TI4	926	70495	732.91	TI4	SDS/LGSS
37	12983554002	500146350	SGT	TI4	926	70495	732.91	TI4	SDS/LGSS
37	12983556001	400475899	SGT	TIB	906	70456	8,689.61	TIB	SDS/LGSS
37	12983557001	400473076	SGT	TI4	908	70404	982.95	TI4	SDS/LGSS
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	12983603001	400472840	SGT	TI4	4550	70405	2,829.72	TI4	SDS/LGSS
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	TAG6	996	310911	3,442.72	TAG6	SGSS2/SCD2/SGDS2
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	10,801.61	TIB	SDS/LGSS
37	12983645004	400492992	SGT	802	1121	1252804	12,553.25	802	FLEX MDS
37	12983645004	500142415	SGT	802	1121	1252804	12,553.25	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	18,010.19	TI4	SDS/LGSS
37	12983693004	400506899	SGT	TI4	14766	1252821	4,992.09	TI4	SDS/LGSS
37	12983778004	400526322	SGT	TI4	44903	30287	27,762.30	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	35,737.31	TIB	SDS/LGSS

37	12983816001	400497901	SGT	847	14538	30298	6,397.42	847	FLEX
37	12983822001	400472761	SGT	TAG6	1252	30244	1,277.77	TAG6	SGSS2/SCD2/SGDS2
37	12983855001	400472621	SG2		3401	30224	1,484.68	SG2	SGSS2/SCD2/SGDS2
37	12983862002	400472577	SGT	TAG2	4353	30298	10,749.20	TAG2	SGSS2/SCD2/SGDS2
37	12983868001	800800388	LG1		1073	30236	1,054.99	LG1	SDS/LGSS
37	12983871001	400472535	SGT	TAG6	1049	30298	12,117.18	TAG6	SGSS2/SCD2/SGDS2
37	12983873001	400472530	SGT	TAG6	4287	30287	1,952.86	TAG6	SGSS2/SCD2/SGDS2
37	12983875003	501090417	SGT	TIB	49141	30287	77,635.13	TIB	SDS/LGSS
37	12983885004	400472514	SGT	TIB	48589	30295	0.00	TIB	SDS/LGSS
37	12983886001	400472513	SGT	TAG2	4687	30295	2,325.82	TAG2	SGSS2/SCD2/SGDS2
37	12983915002	400472655	SGT	TIB	1159	30216	15,518.72	TIB	SDS/LGSS
37	12983934001	400484301	SGT	TIF	937	70452	4,620.19	TIF	LDS/LGSS
37	12983936001	400473091	SGT	TI8	916	30225	17,199.27	TI8	LDS/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	12983946001	400493917	SGT	TMC	14046	70452	129,641.36	TMC	MDS/NSS
37	12983954001	400518548	SGT	TAG2	1016	30280	1,793.76	TAG2	SGSS2/SCD2/SGDS2
37	12983968001	400473146	SGT	TI4	971	30280	1,505.38	TI4	SDS/LGSS
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	12983989001	400473067	SGT	TAG6	897	30255	1,605.63	TAG6	SGSS2/SCD2/SGDS2
37	12983993001	400473045	SGT	TI4	881	30235	2,566.18	TI4	SDS/LGSS
37	12983994003	400473044	SGT	TI4	880	30235	2,280.48	TI4	SDS/LGSS
37	12984012005	400526772	SGT	TAG6	810	30272	2,131.13	TAG6	SGSS2/SCD2/SGDS2
37	12984057001	400472794	SGT	TAG2	14003	70452	2,817.69	TAG2	SGSS2/SCD2/SGDS2
37	12984060001	400472789	SGT	TI4	675	30231	2,006.04	TI4	SDS/LGSS
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	2,599.58	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	TIB	4502	1252819	3,398.13	TIB	SDS/LGSS
37	12984129002	400472553	SGT	TIB	1070	1252807	4,903.64	TIB	SDS/LGSS
37	12984131002	500789128	SGT	TIB	48657	1252822	6,756.22	TIB	SDS/LGSS
37	12984147008	400520146	SGT	TAG6	47452	1252807	398.38	TAG6	SGSS2/SCD2/SGDS2
37	12984148002	500185413	SGT		49412	30241	45,917.22	SGT	INACTIVE
37	12984148003	400518885	SGT	TIB	44408	30241	7,603.27	TIB	SDS/LGSS
37	12984150004	501030792	SGT	875	49154	273860	490.06	875	FLEX
37	12984150004	800800371	SGT	875	4385	273804	8,104.06	875	FLEX
37	12984150007	501179703	SG2		49333	273860	490.06	SG2	SGSS2/SCD2/SGDS2
37	12984151020	400475666	SGT	TIF	1565	273860	287.79	TIF	LDS/LGSS
37	12984151020	400514859	SGT	TIF	48789	273860	490.06	TIF	LDS/LGSS
37	12984151020	400514976	SGT	TIF	48788	273860	490.06	TIF	LDS/LGSS
37	12984151020	400526997	SGT	TIF	45666	273860	490.06	TIF	LDS/LGSS
37	12984151020	500008214	SGT	TIF	48790	273860	490.06	TIF	LDS/LGSS
37	12984151020	500130476	SGT	TIF	45665	273860	490.06	TIF	LDS/LGSS
37	12984151020	500130460	SGT	TIF	45732	273804	233.25	TIF	LDS/LGSS
37	12984151020	500130474	SGT	TIF	48526	273860	490.06	TIF	LDS/LGSS
37	12984151020	500130459	SGT	TIF	48889	273860	490.06	TIF	LDS/LGSS
37	12984151020	500136322	SGT	TIF	45731	273804	233.25	TIF	LDS/LGSS
37	12984151020	500150517	SGT	TIF	45908	273860	490.06	TIF	LDS/LGSS
37	12984151020	500162068	SGT	TIF	45949	273860	490.06	TIF	LDS/LGSS
37	12984151020	500198356	SGT	TIF	46017	273804	233.25	TIF	LDS/LGSS
37	12984151020	500198359	SGT	TIF	46018	273804	5,166.36	TIF	LDS/LGSS
37	12984151020	500208315	SGT	TIF	46494	273804	233.25	TIF	LDS/LGSS
37	12984151020	500555580	SGT	TIF	48444	273860	490.06	TIF	LDS/LGSS
37	12984151020	500558423	SGT	TIF	48887	273860	490.06	TIF	LDS/LGSS

37	12984151020	500612327	SGT	TIF	48438	273804	233.25	TIF	LDS/LGSS
37	12984151020	500625771	SGT	TIF	48958	273860	586.51	TIF	LDS/LGSS
37	12984151020	500659013	SGT	TIF	48965	273860	490.06	TIF	LDS/LGSS
37	12984151020	500667297	SGT	TIF	48439	273804	233.25	TIF	LDS/LGSS
37	12984151020	500667298	SGT	TIF	48440	273860	(10,506.34)	TIF	LDS/LGSS
37	12984151020	500692603	SGT	TIF	48625	273860	490.06	TIF	LDS/LGSS
37	12984151020	500707423	SGT	TIF	48970	273804	233.25	TIF	LDS/LGSS
37	12984151020	500709556	SGT	TIF	48543	273860	490.06	TIF	LDS/LGSS
37	12984151020	500716291	SGT	TIF	48471	273860	490.06	TIF	LDS/LGSS
37	12984151020	500806647	SGT	TIF	48678	273860	490.06	TIF	LDS/LGSS
37	12984151020	500856054	SGT	TIF	48736	273804	233.25	TIF	LDS/LGSS
37	12984151020	500875536	SGT	TIF	48749	273804	233.25	TIF	LDS/LGSS
37	12984151020	500918034	SGT	TIF	48624	273860	490.06	TIF	LDS/LGSS
37	12984151020	500949336	SGT	TIF	48808	273860	490.06	TIF	LDS/LGSS
37	12984151020	500949337	SGT	TIF	48809	273860	490.06	TIF	LDS/LGSS
37	12984151020	800800356	SGT	TIF	4371	273860	490.06	TIF	LDS/LGSS
37	12984151020	800800357	SGT	TIF	4373	273860	490.06	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	490.06	TIF	LDS/LGSS
37	12984151020	800800361	SGT	TIF	4377	273860	825.56	TIF	LDS/LGSS
37	12984151020	800800362	SGT	TIF	4378	273860	2,892.02	TIF	LDS/LGSS
37	12984151020	800800364	SGT	TIF	4380	273860	550.88	TIF	LDS/LGSS
37	12984151020	800800365	SGT	TIF	4381	273804	233.25	TIF	LDS/LGSS
37	12984151020	800800366	SGT	TIF	4382	273860	490.06	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	233.25	TIF	LDS/LGSS
37	12984151020	800800354	SGT	TIF	49234	273860	490.06	TIF	LDS/LGSS
37	12984151070	500599616	SGT		48888	273860	490.06	SGT	INACTIVE
37	12984151071	500972343	SGT		48807	273804	233.25	SGT	INACTIVE
37	12984151071	501078814	SGT		49357	273860	490.06	SGT	INACTIVE
37	12984151071	501102376	SGT		49356	273860	490.06	SGT	INACTIVE
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	12984182002	400472462	SGT	TIB	4457	273860	10,145.74	TIB	SDS/LGSS
37	12984188002	400472449	SGT	TIF	4450	273804	353,710.72	TIF	LDS/LGSS
37	12984215001	400526343	SGT	TI4	44949	273804	233.25	TI4	SDS/LGSS
37	12984218002	400472435	SGT	TIB	1493	551552	0.00	TIB	SDS/LGSS
37	12984219005	400472431	LG2		294	551501	1,230.00	LG2	SDS/LGSS
37	12984219005	500165435	LG2		294	551501	1,230.00	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	1,085.90	NSI	MDS/NSS
37	12984233004	400472404	SGT	TI8	1508	551553	0.00	TI8	LDS/LGSS
37	12984233004	800800336	SGT	TI8	4507	551553	9,209.77	TI8	LDS/LGSS
37	12984235003	400503659	SGT	TI4	14732	551511	8,739.95	TI4	SDS/LGSS
37	12984235003	500232234	SGT	TI4	48041	551511	1,085.90	TI4	SDS/LGSS
37	12984245001	400514975	SGT	TAG6	44087	10153	2,947.61	TAG6	SGSS2/SCD2/SGDS2
37	12984246003	500416284	SGT	TAG6	47469	1333025	22,467.14	TAG6	SGSS2/SCD2/SGDS2
37	12984247004	400472434	SGT	TIF	297	10109	12,937.44	TIF	LDS/LGSS
37	12984247004	400472433	SGT	TIF	4339	10109	4,963.02	TIF	LDS/LGSS
37	12984247004	800800335	SGT	TIF	14446	10109	6,918.53	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	TIB	1510	10120	13,172.01	TIB	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	11,461.41	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	12984271002	400490462	SGT	TIB	14386	10156	7,754.25	TIB	SDS/LGSS
37	12984273001	400522508	SGT	TIB	44530	10105	4,338.27	TIB	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		48785	10109	16,768.97	SGT	INACTIVE
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	708.65	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	708.65	TI8	LDS/LGSS
37	12984318001	400505362	SGT	TI8	48677	1333063	708.65	TI8	LDS/LGSS
37	12984318001	400507194	SGT	TI8	46075	1333063	708.65	TI8	LDS/LGSS
37	12984318001	400514810	SGT	TI8	48034	1333063	708.65	TI8	LDS/LGSS
37	12984318001	500005922	SGT	TI8	48032	1333063	708.65	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	12984327001	400472263	SGT	TI4	4536	1333025	1,730.75	TI4	SDS/LGSS
37	12984329001	400526741	SGT	TIG	45205	1333025	29,437.80	TIG	LDS/LGSS
37	12984343004	400490919	SGT	TIG	14417	1333063	18,898.59	TIG	LDS/LGSS
37	12984343004	500023117	SGT	TIG	48880	1333063	708.65	TIG	LDS/LGSS
37	12984343004	500535850	SGT	TIG	48881	1333063	708.65	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	194.35	TIF	LDS/LGSS
37	12984366001	400472272	SGT	TI8	3506	1333063	5,146.65	TI8	LDS/LGSS
37	12984368001	400472269	SGT	TIB	3504	1333063	3,476.30	TIB	SDS/LGSS
37	12984378001	400496892	SGT	TAG6	14565	1333017	2,669.44	TAG6	SGSS2/SCD2/SGDS2
37	12984382001	400493516	SGT	TIB	14532	1333017	12,842.45	TIB	SDS/LGSS
37	12984392002	400472214	SGT	TIB	3569	1333074	2,525.70	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	12984428001	400493347	SGT	TI4	3950	1333032	4,743.56	TI4	SDS/LGSS
37	12984433001	400474737	SGT	TIB	14041	1333014	5,653.11	TIB	SDS/LGSS
37	12984438005	400517692	SGT	TI8	14678	1333029	4,928.91	TI8	LDS/LGSS
37	12984438005	400526273	SGT	TI8	44876	1333029	5,910.79	TI8	LDS/LGSS
37	12984438005	800800325	SGT	TI8	3916	1333029	6,020.27	TI8	LDS/LGSS
37	12984438005	800800326	SGT	TI8	3917	1333029	5,990.82	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	43,301.57	TI8	LDS/LGSS
37	12984448001	400472085	SGT	TI8	3893	1333027	932.88	TI8	LDS/LGSS
37	12984450007	500793520	SGT	TIF	48680	1333027	13,001.87	TIF	LDS/LGSS
37	12984453004	400505585	SGT	TIB	3881	1333029	15,312.79	TIB	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	121.30	TIB	SDS/LGSS
37	12984484006	400471998	SGT	TIB	14566	1333083	4,528.52	TIB	SDS/LGSS
37	12984484006	500151812	SGT	TIB	47456	1333083	121.30	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	1,122.71	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	TAG6	14383	1333029	323.82	TAG6	SGSS2/SCD2/SGDS2
37	12984538001	400496374	SGT	TIB	14554	1333095	2,344.33	TIB	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	5,049.11	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	5,990.82	TIF	LDS/LGSS
37	12984569008	400516746	SGT	TIF	47028	1333029	5,990.82	TIF	LDS/LGSS
37	12984585004	400472035	SGT	TIB	3824	1333029	12.68	TIB	SDS/LGSS
37	12984585004	800800310	SGT	TIB	3825	1333029	211.51	TIB	SDS/LGSS
37	12984592001	400471991	SGT	TI8	3698	1333069	12,248.59	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	TI4	3728	1333027	4,576.34	TI4	SDS/LGSS
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	4,477.49	TIB	SDS/LGSS
37	12984643001	400471809	SGT	TIB	4526	1333017	4,064.30	TIB	SDS/LGSS
37	12984645001	400471795	SGT	TAG2	3777	1333095	272.52	TAG2	SGSS2/SCD2/SGDS2
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	20,273.39	TIB	SDS/LGSS
37	13188422011	500079934	SGT	TIF	49385	273806	3,326.29	TIF	LDS/LGSS
37	13188422011	500325346	SGT	TIF	49384	273806	2,119.27	TIF	LDS/LGSS
37	13237020002	500135596	SGT	TI8	4638	511396	31,407.24	TI8	LDS/LGSS
37	13241895007	501021913	SGT	TIF	49028	30225	41,352.90	TIF	LDS/LGSS
37	13241895007	501028115	SGT	TIF	49013	30225	41,352.90	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	TAG6	45872	1252862	11,513.92	TAG6	SGSS2/SCD2/SGDS2
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	17,889.42	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	TM3	46567	511324	286,814.93	TM3	MDS/NSS
37	14012426004	400516863	SG2		761	30272	1,160.93	SG2	SGSS2/SCD2/SGDS2
37	14161126001	400472230	SGT	TIB	3588	1333034	4,042.39	TIB	SDS/LGSS

37	14172457001	500278290	SGT	TAG6	46926	273804	233.25	TAG6	SGSS2/SCD2/SGDS2
37	14203427002	400483822	SGT	TAG6	14283	511304	7,594.01	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	SGT	TAG6	47466	10155	12,751.38	TAG6	SGSS2/SCD2/SGDS2
37	14318082003	400519776	SGT	TIB	47451	1333032	12,859.08	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	10,935.22	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	LG3		49158	1112521	15,825.73	LG3	LDS/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	SG4		621	832206	5,915.22	SG4	SGSS2/SCD2/SGDS2
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	15171839005	400472256	SGT	TI4	3642	1333074	279.49	TI4	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	60.31	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	TI4	48533	1112512	13,388.88	TI4	SDS/LGSS
37	15641400003	400502082	LG1		46814	1333017	12,842.45	LG1	SDS/LGSS
37	15674018001	500648810	SGT	TIF	48541	273801	100,011.17	TIF	LDS/LGSS
37	15878297001	500766884	SGT	TI4	48455	1333007	2,215.93	TI4	SDS/LGSS
37	15886667015	400472089	SG4		3897	1333032	4,697.05	SG4	SGSS2/SCD2/SGDS2
37	15897246001	500635532	SGT	TIB	48654	1333004	10,255.49	TIB	SDS/LGSS
37	15932079001	500755822	SGT	TI8	48661	511311	11,097.65	TI8	LDS/LGSS
37	16032404001	400493513	SG2		3428	1112521	1,471.35	SG2	SGSS2/SCD2/SGDS2
37	16195289003	400472627	SGT	TAG6	1134	30276	3,736.41	TAG6	SGSS2/SCD2/SGDS2
37	16211690001	400522880	SGT	TAG6	1081	30243	1,018.27	TAG6	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	16630957002	400526998	SGT	TMB	14788	70470	33,446.59	TMB	MDS/NSS
37	16656334003	501222616	LG1		49396	511304	26,053.55	LG1	SDS/LGSS
37	16804444002	500146391	SGT	TI8	861	70495	5,786.00	TI8	LDS/LGSS
37	16804444008	500175309	SGT	TIB	49139	70495	21,018.66	TIB	SDS/LGSS
37	16919869001	500215263	SGT	TAG6	48787	1333095	14,904.77	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	18,913.52	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	6,490.58	TI8	LDS/LGSS
37	17230495003	400479417	SG2		888	30225	1,962.15	SG2	SGSS2/SCD2/SGDS2
37	17264884002	400500238	SGT	TIH	14403	1333032	13,842.91	TIH	LDS/LGSS
37	17297010001	400474558	SGT	TI4	14055	1333035	8,795.26	TI4	SDS/LGSS
37	17329614003	500162630	SGT	868	44642	1333027	12,763.43	868	FLEX
37	17329614003	500162631	SGT	868	44642	1333027	12,763.43	868	FLEX
37	17374299002	400473323	LG2		1351	511314	9,043.84	LG2	SDS/LGSS
37	17409498001	501027922	SGT	TIB	49021	1333095	13,667.74	TIB	SDS/LGSS
37	17432474003	400472075	SGT	TIB	3879	1333027	0.00	TIB	SDS/LGSS
37	17439660001	400471850	SGT	TI4	4149	1333035	290.07	TI4	SDS/LGSS
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	17451537003	400473024	SG2		862	30272	142.84	SG2	SGSS2/SCD2/SGDS2
37	17486118001	501043836	SG4		49030	273821	13,756.34	SG4	SGSS2/SCD2/SGDS2
37	17509433003	501049268	SGT	TI8	49070	511306	17,829.30	TI8	LDS/LGSS
37	17556648001	500988325	LG1		49016	1252829	60,036.77	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	TIF	689	70477	23,230.13	TIF	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	18941652003	400473297	SGS		1332	511318	3,863.92	SGS	SGSS1/SCD1/SGDS1
37	18973174002	400526191	SGT	873	44761	190613	52,867.22	873	FLEX
37	18985473001	501047288	SGT	TIB	49243	1333035	403.68	TIB	SDS/LGSS
37	18988904003	501281830	LG1		49425	70479	30,721.08	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	1,216.31	TI8	LDS/LGSS
37	19075101001	400473322	SG2		4421	1292916	10,041.93	SG2	SGSS2/SCD2/SGDS2
37	19114953001	500688577	SGT	TAG6	48544	511312	1,115.13	TAG6	SGSS2/SCD2/SGDS2
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	17,467.57	TI4	SDS/LGSS
37	19252407003	800800378	SGT	TAG6	849	30234	2,908.76	TAG6	SGSS2/SCD2/SGDS2
37	19336466001	400501188	SGT	TI4	45609	1333032	43,301.57	TI4	SDS/LGSS
37	19430896001	501122186	SGT	TIB	49298	70412	11,219.30	TIB	SDS/LGSS
37	19431194001	400473171	SGT	TIB	989	70461	20,862.41	TIB	SDS/LGSS
37	19441257001	500095996	SG2		46960	1333017	4,780.17	SG2	SGSS2/SCD2/SGDS2
37	19443642001	400472814	SGT	TIB	697	70403	8,081.85	TIB	SDS/LGSS
37	19447200001	400472448	LG2		4581	273851	1,746.45	LG2	SDS/LGSS
37	19447200003	500153394	LG1		4581	273851	1,746.45	LG1	SDS/LGSS
37	19451537002	501178063	LG2		49337	1112521	16,774.06	LG2	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	TI4	46707	511304	26,053.55	TI4	SDS/LGSS
37	19791817001	500175440	SGT	TAG5	45528	70452	31,330.69	TAG5	SGSS1/SCD1/SGDS1
37	19817465001	400472437	SG2		3304	10104	8,152.83	SG2	SGSS2/SCD2/SGDS2
37	19845214005	400472052	SGT	TIB	3847	1333032	7,490.23	TIB	SDS/LGSS
37	19854159001	501154755	SGT	TI8	49338	273804	2,245.53	TI8	LDS/LGSS

37	19854159002	501162824	LG2		49322	1333029	5,990.82	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	20091569037	400479518	SGT	TAG6	774	30272	1,641.60	TAG6	SGSS2/SCD2/SGDS2
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	3,535.27	TM1	MDS/NSS
37	20271953001	500214064	LG2		47053	1252822	26,943.19	LG2	SDS/LGSS
37	20271953003	500459284	LG1		47484	1252822	5,248.14	LG1	SDS/LGSS
37	20352622001	400493366	SGT	TIF	14458	1333025	4,349.04	TIF	LDS/LGSS
37	20403776001	501228775	SG2		49390	10157	3,188.39	SG2	SGSS2/SCD2/SGDS2
37	20428036001	400494812	SG2		14520	1333095	3,163.10	SG2	SGSS2/SCD2/SGDS2
37	20436639001	400516841	SC2		671	30272	860.03	SC2	SGSS2/SCD2/SGDS2
37	20460679003	400472903	SG2		775	732195	1,532.00	SG2	SGSS2/SCD2/SGDS2
37	20480473001	501093555	SGT	880	49361	1333014	467,690.79	880	FLEX
37	20480473002	400471977	SGT	TIB	4335	1333077	5,839.08	TIB	SDS/LGSS
37	20503074001	501173051	SGT	TIB	49398	1333029	2,795.00	TIB	SDS/LGSS
37	20540367001	501221207	SGT	810	49395	732195	32,565.34	810	FLEX
37	20556961001	400494798	SGT	TI8	14599	10160	3,955.51	TI8	LDS/LGSS
37	20665631001	400473191	SGT	TIF	1007	30225	5,974.11	TIF	LDS/LGSS
37	20669499001	501163330	SGT	TIB	49411	70452	31,330.69	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	SGT	TIB	3863	1333029	12,486.40	TIB	SDS/LGSS
	Total								

	Total Cost	**Percent**
RSS/RTS	**0.00**	**0.000%**
SGSS1/SCD1/SGDS1	**81,966.67**	**1.596%**
SGSS2/SCD2/SGDS2	**712,666.88**	**13.872%**
SDS/LGSS	**1,742,719.49**	**33.923%**
LDS/LGSS	**1,745,448.70**	**33.976%**
FLEX	**854,489.86**	**16.633%**
TOTAL BEFORE MDS/NSS	**5,137,291.60**	**100.000%**
MDS/NSS	**473,035.29**	
FLEX MDS	**25,106.50**	
TOTAL	**5,635,433.39**	

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	290,954	222,772	24,158	19,040	9,599	7,731	18	7,638
2	874.00	MAINS & SERVICES	22,963,878	18,397,970	1,844,688	1,214,330	583,971	464,100	1,148	457,670
3	875.00	M & R - GENERAL	1,000,400	765,966	83,063	65,466	33,003	26,581	60	26,261
4	876.00	M & R - INDUSTRIAL	382,620	-	6,107	53,077	129,796	129,999	-	63,641
5	878.00	METERS & HOUSE REGULATORS	2,274,895	1,791,753	298,489	157,719	21,225	4,459	228	1,024
6	879.00	CUSTOMER INSTALLATIONS	7,286,676	6,636,486	524,641	102,742	15,302	4,445	-	3,060
7	886.00	STRUCTURES AND IMPROVEMENT	82,677	63,302	6,865	5,410	2,728	2,197	5	2,170
8	887.00	MAINS	18,854,683	14,436,277	1,565,504	1,233,851	622,016	500,969	1,131	494,935
9	889.00	M & R - GENERAL	1,227,716	940,013	101,937	80,342	40,502	32,620	74	32,228
10	890.00	M & R - INDUSTRIAL	177,871	-	2,839	24,674	60,339	60,434	-	29,585
11	892.00	SERVICES	3,535,898	3,220,390	254,585	49,856	7,425	2,157	-	1,485
12	893.00	METERS & HOUSE REGULATORS	1,032,820	813,470	135,516	71,605	9,636	2,024	103	465
13		TOTAL	59,111,088	47,288,398	4,848,392	3,078,112	1,535,543	1,237,715	2,767	1,120,162
14		**ALLOCATOR #18**	100.000%	79.999%	8.202%	5.207%	2.598%	2.094%	0.005%	1.895%

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	162,957,347	120,793,944	18,175,736	19,903,319	3,691,732	170,037	222,579	-
2		TOTAL DISTRIBUTION O&M [2]	73,601,022	58,880,201	6,036,856	3,832,603	1,911,991	1,541,134	3,491	1,394,746
3		TOTAL CUSTOMER ACCOUNTS [3]	42,920,388	41,151,015	892,021	362,022	251,249	215,875	13,617	34,588
4		TOTAL CUSTOMER SERVICE & INFORMATION [4]	2,047,710	1,875,108	143,647	26,190	2,273	348	41	103
5		TOTAL SALES [5]	456,184	417,732	32,001	5,835	506	78	9	23
6		TOTAL	281,982,651	223,118,000	25,280,261	24,129,969	5,857,752	1,927,472	239,737	1,429,460
	LESS:									
7		GAS PURCHASED COST [6]	161,368,307	119,615,901	17,998,184	19,709,532	3,655,831	168,466	220,393	-
8	904.00	UNCOLLECTIBLES-DIS REVENUE [7]	6,235,204	5,800,673	222,285	212,246	-	-	-	-
9	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE [8]	482,584	(0)	217	13,135	241,421	214,370	13,440	34,146
10	904.00	UNCOLLECTIBLES-UNBUNDLED GAS [9]	782,615	739,685	21,461	21,469	-	-	-	-
11	904.00	DIRECT USP UNCOLLECTIBLES [10]	26,432,574	26,432,574	-	-	-	-	-	-
12		TOTAL	195,301,284	152,588,833	18,242,147	19,956,383	3,897,252	382,836	233,833	34,146
13		TOTAL	86,681,368	70,529,168	7,038,114	4,173,586	1,960,500	1,544,636	5,904	1,395,314
14		**ALLOCATOR #19**	100.000%	81.404%	8.120%	4.815%	2.262%	1.782%	0.007%	1.610%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2020

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: C. E. Notestone

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		14,572,470	297,350,015	$20.40				
2	All Pipe		41,023,960	1,544,125,441					
3	Unit Cost of 2" x All Pipe Footage			836,888,784					
4	Customer Component			54.198%					
5	Demand Component			45.802%					
6	Number of Customers (Total Company excl MDS)		444,012	406,599	31,147	5,677	492	74	23
7	Percent Customers		100.000%	91.572%	7.015%	1.279%	0.111%	0.017%	0.006%
8	Customer Component		54.198%	49.634%	3.802%	0.693%	0.060%	0.009%	0.003%
9	Design Day Volumes (Total Company excl MDS)		790,500	465,000	77,700	101,000	55,900	45,700	45,200
10	Percent Design Day Volumes		100.000%	58.824%	9.829%	12.777%	7.071%	5.781%	5.718%
11	Demand Component		45.802%	26.942%	4.502%	5.852%	3.239%	2.648%	2.619%
12	**Minimum System Allocation Factor**		**100.000%**	**76.573%**	**8.304%**	**6.545%**	**3.299%**	**2.657%**	**2.622%**

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	MDS	FLEX	TOTAL
1	RC2	240,056	0	0	0	0	0	0	240,056
2	RS	2,534,519	0	0	0	0	0	0	2,534,519
3	RTC	450,812	0	0	0	0	0	0	450,812
4	LG1	0	0	0	548	0	0	0	548
5	LG2	0	0	0	462	0	0	0	462
6	LG3	0	0	0	0	12	0	0	12
7	LG4	0	0	0	0	12	0	0	12
8	NSI	0	0	0	0	0	12	0	12
9	SGS	0	170,062	0	0	0	0	0	170,062
10	SG2	0	0	26,355	0	0	0	0	26,355
11	SG3	0	233	0	0	0	0	0	233
12	SG4	0	0	448	0	0	0	0	448
13	TAG1	0	1,149	0	0	0	0	0	1,149
14	TAG2	0	0	2,895	0	0	0	0	2,895
15	TAG5	0	6,263	0	0	0	0	0	6,263
16	TAG6	0	0	12,706	0	0	0	0	12,706
17	TIB	0	0	0	2,604	0	0	0	2,604
18	TIF	0	0	0	0	324	0	0	324
19	TIG	0	0	0	0	72	0	0	72
20	TIH	0	0	0	0	12	0	0	12
21	TI4	0	0	0	2,153	0	0	0	2,153
22	TI8	0	0	0	0	468	0	0	468
23	TMA	0	0	0	0	0	0	0	0
24	TM1	0	0	0	0	0	24	0	24
25	TM2	0	0	0	0	0	0	0	0
26	TM3	0	0	0	0	0	12	0	12
27	TMB	0	0	0	0	0	36	0	36
28	TMC	0	0	0	0	0	12	0	12
29	808	0	0	0	0	0	0	12	12
30	809	0	0	0	0	0	0	24	24
31	810	0	0	0	0	0	0	24	24
32	816	0	0	0	0	0	0	12	12
33	833	0	0	0	0	0	0	12	12
34	838	0	0	0	0	0	0	0	0
35	840	0	0	0	0	0	0	12	12
36	841	0	0	0	0	0	0	0	0
37	845	0	0	0	0	0	0	12	12
38	846	0	0	0	0	0	0	12	12
39	847	0	0	0	0	0	0	12	12
40	848	0	0	0	0	0	0	0	0
41	856	0	0	0	0	0	0	0	0
42	857	0	0	0	0	0	0	12	12
43	858	0	0	0	0	0	0	0	0
44	859	0	0	0	0	0	0	0	0
45	868	0	0	0	0	0	0	12	12
46	872	0	0	0	0	0	0	1	1
47	873	0	0	0	0	0	0	12	12
48	874	0	0	0	0	0	0	0	0
49	875	0	0	0	0	0	0	12	12
50	876	0	0	0	0	0	0	12	12
51	877	0	0	0	0	0	0	12	12
52	879	0	0	0	0	0	0	12	12
53	880	0	0	0	0	0	0	12	12
54	881	0	0	0	0	0	0	12	12
55	SCC	0	62,011	0	0	0	0	0	62,011
56	SC2	0	0	11,509	0	0	0	0	11,509
57	**Total**	**3,225,387**	**239,718**	**53,913**	**5,767**	**900**	**96**	**241**	**3,526,022**
58	**ALLOCATOR #21**	91.472%	6.799%	1.529%	0.164%	0.026%	0.003%	0.007%	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	52.014%	8.606%	12.258%	8.427%	10.145%	8.550%	100.000%
2	ALLOCATOR #20	76.573%	8.304%	6.545%	3.299%	2.657%	2.622%	100.000%
3	TOTAL OF BOTH STUDIES	128.587%	16.910%	18.803%	11.726%	12.802%	11.172%	
4	AVERAGE OF BOTH STUDIES	64.294%	8.455%	9.402%	5.863%	6.401%	5.586%	100.000%
5	**ALLOCATOR #22**	64.294%	8.455%	9.402%	5.863%	6.401%	5.586%	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	42,969,482	32,988,531	6,144,636	3,405,331	333,443	78,205	3,008	16,328
2	381.10	AUTOMATIC METER READING	24,684,074	18,950,457	3,529,823	1,956,213	191,548	44,925	1,728	9,380
3	381.10	AUTOMATIC METER READING	404,440	-	-	-	333,307	50,130	5,420	15,583
4	382.00	METER INSTALLATIONS	44,125,107	33,875,727	6,309,890	3,496,915	342,411	80,308	3,089	16,768
5	383.00	HOUSE REGULATORS	16,515,236	15,106,816	1,122,871	252,518	27,085	4,294	496	1,156
6	384.00	HOUSE REG INSTALLATIONS	3,484,788	3,187,606	236,931	53,282	5,715	906	105	244
7		TOTAL	132,183,126	104,109,137	17,344,150	9,164,259	1,233,510	258,768	13,844	59,459
8		**ALLOCATOR #23**	100.000%	78.762%	13.121%	6.933%	0.933%	0.196%	0.010%	0.045%

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	65,391	48,598	7,566	7,737	1,393	-	97	-
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	4,038,213	3,230,530	331,214	210,270	104,913	84,560	202	76,524
10	871.00	LOAD DISPATCHING	13	206,855	158,381	17,175	13,537	6,824	5,496	12	5,430
11	874.00	MAINS & SERVICES	14	9,521,470	7,628,316	764,860	503,495	242,131	192,429	476	189,763
12	875.00	M & R - GENERAL	13	367,270	281,204	30,494	24,034	12,116	9,758	22	9,641
13	876.00	M & R - INDUSTRIAL	17	218,157	(0)	3,482	30,263	74,005	74,121	-	36,286
14	878.00	METERS & HOUSE REGULATORS	23	1,220,959	961,652	160,202	84,649	11,392	2,393	122	549
15	879.00	CUSTOMER INSTALLATIONS	15	4,687,734	4,269,448	337,517	66,097	9,844	2,860	-	1,969
16	880.00	OTHER	18	2,607,571	2,086,030	213,873	135,776	67,745	54,603	130	49,414
17	885.00	SUPERVISION & ENGINEERING	18	145,273	116,217	11,915	7,564	3,774	3,042	7	2,753
18	886.00	STRUCTURES AND IMPROVEMENTS	13	18,314	14,023	1,521	1,199	604	487	1	481
19	887.00	MAINS	13	4,213,303	3,225,958	349,831	275,719	138,997	111,948	253	110,599
20	889.00	M & R - GENERAL	13	693,655	531,104	57,594	45,393	22,884	18,430	42	18,209
21	890.00	M & R - INDUSTRIAL	17	37,756	-	603	5,238	12,808	12,828	-	6,280
22	892.00	SERVICES	15	1,414,805	1,288,562	101,866	19,949	2,971	863	-	594
23	893.00	METERS & HOUSE REGULATORS	23	575,459	453,243	75,506	39,897	5,369	1,128	58	259
24	894.00	OTHER EQUIPMENT	18	582,208	465,760	47,753	30,316	15,126	12,191	29	11,033
25	902.00	METER READING	6	253,477	232,111	17,781	3,242	281	43	5	13
26	903.00	CUSTOMER RECORDS AND COLLECTION EXPENSES	6	678,981	621,749	47,631	8,684	754	115	14	34
25	920.00	SALARIES	19	4,198,858	3,417,745	341,073	202,259	95,020	74,866	294	67,602
26	921.00	OFFICE SUPPLIES & EXPENSES	19	584,621	475,864	47,489	28,161	13,230	10,424	41	9,412
27	923.00	OUTSIDE SERVICES EMPLOYED	19	-	-	-	-	-	-	-	-
28		TOTAL		36,330,329	29,506,494	2,966,945	1,743,477	842,181	672,584	1,805	596,843
29		**ALLOCATOR #24**		100.000%	81.217%	8.167%	4.799%	2.318%	1.851%	0.005%	1.643%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 26
C&I NETWORK CUSTOMERS

	RSS/RDS	SGS-1	SGS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX	Total
Allocation Factor #6	406,599	31,147	5,677	492	74	8	23	444,020
Less: Residential Customers	(406,599)	0	0	0	0	0	0	(406,599)
Less: SGSS1/SCD1/SGDS1	0	(31,147)	0	0	0	0	0	(31,147)
Less: SGSS2/SCD2/SGDS2	0	0	(5,677)	0	0	0	0	(5,677)
Total	0	0	0	492	74	8	23	597
ALLOCATOR #26	0.000%	0.000%	0.000%	82.412%	12.395%	1.340%	3.853%	100.000%

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 CEN-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 11. 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. 11.

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 11. 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, 2019.

Accounts 488, 493 and 495

Miscellaneous Revenue and Other revenue were allocated using Factor No. 6 - Average Number of Customers since costs incurred throughout these accounts are directly related to the customers served. Rent Revenue was allocated using Factor No. 11 because the rent is derived

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

mostly from the rent of Company-owned office buildings, making the use of the Distribution Plant allocator appropriate.

OPERATING EXPENSES – PURCHASED GAS EXPENSES - PAGE 7

Gas purchased cost

These costs were directly assigned based on revenue for the fully projected future test year as presented in Exhibit No. 103.

Account 807

Gas Purchase Expense and Gas Procurement Expenses were allocated using Factor No. 4, which is based on the direct assignment of gas costs. Factor No. 4 was used reflecting the relationship of these costs to gas purchase costs. Gas purchase expense related to the gas procurement activity was also allocated using Factor No. 4.

OPERATING EXPENSES – UNDER STORAGE EXPENSES - PAGE 7

Accounts 814 through 837

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

DISTRIBUTION EXPENSES – OPERATIONS - PAGE 7

Accounts 870, 880, 881

General costs for supervision and engineering, rents and other items of the distribution function were allocated using Factor No. 18, Other Distribution Expense, because these costs benefit customers in the way that all other distribution costs provide benefit.

Account 871

Distribution Load Dispatch Expenses were allocated on Factor No. 13 – Direct Plant – Mains because these are costs incurred monitoring and directing the flow of gas through the distribution system.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 874

Mains and Services Operation Expenses (a dual function account) were allocated on Factor No. 14 – Composite Direct Plant - Mains and Services combined.

Accounts 875

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures because these costs are incurred in direct relation with mains.

Accounts 876

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 – Direct Assignment – IND M&R - because these costs are incurred in direct association with the stations in Account 385.

Accounts 878 and 879

Meters & House Regulators Expenses were allocated using Factor No. 23, which was based on an actual inventory of meters and house regulators installed on customer premises as explained in Statement No. 11. 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.

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

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. 11.

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. 11.

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

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.

Accounts 252 and 186

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

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 10.95%
For the 12 Months Ending December 31, 2022

Ln. No.	Item	Total	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	Account 117	3,631,226	2,698,691	420,133	429,647	77,345	-	5,411
2	Account 164	34,854,214	25,903,303	4,032,633	4,123,951	742,395	-	51,933
3	Allocated Storage Per ACOS Study using Allocation Factor #25	38,485,440	28,601,994	4,452,765	4,553,597	819,740	-	57,343
4	Sales & CHOICE Transportation (Ditch)	46,614,960.9	34,643,463.1	5,393,499.4	5,515,384.1	993,014.3	0.0	69,600.0
5	Factor 25 Allocation of Storage	100%	74.319%	11.570%	11.832%	2.130%	0.000%	0.149%
6	Pre-Tax as Filed	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%
7	Revenue Requirement related to storage assigned to rate schedule (Ln. 6 * Ln. 7)	3,963,778	2,945,840	458,609	468,994	84,428	-	5,906
8	Rate Per Ditch	0.0850						

Ln. No.	Item	Total DTH	% of Total	Included In Proposed Rates	Ratio	Redistributed Per Settlement
9						
10						
11						
12						
13	SGSS1 - Subject to Storage	3,901,993.9	68.990%	316,394	0.7235	15,363
14	SCD1 - Subject to Storage	1,491,505.5	26.370%	120,935	0.2765	5,871
15	SGDS1 - Not Subject to Storage	262,006.4	4.630%	21,234		(21,234)
		5,655,505.8	99.990%	458,563		0

Ln. No.	Item	Total DTH	% of Total	Included In Proposed Rates	Ratio	Redistributed Per Settlement
16						
17						
18						
19						
20	SGSS2 - Subject to Storage	3,903,397.1	43.400%	203,543	0.7078	128,367
21	SCD2 - Subject to Storage	1,611,987.0	17.920%	84,044	0.2922	52,993
22	SGDS2 - Not Subject to Storage	3,477,754.6	38.670%	181,360		(181,360)
		8,993,138.7	99.990%	468,947		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	1.26	1.08	1.14	0.95	0.17	30.41	(0.84)
2	Peak & Average Proposed Rates	1.22	1.06	1.08	1.00	0.38	20.00	(0.55)
3	Customer/Demand Current Rates	0.72	1.14	2.87	3.92	3.60	30.41	(0.31)
4	Customer/Demand Proposed Rates	0.77	1.11	2.46	3.50	3.36	20.00	(0.20)
5	Average of P/A & C/D Current Rates	0.95	1.11	1.77	1.81	0.90	30.41	(0.72)
6	Average of P/A & C/D Proposed Rates	0.96	1.08	1.57	1.72	1.01	20.00	(0.47)

		Amount	Rate	
1	**Labor and Benefits** [1]	**Amount**	**Rate**	
2	Accounting Support	$4,531.43		
3	Gas Supply Support	$203,428.42		
4	Legal Support	$5,685.68		
5	Regulatory Support	$84,506.70		
6	Treasury Support	$11,999.46		
7	**Total Labor and Benefits (Line 2 + Line 3 + Line 4 + Line 5 + Line 6)**	**$310,151.69**		
8	**Outside Services - Legal Support**	**$61,000.00**		
9	**Information Technology Systems Maintenance**			
10	Gas Source	$49,021.00		
11	% of customers taking Sales Service	80.00%		
12	**Cost allocated to Sales Service Customers (line 10 * Line 11)**	**$39,216.80**		
13	**TOTAL (line 6 + line 8 + line 9)**	**$410,368.49**		
14	Total Sales (Therms)	362,959,766 [2]		
15	Gas Procurement Charge (Line 13 / Line 14)		$0.00113	per / therm
16	Gas Procurement Charge (Line 15 * 10)		$0.01130	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, 2022

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	329,203	56,712	3,317	295	0	(177)	389,350
February	330,067	56,356	3,952	314	279	(177)	390,791
March	330,684	55,954	4,104	310	518	(177)	391,393
April	329,996	55,511	3,491	298	672	(177)	389,791
May	328,948	55,098	3,519	282	820	(176)	388,491
June	327,718	54,752	3,933	308	920	(175)	387,456
July	327,026	54,388	5,206	441	1,116	(175)	388,002
August	326,833	54,107	5,664	437	1,974	(175)	388,840
September	327,359	53,807	4,904	438	2,320	(175)	388,653
October	328,787	53,502	4,610	432	4,185	(175)	391,341
November	331,477	53,158	4,528	417	4,570	(176)	393,974
December	334,090	54,640	4,363	398	4,257	(177)	397,571
Total	3,952,188	657,985	51,591	4,370	21,631	(2,112)	4,685,653

Volumes (Dth)

	Residential FPFTY RS	Residential RDS FPFTY	Residential RS Final Bills	Residential RDS Final Bills	New Residential Customers	Residential Customer Attrition	Total
January	5,297,753.2	961,909.7	0.0	0.0	2,606.0	(2,904.0)	6,259,364.9
February	5,328,609.5	954,375.6	0.0	0.0	6,906.0	(2,915.0)	6,286,976.1
March	4,536,716.3	806,508.2	0.0	0.0	10,373.0	(2,479.0)	5,351,118.5
April	2,932,424.2	524,474.6	0.0	0.0	11,572.0	(1,604.0)	3,466,866.8
May	1,256,981.3	222,757.4	0.0	0.0	11,931.0	(687.0)	1,490,982.7
June	638,282.0	112,429.8	0.0	0.0	11,254.0	(348.0)	761,617.8
July	342,590.5	59,409.2	0.0	0.0	11,661.0	(187.0)	413,473.7
August	307,370.5	53,001.4	0.0	0.0	17,964.0	(167.0)	378,168.9
September	380,818.4	64,940.3	0.0	0.0	18,782.0	(207.0)	464,333.7
October	603,602.2	105,070.5	0.0	0.0	30,830.0	(329.0)	739,173.7
November	1,815,667.4	309,887.2	0.0	0.0	32,025.0	(986.0)	2,156,593.6
December	3,875,261.8	669,001.0	0.0	0.0	30,512.0	(2,109.0)	4,572,665.8
Total	27,316,077.3	4,843,764.9	0.0	0.0	196,416.0	(14,922.0)	32,341,336.2

Calculation of Benchmark Distribution Revenue per Bill (BDRB)

	Bills	Rate	Customer Based Revenue	Volumes (Dth)	Rate/Dth	Volumetric Based Revenue	BDRB
	(1)	(2)	(3=1*2)	(4)	(5)	(6=4*5)	(7=((3+6)/1)
January	389,350	$ 19.33	$ 7,526,136	6,259,364.9	$ 8.8796	$ 55,580,657	$ 162.08
February	390,791	$ 19.33	$ 7,553,990	6,286,976.1	$ 8.8796	$ 55,825,833	$ 162.18
March	391,393	$ 19.33	$ 7,565,627	5,351,118.5	$ 8.8796	$ 47,515,792	$ 140.73
April	389,791	$ 19.33	$ 7,534,660	3,466,866.8	$ 8.8796	$ 30,784,390	$ 98.31
May	388,491	$ 19.33	$ 7,509,531	1,490,982.7	$ 8.8796	$ 13,239,330	$ 53.41
June	387,456	$ 19.33	$ 7,489,524	761,617.8	$ 8.8796	$ 6,762,861	$ 36.78
July	388,002	$ 19.33	$ 7,500,079	413,473.7	$ 8.8796	$ 3,671,481	$ 28.79
August	388,840	$ 19.33	$ 7,516,277	378,168.9	$ 8.8796	$ 3,357,989	$ 27.97
September	388,653	$ 19.33	$ 7,512,662	464,333.7	$ 8.8796	$ 4,123,098	$ 29.94
October	391,341	$ 19.33	$ 7,564,622	739,173.7	$ 8.8796	$ 6,563,567	$ 36.10
November	393,974	$ 19.33	$ 7,615,517	2,156,593.6	$ 8.8796	$ 19,149,689	$ 67.94
December	397,571	$ 19.33	$ 7,685,047	4,572,665.8	$ 8.8796	$ 40,603,443	$ 121.46
Total	4,685,653.0		$ 90,573,672	32,341,336.2		$ 287,178,129	$ 965.69
BDRBp (Oct-Mar)							$ 690.49
BDRBo (Apr-Sep)							$ 275.20

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAp")
Peak Period RNAp Effective October 2022 through March 2023

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-2021-3024296	$ 36.10	$ 67.94	$ 121.46	$ 162.08	$ 162.18	$ 140.73	$ 464.99
4									
5	**Actual Distribution Revenue per Bill ("ADRBp")**								Three month
6									ADRBp
7	Monthly ADRBp*	Jan 2022 - Mar 2022	NA	NA	NA	$ 160.00	$ 159.00	$ 139.00	$ 458.00
8									Total
9	Monthly BDRBp - Monthly ADRBp	ln 3 - ln 7				$ 2.08	$ 3.18	$ 1.73	$ 6.99
10									
11	**Actual Number of non-CAP residential Bills ("ANBp")**								
12									Average ANBp
13	Monthly ANBp*		NA	NA	NA	381,820	383,014	383,821	382,885
14									
15									
16	**Revenue to be Assigned to RNAp Rate**					$ 794,185.60	$ 1,217,984.52	$ 664,010.33	$ 2,676,366.15
17									
18	**Forecast Decatherms (Dth) for Effective RNAp Period (FTp)***		739,174	2,156,594	4,572,666	6,259,365	6,286,976	5,351,119	25,365,893
19									
20	**RNAp Rate Effective October 2022 through March 2023**	ln 16 / ln 18							$ 0.1055

* For illustrative purposes only.

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAo")
Off-Peak Period RNAo Effective April 2023 through September 2023

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-2021-3024296	$ 98.31	$ 53.41	$ 36.78	$ 28.79	$ 27.97	$ 29.94	$ 275.20
4									
5	**Actual Distribution Revenue per Bill ("ADRBo")**								
6									Total ADRBo
7	Monthly ADRBo*		$ 100.00	$ 54.00	$ 35.00	$ 26.00	$ 30.00	$ 32.00	$ 277.00
8									Total
9	Monthly BDRBo - Monthly ADRBo	ln 3 - ln 7	$ (1.69)	$ (0.59)	$ 1.78	$ 2.79	$ (2.03)	$ (2.06)	$ (1.80)
10									
11	**Actual Number of non-CAP residential Bills ("ANBo")**								
12									Average ANBo
13	Monthly ANBo*		384,678	383,240	383,009	381,997	382,555	382,883	383,060
14									
15									
16	**Revenue to be Assigned to RNAo Rate**		$ (650,105.82)	$ (226,111.60)	$ 681,756.02	$ 1,065,771.63	$ (776,586.65)	$ (788,738.98)	$ (689,508.60)
17									
18	**Forecast Decatherms (Dth) for Effective RNA Period (FTo)***		3,466,867	1,490,983	761,618	413,474	378,169	464,334	6,975,444
19									
20	**RNAo Rate Effective April 2023 through September 2023**	ln 16 / ln 18							$ (0.0988)

* For illustrative purposes only.

R. DANHIRES

COLUMBIA STATEMENT NO. 12

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

I. Introduction

Q. Please state your name and business address.

A. Ribeka Danhires, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

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

A. I am employed by Columbia Gas of Pennsylvania, Inc., ("Columbia" or "the Company") as Manager, Rates & Regulatory Service.

Q. What are your responsibilities as Manager, Regulatory Policy?

A. I am responsible for managing Columbia's rates and regulatory activity before the Pennsylvania Public Utility Commission ("Commission"). This responsibility includes ensuring timely, accurate rate and regulatory filings before the Commission as well as compliance with Columbia's Rates and Rules for Furnishing Gas Service, known as Tariff Gas Pa. P.U.C. No. 9 ("tariff").

Q. Please describe your professional experience.

A. I hold a Bachelor of Arts degree in Accounting from the University of Pittsburgh and a Master's of Business Administration degree from Seton Hill University. After graduating from college, I was employed by Duquesne Light Company for ten years. I started in the Rates & Tariff Services Department as a Rates Analyst and concluded my time at Duquesne Light Company in the Regulatory Affairs Department as the Pennsylvania State Regulatory Coordinator. I joined Columbia in December 2015 as a Senior Rate Analyst and moved into my current role as Manager, Rates & Regulatory Service in September 2018.

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

A. Yes. While I have only testified before the Pennsylvania Public Utility Commission in various customer complaint matters, I submitted direct testimony and testified in support of Columbia Gas of Maryland's ("CMD's") 2016, 2017, 2018, 2019 & 2020 Purchased Gas Adjustment ("PGA") filings before the Maryland Public Service Commission in Case Nos. 9510(j), 9510(k), 9510(l), 9510(m) and 9510(n), respectively. I submitted direct testimony in support of the settlement in CMD's 2019-2023 Strategic Infrastructure Development and Enhancement Plan in Case No. 9479. And, I provided testimony in CMD's 2018 Rate Case, Case No. 9480, as the Tariff witness.

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. 325 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 Federal Tax Reform Adjustment ("FTRA"). Columbia is also proposing to amend its Capital Expenditure Policy so that agreements with applicants for commercial and industrial distribution service could be based upon minimum revenue requirements in addition to, or in lieu of, minimum use requirements. Further, Columbia proposes to expand its Rules and Regulations to include a comprehensive gas quality standard with a focus on renewable natural gas ("RNG"). 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 2b, 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. 325 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 30, 2021" and "May 29, 2021", respectively. The President, where applicable, has also been updated in the footer to reflect Columbia's current president, Mark Kempic. Additionally, as shown in the Table of Contents on page 3 of the tariff, the blank space between sections 1 and 2 of the Rules and Regulations has been removed and the pages held for future use have been revised to now include pages 72 through 75 of the tariff. Page 71 of the tariff is now used to propose the Quality of Gas Delivered to Company which will be explained in more detail as one of the "Substantive Tariff Changes".

IV. Substantive Tariff Changes

Q. Please explain the changes to rates within Supplement No. 325 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 reset to zero. A column for the newly proposed Rider RNA has been added to page 16 and the column that used to reflect the "Federal Tax Adjustment Credit (FTAC)" has been renamed the "Federal Tax Reform Adjustment" ("FTRA").

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, the Distribution Charge and Gas Supply Charge, and a reset of Rider DSIC to zero. The FTAC has been renamed FTRA.

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, and a reset of Rider DSIC to zero, for all rate schedules. The FTAC has been renamed FTRA.

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, however, Rider DSIC is being reset to zero for these customers and the Gas Supply Charge has increased, as reflected on page 19. The FTAC has been renamed FTRA.

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 increases to the Price-to-Compare for both residential and commercial gas supply. Those increases are a direct result of the increase to the Gas Procurement Charge ("Rider GPC") and 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 increases too. Page 20 also reflects the name change to the existing FTAC which has been renamed FTRA.

Page 21, which is the "Rider Summary", reflects an increase to the Rider Universal Service Plan ("Rider USP") rate, the Rider GPC rate and the Rider MFC rate and a decrease to the Rider DSIC percentage. The "Rider Summary" page also includes a new line for Rider RNA.

The residential rates included on the "Pass-through Charge Summary" on page 21b are impacted by the Rider USP increase which causes the rate in the "Total Pass-through" column to increase for Rate Schedules RSS and RDS.

The rate change for Rider GPC, the Rider MFC percentage and the Rider DSIC percentages are included on Tariff pages 160, 161 and 177 respectively, which are the tariff pages that describe each rider.

Q. Pages 16 and 20 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 2022 billing cycle.

Columbia has filed the proposed Tariff with an effective date of May 29, 2021, 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. Pages 16 through 20 of the tariff designate a location for the FTRA, however, a rate is not indicated. Please explain.

A. As described in Witness Harding's testimony (Columbia Statement No. 10), the Company is not proposing an adjustment in this case. Rather, the Company is proposing a rider to allow the Company to make any future adjustments to its federal taxes outside of a base rate case. Columbia has filed the proposed tariff with an effective date of May 29, 2021 to allow for the rider to become effective should it be needed. Therefore, it is appropriate that a specific adjustment is not specified in the Tariff at this time. The FTRA replaces the FTAC on page 164 of the Company's tariff.

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. Rider GPC 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 Notestone's testimony (Columbia Statement No. 11). The percentages for Rider MFC are identified in Exhibit MJB-1 attached to Company witness Bell's testimony (Columbia Statement No. 3).

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

A. Company witness Notestone's testimony, Statement No. 11, 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 to continue the Rider WNA for an additional five years. Please explain.

A. Company witness Notestone's testimony addresses this proposal, but essentially, the Rider WNA will expire upon the issuance of a final order in this case unless the Commission authorizes Columbia to continue the rider. Columbia is proposing to continue the Rider WNA until a final order is entered in the Company's first rate case filed after May 31, 2026. This has been revised on page 162 of the Company's tariff.

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

A. Company witness Harding's testimony, Statement No. 10, introduces and explains the need for a rider to adjust for federal taxes, when applicable. The FTRA has been added to the Company's tariff, replacing the existing FTAC on page 164.

Q. Please explain the reason for minimum use agreements that are authorized under Columbia's Tariff provisions regarding Commercial and Industrial Distribution Service.

A. Tariff Section 8.2.2, on page 49 of the Company's tariff, requires an applicant for commercial or industrial distribution service to provide a deposit to the Company that is equal to difference between the minimum capital investment required to serve the applicant's gas requirements and the amount of capital that the Company can justify investing in the project, based on the applicant's anticipated gas requirements. Where anticipated gas requirements justify a project without the need for a deposit, subpart (a) of Section 8.2.2 allows the Company to employ minimum use agreements as a means of guarding against actual gas usage that falls short of those anticipated requirements. Subpart (b), which addresses situations where anticipated gas requirements do not justify an extension of facilities without further customer participation in the project, also permits the Company to employ minimum use agreements to guard against actual gas usage falling short of anticipated gas requirements.

Q. You are proposing to add the phrase "or (2) a minimum revenue agreement, in which applicant contractually agrees to pay a minimum amount over the term of the agreement" to subparts (a) and (b) of Tariff Section 8.2.2. Why?

A. Currently, minimum use agreements are based upon anticipated revenues that are derived from an analysis that uses current rates. In the event of a base rate increase, a customer who complies with their minimum use obligation under such an agreement could end up paying more than the original contract anticipated as the revenue that is required to justify Columbia's investment. Therefore, Columbia seeks approval to employ either a "minimum use" or "minimum revenue agreement" so that the Company may use agreements that focus on the minimum revenue needed to justify its investment to serve applicants in lieu of minimum use. An agreement that uses revenue as the measuring stick, rather than usage, will continue to protect the Company from the risk of unjustified capital investments where anticipated usage does not come to fruition, while also protecting customers from being required to pay more than the amount that would justify the investment to serve them.

Q. The Company's tariff includes a proposal to include a standard gas quality section under its Rules and Regulations with a focus on RNG. Please explain.

A. The changes will allow Columbia to have a more comprehensive gas quality standard dependent upon the origin of natural gas entering Columbia's system. More specifically, these changes provide for a more detailed list of particulate and gas compounds and levels that Columbia will require any gas to meet when introduced into its system. Likewise, these standards provide for a more formalized gas quality testing methodology to ensure that any supplier providing gas to Columbia's system has a clear understanding of testing requirements. Finally, the standards set forth the multiple origins of natural gas supply and define which chemical and particulate standards would likely apply to the natural gas origin. The Quality of Gas section has been added to the Company's tariff on pages 71 through 71d.

Q. Does this complete your Prepared Direct Testimony?

A. Yes.

D. DAVIS

COLUMBIA STATEMENT NO. 13

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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I. <u>Introduction</u>

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 28-year career at Columbia.

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

A. I will provide a summary of customer initiatives in 2020 and the Company's plans to improve its budget program as a result of the 2020 rate case. I will also provide an update to the Company's response to the impacts of COVID-19 on its customers. Pursuant to Columbia's 2016 rate case Joint Stipulation and Settlement, paragraph 41[1], I will provide an update on Columbia's efforts to increase voluntary contributions to Columbia's Hardship Fund. Finally, I will address the Commission's final order in the Company's 2020 rate case (R-2020-3018835) to the extent it addresses universal service programs. I will specifically provide an update on the Company's outreach to low income customers to enroll in the Hardship Fund program, as directed in the 2020 rate case order.

II. Customer Initiatives & the Company's COVID-19 Response

Q. Please explain any new initiatives that the Company has implemented to improve the customer experience?

A. There were several new initiatives that the Company implemented in 2020 to improve customer service.

One initiative was the new customer "welcome" emails. When new and transfer customers start service with the Company, Columbia now sends a series of four emails welcoming them as customer, sharing useful resources and information, and providing natural gas safety information.

Another Company initiative made it easier and quicker for customers to pay their bill with a checking account by having their payment information automatically populate during the payment process. Columbia also improved its

[1] Docket No. R-2016-2529660 (Order Entered October 27, 2016).

AutoPay process by adding PayPal, Amazon Pay and Venmo as payment options. Columbia also updated and improved billing and payment alerts to customers.

Columbia also made improvements to its website. The Company's website now has Google Translate prior to website self-service log-in. The website also now has the ability for customers to enroll in COVID-19 payment plans digitally. In addition, the Company improved the visibility of energy usage information on the customer's web dashboard and made improvements to the budget billing plan explanations on its website.

Columbia's online CAP application also went live in 2021, so now customers have another method in which to apply to the CAP program.

Q. Please explain the planned changes to the budget billing program.

A. In the Company's 2020 rate case, Columbia proposed to revise its budget billing program to offer customers a rolling 12-month payment plan. With the Commission's approval of the case, the Company is moving forward with the necessary programming to update the budget billing program. This update will allow customers to enroll in the budget billing program at any time during the year and have a payment plan equal to $1/12^{th}$ of their expected annual bill. This new enhanced program will continue to be compliant with existing regulations by not having a true up during the winter months and adjusting the bill periodically to minimize a large true up at the cycle's end.

Q. Please explain how the Company has supported customers in response to the COVID-19 Pandemic.

A. The Company has adapted many of its policies and procedures, as well as implemented additional initiatives, to assist customers who have been affected by the pandemic. Specifically, I will address the following areas: Customer Education and Outreach; Termination/Billing/Flexible Payment Plans; Universal Services and Other Assistance Programs; and Waiver of Fees.

<u>Customer Education and Outreach:</u>

Q. Please provide descriptions and/or examples of Columbia's education and outreach to its customers about their rights and responsibilities, available assistance programs, and energy efficiency and conservation opportunities during the COVID-19 pandemic.

A. Columbia has used several different resources to educate customers regarding the Company's current collection practices and available assistance programs. Examples include:

- Social media posts on Facebook and Twitter;
- Targeted outbound calls for Low Income Home Energy Assistance Program ("LIHEAP") recovery CRISIS program;
- E-mails to customers that may be eligible for the LIHEAP recovery CRISIS program;
- E-mails to customers regarding current collection practices;

- Updated information on its website regarding available programs;
- Announcement on its website that the Company has suspended all terminations for non-payment;
- Bill inserts; and
- Customer Newsletters.

Q. Are there any other efforts you would like to highlight?

A. Yes. The Company made outbound calls to customers who were determined to be eligible for the LIHEAP Recovery CRISIS program. The purpose of the call was to obtain customer consent to apply to the LIHEAP program on their behalf. Of the 7,048 accounts that Columbia reviewed, 4,544 customers were identified that qualified for assistance. Multiple phone calls were made to each customer over several weeks, and Company representatives were able to receive authorization to apply for funds on behalf of 947 customers. The Company ultimately received LIHEAP Recovery CRISIS assistance for 1,376 customers for a total of $405,142. Thus, the Company's outbound calling campaign was responsible for 68% of the grants received in 2020.

<u>Termination/Billing/ Flexible Payment Plans:</u>

Q. Is the Company currently terminating service to its customers?

A. Columbia ceased performing customer shut-offs for all customers on March 13, 2020, consistent with the Pennsylvania Public Utility Commission's ("Commission") March 13, 2020 Emergency Order at Docket M-2020-3019244.

Although the Commission lifted the absolute termination moratorium as of November 9, 2020, the Company has not terminated customers.

Q. Does the Company intend to resume service terminations in April once the winter protections expire?

A. Yes. The Company has sent pre-10 day communication letters to those customers that will be subject to termination of service beginning in April 2021. Subsequently, the Company will send out termination notices to customers, as authorized and as required, if they are still at risk for termination at least ten days prior to any termination of service.

Q. What types of payment arrangements did Columbia offer during the pandemic?

A. For residential customers, the Company offered two options in 2020. In addition to Columbia's normal budget plus payment plan offered to its customers based on financial information and household size, the Company provided customers the option of a six month payment plan that allowed customers to pay their current bills, plus 1/6 of their arrears.

In May 2020, the Company began offering commercial customers with arrears of more than $90 and less than $600 a 6 month payment plan. This payment plan option was intended for customers who are normally not payment troubled and financial information was not required for enrollment in this plan. Pursuant to the Commission's October 13, 2020 Order at Docket No. M-2020-

3019244, Columbia began offering small commercial customers an extended 18 month payment plan.

Universal Services Programs and Other Assistance Programs:

Q. Is the Company currently removing customers from the Customer Assistance Program ("CAP") for failure to verify their incomes?

A. No. While CAP participants are subject to removal from CAP if they do not verify their income eligibility annually, Columbia is currently not removing customers from CAP if they do not provide income verification. The Company intends to continue this temporary relief through the remainder of 2021.

Q. What changes has the Company made to CAP, or to other programs, as a result of the pandemic?

A. The Company has made the following changes to the CAP program and Hardship Fund program as a result of the pandemic:

- Customers were not removed from CAP for failing to pay their CAP bill.
- Any additional per week increase from Unemployment Compensation due to Pandemic relief funding is not/was not being counted as income in the determination of CAP eligibility since the income is short term.
- Any "stimulus" income received by customers is not being counted as income.
- Proof of income is not required at this time for CAP customers who are unable to verify income.

- The Company has also made changes to its Hardship Fund guidelines in order to assist customers during the pandemic. The Hardship Fund is a fund of last resort that assists customers in maintaining or restoring their service with a maximum grant of $500 and is typically available to customers who are at or below 200% of poverty and have arrears. In response to the pandemic, the Company is waiving the requirement of a sincere payment effort and, therefore, no payment is required in order to be eligible for hardship funds. Second, all low income customers are eligible regardless of CAP status so long as their account is in arrears.

Q. Will the Company continue these practices for the duration of 2021?

A. The Company will continue to not count stimulus money, including temporary increases to unemployment compensation, as household income for potential CAP customers. The Company will also accept self-certification of income for CAP eligibility if income documentation is unavailable.

The changes to the Hardship Fund eligibility guidelines will remain in effect through the program year ending September 2021. This includes eliminating the sincere effort of payment and ensuring all customers are eligible regardless of CAP status so long as their account is in arrears.

The Company will also begin actively collecting on delinquent CAP accounts as described in its approved USECP on or after April 1, 2021. The Company will continue to promote all available programs to customers through its contact center, website and social media postings.

Q. Are there other assistance programs that Columbia developed as a result of the COVID 19 pandemic?

A. Yes. On April 24, 2020, the Company filed a petition for approval of a temporary customer grant program aimed at assisting residential customers not eligible for Columbia's low income customer programs. The temporary grant program would have provided customers with grants up to $400 to reduce arrears and offer credit counseling. This petition was denied by the Commission on July 16, 2020. In response to this denial, the Company sought and obtained Commission approval to temporarily expand the Hardship Fund income guidelines from 200% of FPIG to 300% FPIG in an effort to provide relief to those struggling as a result of the Covid-19 pandemic but who are slightly over the income guidelines. Columbia shareholders donated an additional $400,000 to help fund the expansion. This was approved on November 17, 2020 and was implemented on December 15, 2020.

<u>Waiver of Fees</u>:

Q. Please summarize the fees that are being waived as a result of the pandemic.

A. Policies for late fees and reconnect fees have been modified, as per below:

Late Payment Fees: The Company has waived all late payment fees since April 2020. Since then, late fees in excess of $1,800,000 have been waived for customers.

Reconnect Fees: Columbia's normal policy is to waive the $24 reconnect fee for customers who are identified as having a household income of less than 150% FPIG. However, during the COVID-19 pandemic, Columbia has expanded that policy and is waiving the reconnect fees for customers who contact the Company to have service restored and are identified as payment troubled. Some customers during the pandemic have experienced a loss in income, thereby becoming payment troubled, yet still remain above 150% of FPIG and may or may not be eligible for energy assistance. Additionally, for customers who have been previously disconnected for lack of payment, and who would normally be charged a reconnect fee prior to reconnection, the Company is using discretion in applying the reconnect fee to the customer's first bill if the customer informs us that an upfront payment would result in financial hardship due to loss in income experienced during the pandemic.

III. 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 the customer must 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.

Over the past ten years, the average Hardship Fund grant provided to Columbia customers has ranged from $370 to $410. 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. As stated earlier in my testimony, in 2020 the Company implemented an on-line CAP application, but customers can use the on-line application to apply for the Hardship Fund program too. The on-line application makes it very convenient for customers to apply for the program because they no longer have to go to an agency or speak with a DEF representative.

Q. How does Columbia fund its Hardship Fund program?

A. Columbia contributes one dollar of shareholder money for every dollar contributed by its customers to its Hardship Fund. Annually, through fundraising efforts, Columbia raises between $125,000 and $150,000 in customer contributions. Combined with the shareholder match, typically about $300,000 is contributed by customers and Columbia towards the accounts of Columbia's payment-troubled, low-income customers through the Hardship Fund. Columbia also has Commission approval to use the residential portion of federal pipeline penalty credits and supplier refunds to supplement the Hardship Fund up to $375,000 annually. 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.[2]

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

A. The current balance is $336,098.28. The Company made its annual transfer of $375,000 to the DEF in January 2021. 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

[2] If the amount of the residential portion of the pipeline penalty credits and supplier refunds received by Columbia exceed the $750,000 maximum balance, the excess funds are passed back to residential customers through gas cost rates.

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
2010	$73,803.22
2011	$76,566.00
2012	$73,094.50
2013	$70,798.26
2014	$63,494.50
2015	$74,001.50
2016	$68,819.00
2017	$68,249.00
2018	$62,282.00
2019	$57,229.00
2020	$68,043.50

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 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 as well as brings 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.

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 include:

- Station Square – Pittsburgh Light Up Night – Columbia provided volunteers to staff the event.
- Westmoreland County Light Up Night – Columbia assisted in planning and staffing the event.
- Duquesne vs. Pitt basketball game donation at the door event – Columbia provided volunteers to collect money at the entrances.

- Warmathon radio call-in campaign — Columbia provides sponsorship money and volunteers to answer telephone calls.
- Cool Down for Warmth - Now in its seventh year, Columbia's President has participated for two years, Columbia's Assistant General Counsel participated in 2017 and in the past four years, a new 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.
- 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 in December 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;
- Website postings which explain how and where to contribute; and
- Annual Thank you letter or post card to existing donors from the President of Columbia Gas and The CEO of the Dollar Energy Fund.

Q. Does Columbia continue to seek and support new opportunities to promote the Hardship Fund and donations to Dollar Energy Fund?

A. Yes. Last year, 2020, was a difficult year to fundraise due to the COVID 19 pandemic restrictions on large gatherings of people. The Tran Siberian Orchestra 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 broadcast 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.

Additionally, 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.

IV. CAP Outreach & Collection Issues

Q. Are there any other issues you would like to address?

A. Yes. I will address the Commission's final order in the Company's 2020 rate case to the extent it addressed Universal Service programs.

Q. Please summarize the issue raised regarding CAP outreach.

A. Essentially, there was feedback that the Company should expand its efforts to more effectively target the lowest income customers with incomes at or below 50% FPIG.

Q. Do you agree that the Company needs to expand its outreach efforts?

A. The Company endeavors to implement new outreach avenues on a regular basis and will continue to do so. The Company met with its Universal Service Advisory Council ("USAC") in April 2020 and again in October, 2020. The agenda for both meetings included a review of existing and planned outreach activities. At both times, the Company asked for feedback and recommendations. The Company will continue to meet with its USAC regarding outreach to identify potential improvements. While the Company recognizes the importance of investigating ways to improve outreach, the Company notes that its CAP participation rates are not below that of other Pennsylvania utilities.

Q. Does the Company specifically target customers between 0 and 50% of poverty?

A. The Company utilizes a broad range of outreach efforts and opportunities to reach all low income customers. Columbia partners with other utilities on outreach initiatives and often mirrors similar events held by other utilities across the state to reach out to customers. The 2019 USRR reports Columbia has the second highest number of customers between 0 and 50% of poverty enrolled in CAP of all gas utilities. Currently, the Company has 5,921 customers enrolled in CAP that are between 0 and 50% of poverty which is 25% of all CAP customers. Nevertheless, the Company has already implemented several changes and will be consulting with its USAC this year to examine further outreach efforts focused on those in the lowest poverty levels.

Q. Please explain the changes that have been made in the last year that may increase CAP participation from customers within this lowest poverty guideline?

A. In its last Universal Service and Energy Conservation Plan, the Company agreed to change reverification of customers with zero income from three to six months. In addition, the Company implemented an on line application for customers to complete without having to make a phone call to the Company or a screening agency. The application went on line December 1st and in the first three months of operation, 105 customers were enrolled via the on line application. The Company plans to promote this new opportunity as soon as the existing process is streamlined and optimized. The Company is projecting a campaign as early as April, 2021.

Q. Are there any other new strategies the Company will be implementing to promote programs?

A. Yes, the Company will be reviewing its website to ensure programs information is visible and accessible to any customers looking for information on its website. In addition, the Company will be creating an ad campaign focused on energy efficiency and educating customers on the importance of reducing energy usage and what Columbia can do to help customers conserve energy.

Q. Please summarize the issues raised related to CAP collections.

A. The Commission's 2020 base rate case order concluded that "the manner in which Columbia conducts collection activity for CAP accounts presents some concerns and that Columbia should submit to its USAC, within six months of the entry of this Opinion and Order, the question of how customer payments on CAP bills can be pursued through a reasonable collections process, consistent with the OCA's recommendation." The order questions whether the Company is following Commission advice to conduct timely collections of CAP customers to ensure a balance does not accrue beyond an ability to catch up.

Q. Do you agree with the Commission recommendation that timely collections are important to ensure balances do not accrue?

A. Yes. The Company put into place its current collections policies based on feedback from the Commission as early as 1996. At that time, the Commission recommended the Company not only remove customers from the CAP program for failure to pay, but first terminate service as a response to non-payment. The Commission also recommended prioritizing CAP accounts after two missed payments for shut off. The Company complied with both of these recommendations and these remain in the Company's plan today. However, due to the requirement to terminate service for failing to pay, the Company must also follow all collections regulations established for all residential customers. Therefore, a CRISIS grant will delay a termination until at least May of each year, a medical certificate will delay collections, a complaint filed with the Commission will delay collections activity and finally no collections occurs on CAP accounts from December 1 through April 1. Additionally the month of November is limited in collections due to holidays and temperatures. These all impact timely collections. The Company made the decision to accept the maximum the Department of Human Services (DHS) will authorize for CRISIS in an effort to assist the customer with bill payment regardless if it pays the entire CAP amount owed. This benefits the customer, however, it will lead to delayed collections.

Q. What is the status of CAP accounts today?

A. The Company has experienced a further decline in payments to billing. Due to the Pandemic, there were minimal collections activities occurring in 2020. Instead, the Company focused on extensive outreach efforts to promote the programs available for assistance. However, customer engagement was very low, which was experienced by most utilities and evidenced by low LIHEAP CARES Act applications. The Company received 65% payments of CAP bills in 2020. Recent statistics show 68% of customers billed in February, 2021 were current on their

CAP payment plan or had a credit and another 6% of customers owed less than one month's bill. 619 customers had arrears over $800 suggesting that CRISIS could assist the majority of customers to reduce their arrears if they apply for assistance. In total, 12% of CAP customers have arrears over $300.

Q. Please summarize the actions the Company is prepared to take to address the concerns raised by the Commission.

A. The Company will present a detailed review of its current CAP collections policies at its next Universal Service Advisory Council meeting in April 2021. As part of the response to the Company's management audit, the Company will convene a team of interdepartmental personnel representing Universal Services, Regulatory Compliance, Meter to cash and operations personnel to develop a plan to improve overall collections with implementation to begin in April, 2022. The Company will present its plan to its Universal Service Advisory Council at its October 2021 meeting and solicit feedback.

Q. Please address the Commissions directive to explain Columbia's efforts to promote the Hardship Fund program to low income customers?

A. The Hardship Fund was promoted beginning in October 2020 with multiple channels. Information was included in the various forms of legislative events and forums, The Company held a virtual town hall with legislative offices and community based agencies to explain programs including the Hardship Fund, information was posted on the Company's website, the Company posted information on various social media channels. In addition, the Company implemented an online application for Hardship funds in conjunction with its CAP on line application. Finally, all low income customers are eligible for assistance regardless of CAP status. As of February, 28, 2021, 767 customers have received grants as compared to 356 customers during the same program time frame in 2020.

Q. Does this conclude your direct testimony?

A. Yes, it does.

C. ANSTEAD

COLUMBIA STATEMENT NO. 14

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2021-3024296
Columbia Gas of Pennsylvania, Inc.	)	

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

March 30, 2021

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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 and system regulation;
- 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, primarily 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 in field activity based roles and manager level roles. Most recently, I served as the Director of Technical Services for NiSource Corporate Services 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 will transition into the Vice President of Gas Operations role for Columbia Gas of Pennsylvania on April 1, 2021.

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

A. No.

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

A. I have been a member of the American Gas Association Quality Management

Committee since March of 2017.

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 436,000 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 7,737 miles of distribution and transmission mains and approximately 435,106 services that it owns, operates, and maintains.[1] These facilities (as of January 1, 2021) are composed of

[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

approximately 1,046 miles of bare steel, 23 miles of cathodically protected bare steel, 4 miles of cast iron, 54 miles of wrought iron mains (in total, 1,127 miles of "first generation priority pipe" main), and 40,456 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 26.8 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 in order to meet the demands of end-use customers. After taking delivery of natural gas at the city gate, Columbia then steps down the transmission pressure to local distribution pressure, further filters the gas to remove moisture and particulates that may damage Columbia's system, and then in some cases increases the amount of odorant known as mercaptan (the "rotten egg smell")

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 26.8 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.

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. In order 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 of 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 bare steel or cast iron replacement.

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 cast iron or 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 very likely to damage them. Cast iron and steel piping have greater tensile strength and thus are 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 and more brittle than today's material (due to the different composition of the base plastic material), 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 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 significant 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 2020, Columbia was able to reduce the damages per thousand locate tickets to 2.05. Locate ticket volumes were down 6% last year. Total number of damage reduced from 287 in 2019 to 278 in 2020. 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 57% of total damages in 2019. Columbia continued to intervene and educate excavators – especially the problematic ones – and was able to achieve a 7% reduction to excavator error between 2019 and 2020. 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 is replacing those sections which are uncovered in the course of executing the bare steel and cast iron replacement program Additionally, depending on future failure rates of this first generation plastic pipe, and the relationship between those failure rates and other risks in the Columbia system at the time, Columbia's annual DIMP Plan risk evaluation may determine, at some point in the future, that a systematic program will be needed to replace the remainder of this softer, more vulnerable, first generation plastic material.

Q. How does Columbia classify leaks it detects on its system?

A. Columbia classifies each gas leak according to its severity: Type-1, Type-2, or Type-3. A Type-1 leak is hazardous and requires immediate remediation and repair. A Type-2 gas leak is non-hazardous at the time of detection, but requires a scheduled repair based on the potential for becoming a hazard. A Type-3 gas leak is defined as "non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous."

These gas leak classifications are defined in the Gas Piping Technology Committee ("GPTC") American National Standards Institute ("ANSI") Z380.1 "Guide for Gas Transmission and Distribution Piping Systems." The Guide is commonly utilized by gas operators and State pipeline regulators, including the Commonwealth of Pennsylvania, as an interpretation of "DOT 192 2003 CFR Title 49, Part 192 Transportation Of Natural And Other Gas By Pipeline: Minimum Federal Safety Standards."

III. Federal Pipeline Safety Rules and Advisories

Q. Please describe the Federal Pipeline Safety Rules and Advisories that are affecting and will continue to affect Columbia's Pipeline Safety Strategy and Operational Execution.

A. Some of the more significant and impactful Final Rules or Advisories issued in the last several years or that are being considered for the future, are as follows:

- Integrity Management Program for Gas Distribution Pipelines (74 FR 63906) - This final rule amended the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management ("IM") programs. The IM programs required by this rule are similar to those required for gas transmission pipelines but tailored to reflect the differences in and among distribution facilities. Distribution integrity management is playing a significant role in Columbia's gas operations, allowing us to focus resources to reduce risks, thereby improving safety for our customers, the public, and our employees.

- 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> Gas Pipeline Regulatory Reform (86 FR 2210) PHMSA is amending 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:

- Amending 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.
- Removes 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 is revising 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.
- Giving 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).

- Revision of § 192.465, External corrosion control: Monitoring, to clarify that operators may remotely inspect rectifier stations for external corrosion.
- Revision of 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 would provide operators some flexibility in scheduling welding activities to maintain welder requalification.
- Revision of 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.
- Revision of 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.

  - Revision of 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.
  - Revision of 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.
- <u>Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments</u> (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.

- <u>Pipeline Safety:</u> 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)).

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:

- <u>Valve Installation and Minimum Rupture Detection Standards</u> (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 new 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 a 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. Strategic O&M Safety Initiatives

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:

- **System Pressure Viability Program:** The System Pressure Visibility Program is an example of how Columbia's SMS is identifying risks and, at times, results in changes to priorities. The System Pressure Visibility Program focuses on the installation of digital pressure recording telemetry equipment at natural gas pressure regulator stations across the CPA operating territory to remotely monitor operating pressures and abnormal operating pressure conditions. The new digital devices will transmit pressure data back to Gas Control Supervisory Control and Data Acquisition (SCADA) systems where pressures and alarms will be monitored by Gas Control personnel and computer systems 24/7. The new digital devices will replace the existing analog paper pressure chart recording devices that are stand alone and unable to be observed in real time.

Benefits include the real time monitoring of natural gas pressure regulator stations, resulting in improved operational safety thru immediate awareness of operating pressure conditions at the regulator stations. The new digital devices will provide for additional trending and analysis opportunities given the pressure data granularity and data storage capabilities that analog devices cannot provide, further enhancing the understanding of how the system is or was operating at any point in time. The use of digital devices that communicate back to a SCADA system will reduce the human error that can occur when interpreting analog paper pressure chart recording devices. The Company is requesting $230,000 of incremental expense for the implementation of this program as reflected in Exhibit 104, Schedule 2, pg. 19, Line 11.

- **Enhanced Red Tag Process:** Another initiative identified by SMS is an enhanced red tag process, which consists of two processes. First, Columbia will re-design the red tag itself to enable current and new data to be collected about our customer's assets and safety issues encountered. Specifically, the re-design will enable the Company to standardize processes and procedures, provide clear actions for customers to take once an appliance has been red tagged, and will include a carbon copy of the tag for the Company's record retention purposes. Second, subsequent to appliances being red tagged, when requested by the customer, the Company will perform an inspection in the customer's home in order to proactively identifying unsafe gas situations downstream of the meter. Examples of when this could occur would be after a red tag is identified and repaired by a contractor, for a new home-owner or after a remodel. Such inspections identify risks that may be present downstream of the meter, while closing the loop in the company red tag process by providing a follow up for our customers. Allows for data collection on corrected red tag conditions. The Company is requesting $20,000 of incremental expense for the implementation of this program as reflected in Exhibit 104, Schedule 2, pg. 19, Line 11.

- **Low Pressure Program.** Columbia is continuing its Low Pressure ("LP") Program that resulted in enhanced engineering designs, enhanced damage prevention practices and changes to work rules for tie-ins, construction involving system configuration changes, and any O&M work that involved excavation to include additional field monitoring of stations. Installation of automatic shut off devices continue to be the primary form of additional overpressure protection.
- **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 445.2 miles of sanitary and storm sewer mains, and 29,872 customer laterals since

2013. During this inspection, 475 cross bores were identified, with 311 of those involving Columbia's system. Given program results, cross bores are now identified as a high risk in Columbia's DIMP plan. Consistent with Company's proposal in its 2020 rate case (Docket No. R-2020-3018835) to accelerate this program by increasing resources to it, the program is currently on pace to be completed in 31 years.

- **Legacy Service Line Enhancement Program.** In January 2019, Columbia implemented a legacy service line record enhancement program, and was granted part of its request to fund this initiative in the Company's 2020 rate case. Based upon the Commission's recent order, the Company will move forward with this program in 2021, which will correct inaccurate and/or incomplete data within legacy records. This is vital, as accurate records are critical to ongoing maintenance of the system.
- **Field Assembled Riser Replacement Program.** During the winter of 2014-2015, failures were experienced with field assembled risers and as such, they have been identified as a high risk in Columbia's DIMP plan. Columbia developed a program to address the risk of field assembled riser failures. The program included a survey of customer-owned and Company-owned service lines to identify and quantify field assembled risers in use. Columbia utilized the collected data to further assess DIMP risk and prioritize efforts. Columbia began replacing field assembled risers identified on Company-owned service

lines in 2015. Recognizing the same risk existed on customer-owned facilities, the Company petitioned for a waiver to address customer-owned field assembled risers, which was approved by the Pennsylvania Public Utility Commission on December 6, 2018. In deciding the Company's 2020 rate case, the Commission granted, in part, Columbia's request for funding in order to accelerate this important program. At this time, Columbia is working to build in the acceleration of its field-assembled riser program into its 2021 work plans.

- **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.
- **Safety Management System (SMS).** As previously noted in my testimony, Columbia is pursuing 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 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. The implementation of SMS will continue to mature and strengthen the culture of risk identification and reduction at Columbia.

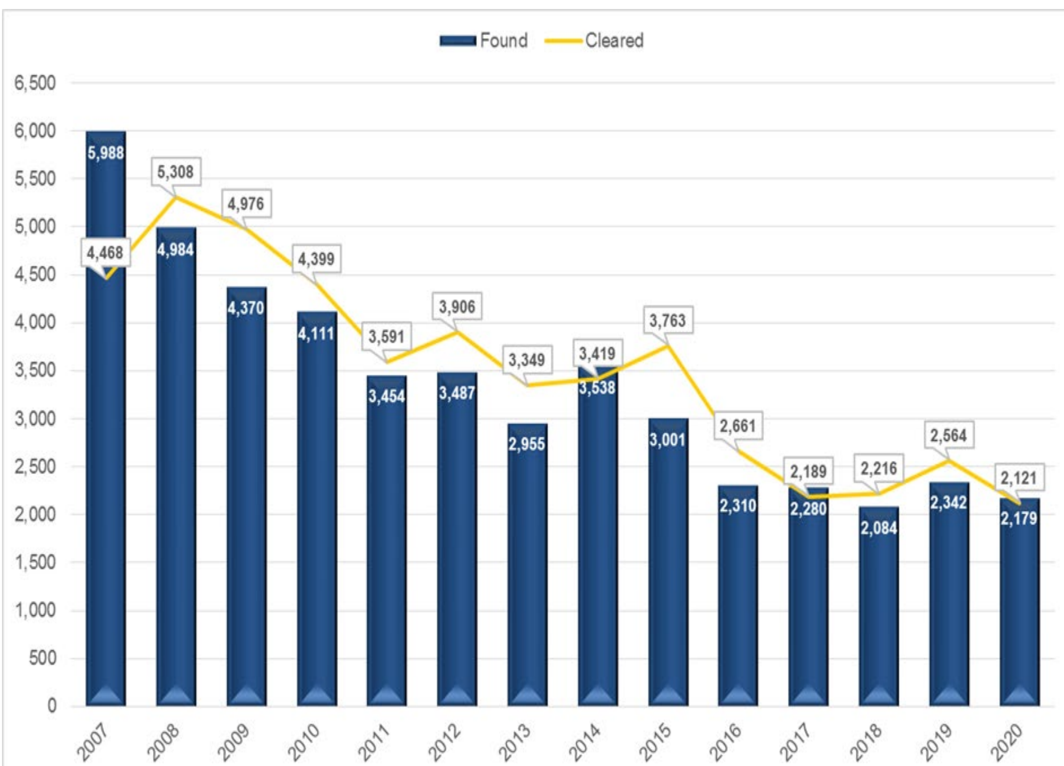
Q. Are there any additional details demonstrating the improvement of Columbia's system operations?

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

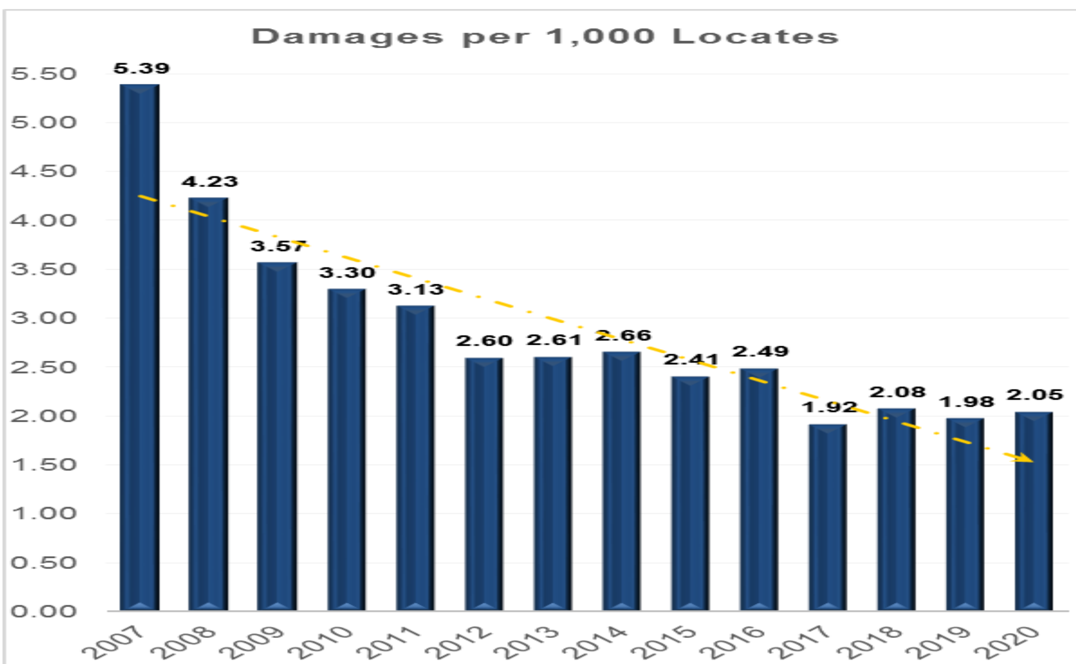
2 leaks found during the year, as compared to Grade 2 leaks repaired during the year. In the last ten years alone, Columbia's pipeline replacement efforts were responsible for cutting the number of leaks found from 4,111 in 2010 to only 2,179 in 2020. That's nearly a 50% reduction in leaks. That reduction 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 62% reduction in the damage rate on the Columbia system between 2007 and 2020, from a damage per thousand (locate requests) rate of 5.39 in 2007 to a damage per thousand rate of 2.05 through December 31, 2020, 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. Columbia's Operating Performance

Q. In addition to Columbia's intense focus on pipeline safety, what are some of the practice enhancements or procedural changes regarding operating performance that are specific to customer delivery performance?

A. Over the course of the last 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 2020 as follows:

	2015	**2016***	**2017**	**2018**	**2019**	**2020**
Day	96.79%	99.17%	99.16%	98.70%	98.99%	99.51%
Evening	90.95%	95.24%	94.87%	95.61%	97.28%	97.09%
Holiday	91.59%	92.11%	85.25%	86.32%	88.79%	95.35%
Overnight	85.87%	94.86%	95.19%	92.43%	90.42%	95.62%
Weekend	82.76%	91.83%	92.66%	91.72%	93.66%	95.31%
Total	**92.68%**	**96.88%**	**96.82%**	**96.40%**	**97.28%**	**98.12%**
**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

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

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 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 2020.

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 2020 that number was 14 OSHA recordable injuries which is a reduction in frequency of 71%. 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 uses Safety Telematics in Company vehicles across its operations. This program provides real time feedback to drivers on their driving performance. It also provides detailed reporting to enable analysis of driving trends and habits providing actionable information to improve driver safety.
- 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. Near miss 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.

- Columbia employees evaluate risk and 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 completed when the risks or the scope of the work changes so that our teams perform our work as safely as possible. This process was reviewed and updated in 2020 with updated pre-job safety briefing form supported by employee computer-based training in November of 2020.
- In March of 2020, Columbia hired an additional safety professional to support our PA East operating area. Our team of safety professionals include a Safety Manager and four Safety Coordinators who each support one of operating areas.

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. As a result, Columbia routinely exceeds the requirements of existing Federal Regulations, which provides the Company the ability to discover system leakage on a timelier basis than if it were only meeting the minimum federal standards.

Q. Does this complete your Prepared Direct Testimony?

A. Yes, it does.