Columbia Gas of Pennsylvania, Inc.
2020 General Rate Case
Docket No. R-2020-3018835
Standard Filing Requirements
Testimony - All
Volume 10 of 10

COLUMBIA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	)	

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

April 24, 2020

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I. INTRODUCTION

Q. Please state your name and business address.

A. Michael Huwar, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

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

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

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

A. I am the corporate officer responsible for the leadership of Columbia Gas of Pennsylvania, Inc. and its various departments, including Safety Compliance and Risk Management, Rates and Regulatory Policy, Field Operations, Construction, Governmental Affairs, Communications and Community Relations.

Q. What is your educational and professional background?

A. I hold a bachelor's degree from the University of Pittsburgh, and completed a leadership development program at the University of Pennsylvania's Wharton School. I held various positions within Columbia and its parent company, NiSource Inc. ("NiSource") from 1986 through 2015, including Vice President and General Operations Manager for Columbia Gas of Virginia, where I oversaw employee safety, pipeline safety and regulatory compliance initiatives. Prior to that, I served in a number of leadership positions including Vice President of Sales, Vice President of Products and Services and Director of Large Customer Relations throughout the Columbia companies. From 2015 through 2017, I served as Vice President of Marketing for Columbia Midstream, a subsidiary of Columbia Pipeline Group and TransCanada, where I had overall responsibility for building and advancing Columbia Midstream marketing capabilities, as well as supporting business development efforts and processes across the company's growing customer base. I also provided leadership for Columbia Midstream's Canonsburg office. I assumed my current responsibilities when I was named President of Columbia in February 2017.

Q. Have you ever testified before a regulatory Commission?

A. Yes. I have testified before the Pennsylvania Public Utility Commission ("Commission") in the Company's 2018 rate case at Docket R-2018-2647577. I have also testified in Case No. PUE-2014-00020 before the State Corporation Commission of Virginia.

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, discuss the objectives that Columbia seeks to accomplish in this proceeding and discuss the Company's progress since the last base rate proceeding. I will also address Columbia's performance quality in compliance with Section 523 of the Public Utility Code, and 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 433,000 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 4 million customers located within a corridor that runs from the Midwest to New England. 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.

In September 2014, NiSource announced a major strategic initiative that involved the separation of its distinct business segments. Specifically, the separation which took effect July 1, 2015, resulted in two highly-focused, premier energy companies – a fully regulated natural gas and electric utilities company (NiSource) and a natural gas pipeline, midstream and storage company (Columbia Pipeline Group). Post-separation, NiSource maintains significant scale and remains one of the largest natural gas utility companies in the United States, serving more than 3.5 million customers in seven states under the Columbia Gas and NIPSCO brands. Since separation, NiSource has maintained strong levels of customer focus, local employment, community involvement, and commitments made to Pennsylvania. Safe, reliable, and efficient service remains the top priority.

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"), Bay State Gas Company d/b/a Columbia Gas of Massachusetts, Columbia Gas of Kentucky, Columbia Gas of Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and Columbia Gas of Virginia.

Finally, NiSource is one of 325 companies across 50 industries included in the 2020 Bloomberg Gender-Equality Index ("GEI"), marking the third consecutive year that the Company has been listed in that index. NiSource was one of 24 utility companies listed in the 2020 GEI, and was also included in the 2018 and 2019 GEI. The GEI tracks the financial performance of public companies committed to supporting gender equality through policy development, representation and transparency. The reference index measures gender equality across five pillars: female leadership and talent pipeline, equal pay and gender pay parity, inclusive culture, sexual harassment policies, and pro-women brand. This year, Bloomberg expanded the eligibility for inclusion in the index to nearly 6,000 companies across 84 countries and regions.

II. CASE OBJECTIVES

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

A. 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 accelerated pipeline replacement program. Approval of the Company's request is necessary for Columbia to continue to provide safe and reliable natural gas service at the lowest reasonable price to its customers, while providing the Company with a reasonable opportunity to recover its costs and to earn a fair rate of return. Further, approval of this request will demonstrate to the investment community that the Commission continues to support the need for intensified focus on pipeline safety matters as well as the need for reasonable and predictable earnings. My testimony will outline, at a high level, the objectives of Columbia's filing. Details and documentation supporting each of the objectives will be provided by Company witnesses that I will introduce later in my testimony.

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

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

A. Columbia seeks recovery of, and an opportunity to earn a return on, the capital investments being made in its distribution system which are necessary to provide safe and reliable natural gas distribution service to its customers. In light of the substantial capital investment Columbia has made since its last rate case and the large capital investments that will be made through the end of 2021, 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 on DSIC surcharges.

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 $100.4 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 Kitchell's testimony (Columbia Statement No. 14), since Columbia started its accelerated pipeline replacement program in 2007, Columbia has replaced 5,690,833 feet (over 1,077 miles) of cast iron and bare steel pipe.

b. Other Objectives

Q. Does Columbia have other objectives in this case?

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

Enhancement of Safety Measures: The Company continues to focus its efforts and resources on the top risks to the Company's system, and is expanding focus in several critical areas to maintain and enhance its operational capabilities. In addition, NiSource is now accelerating implementation of Safety Management System (SMS) across its seven-state footprint with a focus on identifying and mitigating potential risks while continually assessing and improving processes and procedures to keep its employees, contractors, customers, and the public safe. The Company has narrowed its focus on the follow risks:

1. **Cross Bores:** Columbia has implemented a staged approach in reducing the number of cross bores throughout our system. Cross bores can occur when existing underground facilities such as water or sewer lines are damaged during direct bore installation of underground facilities. Since the inception of the cross bore program in 2013, Columbia has inspected over 373 miles of sanitary and storm sewer mains, and 25,903 customer laterals. During this inspection, 406 cross bores were identified, with 278 of those involving Columbia's system. Accordingly, this program has been identified as high risk in Columbia's Distribution Integrity Management Plan ("DIMP"), and the Company is seeking to complete cross bore remediation

in as short a period as practical. Company witness Davidson will discuss cross bores in more detail in Columbia Statement No. 7.

2. **Field Assembled Risers:** The Company has expanded the field assembled riser replacement program to include customer owned facilities. During the winter of 2014-2015, failures were experienced with field assembled risers, resulting in field assembled risers being identified as a high risk in Columbia's DIMP plan. Columbia began replacing field assembled risers identified on Company-owned service lines in 2015. Recognizing the same risk exists on customer owned facilities, in Docket No. P-2018-2641560, Columbia sought and obtained a tariff waiver that permits the Company to replace customer-owned field assembled risers. Company witness Davidson will discuss field assembled risers in Columbia Statement No. 7.

3. **Service Line Record Enhancement Program**: In January 2019, Columbia implemented a Legacy service line record enhancement program to correct inaccurate and/or incomplete data within legacy records. Currently the program is staffed with temporary employees, and Columbia intends to add seven fulltime employees, and supplement with temporary employees to accelerate the program. Company witness Davidson will discuss field assembled risers in Columbia Statement No. 7.

Removal of Weather Normalization Adjustment ("WNA") Dead Band: In this proceeding, Columbia is proposing to eliminate the 3% dead-band in the

WNA. A dead-band results in revenue variation due to weather, and thus, the goal of the WNA, to improve revenue stability, is not fully realized. Company witness Bell will discuss elimination of the WNA dead band in Columbia Statement No. 3.

Establishment of a Revenue Normalization Adjustment ("RNA"): Columbia proposes that it be permitted to implement an RNA to be used in conjunction with the 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 Bell will discuss the proposed RNA further in Columbia Statement No. 3.

Capitalizing Cloud Based Assets in Rate Base: Based on the FERC guidance issued on December 20, 2019, Columbia is changing its accounting treatment of cloud based assets. Company witness Shultz discusses this issue in Columbia Statement No. 6.

Budget Billing: In this proceeding, the Company proposes to modify existing programming to calculate a twelve month average budget bill, every month, to offer customers year round. As proposed, this modification addresses the concern raised in Docket R-2018-2647577 that Columbia's current processes for the budget payment plan may result in a budget amount that could include two winter periods. Company witness Davis discusses this proposal in Columbia Statement No. 13.

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

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

A. The Company intends to continue replacement at an accelerated pace in order to retire its remaining bare steel and cast iron facilities as soon as possible. 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

Columbia Gas of Pennsylvania
Capital Program
($000)

Budgeted Capital Expenditures

Class	2020	2021	2022	2023	2024
Growth	$36,252	$37,727	$38,378	$43,640	$49,873
Betterment	$11,700	$42,400	$20,800	$14,800	$9,400
Public Improvement	$7,500	$6,000	$6,000	$7,500	$7,939
Replacement	$250,634	$259,559	$279,578	$336,817	$348,635
Support Services	$2,000	$2,600	$1,950	$1,750	$1,600
Total Gross Capital	**$308,085**	**$348,286**	**$346,705**	**$404,507**	**$417,448**

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 LDC's – Pipeline Mileage

NGDC	Miles of Pipe (2018)
Columbia Gas	7,622.0
PGW	3,041.7
PECO	6,909.4
UGI[1]	12,022.0
Peoples[2]	13,061.8.
National Fuel	4,830.0

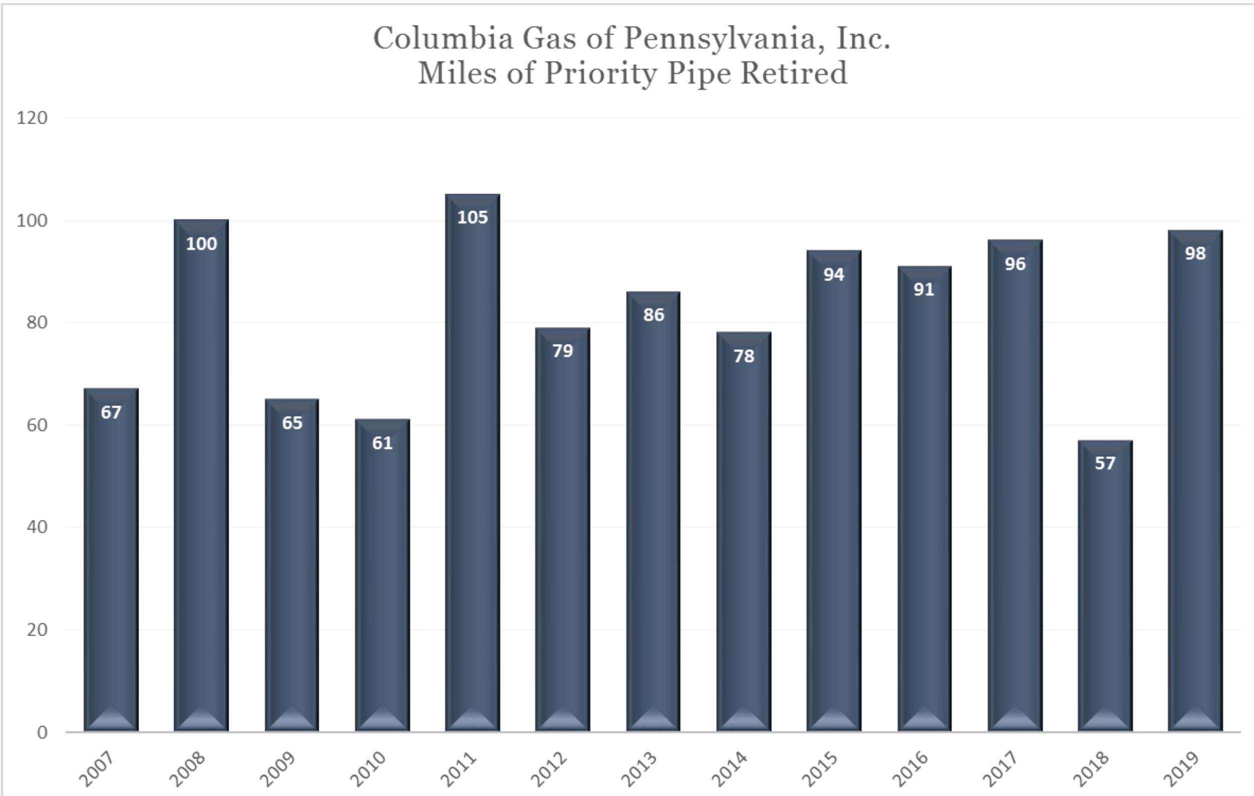
The size of the Company's capital program is largely driven by the amount of pipe that needs to be maintained and ultimately replaced. Just under 16% of Columbia's total inventory of pipe is either bare steel or cast iron, which is nearing the end of its useful life and needs to be replaced. Further, 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 since 2007, which was the first year the Company began replacing pipe at an accelerated rate.

[1] All companies/ divisions combined.

Figure 3



Q. What were the underlying reasons for the drop in miles of bare steel and cast iron pipe replaced in 2018?

A. There were two primary reasons. First, on September 13, 2018, Columbia Gas of Massachusetts experienced an unexpected over-pressurization that resulted in significant damage to a low pressure natural gas distribution system in its service territory. Over the remainder of 2018, a substantial recovery effort was undertaken to restore service to over 8,500 impacted customers. Mutual aid in the restoration

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[2] All companies/ divisions combined.

efforts in Massachusetts was provided from Company and contractor resources across the NiSource footprint to assist in replacing over 43 miles of pipe in order to restore service to impacted customers before the winter.

Second, as a result of the Merrimack Valley event, the Company's policies and procedures relative to work on low pressure systems changed. Changes to the low pressure procedures are discussed by Company witness Kitchell in Columbia Statement 14.

Q. Was the Company able to resume its infrastructure replacement program levels in 2019?

A. Yes, as Figure 3 above indicates, the Company replaced 98 miles of bare steel and cast iron in 2019.

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 of the 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 may expand 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 98 miles of bare steel and cast iron pipe replaced in 2019, the Company replaced an additional 58 miles of pipe, consisting largely of first generation plastic pipe installed prior to 1982. As Company witness Davidson discusses in Columbia Statement No. 7, first generation plastic pipe, typically installed between 1970 and 1981 in most distribution systems is softer than today's material composition of plastic pipe and has demonstrated itself to be prone to stress propagation cracking under some circumstances. The Company has identified risks regarding the failure of pre-1982 plastic pipe, and has incorporated replacement of these facilities into the infrastructure replacement plan when they are identified as high risk pipe or are present in the course of the bare steel and cast iron replacement program.

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.

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 will SMS benefit Columbia's customers?

A. It will enhance Columbia's risk prioritization and modeling, and will strengthen and formalize our continuous improvement processes. Columbia anticipates that these enhancements will improve the integration of all pipeline safety initiatives across the Company's organization.

III. REVENUE REQUIREMENT

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, 2021, 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. 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 4.86% 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 7.98%. 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. What evidence supports adjusting the Company's requested rate of return for management effectiveness?

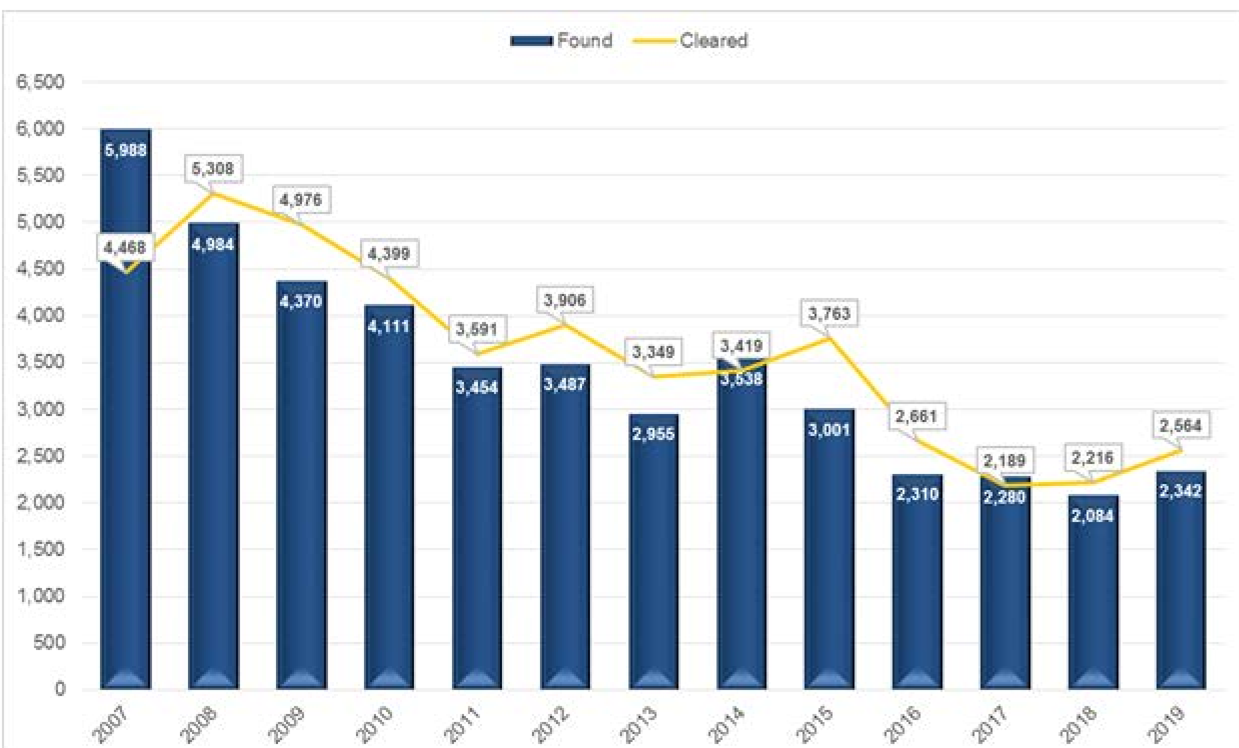
A. Columbia continues to maintain high levels of customer service, both in the field and in back office operations. I will discuss each item individually.

Q. Please describe Columbia's performance regarding Key Operating and Maintenance (O & M) safety initiatives.

A. In addition to the Enhanced Safety Measures previously described in my testimony, the following areas of focus have been noted and are further discussed by Company witness Davidson in Columbia Statement No. 7.

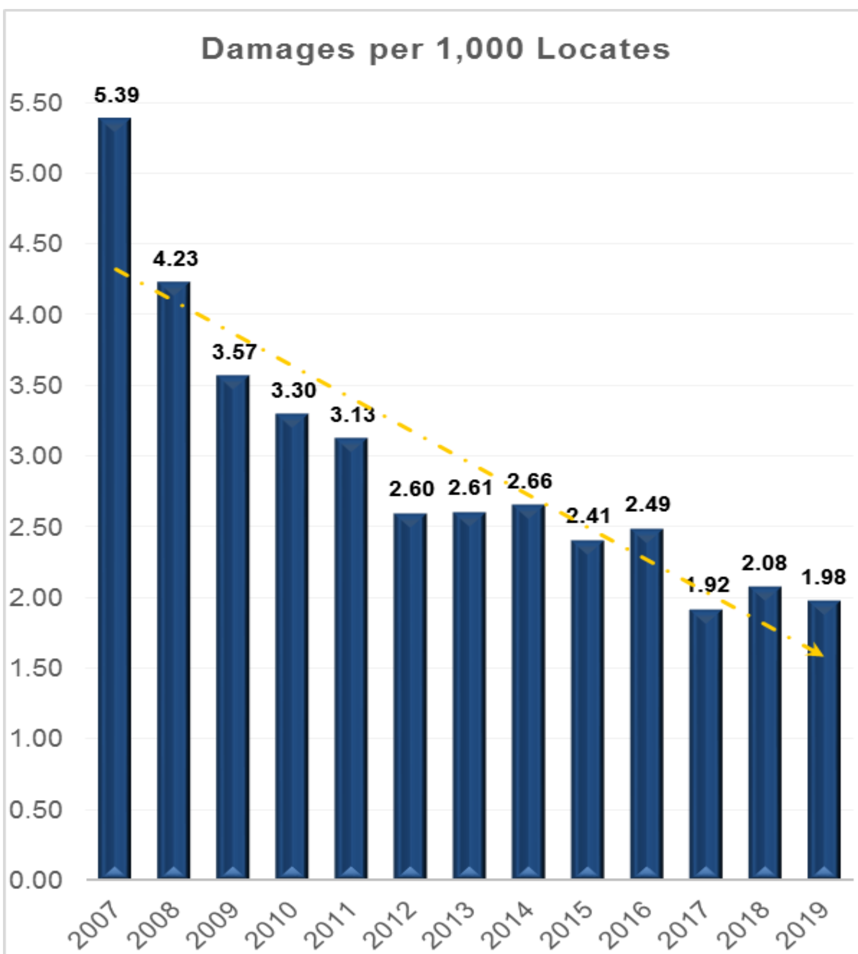
Leakage Reduction: Since the inception of our accelerated infrastructure replacement program, Grade 2 leaks have been significantly and consistently reduced, thereby increasing the safety of our customers. Figure 4 below shows a comparison of Grade 2 leaks found during the year, as compared to Grade 2 leaks repaired during the year. 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 2008, the Company has shown a steady decline in damage 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 63% reduction in the damage rate on the Columbia system between 2007 and 2019, from a damage per thousand (locate requests) rate of 5.39 in 2007 to a damage per thousand rate of 1.98 through December 31, 2019, as shown in Figure 5 below.

Figure 5



Emergency Response: Since 2006, Columbia has implemented a very structured approach to improving its emergency response times. The results of these focused efforts have resulted in improved performance, thus increasing public safety. See Figure 6 and Figure 7 below. In those charts, the term "Priorities" refers to service calls that deal with a gas emergency, such as a reported odor of gas.

Figure 6
Columbia Emergency Response

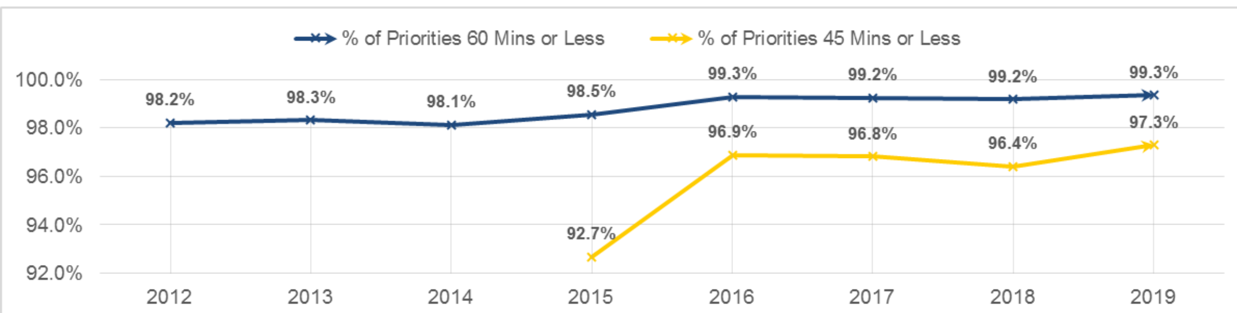
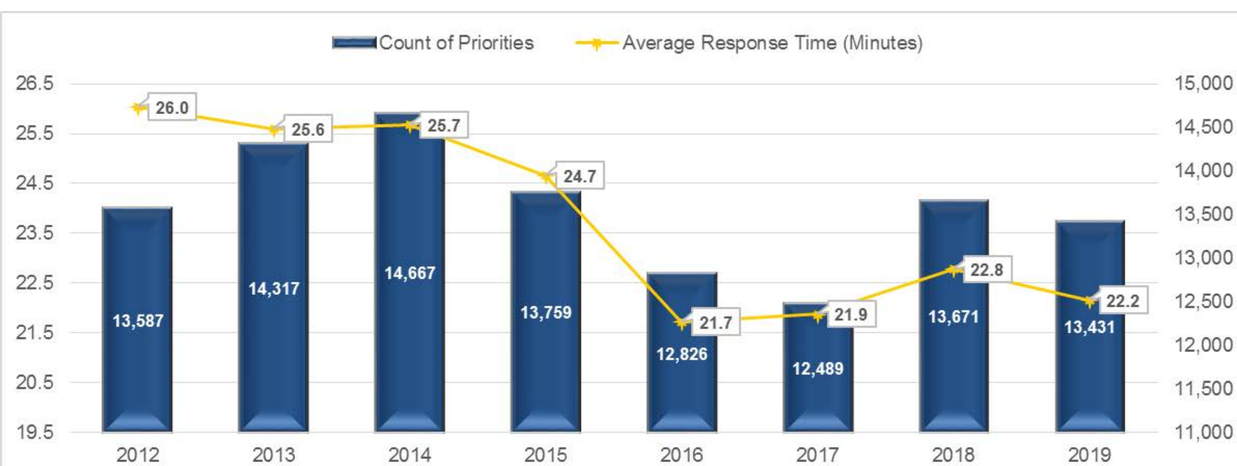


Figure 7
Columbia Emergency Response Time



On-Time Appointments: On time appointments have increased from 97.10% in 2014, to a rate of 98.7% in 2019, thereby increasing the efficiency of the customer's time.

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 Kitchell, which demonstrates the effectiveness of Columbia's management and its concern for 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 MAH-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	50%	27%	6%	0%	55%	20%
Minor Improvement Necessary	25%	27%	44%	58%	45%	47%
Moderate Improvement Necessary	25%	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, Equitable and People's TWP

As Figure 8 illustrates, Columbia achieved the "Meets Expected Performance" ranking category in 50% 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 MAH-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 2018. 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 2018 performance, as reflected in the UCARE report with regard to the seven major natural gas companies, appears to be the best in most categories in the gas industry. In the measure of Residential Consumer Complaints, Columbia had the lowest consumer complaint rate of .40 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 electric companies, which averages 1.62.

Figure 9

2018 Residential Consumer Complaint Rates/
Justified Consumer Complaint Rates
Major Natural Gas Distribution Companies

Company	Consumer Complaint Rate	Justified Consumer Complaint Rate
Columbia	0.40	0.01
NFG	0.57	0.05
Peoples	0.70	0.02
Peoples-Equitable	0.80	0.04
PGW	2.21	0.15*
UGI-Gas	0.99	0.14
UGI Penn Natural	1.49	0.29
Average	**1.02**	**0.10**

Per Figure 10 below, Columbia's Justified Consumer Rate per 1,000 residential customers is at .01, which is the same as 2017. Columbia's Justified Consumer Rate is better than the natural gas utility average rate of .10. Columbia's rate is still better than all of the electric companies for 2018. Columbia's .01 rate in 2018 and 2017 is down from .02 in 2016.

Figure 10

2016-18 Justified Residential
Consumer Complaint Rates
Major Natural Gas Distribution Companies

Company	2016	2017	2018
Columbia	0.02	0.01	0.01
NFG	0.02	0.04	0.05
Peoples	0.02	0.00	0.02
Peoples-Equitable	0.04	0.01	0.04
PGW*	0.37	0.14	0.15
UGI-Gas	0.02	0.03	0.14
UGI Penn Natural	0.03	0.04	0.29
Average	**0.07**	**0.04**	**0.10**

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

Columbia's Payment Arrangement Request ("PAR") rate was 1.35 in 2018 and the Justified PAR rate was 0.02. Columbia had the lowest score amongst all seven Pennsylvania gas utility companies, as shown in Figure 11 below.

Figure 11

2018 Residential Payment Arrangement Request (PAR) Rates/
Justified PAR Rates
Major Natural Gas Distribution Companies

Company	PAR Rate	Justified PAR Rate
Columbia	1.35	0.02
NFG	2.98	0.23
Peoples	2.12	0.15
Peoples-Equitable	2.48	0.15
PGW	12.80	1.28*
UGI-Gas	6.37	0.63*
UGI Penn Natural	9.06	1.41*
Average	**5.31**	**0.55**

* Based on a probability sample of cases.

In the measure of Commission Infractions, Columbia had the lowest infraction rate per 1,000 residential customers of .01 in the gas industry during 2018, which has been Columbia's infraction rate since 2013, except for the year 2017, during which the Company's infraction rate was .00. Figure 12, below, is illustrative.

Figure 12

Commission Infraction Rates
Major Natural Gas Distribution Companies

Company	2016	2017	2018
Columbia	0.01	0.00	0.01
NFG	0.02	0.03	0.05
Peoples	0.02	0.00	0.03
Peoples-Equitable	0.03	0.00	0.02
PGW	0.49	0.12	0.16
UGI-Gas	0.01	0.02	0.15
UGI Penn Natural	0.04	0.06	0.33

Additionally, during 2015, Columbia voluntarily began to participate in the Bureau of Consumer Services ("BCS'") Customer and Utility Resolution Effort ("CURE") Program. This initiative was designed to expedite the closing of customer complaints, whereby the Company can contact the customer and resolve the matter over the phone without BCS intervention. Since implementing this process, Columbia has been successful in closing roughly 23% of its informal complaints. The program has proved to be a winning outcome for the customer, the Company and the Commission.

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, 2020, 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 11 years. Currently the Calls Answered within 30 seconds is at 83%. Although the rate is lower than 2018's rate at 85%, it is still higher than 2017's at 82% and 2016's at 78%.

Columbia experienced an abandonment rate of 1.94%. Although the abandonment rate was higher than 2018's of 1.52%, it is lower than 2017's abandonment rate of 2.06%.

The Company continues to focus on the retention rate for the call center employees. In 2017, Columbia insourced the call center, and the Company continues to recruit via NiSource job postings, on-site hiring events, radio and digital print advertising, community and college Career Fairs as well as third party employment services. Columbia has also implemented a new Customer Service Representative ("CSR") selection process that includes a personality assessment and call center aptitude testing prior to having a face to face employment interview.

2. <u>Residential and Small Commercial Billing Data:</u>

For the ninth consecutive year, Columbia did not have any deferred billings for its residential or small commercial customers during 2019. 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 and pride in achieving a zero deferred bill rate.

Columbia printed and mailed 4.2 million bills to customers in 2019. In addition, over 1,007,000 paperless bills were issued to customers.

3. <u>Meter Reading:</u>

In 2019, Columbia obtained over 5.3 million meter readings with a 99.86 % of meters read on the scheduled meter reading date. Columbia experienced a slight decrease in the number of meters not read monthly in accordance to the Commission's regulations at 56.12 (4)(ii). For 2019, the Company averaged only two (2) meters read outside the 6 month timeframe compared to 2018, when we accounted for three (3) meters not being read. 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). The Company attributes this to the Automated Meter Reading technology.

4. Customer Satisfaction:

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 of 667 Pennsylvania participants 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 2019. In 2019, Columbia's "First Contact Resolution" rate was 91.37%. 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 2019.

Figure 13

Phone Rep Performance	
	YE 2019
Overall satisfaction	93.80%
Put on hold after speaking with a rep	21.50%
Rep explained reason for hold	92.55%
Being courteous and professional	94.07%
Treated as a respected customer	93.76%
Showing concern for the situation	89.78%
Displaying knowledge in job	90.01%
Adequately answering questions	90.66%
How well rep listened to customer	92.74%
Having authority to make decisions	88.95%
Working quickly and efficiently	90.43%
Clarity of speech, speed, tone, and volume	93.58%
First contact resolution	91.37%

CPA Automated Phone Service	
	YE 2019
Overall satisfaction	82.24%
Offering choices that helped get directly to the information wanted	76.05%
Ease of navigating prompts	74.59%
Ease of getting connected to live representative	75.13%
Number of steps required to complete the transaction	70.78%
IVR first contact resolution	75.88%

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 2019
Willing to accommodate needs	89.47%
Told when work would take place	90.98%
Arrived on time	94.26%
Total time to resolve	91.02%
CPA Field Work Crew Performance Ratings	
	YE 2019
Overall satisfaction with performance	95.11%
Courteous and professional	96.82%
Displayed skill and knowledge	97.39%
Explained work being performed	95.43%
Adequately answered questions	96.65%
Aware of service performed	91.28%
Worked quickly and efficiently	96.67%
Being respectful of your property	98.29%
Left work property as found before work began	99.18%
Work crew identified themselves	97.10%
Work was completed by the work crew	91.91%
Satisfied request on the first visit	91.90%

Q. How did Columbia perform in the 2019 J.D. Power Residential Customer Satisfaction Survey?

A. Columbia achieved an overall Customer Satisfaction Index ("CSI") score of 745 overall in the annual J.D. Power survey of mid-sized eastern natural gas utilities, ending 2017 in second place. This is an increase of 11 points over the Company's 2018 final survey result of 734. The Company outperformed the mid-sized eastern utility average of 724 by 21 CSI points. In addition, Columbia Gas beat the mid-sized eastern utility averages in six out of seven categories and had the top mid-sized eastern ranking in the Billing & Payment category.

Columbia continues to show improvement through 2020 Midyear (Wave 1 and Wave 2) results with an overall CSI score of 760. Columbia Gas improved 15 points over the 2018 year end final results. The Company improved in every factor over 2018 year end scores, scoring above the mid-size eastern utility average in every factor as well. Columbia scored in the first or second quartile for 30 of 35 attribute survey questions.

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 4.81% in 2004 to 1.98% in 2018. It also reduced its net write-off for the same period from 3.48% to 1.20%.

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 2018 Universal Service and Collections Report, Columbia had the most affordable Customer Assistance Program ("CAP") in the Commonwealth. In 2018, Columbia's monthly average CAP bill was $50.00. This was the lowest bill amount of all gas utilities in the industry during 2018, and $26.00 less than the average of all gas utilities. Columbia CAP has the lowest default rates, in each poverty level, than all other gas utilities.

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 obstacles to weatherization such as knob and tube wiring and moisture issues.

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

A. Since our last base rate case, Columbia has undertaken a number of process improvements to better serve our customers. Through its Customer Insights Program, the Company routinely engages our customer base to survey them on a variety of topics including:

- Understanding how customers use their natural gas
- Ease of Doing Business Online Discussion
- Natural Gas Safety

- Customer Expectations: preferred payment methods and appointment preferences
- Social Media Customer Care
- New Website Feedback

Columbia deployed a new, more responsive website to make it easier for customers to access information and complete transactions with Columbia (pay bill, sign up for payment programs, navigate the website, etc.). The Company also developed modern capabilities to deliver text and email messages to customers more efficiently and accurately during an emergency. Customers can choose their communications preferences on the company website.

In addition, Columbia has a continued focus on providing a simple and seamless experience for customers. Examples of enhancements that Columbia launched in 2019 include:

- Ability for customers to download billing, usage and payment history;
- Updated paperless billing notifications with new customer friendly design and language;
- Launched Paypal as a new payment method;
- Enhanced credit/debit card process for easy payment by logging into their MyAccount online;
- New paperless billing icon on website for easier enrollment in paperless billing; and

- Improved simpler online registration process for customers with multiple accounts.

Finally, 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.

The Company and its employees commit to donating time, money and resources each year to hundreds of local philanthropic programs and organizations. Throughout 2019, over 210 Columbia employees participated in over 70 different Company organized volunteer events, totaling over 1,730 hours of volunteerism.

In 2019, Columbia employees pledge over $178,300 of their personal income to the United Way, the thirteenth consecutive year that we have increased donations for the non-profit organization. For the past two years, Columbia has been recognized as the United Way of Washington County's first place, top campaign contributor. In 2019, Columbia was also selected and awarded the Charles C. Keller Excellence Award for Corporate Philanthropy through the

Washington County Community Foundation.

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 will be constructed through the currently unserved town of Centre Hall, to provide approximately six commercial businesses and 89 residential units with natural gas. 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 began on the project in 2019.

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. INTRODUCTION OF WITNESSES

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

A. Columbia presents the following witnesses:

- Company witness Mahamadou Bikienga, Manager of Demand Forecasting for NiSource Corporate Services Company ("NCSC"), provides demand forecasting services for Columbia. In Columbia Statement No. 2, he explains how residential and commercial sales volumes are normalized for weather. The results of the normalization procedure are contained in Company witness Bell's' testimony (Columbia Statement No. 3) and Exhibit 3, Schedule 4. Company witness Bikienga 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 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, 2020 and for the twelve months ending December 31, 2021 (FPFTY). Company witness Bell will also address removing the deadband from the WNA, the Company's RNA proposal, and revenue allocation and rate design.
- 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 Michael Davidson is the Vice President and General Manager for Columbia. In Columbia Statement No. 7, Company witness Davidson 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.
- 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 Nancy J. D. Krajovic is the State Finance Director for Columbia. In Columbia Statement No. 9, Company witness Krajovic 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.
- Company witness Chad Notestone is a Manager of Regulatory Studies. In Company Statement No. 11, he testifies about Columbia's allocated cost of service studies.
- Company witness Shirley Bardes Hasson is Manager, Regulatory Policy for Columbia. In Columbia Statement No. 12, Company witness Bardes-Hasson explains and supports the tariff changes that the Company seeks to make in this proceeding.
- 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 proposal to offer a rolling 12 month budget plan as discussed in Docket R-2018-2645477.

- Company witness Robert Kitchell is the Vice President of Construction Services for Columbia. In Columbia Statement No. 14, Company witness Kitchell 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, 2021).

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.

Exhibit I – 1
Columbia Gas of Pennsylvania, Inc.
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
Corporate Governance		X			
Executive Management and Organizational Structure	X				
Affiliated Interests	X				
Financial Management		X			
Customer Service			X		
Gas Operations			X		
Emergency Preparedness	X				
Human Resources	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. However, 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.

E. Recommendation Summary

Chapters III through X 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.

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. <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 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. Benefits

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

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

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

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

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

E. Recommendation Summary

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

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

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

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

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

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

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

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

D. Benefits

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

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

E. Recommendation Summary

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

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

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

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

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

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

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

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

D. Benefits

Where possible, the Audit Staff attempts to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. The audit report contains identifiable potential quantifiable cost savings of approximately $2,933,000 to $5,667,000 in annual savings and $2,200,000 to $3,110,000 in one-time savings from effective implementation of the recommendations. We try to identify, whenever it is reasonably practical, the potential savings net of the projected costs for implementation. Some of these savings could be considered an actual reduction in costs, avoided costs or increased revenues; whereas others would result from better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore the actual benefits from effective implementation of the recommendations are subject to some degree of uncertainty, and could be higher or lower than the amounts estimated by the Audit Staff. An overall summary of the annual and one-time cost savings quantified in the audit report are shown in Exhibit I-2.

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

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

For the majority of recommendations, it is not possible or practical to estimate quantitative benefits as their benefits are of a qualitative nature or there was insufficient data available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist or was not fully functional. Similarly, changes in work flow processes or to implement good business practices will result in improved effectiveness and efficiency of a specific function but cannot be easily quantified.

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

E. <u>Recommendation Summary</u>

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

- <u>INITIATION TIME FRAME</u> – 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.

- <u>BENEFITS</u> – 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.

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

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

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

COLUMBIA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
vs.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
MAHAMADOU BIKIENGA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

April 24, 2020

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I. <u>Introduction</u>

Q. Please state your name and business address.

A. My name is Mahamadou Bikienga and my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

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

Q. What are your responsibilities as Manager of Demand Forecasting?

A. As Manager of Demand Forecasting, I am responsible for the development of short-range and long-range forecasts of customers, energy consumption, and peak demand for seven natural gas utilities in NiSource's natural gas distribution segment, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"), and also NiSource's one combination gas-electric utility. I am also responsible for other business related analyses and forecasts.

Q. What is your educational and professional background?

A. I graduated from Carnegie Mellon University with a Master of Information Systems Management, from the University of Pittsburgh with a Bachelor of Science in Mathematics – Economics, and from the Community College of Allegheny County with an Associate of Science in Mathematics and a certificate of Business Management. In 2013, I began working as a Regulatory Analyst for Columbia and Columbia Gas of Maryland, Inc. assisting with regulatory compliance and proceedings, including rate case filings. In 2015 I was promoted to senior Regulatory Analyst. Between August 2015 and December 2016, I attended the Heinz College of Information Systems and Public Policy at Carnegie Mellon University where I earned a Master of Information Systems Management. During that time I concentrated my elective courses in Data Analytics and Business Intelligence. In 2017 I was rehired by NiSource as a Business Intelligence Analyst. In that capacity I delivered analytics solutions across NiSource's operating companies. In 2018 I was promoted to Lead Forecasting Analyst in the Regulatory Department where I supported NiSource's state regulatory teams with forecast and weather normalization related analyses and filings. In 2019 I was promoted to my current position of Manager of Demand Forecasting.

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

A. Yes, I testified before the Maryland Public Service Commission in the matter of Columbia Gas of Maryland, Inc.'s Purchased Gas Adjustment matter, Case 9510(i).

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

A. I will be addressing the twelve-month period ending November 30, 2019 as the Historic Test Year ("HTY"), the twelve-month period ending November 30, 2020 as the Future Test Year, and the twelve-month period ending December 31, 2021 as the Fully Projected Future Test Year.

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 3, Schedule 4.

II. Weather Normalization Process

Q. Please explain the weather normalization process.

A. For each month of the HTY for the residential and commercial classes, actual billing month sales per customer are separated into base-usage and temperature-sensitive usage. Temperature-sensitive usage is then scaled by the ratio of normal to actual heating degree days ("HDD") to derive normal temperature-sensitive use per customer. The normal temperature-sensitive use per customer is then added to the base-use per customer to arrive at the normal sales per customer. This value is then multiplied by the customer count to derive the normal sales.

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

A. I used the Company's billing records to obtain monthly customer counts and billed sales. The temperatures used to calculate HDD were obtained from DTN, a weather consulting service which aggregates National Weather Service weather stations throughout the Company's service territory. Due to the geographical dispersion of Columbia's customers, temperature data from multiple weather stations is used. A weighted average HDD for the Company is calculated by using the percent of residential heating customers assigned to each station as a weight for that station.

Q. How does the process calculate base usage?

A. The process assumes no temperature sensitive (heat) usage in July and August. For September, no temperature sensitive (heat) use is assumed when total use per customer per day (Total Use/Customer/Day) is less than July and/or August. The base use per customer per day is calculated by taking the average of the two lowest observed values from the months of July through September.

Q. How does the process weather normalize monthly sales?

A. First, the monthly base use per customer is determined. This equals the lesser of the base use per customer per day multiplied by the days in the billing cycle ((base use/customer/day)*days in billing cycle) or the monthly total use per customer. Second, monthly heat use per customer is calculated. Heat use per customer equals the total use per customer minus the base use. Third, the heat use per customer is normalized by multiplying by a ratio of Normal HDD to Actual HDD. Finally, normal use per customer is calculated by adding the base use per customer to the normal heat use per customer. Total monthly normalized usage is generated by multiplying monthly customers by the monthly normal use per customer. This calculation for the HTY is prepared separately for residential and commercial customers and the results are presented in Exhibit 10, Schedule 8.

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

A. No, the process has not changed other than updating the historic averages to include the most recent 20-year history. Normal weather is defined in this filing as the average HDD for the 20 years ended 2019. The previous base rate case filing defined normal weather as the 20-year average ending in 2017. In all other respects, the normalization process is the same.

Q. Why is Columbia using the 20-year average?

A. The settlement of the Company's 2016 base rate proceeding at Docket No. R-2016-2529660 designed rates based upon the Company's proposed throughput volumes, which reflected the Company's use of the 20-year average. Consistent with the Company's approach since 2008, the Company proposes to continue to use the 20-year average because an analysis of weather data shows that a rolling 20-year average is a superior measure to a rolling 30-year average. Table 1 below illustrates that, as a predictor of one-year-ahead weather, the 20-year average outperforms the 30-year average in 70% of the most recent 38 years. Table 1 also illustrates that the 20-year average has a lower mean absolute error, as compared to the 30-year average when considering both the most recent 38 year period and the most recent 10 year period.

In Table 2, the averages are used every year to predict each five year period for the 5-years ended 1987 through the five years ended 2019. In this analysis, the performance of the 20-year averages are compared to the 30-year averages. When determining the smallest difference over the 5-year period, the 20-year average outperforms the 30-year average in 91% or 30 out of the 33 periods. When considering the most recent 10 periods, the 20-year average outperforms the 30-year average in 100% or all of the 10 periods.

Table 3 demonstrates that stability is not sacrificed when using a 20-year average. The average annual change for the 20-year average is 0.4%, while the average annual change for the 30-year average is 0.3%. The 20-year normal is not only a better predictor, but also a more dynamic measure that is better able to react more quickly to change because it replaces 5% of the data each year rather than the 3% that is replaced with the 30-year average. In conclusion, the 20-year measure performs better as compared to the 30-year in both the year ahead analysis and the five year analysis, and is both a better predictor and a more dynamic measure when compared to the 30-year average.

Table 1

Weather Averages as Predictors

Moving Averages used to Predict Following Years

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
1982	5878	5924	5858				
1983	5658	5893	5880	266	200		x
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	

	Mean Absolute Error		Frequency of Lowest Absolute Error	
1983-2019	293	321	26	11
2010-2019	336	342	6	4

	Relative Frequency of Lowest Absolute Error	
1983-2019	70%	30%
2010-2019	60%	40%

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
1982	5878	5924	5858				
1983	5658	5893	5880				
1984	6040	5904	5898				
1985	5340	5879	5892				
1986	5593	5863	5887				
1987	5495	5842	5885	-1493	-1163		x
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	

	Mean Absolute Error		Frequency of Lowest Error	
1987-2019	-994	-1330	30	3
2010-2019	-444	-914	10	0

	Relative Frequency of Lowest Error	
1987-2019	91%	9%
2010-2019	100%	0%

Table 3

Stability of Weather Averages Annual Change in Averages 1983-2019 Absolute Values Columbia Gas of Pennsylvania			
	20-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	6.9%
Maximum	1.4%	0.8%	19.6%

III. Forecast Method

Q. Please explain the methodology employed for developing the forecasted number of customers and customer usage for the Future Test Year and the Fully Projected Future Test Year.

A. Development of the forecasting methodology is presented in the summary that follows. This method was used to develop both the Future Test Year and the Fully Projected Future Test Year. Price information included in the models is from U.S. Energy Information Administration ("EIA"), and average efficiency data is from Itron Inc., a national utility consulting firm. The economic variables and deflator information are from IHS Global Insight, Inc., a data consultant, and weather data is provided by DTN, a weather consulting service.

Residential and Commercial Customers

- Total new customer additions are forecasted for the initial six years of the forecast by Columbia's New Business Team. CHOICE customers are calibrated to the most recently observed level and the forecast is set to the current observed percentage of customers participating in the CHOICE program.

- Traditional transportation customers = existing transportation customers + new customers identified by the Company's Large Customer Relations group.
- Total customer forecasts were developed using monthly econometric models of total customer count. The reasonableness of the forecast is gauged by ensuring that forecast trend and levels are reflective of new customer forecast by Columbia's New Business Team. The residential customer forecast was developed using a monthly econometric model that incorporates number of households and real income per capita. The commercial customer forecast was developed using a monthly econometric model that incorporates non-manufacturing employment.
- Sales customers = total customers – CHOICE customers – traditional (commercial) transportation customers.

Residential Dekatherm ("Dth")/Customer

- Residential use per customer is forecasted with an econometric model that incorporates real price, an average energy intensity variable, and heating degree days. Residential CHOICE usage follows the total Residential usage trend.

Residential Volume

- Dth is forecasted for total customers.

  Dth = customers * Dth/customer

- CHOICE Dth is forecasted as a percentage of total Dth. The percentage is determined by most recent choice Dth levels.
- Sales Dth is forecasted as residual.

  Sales Dth = Dth – CHOICE Dth

Commercial Dth/Customer

- Commercial use per customer is forecasted with an econometric model that incorporates real price and heating degree days. Commercial CHOICE usage follows the total Commercial usage trend.

Commercial Dth

- Dth is forecasted for total customers.

  Dth = customers * Dth/customer
- CHOICE Dth is forecasted as a percentage of total Dth. The percentage is determined by most recent choice Dth levels.
- Non-CHOICE transportation Dth for large commercial customers is forecasted by the Large Customer Relations group. Non-CHOICE transportation Dth for smaller commercial customers is forecasted as the trend in the forecast for total commercial use per customer.
- Sales Dth is forecasted as residual.

  Sales Dth = Dth – CHOICE Dth – non-CHOICE transportation

Industrial Volume

- The majority of the Industrial class forecast is provided by the Large Customer Relations group. This portion constitutes over 93% of the total Industrial class forecast. The large customer portion of the forecast is developed by incorporating information generated through individual customer interviews. The remainder of the industrial class forecast is estimated using the trend from an econometric model for the full class. The model incorporates real price, and HDDs. The total industrial volume forecast is the sum of the large industrial forecast and the all other industrial forecast.
- The information provided through the interviews with customers provides sales/transportation detail. Additional transportation Dth is forecasted with the trend from the econometric model.

Q. Please discuss the past performance of the forecast.

A. Residential and commercial forecast models are updated annually with the most current data. An internal review of forecast performance occurs on a regular basis. Variances for the residential and commercial predictions are calculated and assessed in order to measure accuracy. The 2020 forecast volume variance from weather normalized volumes will be evaluated at the end of the year. The average annual one year weather normalized variance for the residential models is 0.8%. For commercial, the average one year variance of the forecast is 0.6%.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

April 24, 2020

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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"), Columbia Gas of Virginia ("CVA") and Columbia Gas of Massachusetts ("CMA"). 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 this 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 Columbia Gas of Virginia ("CGV"), 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 have testified once before the Pennsylvania Public Utility Commission ("Commission") in a formal complaint proceeding during my tenure as a GTS analyst. In 2019, I testified before the Maryland Public Service Commission in support of CMD's base rate proceeding, Case No. 9609. I have also submitted direct testimony in Columbia's previous base rate proceedings, at Docket Nos. R-2016-2529660, R-2014-2406274, and R-2012-2321748, as well as CMD's base rate proceedings, Case Nos. 9447, 9417 and 9316, on behalf of CKY in its 2016 base rate proceeding, Case No. 2016-00162, and CMA'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 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, 2021 (Fully Projected Future Test Year "FPFTY"). The 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. Specifically, I am responsible for the preparation and presentation of Exhibits 3 and 103 (Operating Revenues), including Exhibit 103 Schedule 8 (Rate Design). In addition, I will be supporting the Company's residential rate structure proposals regarding the Weather Normalization Adjustment ("WNA") and the Revenue Normalization Adjustment ("RNA"). 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 013, Schedule 01, (a) (b), Pages 01-03
Exhibit 016, (7), Pages 01-04
Exhibit 017, (01) (28) Pages 01-07
Exhibit 103, Schedules 01 through 8 08, (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 111, Schedule 05, Pages 01-09, Exhibit 111, Schedule 06 Pages 01-09
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 seven additional exhibits that support the Company's revenue and rate design proposals. Each exhibit 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)
Exhibit MJB-3	Calculation of Gas Procurement Charge
Exhibit MJB-4	Total Operating Revenues for the Twelve Months Ending December 31, 2019
Exhibit MJB-5	Benchmark Distribution Revenue per Bill (BDRB)
Exhibit MJB-6	Revenue Normalization Adjustment for Peak Period
Exhibit MJB-7	Revenue Normalization Adjustment for Off Peak Period

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, 2019. 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 Mahamadou Bikienga (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, 2020 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, 2020 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 29, 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 most recent 12 month periods, including the HTY, and calculates a three year average. The average of the last three years 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. 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, 2019. 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, 2020. Column 3 shows a summary of Rider USP at present rates in effect as of January 1, 2020. 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 Bikienga 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 Bikienga 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 and Small Commercial Sales and CHOICE customers. The spread for Large 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.

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 Bikienga's testimony for an explanation of the forecast models.

C. Exhibit MJB-4

Q. Please describe Exhibit MJB-4

A. Pursuant to Provision Number 36 of the Joint Settlement Agreement for R-2018-2647577, I am sponsoring Exhibit MJB-4, which provides a comparison of actual versus projected revenues for the twelve months ending December 31, 2019.

IV. Residential Rate Structure

Q. Describe the Company's current base rate structure for residential customers.

A. The Company's current residential base rate structure includes a customer charge, a volumetric usage charge and a Weather Normalization Adjustment (Rider WNA).

Q. Does the Company propose any changes to the current residential rate structure?

A. Yes. The Company proposes to modify the currently effective Rider WNA and also implement a Revenue Normalization Adjustment (Rider RNA) for residential customers. Residential customers would continue to be billed a customer charge and a volumetric rate.

Q. Provide some background concerning Columbia's Rider WNA.

A. In Columbia's 2012 base rate proceeding, the Commission approved the establishment of a pilot WNA program. 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.

Q. Please explain how the existing Rider WNA operates.

A. Columbia's existing WNA is applied to the bills of Residential customers under Rate Schedules RSS, RDS, and CAP, for the months of November through May. The adjustment is applied to each individual bill and is calculated as shown below:

WNA	= WNAT x Distribution Usage Charge, where:
WNAT	= WNBT – AMT
WNBT	= BLMT + [(NHDD / AHDD) x (AMT-BLMT)]
WNAT	= Weather Normalized Adjustment Therms
WNBT	= Weather Normalized Billing Therms
BLMT	= Base Load Monthly Therms
NHDD	= Normal Heating Degree Days
AHDD	= Actual Heating Degree Days

AMT = Actual Monthly Therms

Q. How are BLMT determined?

A. BLMT are established for each residential customer using the customer's actual average daily consumption from the billing system, for the two months with the lowest consumption per billing day for the three billing months of July, August and September.

Q. Explain the dead-band included in the Company Rider WNA.

A. Columbia's existing Rider WNA includes a 3% dead-band, which means that a billing adjustment only occurs if the variation of actual heating degree days is lower than 97% or higher than 103% of the normal heating degree days for an individual billing cycle. The Company agreed to a reduction in the dead-band to 3% from 5% as a provision of the Settlement Agreement in its 2018 base rate proceeding at Docket No. R-2018-2647577.

Q. Has Rider WNA mitigated the impacts of colder and warmer than normal weather on residential customers?

A. Yes. Pursuant to Paragraph 41(b) of the Joint Petition for Settlement approved by the Commission in Columbia's 2012 base rate proceeding, Columbia has filed reports concerning the operation of the WNA for the 2013/2014, 2014/2015, 2015/2016, 2016/2017, 2017/2018 and 2018/2019 heating seasons. These reports include the monthly computation and supporting data for the WNA. The first two WNA heating seasons were colder than normal and, as a result, the Company billed less to residential customers than it would have billed without the WNA mechanism. For the 2013/2014 season, the WNA revenue adjustment was ($9.36M), and for the 2014/2015 season, the WNA revenue adjustment was ($10.98M). The 2015/2016 and 2016/2017 heating seasons were warmer than normal and, as a result, the Company billed more to residential customers than it would have billed without the WNA mechanism. For the 2015/2016 heating season, the WNA revenue adjustment was $11.52M. For the 2016/2017 heating season, the WNA revenue adjustment was $13.9M. The 2017/2018 and 2018/2019 heating seasons were colder than normal, and as a result, the Company billed less to residential customers than it would have billed without the WNA mechanism. For the 2017/2018 heating season, the WNA revenue adjustment was ($6.1M) and for 2018/2019, the WNA revenue adjustment was ($3.7M). Through the end of January 2020, the 2019/2020 heating season has been warmer than normal and, as a result, the Company has billed more to residential customers than it would have billed without the WNA mechanism. Through the end January 2020, the WNA revenue adjustment for the current winter season was $2.45M. Thus, the total WNA revenue adjustment from October 2013 through the end of January 2020 was ($2.27M). Columbia's nearly seven years of experience with the WNA demonstrates that this rate design mechanism provides stability by adjusting bills for colder and warmer than normal weather. The WNA is effective at providing customer-specific billing adjustments in a timely manner.

Q. Describe any modifications that the Company proposes for the existing Rider WNA.

A. Columbia is proposing to eliminate the 3% dead-band.

Q. Why does the Company propose to eliminate the 3% dead-band applicable to the currently effective Rider WNA?

A. A 3% dead-band means that a portion of revenue variation due to weather continues to be unaddressed. Thus, the goal of the WNA, to improve revenue stability, is not fully realized. The dead-band ignores the true effect of weather. For example, if a billing cycle is 2% colder than normal, no adjustment will be made. Additionally, as described later in the testimony, the Company proposes to implement a RNA, along with Rider WNA. Eliminating the 3% dead-band would cause all billing adjustments related to weather to occur through the WNA in real time and would limit adjustments passing through the RNA.

Q. Do any of Columbia's other jurisdictions have WNA mechanism without dead-bands?

A. Yes. The Columbia companies operating in Kentucky, Virginia and Maryland have WNA mechanisms without dead-bands.

Q. Has the Company submitted a revised Rider WNA?

A. Yes. Please refer to the testimony and exhibits sponsored by witness Bardes Hasson (Columbia Statement No. 12).

Q. In general, please describe the RNA being proposed by the Company.

A. The RNA proposed by Columbia provides benchmark distribution revenue levels 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 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 2021 billing cycles and ending with March 2022 billing cycles would be applied to residential customers' bills for the period beginning with October 2022 billing cycles and ending with March 2023 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 MJB-5 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 MJB-5 shows the following BDRB levels for Rider RNA:

	Peak BDRB		Off-Peak BDRB
January	$144.08	April	$86.08
February	$142.79	May	$51.98

March	$122.42	June	$37.64
October	$38.53	July	$32.11
November	$61.68	August	$31.46
December	$109.86	September	$31.72
6-Month Total	$619.36		$270.99

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 and is presented by witness Bardes-Hasson (Columbia Statement No. 12).

Q. Why does the Company propose to modify and continue Rider WNA, given that Rider RNA is being proposed?

A. Columbia's WNA adjusts each individual customer's monthly bill based upon actual temperatures experienced during the billing month. Maintaining Rider WNA ensures that deviations in distribution revenue caused solely by warmer or colder than normal weather are reflected in real time. Because Rider WNA adjustments are based on each customer's usage behavior and are billed monthly, the adjustments occurring through Rider RNA would be less impactful due to the existence of Rider WNA.

Q. Can you please provide more explanation concerning 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 affliates successfully implemented WNA and RNA in any of its 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 coupled with WNA. 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 modified WNA and the RNA?

A. Columbia proposes to implement the modified WNA effective with February 2021 billing cycles and to begin tracking the RNA with January 2021 billing cycles. This initial Peak Period RNA ("RNAp") would become effective with October 2021 billing cycles.

Q. Will the currently effective Rider WNA continue to operate until the modified Rider WNA becomes effective?

A. Yes. The 3% dead-band would continue to be effective through January 2021 billing cycles.

Q. Would Columbia continue to submit its annual Filing related to the operation of the WNA mechanism?

A. Yes.

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:

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

RNA is the Revenue Normalization Adjustment for non-CAP residential customers for the applicable period.

BDRB is the Benchmark Distribution Revenue per Bill for non-CAP residential customers for the applicable period.

ADRB is the Actual Distribution Revenue per Bill for non-CAP residential customers for the applicable period. ADRB includes Rider WNA adjustments in the applicable months.

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

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

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

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

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

A. Yes. Refunds to customers shall be made with 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 2021.

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

A. Please refer to Exhibits MJB-6 and MJB-7 for sample RNA calculations for the initial Peak and Off-Peak Periods. Exhibit MJB-6 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 2021. Line 3 of Exhibit MJB-6 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 2021 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 2021 through March 2022. The RNAp rate effective for October 2021 billing cycles through March 2022 billing cycles is calculated on line 20 with line 16 being divided by line 18. Exhibit MJB-7 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 2022 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.

V. Revenue Allocation and Rate Design

Q. What is the Company's proposed revenue increase?

A. The proposed rates will produce an increase in annual revenues of approximately $100.4 million. Please refer to the testimony and schedules of Company witness Miller (Columbia Statement No. 4) for details concerning the Company's revenue requirement.

Q. Please describe the rate design principles that the Company considered when developing the proposed 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 produces an accurate basis for consumers' decisions and affords the Company the opportunity to recover the cost of providing service. A simple rate structure aids understanding for customers. The goal of rate continuity implies that customers will have an adequate opportunity to adjust their consumption patterns, as needed. A fair rate design considers the results of the allocated cost of service ("ACOS") 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.

Q. Please describe how the revenue increase was allocated among rate schedules.

A. The initial allocation of the revenue requirement to the rate schedules was performed using the FPFTY non-gas revenues for each customer group being allocated a portion of the increase. The revenues are shown in Exhibit 103, Schedule 1 and summarized on Schedule 8, page 1. In order to develop allocation percentages, rate schedules were assigned to groups. For example, all residential rate schedules, included RSS, CAP, and RDS (Choice) were grouped together. Similarly, commercial and industrial customers using less than 6,440 therms annually were combined (SGS-1/SCD-1/SGDS-1). The other customer groups include SGS-2/SCD-2/SGDS-2 (Annual use between 6,440 and 64,400 therms), SDS/LGS (commercial and industrial customers using between 64,400 and 540,000 therms annually), LDS/LGS (commercial and industrial customer using greater than 540,000 therms annually), Mainline Service and Flex/Negotiated Contract Service.

Q. Please state the basis for evaluating the reasonableness of the Company's proposed revenue allocation.

A. The three ACOS studies developed by Company witness Notestone (Columbia Statement No. 11) were used to evaluate the reasonableness of the proposed revenue allocation. The results of the Customer/Demand Study and Peak and Average Study provide a range of costs to serve each customer class. The Average Study shows a combination of the two studies and is the study that the Company relied upon to provide guidance for the revenue allocation and rate design process. Please refer to Columbia witness Notestone's testimony (Columbia Statement No. 11) for the detailed cost of service methods employed by the Company.

Q. What is the Company's proposed revenue allocation?

A. Columbia's proposed allocation of the base rate increase is shown on line 14 of Exhibit 103, Schedule No. 8, Page 4 of 9. The percent distribution to each customer class is reflected on line 15.

Q. Were there any adjustments to the revenue allocation based upon the initial results of the Class Cost of Service Study?

A. Yes. The initial results indicated that four rate classes (SGS/DS-1, SGS/DS-2, SDS/LGSS and MLDS) are over-contributing compared to the rate of return earned on rate base of 7.98% (Exhibit 111, Schedule 3, Page 1, Line 13), and three rate classes (RS, LDS and Flex) are under-contributing. Revenue was shifted between the classes in an effort to move each class toward parity (system average of 1.00). This resulted in an additional $468,497 being re-allocated to the residential class, which was capped at the system average. An additional $313,389 was re-allocated to the LDS class. The overall proposed base revenue increase by class was less than 1% different as compared to base revenue at current rates. (Lines 19 and 17 on Exhibit 103, Schedule 8, Page 4). To illustrate, the residential class base distribution revenue at proposed rates is $366,175,904 (Exhibit 103, Schedule 8, Page 4, Line 18), or 71.89% of the total Company proposed revenue request of $509,351,454, which is approximately 0.1% more than the Company is currently collecting through the base revenue for the residential class. The resulting re-allocation of revenue and percentage increases for all classes is shown on Exhibit 103, Schedule 8, Page 4, Line 18 and the results are presented in Exhibit 111, Schedule 3, Page 1, Line 14. The tables below summarize the initial and final revenue allocations.

<u>Columbia's Initial Revenue Allocation Proposal of Revenue Requirement</u>

RS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	Flex
$73,521,431	$8,465,322	$9,714,590	$5,477,321	$3,854,297	$138,239	$1,227,764
72.99%	8.27%	9.49%	5.35%	3.76%	0.14%	1.20%

Columbia's Final Revenue Allocation Proposal of Revenue Requirement

RS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	Flex
$73,989,928	$8,615,322	$9,889,590	$5,722,321	$4,167,686	$0	$14,117
72.27%	8.41%	9.66%	5.59%	4.07%	0.0%	0.01%

Q. With this allocation of revenue, were there any rate classes that did not receive a revenue increase?

A. Yes. Please refer to the testimony of witness Notestone. Exhibit 111, Schedule 3, Page 2 reflects returns by rate class at current rates. As shown on this exhibit, Mainline service customers are sufficiently covering their allocated share of the revenue requirement at present rates under the Average study, and in fact, all three studies. Therefore it was necessary to shift the initial revenue allocation of $138,389 to the residential and LDS classes. In addition, any increase to Flex, above what would be collected through the increased customer charges to SGS/DS-2, SDS/LGSS and LDS/LGSS customer classes, was also shifted to all rate classes.

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[1].

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. Does the reallocation of revenue requirement mentioned above bring the return for the residential or LDS classes equal to the system average at proposed rates?

A. It does not for the LDS class. As previously mentioned, the increase to the residential class was capped at the system average.

Q. Was more revenue allocated to the LDS group than initially assigned?

A. Yes. The LDS group is assigned an additional $313,389 of the revenue requirement.

Q. Why did the Company not allocate more of the revenue requirement to the LDS class to achieve the required 7.98 return?

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

A. The Company is trying to strike a balance between competing rate design goals of fairness and gradualism.

Q. Will Customer Assistance Program ("CAP") customers receive a rate increase as a result of this rate proceeding?

A. For rate design purposes, Columbia anticipates that current CAP customers will not receive an increase in their required payment, and thus the revenue increment that is assigned to CAP customers will be collected from other residential customers through Rider USP.

Q. Does the Company propose to change the Gas Procurement Charge – Rider GPC?

A. Yes. Please refer to Exhibit MJB-3 attached to this testimony for the calculation of the proposed GPC surcharge of $0.00102 per therm.

Q. What are the new base rates proposed for residential customers?

A. Exhibit No. 103, Schedule No. 8, Page 5, shows the distribution rates proposed by the Company for residential customers. Columbia proposes to increase the residential customer charge from $16.75 to $23.00. The remaining residential revenue increase was assigned to the volumetric charge for a resulting rate of $7.3323 per Dth.

Q. Why is the Company proposing a residential customer charge of $23.00?

A. Witness Notestone performed two customer charge calculations, one which excludes mains and the other including mains. Please refer to Exhibit No. 111, Schedule 1, page 25, for the customer-based costs excluding mains. Column (E) of this page shows a monthly customer cost of $23.05. Exhibit No. 111, Schedule 1, page 16, provides the monthly customer charge computations including a mains components. This results in a $54.16 per month for residential customers. A residential customer charge of $23.00 is below the monthly customer-based cost computed by witness Notestone.

Q. Describe the new base rates proposed for Small General Service customers consuming less than or equal to 6,440 therms annually.

A. The Company proposes to increase the customer charge from $22.75 to $30.00 an increase of $7.25 for Small General Service customers. The remaining revenue requirement for this customer class would be recovered through the volumetric rate.

Q. What are the customer based costs for the Small General Service customers using less than or equal to 6,440 therms annually?

A. Please refer to Exhibit No. 111, Schedule No. 1, pages 16 and 25 prepared by witness Notestone. The customer costs for this rate class range from $25.87 (excluding mains) to $60.16 (including mains). Columbia's customer charge proposal of $26.00 falls just above the bottom of the range of costs. At $30.00, the volumetric base rate will be $5.4497/Dth for SGSS1/SCD1 service and $5.3413/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 $60.00, which is $12.00 more than the current $48.00. The volumetric charge will be $4.7467/Dth for SGSS/SCD service and $4.6384/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 Company 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 part of this current proceeding, and as explained by Company witness Notestone in testimony and shown on Exhibit CEN-4, the Company has re-allocated $267,389 of storage working capital costs from the SGDS class to SGSS/SCD. This intra-class re-allocation is shown on Line 16 of Exhibit 103, Schedule 8, Page 6 and Line 16 of Page 7. As a result, the Company charges a different volumetric base rate to the SGSS and SCD customers than to the SGDS customers and that principle will not change under proposed rates.

Q. Please summarize Columbia's SDS/LGSS rate design proposal.

A. The proposed SDS/LGSS Customer Charge for customers whose usage is between 64,400 therms and 110,000 therms is $290.00. The $290.00 is $60.25 more than the current SDS/LGSS Customer Charge of $229.75.

The proposed SDS/LGSS Customer Charge for customers whose usage is between 110,000 therms and 540,000 therms is $940.00. The $940.00 is $182.66 more than the current SDS/LGS Customer Charge of $757.34. The volumetric base rate will be $3.3081Dth for SDS/LGSS customers whose usage is between 64,400 therms and 110,000 therms and $3.0928/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 and current Customer Charges for the LDS/LGSS rate class:

Annual Usage Levels	Current Cust. Charge	Proposed Cust. Charge
> 540,000 to ≤ 1,074,000 Therms	$1,947.06	$2,419.00
> 1,074,000 to ≤ 3,400,000 Therms	$3,028.76	$3,759.00
> 3,400,000 to ≤ 7,500,000 Therms	$5,841.18	$7,248.00
> 7,500,000 Therms	$8,653.60	$10,728.00

Q. How is the LDS/LGSS volumetric based rate revenue requirement shown in Exhibit 103, Schedule 8, Page 8, Line 28 spread among the LDS/LGSS annual usage groups?

A. Volumetric Base Rate Revenue requirement is split among the LDS/LGSS annual usage groups proportionately based on revenue produced from current volumetric Base Rates. (See Exhibit 103, Schedule 8, Page 8, Lines 29 through 32).

VI. Revenue Proof and Bill Impacts

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. 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, 2020

Line No.	Description	Reference		Rate $	
1	PGCC Rate	Exhibit 1-A, Schedule 1, Page 1, Col. 3, Line 5 (1/01/2020 Quarterly GCR Filing)		2.2764	
2	Total Commodity Cost of Gas			**2.2764**	per Dth
3	Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 32, Line 7	0.0133699		
4	Non-Residential Uncollectible Expense Ratio[1]	Exhibit No. 4, Schedule No. 2, Page 32, Line 14	0.0027098		
5	Merchant Function Charge - Residential Sales Service	(Line 4 x Line 5)		0.0304	per Dth
6	Merchant Function Charge - Small General Sales Service	(Line 4 x Line 6)		0.0062	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, 2019

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, Line 6)					$ 438,213,365
5	Historic Test Year Revenue -Transportation Revenue (Ex. 3, Page 10, Line 9)					$ 132,850,528
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$ 571,063,893
7	3 Year Average					0.1913%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$ 1,092,445
9	Historic Test Year Acct 487 (Ex. 3, Page 9)					$ 1,080,703
10	Annualization Adjustment (Line 8 - Line 9)					$ 11,742

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	Future Test Year Sales Revenue (Ex. 103, Page 11, Line 5)					$ 417,680,867
5	Future Test Year Transportation Revenue (Ex. 103, Page 11, Line 8)					$ 153,542,439
6	Total Sales and Transportation Revenue (Line 4 + Line 5)					$ 571,223,306
7	3 Year Average					0.1913%
8	Annualized Forfeited Discounts (Line 4 * Line 6)					$ 1,092,750
9	Future Test Year Acct 487 (Ex. 103, Page 10)					$ 1,092,445
10	Annualization Adjustment (Line 7 - Line 8)					$ 305

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending December 31, 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	Fully Projected Future Test Year Sales Revenue (Ex. 103, Page 15, Line 5)					$ 419,910,219
5	Fully Projected Future Test Year Transportation Revenue (Ex. 103, Page 15, Line 8)					$ 151,386,260
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$ 571,296,479
7	3 Year Average					0.1913%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$ 1,092,890
9	Fully Projected Future Test Year Acct 487 (Ex. 103, Page 14)					$ 1,092,750
10	Annualization Adjustment (Line 8 - Line 9)					$ 140

		Amount	Rate
1	**Labor and Benefits** [1]	**Amount**	**Rate**
2	Accounting Support	$8,855.59	
3	Gas Supply Support	$156,387.79	
4	Legal Support	$23,578.72	
5	Regulatory Support	$97,239.45	
6	Treasury Support	$22,309.19	
7	**Total Labor and Benefits (Line 2 + Line 3 + Line 4 + Line 5 + Line 6)**	**$308,370.74**	
8	**Outside Services - Legal Support**	**$43,901.00**	
9	**Information Technology Systems Maintenance**		
10	Gas Source	$22,672.03	
11	% of customers taking Sales Service	78.00%	
12	**Cost allocated to Sales Service Customers (line 10 * Line 11)**	**$17,684.18**	
13	**TOTAL (line 6 + line 8 + line 9)**	**$369,955.92**	
14	Total Sales (Therms)	363,122,058 [2]	
15	Gas Procurement Charge (Line 13 / Line 14)		$0.00102 per / therm
16	Gas Procurement Charge (Line 15 * 10)		$0.01020 per / Dtth

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

(2) Fully Forecasted Rate Year Gas Service Sales per Exhibit 103, Sch. 1, Page 7, Line 60, less Rate NSS Sales as NSS is not subject to GPC

Columbia Gas of Pennsylvania, Inc.
Total Operating Revenues
For the Twelve Months Ending December 31, 2019

Line No.	Description	R-2018-2647577 Twelve Months Ended 31-Dec-19 @ Proposed Rates	Twelve Months Ended 31-Dec-19 Actual	Difference
		(1)	(2)	(3)=(2)-(1)
		$	$	$
1	Operation Revenues			
2	Base Rate Revenues (Incl. Transportation)	401,682,377	396,329,780	(5,352,597)
3	Fuel Revenues	163,506,936	168,114,095	4,607,159
4	Rider USP	30,681,271	29,215,919	(1,465,352)
5	Gas Procurement Charge	2,581,692	2,605,854	24,162
6	Merchant Function Charge	1,216,174	1,033,771	(182,403)
7	Rider CC	47,177	46,707	(470)
8	Total Sales and Transportation Revenue	599,715,627	597,346,126	(2,369,501)
9	Off System Sales Revenue	0	3,597,631	3,597,631
10	Late Payment Fees	1,302,588	1,075,649	(226,939)
11	Other Operating Revenues (Excl. Transportation)	344,604	378,008	33,404
12	Total Operating Revenues	601,362,819	602,397,414	1,034,595

Columbia Gas of Pennsylvania, Inc.
Benchmark Distribution Revenue per Bill (BDRB)
For the 12 Months Ending December 31, 2021

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	295,947	82,954	3,381	313	0	(775)	381,820
February	296,554	82,846	3,859	288	243	(776)	383,014
March	296,889	82,735	4,179	340	454	(776)	383,821
April	295,915	82,639	5,712	493	693	(774)	384,678
May	294,562	82,541	5,600	488	820	(771)	383,240
June	293,418	82,446	6,225	584	1,105	(769)	383,009
July	292,958	82,337	5,716	494	1,260	(768)	381,997
August	292,860	82,218	5,792	485	1,967	(767)	382,555
September	293,581	82,110	5,185	463	2,312	(768)	382,883
October	295,082	82,011	4,612	392	3,636	(771)	384,962
November	297,698	81,908	4,401	372	4,520	(778)	388,121
December	298,856	81,232	4,438	399	4,686	(777)	388,834
Total	3,544,320	987,977	59,100	5,111	21,696	(9,270)	4,608,934

Volumes (Dth)

	Residential FPFTY RS	Residential RDS FPFTY	Residential RS Final Bills	Residential RDS Final Bills	New Residential Customers	Residential Customer Attrition	Total
January	4,722,149.8	1,539,892.7	0.0	0.0	55,936.0	(12,981.0)	6,304,997.5
February	4,706,863.5	1,512,248.2	0.0	0.0	51,043.0	(12,892.0)	6,257,262.7
March	3,909,608.7	1,266,054.1	0.0	0.0	39,259.0	(10,729.0)	5,204,192.8
April	2,472,675.7	820,615.2	0.0	0.0	23,119.0	(6,827.0)	3,309,582.9
May	1,130,943.8	377,105.9	0.0	0.0	9,756.0	(3,126.0)	1,514,679.7
June	579,444.7	182,401.5	0.0	0.0	4,476.0	(1,579.0)	764,743.2
July	362,166.1	110,896.6	0.0	0.0	2,485.0	(981.0)	474,566.7
August	337,980.8	102,328.8	0.0	0.0	2,020.0	(913.0)	441,416.6
September	348,955.2	105,814.4	0.0	0.0	1,740.0	(943.0)	455,566.6
October	612,953.0	201,633.8	0.0	0.0	2,375.0	(1,689.0)	815,272.8
November	1,544,028.3	504,043.7	0.0	0.0	3,592.0	(4,243.0)	2,047,421.0
December	3,505,098.0	1,108,226.0	0.0	0.0	2,631.0	(9,563.0)	4,606,392.0
Total	24,232,867.6	7,831,260.9	0.0	0.0	198,432.0	(66,466.0)	32,196,094.5

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	381,820	$ 23.00	$ 8,781,860.00	6,304,997.5	$ 7.3323	$ 46,230,133.17	$ 144.08
February	383,014	$ 23.00	$ 8,809,322.00	6,257,262.7	$ 7.3323	$ 45,880,127.30	$ 142.79
March	383,821	$ 23.00	$ 8,827,883.00	5,204,192.8	$ 7.3323	$ 38,158,702.87	$ 122.42
April	384,678	$ 23.00	$ 8,847,594.00	3,309,582.9	$ 7.3323	$ 24,266,854.70	$ 86.08
May	383,240	$ 23.00	$ 8,814,520.00	1,514,679.7	$ 7.3323	$ 11,106,085.96	$ 51.98
June	383,009	$ 23.00	$ 8,809,207.00	764,743.2	$ 7.3323	$ 5,607,326.57	$ 37.64
July	381,997	$ 23.00	$ 8,785,931.00	474,566.7	$ 7.3323	$ 3,479,665.41	$ 32.11
August	382,555	$ 23.00	$ 8,798,765.00	441,416.6	$ 7.3323	$ 3,236,598.94	$ 31.46
September	382,883	$ 23.00	$ 8,806,309.00	455,566.6	$ 7.3323	$ 3,340,350.98	$ 31.72
October	384,962	$ 23.00	$ 8,854,126.00	815,272.8	$ 7.3323	$ 5,977,824.75	$ 38.53
November	388,121	$ 23.00	$ 8,926,783.00	2,047,421.0	$ 7.3323	$ 15,012,305.00	$ 61.68
December	388,834	$ 23.00	$ 8,943,182.00	4,606,392.0	$ 7.3323	$ 33,775,448.06	$ 109.86
Total	4,608,934.0		$ 106,005,482.00	32,196,094.5		$ 236,071,423.71	$ 890.35

BDRBp (Oct-Mar)	$ 619.36
BDRBo (Apr-Sep)	$ 270.99

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAp")
Peak Period RNAp Effective October 2021 through March 2022

Line No.	Non-CAP Residential Customers:	Line Applications	Oct	Nov	Dec	Jan	Feb	Mar	Jan - Mar
1	**Benchmark Distribution Revenue per Bill ("BDRBp")**								Three month
2		Per Docket							BDRBp
3	Monthly BDRBp	R-2020-3018835	$ 38.53	$ 61.68	$ 109.86	$ 144.08	$ 142.79	$ 122.42	$ 409.29
4									
5	**Actual Distribution Revenue per Bill ("ADRBp")**								Three month
6									ADRBp
7	Monthly ADRBp*	Jan 2021 - Mar 2021	NA	NA	NA	$ 143.98	$ 142.65	$ 122.75	$ 409.38
8									Total
9	Monthly BDRBp - Monthly ADRBp	ln 3 - ln 7				$ 0.10	$ 0.14	$ (0.33)	$ (0.09)
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**					$ 38,182.00	$ 53,621.96	$ (126,660.93)	$ (34,459.65)
17									
18	**Forecast Decatherms (Dth) for Effective RNAp Period (FTp)***		815,273	2,047,421	4,606,392	6,304,998	6,257,263	5,204,193	25,235,539
19									
20	**RNAp Rate Effective October 2021 through March 2022**	ln 16 / ln 18							$ (0.0014)

* For illustrative purposes only.

Columbia Gas of Pennsylvania
Revenue Normalization Adjustment ("RNAo")
Off-Peak Period RNAo Effective April 2022 through September 2022

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-2020-3018835	$ 86.08	$ 51.98	$ 37.64	$ 32.11	$ 31.46	$ 31.72	$ 270.99
4									
5	**Actual Distribution Revenue per Bill ("ADRBo")**								
6									Total ADRBo
7	Monthly ADRBo*		$ 86.12	$ 51.75	$ 37.43	$ 32.33	$ 31.62	$ 31.59	$ 270.84
8									Total
9	Monthly BDRBo - Monthly ADRBo	ln 3 - ln 7	$ (0.04)	$ 0.23	$ 0.21	$ (0.22)	$ (0.16)	$ 0.13	$ 0.15
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**		$ (15,387.12)	$ 88,145.20	$ 80,431.89	$ (84,039.34)	$ (61,208.80)	$ 49,774.79	$ 57,459.05
17									
18	**Forecast Decatherms (Dth) for Effective RNA Period (FTo)***		3,338,455	1,520,825	836,083	514,226	504,508	538,835	7,252,932
19									
20	**RNAo Rate Effective April 2022 through September 2022**	ln 16 / ln 18							$ 0.0079

* For illustrative purposes only.

COLUMBIA STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

April 24, 2020

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 and R-2018-2647577, and for Columbia Gas of Virginia in Docket No. PUR-2018-00131.

Statement of Purpose

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, 2021 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 Krajovic (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. Are you sponsoring any additional exhibits?

A. Yes. Pursuant to paragraph 12 of the approved Settlement in Docket No. R-2018-2647577, Columbia is required to provide a comparison of its actual revenue, expenses and rate base additions for the twelve months ended December 31, 2019 to the projections in the case. I am sponsoring Exhibit KKM-1, attached to my testimony, which provides a comparison of actual and projected O&M Expenses for the twelve months ended December 31, 2019, provided according to the Company's settlement in its most recent base rate case (R-2018-2647577).

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

A. I will be addressing the twelve month period ended November 30, 2019 as the "historic test year" or "HTY", the twelve month period ending November 30, 2020 as the "future test year" or "FTY" and the twelve month period ending December 31, 2021 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, 2021 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 $100,437,420 based upon pro forma revenue requirement for the twelve months ending December 31, 2021. Columbia's computation of the revenue deficiency reflects total rate base of $2,401,427,019. 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, 2019. 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 11. 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 7.98% 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 $188,447,880 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, 2017) and Column 2 (twelve months ended November 30, 2018).

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 remove the Prepaid Pension Deferral booked in December 2018;

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

e) Removal of the negative OPEB expense;

f) Adjustments to normalize Outside Services;

g) Annualization of building rents and leases;

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

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

j) Adjustment to remove non-recoverable employee expenses;

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

l) Removal of fuel used in company operations;

m) Advertising adjusted to remove non-recoverable items;

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

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

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

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

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

s) Removal of NiFiT Amortization;

t) Removal of Charitable Contributions;

u) Normalization of rate case expense;

v) Uncollectible expense explained and adjusted to a three year average experience;

w) Adjust USP Rider expense to match revenue; and

x) Included interest on customer deposits.

A. Labor

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 763 active Columbia employees as of November 2019. 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 O&M Expense experience percentage for labor has been adjusted to remove the intercompany receivable and payable totaling $462,975 associated with labor-related O&M Expenses that Columbia billed to Columbia Gas of Massachusetts during the month of December 2018 for personnel sent to Massachusetts to assist with restoration and recovery efforts. The annualization adjustment of $3,020,567 as calculated in Schedule 2, Page 1, Line 5, and a downward lobbying adjustment of $8,445 to remove labor relating to lobbying on Line 6, resulting in a total labor annualization and normalization adjustment of $3,012,122 is added to the actual HTY labor expense level of $36,130,190 in Schedule

1, Page 2. Total Pro Forma HTY labor expense level is $39,142,312 as shown on Exhibit 4, Schedule 1, Page 2.

B. Incentive Compensation

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

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

A. Columbia's HTY per books incentive level of $1,472,179 was increased by $4,354 to reflect the actual level of expense associated with incentive compensation paid in 2019. This adjustment removes any out of period true-ups for the prior year and adjusts the accrual made in the test year to the experienced pay out level at the claimed O&M Expense experience percentage. Detail supporting the historic test year adjustment is provided on Exhibit 4, Schedule 2, Page 4.

C. Prepaid Pension Expense Deferral

Exhibit 4: *Schedule 1, Page 2, Line 3; Schedule 2, Page 6*

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

A. On September 15, 2017, NiSource elected to make a $277 million prepayment toward future combined pension plan obligations. Columbia's share of this prepayment contribution was $14,824,162 of which $8,449,772 was recorded to Columbia's pension expense. Columbia received approval to defer the O&M expense associated with the pension prepayment as a part of the Settlement of Columbia's base rate proceeding at Docket No. R-2018-2647577. The deferral entry and establishment of a Regulatory Asset in the amount stated above was recorded in December 2018, after the receipt of the Commission's Final Order approving the Settlement of Docket No. R-2018-2647577. Therefore, to normalize Pension Expense, this adjustment removes the impact of this entry from the HTY.

D. <u>Prepaid Pension Deferral Amortization Expense</u>

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

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 adjusts the amortization expense to an annual amount of $844,977.

E. <u>OPEB – Other Post Employment Benefits</u>

Exhibit 4: *Schedule 1, Page 2, Line 5; Schedule 2, Page 8*

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 $368,716 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.

F. <u>Outside Services</u>

Exhibit 4: *Schedule 1, Page 2, Line 7; Schedule 2, Page 9*

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 fees associated with Columbia's previous base rate case, Docket No. R-2018-2647577. The HTY has also been adjusted to include an out of period reimbursement received in December 2019 for costs incurred in the HTY. The offsetting adjustment is made to the FTY to remove the reimbursement from the FTY.

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

Exhibit 4: *Schedule 1, Page 2, Lines 8 & 9; Schedule 2, Page 10*

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 10 for a total of $2,971,631. This amount was then reconciled with the per book test year level of $2,962,521. The resulting adjustment is an increase of $9,110. 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 $424,186 and remains unchanged as seen on Exhibit 4, Schedule 1, Page 2, Line 9.

H. <u>Corporate Insurance</u>

Exhibit 4: *Schedule 1, Page 2, Line 10; Schedule 2, Page 11*

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 11.

I. Injuries and Damages

Exhibit 4: *Schedule 1, Page 2, Line 11; Schedule 2, Page 12*

Q. Was an adjustment made for injury and damages?

A. Yes. The HTY expense level for injury and damages of $428,366 represents an amount including both actual experience and adjustments to an injury and damages accrual account. A downward adjustment of $90,558 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 12.

J. Employee Expenses

Exhibit 4: *Schedule 1, Page 2, Line 12; Schedule 2, Page 13*

Q. Was an adjustment made for employee expenses?

A. Yes. Downward adjustments of $93,453 and $4,250 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 13.

K. Company Memberships

Exhibit 4: *Schedule 1, Page 2, Line 13; Schedule 2, Page 14*

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 $6,213 were made to first remove expenses inadvertently recorded in the historic test year for Columbia related to another NiSource affiliate. Next, an annualization adjustment was made for the American Gas Association dues reflective of the payments made relating to calendar year 2019. Column 2, Line 5 additionally contains the removal of an out-of-period item recorded in the HTY. Lastly, adjustments in Column 4, totaling a decrease of $29,488, 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 14.

L. <u>Utilities and Fuel Used in Company Operations</u>

Exhibit 4: *Schedule 1, Page 2, Line 14; Schedule 2, Page 15*

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 $379,743 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. An off-setting non-recurring historic test year utilities and fuel used in company operations expense of $1,100 is also included for a net downward adjustment of $378,643. The remaining historic test year level of $2,258,855 represents other utility costs, such as electric and telecommunications (internet service, cell phones, land lines, etc.), not recovered through the 1307(f) process.

M. Advertising

Exhibit 4: *Schedule 1, Page 2, Line 15; Schedule 2, Page 16*

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 $141,192 of brand advertising from HTY costs. Please see Exhibit 4, Schedule 2, page 16 for details.

N. Materials and Supplies

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

Q. Was material and supplies adjusted?

A. Yes. Columbia has made an adjustment to remove lobbying-related materials and supply expenses $5,281. Please see Exhibit 4, Schedule 2, page 17 for details.

O. Other O&M

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

Q. Was other O&M adjusted?

A. Yes. Columbia has made an adjustment to HTY Other O&M Expenses to remove non-recurring costs totaling $161,288. Please see Exhibit 4, Schedule 2, page 18 for details.

P. Commission, OCA and OSBA Assessments

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

Q. Please explain the $260,003 decrease to the HTY Commission, OCA and OSBA Assessment expenses.

A. The adjustment is needed to decrease 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 $1,805,024 reflects the most recent invoice amount (September 9, 2019) received as of the submission of this base rate filing.

Q. NiSource Corporate Services Company ("NCSC")

Exhibit 4: *Schedule 1, page 2, Line 20; Schedule 2, pages 20-23*

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. 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 20:

a) Adjustment to Incentive Compensation for actual incentive compensation paid in 2019;
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 20.

A. Page 20, 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 $63,286,180.

Q. Please explain the various adjustments made to the actual HTY O&M costs.

A. Continuing on Exhibit No. 4, Schedule No. 2, Page 20, Lines 4 through 12 reflect adjustments made to the actual HTY O&M expense as follows:

Line 4 – Adjusts the NCSC Incentive Compensation to the level paid in 2019 using the latest percentage of NCSC loaded labor charges to Columbia. This calculation is detailed on Page 21.

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 22 Line 15.

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

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

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

Exhibit 4: *Schedule 1, Page 2, Line 22; Schedule 2, Page 24*

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 24 shows that no adjustment is required as the HTY correctly reflects the annualized level of amortization expense of $90,313.

S. <u>NiFiT Amortization</u>

Exhibit 4: *Schedule 1, Page 2, Line 23; Schedule 2, Page 25*

Q. Please describe the NiFiT expense adjustment.

A. An adjustment has been made for the removal of NiFiT amortization expense as it has been fully amortized. Please see Exhibit 4, Schedule 2, Page 25 for details of this adjustment.

T. <u>Charitable Contributions</u>

Exhibit 4: *Schedule 1, Page 2, Line 24; Schedule 2, Page 26*

Q. How were 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 26 for the details of removing any contributions that were inadvertently booked above the line during the HTY.

U. <u>Rate Case Expense Normalization</u>

Exhibit 4: *Schedule 1, Page 2, Line 25; Schedule 2, Page 27*

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. As explained previously, actual rate case expense from the Company's prior base rate case has been removed from the pro forma HTY expense. I have included a normalized level of rate case expense based on the proposed rate case expense normalization included in this current case as determined on Exhibit 4, Schedule 2, and Page 27. 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.

<u>Uncollectible Accounts Expense</u>

Q. Please explain Columbia's claim for recovery of uncollectible accounts expense.

A. Two major categories of uncollectible accounts have been recorded historically and have been represented in the development of cost of service support. These two categories are "normal" (or non-CAP) uncollectible accounts and Customer Assistance Program ("CAP") uncollectible accounts.

Normal uncollectible accounts expense has been developed on Exhibit 4, Schedule 2, Page 28 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 31 for the HTY.

V. <u>Normal Uncollectible Accounts</u>

(Uncollectible Accounts & Uncollectible Accounts – Unbundled Gas)

Exhibit 4: *Schedule 1, Page 2, Line 26 & 27; Schedule 2, Pages 28 – 30*

Q. Please explain the development of the HTY normal uncollectible accounts expense.

A. Exhibit 4, Schedule 2, Pages 28 through 29 set 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. 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 29 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 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 28, titled as, "Total DIS Billed Revenue," has been adjusted to remove the revenue associated with Columbia's CAP (Page 30), as CAP uncollectibles are accounted for separately. Exhibit 4, Schedule 2, Line 4 of Page 28 represents Adjusted DIS Billed Revenue that relates to the net write-offs as shown on Exhibit 4, Schedule 2, Line 9 of Page 28.

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 28 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. 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. No. DIS is one of three billing systems used to bill revenue related to normal uncollectible write-offs. The other billing systems, the Gas Transportation System ("GTS") and Gas Measurement Billing ("GMB"), are used to bill larger customers including chart read customers, daily read customers, customers with multiple rate components, and non-CHOICE transportation customers. A three year average net write-off was developed for uncollectible accounts related to these larger customers. Columbia did not include these write-off amounts in the calculation of a net write-off rate, as was done for DIS billed accounts, because larger customer write-offs occur infrequently, and can produce disproportionate write-off amounts when they do occur, as can be seen in the three year experience write-offs for this type of customer.

Q. Please summarize Columbia's proposed normal historic test year uncollectible accounts expense adjustments.

A. The historic normal uncollectible adjustments are a total decrease to expense of $481,880 as shown on Exhibit 4, Schedule 1, Page 2, Lines 26 and 27. This amount has been developed by comparing an annualized DIS, GTS, and GMB 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, 2019.

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

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

Exhibit 4: *Schedule 1, Page 2, Line 28; Schedule 2, Page 31*

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 31.

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 $21,752,620 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.

X. Interest on Customer Deposits

Exhibit 4: *Schedule 1, Page 2, Line 29; Schedule 2, Page 32*

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 5% interest rate on customer deposits established under Chapter 14 of the Public Utility Code applied to the average customer deposit balance. No further adjustment is made to this item for either the future test year or the fully projected future test year, because the Company has made no projection of changes to the balance of customer deposits.

IV. FTY/FPFTY – Exhibit 102 – Statement of Income

Q. Is Exhibit 102 presented in the same format as Exhibit 2?

A. Yes. Exhibit 102, Schedule 3 is a Statement of Income based on HTY, FTY, FPFTY at present rates and the FPFTY at Proposed Rates. Note that Columbia has added HTY information to 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 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 $100,437,420 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 $100,437,420 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 18 accounts for additional Late Payments Fees, as well as additional normal uncollectible expense. 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 taking Columbia's requested increase in revenues as calculated on Page 6 of Exhibit 102, Schedule 3. The additional Late Payment Fee is 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.

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 Krajovic (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 "Ratemaking Adjustments" for both the FTY and the FPFTY. Company witness Krajovic 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 Krajovic. 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 Krajovic. 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 Krajovic.

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

A. No. Lines 1 through 27 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 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) NCSC costs adjusted to annualize labor and remove non-recoverable items;
k) Removal of other lobbying expenses;
l) Normalization of rate case expense;
m) Adjust Uncollectible expense;
n) Adjust Rider USP expense to match revenue; and
o) Other Adjustments to the FPFTY.

A. <u>Labor</u>

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

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

A. Columbia has determined annualization adjustments for the FTY of $536,218 and for the FPFTY of $488,732. 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 49.98% and 49.96%, 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. <u>Prepaid Pension Deferral Amortization Adjustment</u>

Exhibit 104: *Schedule 1, Page 2, Line 4; Schedule 2, Page 2*

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

A. The Final Order approving the Settlement of Columbia's base rate case at Docket No. R-2018-2647577 permits Columbia to recover the deferral of prepaid pension O&M expense of $8,449,772 over a ten year period starting December 16, 2018. This ratemaking entry adjusts the associated amortization expense to an annual amount of $844,977 for the FTY and FPFTY.

C. <u>OPEB – Other Post-Employment Benefits</u>

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 last rate case.

A. Provision Nos. 30 and 31 of the settlement agreement of the Company's last 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 $650,000 and $725,000, 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 out of period adjustment to remove a reimbursement received in December 2019 for expenses incurred in the HTY. 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 a decrease of $9,409 for the FTY claim and an increase of $33,903 for the FPFTY claim.

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

A. Yes. The FTY includes the elimination of the Monaca Operating Center to reflect the purchase of the facility. The FPFTY includes the elimination of rents for Uniontown and Connellsville to reflect the construction of a new 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 $337,808 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, 2019.

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 $97,703 plus applicable inflationary adjustments.

H. Utilities and Gas Used in Company Operations

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. Advertising

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 used for FTY and FPFTY periods. This includes making significant reductions to the levels of advertising expense in the Budget for both periods.

J. NiSource Corporate Services Company "NCSC"

Exhibit 104: *Schedule 1, Page 2, Lines 20 & 21; Schedule 2, Pages 11-13*

Q. Are you sponsoring any ratemaking adjustments to NCSC for the FTY and FPFTY?

A. Yes. Exhibit 104, Schedule 2, Page 11 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 12 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 2019 through May 2020, which annualizes labor for the months prior to the budgeted annual 3% merit increase to labor which occurs on June 1. In a similar fashion, the FPFTY has been adjusted to include a 3% increase of budgeted labor charges for January 2021 through May 2021.

Page 13 determines the 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).

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

Exhibit 104: *Schedule 1, Page 2, Lines 13 & 17; Schedule 2, Page 14*

Q. Please describe the lobbying expense adjustment.

A. An adjustment has 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.

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

Exhibit 104: *Schedule 1, Page 2, Line 23; Schedule 2, Page 15*

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

A. Yes. Exhibit 104, Schedule 2, Page 15 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 duplicating. The entire rate case expense included for normalization is $1,060,000. Columbia proposes to normalize these costs over twelve months.

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

(Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

Exhibit 104: *Schedule 1, Page 2, Line 24 & 25; Schedule 2, Page 16*

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 30 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 $867,390 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.

N. <u>Total Rider USP Costs</u>

Exhibit 104: *Schedule 1, Page 2, Line 26; Schedule 2, Page 17*

Q. Please explain the test year adjustments.

A. The adjustments reflected in Exhibit 104 are a result of the matching of expenses to revenue, as Rider USP is a fully reconciled mechanism. As calculated in Exhibit 103, Rider USP revenues at present rates are $22,081,296 for the FTY and $21,970,614 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.

O. <u>Other Adjustments</u>

Exhibit 104: *Schedule 1, Page 2, Line 28; Schedule 2, Page 18*

Q. Please explain the FPFTY other adjustments.

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

- Lines 1 through 4 – Uniontown Ops Center: This adjustment recognizes additional other O&M associated with the new facility as compared to the existing facilities.
- Line 5 through 10 – EC 350 Installations: O&M expense related to Cell Line installations not in the budget.
- Line 11 – Safety Initiatives: Details for this adjustment can be found in Statement No. 7, the testimony of witness Davidson.
- Line 12 – Compensation Adjustment: Details for this adjustment can be found in Statement No. 9, the testimony of witness Krajovic.
- Line 13 – Budget Billing Modification Cost: Details for this adjustment can be found in Statement No. 13, the testimony of witness Davis.

Q. Does this complete your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Summary Statement of Operations and Maintenance Expense

Line No.	Cost Element Description	R-2018-2647577 Normalized FPFTY Twelve Months Ended December 31, 2019 (1) $	Actual Twelve Months Ended December 31, 2019 (2) $	Difference (3)=(2)-(1) $
1	Labor	32,917,256	36,470,815	3,553,559
2	Incentive Compensation	2,214,000	1,245,943	(968,057)
3	Pension	-	11,697	11,697
4	Pension Deferral Amortization 1_/	844,977	844,977	-
5	OPEB	-	(392,631)	(392,631)
6	Other Employee Benefits	6,951,000	6,842,284	(108,716)
7	Outside Services	25,389,024	22,879,226	(2,509,798)
8	Building Leases	2,871,366	3,042,258	170,892
9	Other Rent and Leases	321,000	486,040	165,040
10	Corporate Insurance	3,614,000	4,362,512	748,512
11	Injuries and Damages	352,959	512,291	159,332
12	Employee Expenses	1,549,241	1,711,433	162,192
13	Company Memberships	491,000	563,040	72,040
14	Utilities and Fuel Used in Company Operations	510,813	2,607,962	2,097,149
15	Advertising	93,419	224,156	130,737
16	Fleet & Other Clearing	6,441,000	6,905,801	464,801
17	Materials & Supplies	5,945,000	6,319,612	374,612
18	Other O&M	(7,079,000)	482,770	7,561,770
19	PUC, OCA, OSBA Fees	2,420,000	2,031,807	(388,193)
20	NCSC	66,692,105	64,057,477	(2,634,629)
23	NCSC OPEB costs Amortization	90,000	90,000	-
25	Lobbying	(174,014)	-	174,014
27	**Operation and Maintenance Expense from Budget**	**152,455,147**	**161,299,469**	**8,844,322**
28	Rate Case Expense	1,060,000	-	(1,060,000)
29	Uncollectible Accounts	4,733,676	3,920,077	(813,599)
30	Uncollectible Accounts -Unbundled-gas	1,216,174	1,204,274	(11,900)
31	Total Rider USP	29,305,816	29,274,327	(31,489)
32	Interest on Customer Deposits	108,514	-	(108,514)
33	Other Adjustments	166,316	-	(166,316)
34	**Total Operation and Maintenance Expense**	**189,045,643**	**195,698,146**	**6,652,503**

1_/ Updated to relect settlement amount using a 10 year amortization.

COLUMBIA STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

April 24, 2020

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 33 years of depreciation experience which includes expert testimony in over 320 cases before approximately 41 regulatory commissions, including the Pennsylvania Public Utility Commission ("Commission"). Please refer to Appendix A for my qualifications.

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, 2019. Exhibit No. 109, Schedule No. 1, Attachment A presents the results of the depreciation study as of November 30, 2020. Exhibit No. 109, Schedule No. 1, Attachment B presents the results of the depreciation study as of December 31, 2021. 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 "2019 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2019," includes the results of the depreciation study as related to the original cost at November 30, 2019. The report also includes the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment A, 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 estimated original cost at November 30, 2020. 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 “2021 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2021,” includes the results of the depreciation study as related to the estimated original cost at December 31, 2021.

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, 2020, and December 31, 2021.

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, 2020, estimated?

A. The book reserve at November 30, 2020, 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, 2019. Annual accruals were estimated using the annual accruals calculated as of November 30, 2019. 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, 2020.

Q. Was the book reserve at December 31, 2021, 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 and for other gas companies before the 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 this 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 2015 through 2019.

Table 1, pages V-4 through V-6 presents the estimated survivor curve, the original cost at November 30, 2020, 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, 2020, of the book depreciation reserve as of November 30, 2019. 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, 2015 through 2019.

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, 2021. The descriptions and explanations presented in Exhibit No. 109, Schedule No. 1, Attachment A are also applicable to the depreciation calculations presented in Exhibit No. 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, 2021, are organized and presented in the same manner as those as of November 30, 2020.

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, 2019. 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, 2019, are organized and presented in the same manner as those as of November 30, 2020.

Q. Please use an example to illustrate the manner in which the study is presented in Exhibit Nos. 9, and 109.

A. I will use Account 376, Mains, as my example, inasmuch as it is the largest depreciable group and represents 67 percent of the original cost of depreciable gas plant as of November 30, 2020.

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, 2019, 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, 2020, 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, 2021 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 2014 through 2018 for the calculation as of November 30, 2019, and on experience during the period 2015 through November 30, 2019, plus estimates for the last month of 2019 for the calculation as of November 30, 2020.

The amortization for the December 31, 2021 calculation is based on experience during the period 2016 through November 30, 2019, plus estimates for the period December 2019 through December 2020. 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-11 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, 2021, of the book depreciation reserve as of November 30, 2020?

A. Yes, Exhibit JJS-01 at the end of this testimony provides the monthly detail of the book depreciation reserve and the calculated depreciation. This exhibit agrees with the fully projected future test year reserve balance 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

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	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.		Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

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	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	09-	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		Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC		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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	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		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		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.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-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	NJ BPU	Docket No. ER20-___-000	Jersey Central Power & Light Company	Depreciation

RESERVE BRINGFORWARD

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

			PROJECTED 20			PROJECTED 2021		
Account	2020 NOV 30 Begin. Balance	'Accrual Rates 2020	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2015-2019	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2016-2020
350.20	1,931	0.00						
351.20	2,050,584	7.98			4,287			4,287
352.01	738,926	0.00						
352.02	168,032	0.00						
352.10	206,932	0.00						
353.00	388,775	0.03			171			171
354.00	793,999	3.59						
355.00	104,477	0.00						
374.40	768,179	1.69	0.82		9,729	0.82		12,954
374.50	1,759,636	1.08			2,982			
375.34	1,422,564	2.17	0.32		22,332	0.32		25,212
375.60	74,852	0.63			104			104
375.70	3,562,970	3.03	0.11		4,428	0.11		1,289
375.80	7,890	2.20						
376.00	267,915,997	2.20	0.10		1,269,253	0.10		1,459,708
378.00	15,666,843	4.11	0.26		196,673	0.26		291,029
379.10	50,233	6.71			15,264			15,264
380.00	134,373,865	2.99	0.36		2,864,061	0.36		2,807,800
381.00	17,414,364	2.38		0.12	(60,916)		0.12	(64,052)
381.10	15,387,694	6.21						
382.00	14,321,303	1.89			2			2
383.00	7,551,755	1.99						
385.00	2,813,642	4.75	0.47		103,571	0.47		107,920
387.00	75,217	3.89						
387.40	2,297,595	4.88	0.03		2,096	0.03		1,884
387.50	1,297,985	11.01						
390.10	49,821	0.00						
391.10	1,119,655	3.72						
391.11	41,169	6.42						
391.12	3,305,389	14.87						
392.00	18,335	3.91		0.34	(8,019)		0.34	(2,791)
394.00	7,112,620	3.59			(437)			(437)
395.00	73,171	5.13						
396.00	882,539	2.09		0.59	(57,100)		0.59	(35,221)
397.50	696,012	3.55	0.32		5,932	0.32		4,952
398.00	433,014	6.04						
303.00	16,491,630							
303.60	1,983,415							
362.10	(152,362)				65,329			53,954
375.71	2,436,130							
389.20								
Total	**525,706,778**				**4,439,742**			**4,684,029**

	2020							
	DECEMBER							
Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,072,360
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		388,799
354.00	2,837	0	2,837	0	0	0		796,836
355.00	0	0	0	0	0	0		104,477
374.40	4,873	811	5,684	2,297	1,884	0		769,682
374.50	2,910	249	3,158	0	0	0		1,762,794
375.34	10,149	1,861	12,010	4,499	1,440	0		1,428,636
375.60	45	9	54	0	0	0		74,906
375.70	45,412	369	45,781	4,127	454	0		3,604,170
375.80	30	0	30	0	0	0		7,920
376.00	3,579,322	105,771	3,685,094	1,105,997	110,600	0		270,384,494
378.00	401,003	16,389	417,393	279,630	72,704	0		15,731,902
379.10	760	1,272	2,032	0	0	0		52,265
380.00	1,608,952	238,672	1,847,624	559,723	201,500	0		135,460,266
381.00	79,782	(5,076)	74,706	13,066	0	1,568		17,477,572
381.10	128,105	0	128,105	0	0	0		15,515,799
382.00	66,477	0	66,477	18,445	0	0		14,369,335
383.00	28,953	0	28,953	2,298	0	0		7,578,409
385.00	32,756	8,631	41,387	10,529	4,949	0		2,839,551
387.00	443	0	443	0	0	0		75,660
387.40	42,807	175	42,982	0	0	0		2,340,577
387.50	20,198	0	20,198	0	0	0		1,318,183
390.10	0	0	0	0	0	0		49,821
391.10	7,243	0	7,243	90,789	0	0		1,036,109
391.11	488	0	488	0	0	0		41,657
391.12	46,101	0	46,101	941,918	0	0		2,409,572
392.00	83	(668)	(585)	0	0	0		17,750
394.00	52,756	(36)	52,719	162,417	0	0		7,002,922
395.00	1,144	0	1,144	2,990	0	0		71,324
396.00	1,652	(4,758)	(3,106)	0	0	0		879,433
397.50	4,219	494	4,713	7,657	2,450	0		690,617
398.00	4,843	0	4,843	17,913	0	0		419,944
303.00	443,327	0	443,327	296,400	0	0		16,638,557
303.60	242,230	0	242,230	0	0	0		2,225,645
362.10	0	5,444	5,444	0	0	0		(146,918)
375.71	68,534	0	68,534	3,965	0	0		2,500,699
389.20	0	0	0	0	0	0		0
Total	**6,949,864**	**369,979**	**7,319,843**	**3,524,661**	**395,980**	**1,568**	**0**	**529,107,548**

Account	2021							
	JANUARY							
	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,094,136
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		388,823
354.00	2,837	0	2,837	0	0	0		799,673
355.00	0	0	0	0	0	0		104,477
374.40	4,911	1,080	5,991	1,675	1,373	0		772,625
374.50	2,910	0	2,910	0	0	0		1,765,704
375.34	10,245	2,101	12,346	2,849	912	0		1,437,221
375.60	45	9	54	0	0	0		74,960
375.70	45,661	107	45,768	2,553	281	0		3,647,104
375.80	30	0	30	0	0	0		7,951
376.00	3,621,230	121,642	3,742,873	1,276,201	127,620	0		272,723,546
378.00	410,952	24,252	435,204	150,795	39,207	0		15,977,104
379.10	760	1,272	2,032	0	0	0		54,298
380.00	1,630,899	233,983	1,864,882	506,658	182,397	0		136,636,093
381.00	80,039	(5,338)	74,701	8,777	0	1,053		17,544,549
381.10	128,233	0	128,233	0	0	0		15,644,032
382.00	66,819	0	66,819	12,639	0	0		14,423,515
383.00	28,998	0	28,998	1,866	0	0		7,605,541
385.00	33,246	8,993	42,240	6,385	3,001	0		2,872,404
387.00	443	0	443	0	0	0		76,103
387.40	42,807	157	42,964	0	0	0		2,383,541
387.50	20,198	0	20,198	0	0	0		1,338,380
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,043,212
391.11	488	0	488	0	0	0		42,146
391.12	40,265	0	40,265	0	0	0		2,449,837
392.00	83	(233)	(149)	0	0	0		17,601
394.00	52,945	(36)	52,908	0	0	0		7,055,830
395.00	1,137	0	1,137	0	0	0		72,462
396.00	1,652	(2,935)	(1,283)	0	0	0		878,150
397.50	4,497	413	4,910	7,762	2,484	0		685,281
398.00	4,798	0	4,798	0	0	0		424,742
303.00	443,327	0	443,327	117,100	0	0		16,964,783
303.60	242,230	0	242,230	0	0	0		2,467,876
362.10	0	4,496	4,496	0	0	0		(142,422)
375.71	68,534	0	68,534	2,453	0	0		2,566,780
389.20	0	0	0	0	0	0		0
Total	**7,019,752**	**390,336**	**7,410,088**	**2,097,715**	**357,275**	**1,053**	**0**	**534,063,700**

	2021							
	FEBRUARY							
Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,115,912
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		388,847
354.00	2,837	0	2,837	0	0	0		802,510
355.00	0	0	0	0	0	0		104,477
374.40	4,918	1,080	5,997	1,424	1,168	0		776,030
374.50	2,910	0	2,910	0	0	0		1,768,614
375.34	10,261	2,101	12,362	3,043	974	0		1,445,566
375.60	45	9	54	0	0	0		75,014
375.70	45,653	107	45,761	3,371	371	0		3,689,123
375.80	30	0	30	0	0	0		7,981
376.00	3,629,227	121,642	3,750,869	1,511,858	151,186	0		274,811,371
378.00	412,694	24,252	436,946	175,312	45,581	0		16,193,157
379.10	760	1,272	2,032	0	0	0		56,330
380.00	1,635,141	233,983	1,869,124	585,845	210,904	0		137,708,468
381.00	80,083	(5,338)	74,745	9,324	0	1,119		17,611,089
381.10	128,261	0	128,261	0	0	0		15,772,293
382.00	66,881	0	66,881	12,919	0	0		14,477,477
383.00	29,007	0	29,007	1,773	0	0		7,632,775
385.00	33,330	8,993	42,324	7,290	3,426	0		2,904,012
387.00	443	0	443	0	0	0		76,546
387.40	42,807	157	42,964	0	0	0		2,426,505
387.50	20,198	0	20,198	0	0	0		1,358,578
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,050,316
391.11	488	0	488	0	0	0		42,634
391.12	40,265	0	40,265	0	0	0		2,490,103
392.00	83	(233)	(149)	0	0	0		17,452
394.00	53,037	(36)	53,000	0	0	0		7,108,830
395.00	1,137	0	1,137	0	0	0		73,599
396.00	1,652	(2,935)	(1,283)	0	0	0		876,867
397.50	4,577	413	4,990	9,493	3,038	0		677,740
398.00	4,798	0	4,798	0	0	0		429,540
303.00	443,327	0	443,327	111,700	0	0		17,296,410
303.60	242,230	0	242,230	0	0	0		2,710,106
362.10	0	4,496	4,496	0	0	0		(137,926)
375.71	68,534	0	68,534	3,239	0	0		2,632,074
389.20	0	0	0	0	0	0		0
Total	**7,034,147**	**390,336**	**7,424,483**	**2,436,592**	**416,648**	**1,119**	**0**	**538,636,062**

Account	2021							
	MARCH							
	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,137,688
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		388,871
354.00	2,837	0	2,837	0	0	0		805,347
355.00	0	0	0	0	0	0		104,477
374.40	4,930	1,080	6,009	1,318	1,081	0		779,640
374.50	2,910	0	2,910	0	0	0		1,771,524
375.34	10,291	2,101	12,392	3,576	1,144	0		1,453,238
375.60	45	9	54	0	0	0		75,068
375.70	45,644	107	45,751	4,077	449	0		3,730,348
375.80	30	0	30	0	0	0		8,011
376.00	3,643,419	121,642	3,765,061	1,921,701	192,170	0		276,462,561
378.00	415,797	24,252	440,049	219,909	57,176	0		16,356,121
379.10	760	1,272	2,032	0	0	0		58,362
380.00	1,642,705	233,983	1,876,688	732,017	263,526	0		138,589,613
381.00	80,165	(5,338)	74,827	10,907	0	1,309		17,676,317
381.10	128,308	0	128,308	0	0	0		15,900,601
382.00	66,993	0	66,993	14,614	0	0		14,529,857
383.00	29,024	0	29,024	1,868	0	0		7,659,931
385.00	33,481	8,993	42,474	9,025	4,242	0		2,933,220
387.00	443	0	443	0	0	0		76,990
387.40	42,807	157	42,964	0	0	0		2,469,469
387.50	20,198	0	20,198	0	0	0		1,378,775
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,057,418
391.11	488	0	488	0	0	0		43,123
391.12	40,265	0	40,265	0	0	0		2,530,368
392.00	83	(233)	(149)	0	0	0		17,303
394.00	53,187	(36)	53,151	0	0	0		7,161,981
395.00	1,137	0	1,137	0	0	0		74,737
396.00	1,652	(2,935)	(1,283)	0	0	0		875,585
397.50	4,719	413	5,131	12,329	3,945	0		666,596
398.00	4,798	0	4,798	0	0	0		434,338
303.00	443,327	0	443,327	269,800	0	0		17,469,937
303.60	242,230	0	242,230	0	0	0		2,952,337
362.10	0	4,496	4,496	0	0	0		(133,429)
375.71	68,534	0	68,534	3,918	0	0		2,696,690
389.20	0	0	0	0	0	0		0
Total	**7,059,740**	**390,336**	**7,450,075**	**3,205,060**	**523,733**	**1,309**	**0**	**542,358,655**

	2021							
	APRIL							
Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,159,464
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		388,895
354.00	2,837	0	2,837	0	0	0		808,184
355.00	0	0	0	0	0	0		104,477
374.40	4,946	1,080	6,025	1,271	1,042	0		783,353
374.50	2,910	0	2,910	0	0	0		1,774,434
375.34	10,330	2,101	12,431	3,382	1,082	0		1,461,205
375.60	45	9	54	0	0	0		75,122
375.70	45,633	107	45,740	4,598	506	0		3,770,984
375.80	30	0	30	0	0	0		8,041
376.00	3,661,797	121,642	3,783,439	1,807,514	180,751	0		278,257,735
378.00	419,817	24,252	444,070	207,027	53,827	0		16,539,338
379.10	760	1,272	2,032	0	0	0		60,394
380.00	1,652,507	233,983	1,886,490	689,319	248,155	0		139,538,630
381.00	80,272	(5,338)	74,935	10,319	0	1,238		17,742,171
381.10	128,368	0	128,368	0	0	0		16,028,969
382.00	67,139	0	67,139	13,859	0	0		14,583,137
383.00	29,046	0	29,046	1,782	0	0		7,687,195
385.00	33,676	8,993	42,669	8,504	3,997	0		2,963,389
387.00	443	0	443	0	0	0		77,433
387.40	42,807	157	42,964	0	0	0		2,512,433
387.50	20,198	0	20,198	0	0	0		1,398,973
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,064,521
391.11	488	0	488	0	0	0		43,611
391.12	40,265	0	40,265	0	0	0		2,570,633
392.00	83	(233)	(149)	0	0	0		17,154
394.00	53,377	(36)	53,340	0	0	0		7,215,322
395.00	1,137	0	1,137	0	0	0		75,875
396.00	1,652	(2,935)	(1,283)	0	0	0		874,302
397.50	4,902	413	5,315	11,580	3,706	0		656,625
398.00	4,798	0	4,798	0	0	0		439,136
303.00	443,327	0	443,327	144,700	0	0		17,768,563
303.60	242,230	0	242,230	0	0	0		3,194,567
362.10	0	4,496	4,496	0	0	0		(128,933)
375.71	68,534	0	68,534	4,418	0	0		2,760,806
389.20	0	0	0	0	0	0		0
Total	**7,092,885**	**390,336**	**7,483,221**	**2,908,272**	**493,066**	**1,238**	**0**	**546,441,776**

	2021							
	MAY							
Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,181,240
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		388,919
354.00	2,837	0	2,837	0	0	0		811,020
355.00	0	0	0	0	0	0		104,477
374.40	4,964	1,080	6,044	1,539	1,262	0		786,596
374.50	2,910	0	2,910	0	0	0		1,777,344
375.34	10,374	2,101	12,475	3,606	1,154	0		1,468,920
375.60	45	9	54	0	0	0		75,176
375.70	45,620	107	45,728	5,308	584	0		3,810,820
375.80	30	0	30	0	0	0		8,072
376.00	3,682,920	121,642	3,804,563	1,852,206	185,221	0		280,024,871
378.00	424,433	24,252	448,686	213,550	55,523	0		16,718,950
379.10	760	1,272	2,032	0	0	0		62,427
380.00	1,663,757	233,983	1,897,740	712,428	256,474	0		140,467,468
381.00	80,395	(5,338)	75,058	11,027	0	1,323		17,807,525
381.10	128,434	0	128,434	0	0	0		16,157,403
382.00	67,305	0	67,306	15,069	0	0		14,635,373
383.00	29,071	0	29,071	2,010	0	0		7,714,255
385.00	33,900	8,993	42,893	8,830	4,150	0		2,993,302
387.00	443	0	443	0	0	0		77,876
387.40	42,807	157	42,964	0	0	0		2,555,397
387.50	20,198	0	20,198	0	0	0		1,419,171
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,071,624
391.11	488	0	488	0	0	0		44,100
391.12	40,265	0	40,265	0	0	0		2,610,898
392.00	83	(233)	(149)	0	0	0		17,005
394.00	53,589	(36)	53,553	0	0	0		7,268,875
395.00	1,137	0	1,137	0	0	0		77,012
396.00	1,652	(2,935)	(1,283)	0	0	0		873,019
397.50	5,113	413	5,526	11,741	3,757	0		646,653
398.00	4,798	0	4,798	0	0	0		443,935
303.00	443,327	0	443,327	478,600	0	0		17,733,290
303.60	242,230	0	242,230	0	0	0		3,436,797
362.10	0	4,496	4,496	0	0	0		(124,437)
375.71	68,534	0	68,534	5,100	0	0		2,824,240
389.20	0	0	0	0	0	0		0
Total	**7,130,953**	**390,336**	**7,521,289**	**3,321,014**	**508,124**	**1,323**	**0**	**550,135,251**

	2021							
	JUNE							
Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,203,016
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		388,943
354.00	2,837	0	2,837	0	0	0		813,857
355.00	0	0	0	0	0	0		104,477
374.40	4,984	1,080	6,063	1,664	1,364	0		789,631
374.50	2,910	0	2,910	0	0	0		1,780,253
375.34	10,422	2,101	12,523	4,068	1,302	0		1,476,072
375.60	45	9	54	0	0	0		75,230
375.70	45,864	107	45,971	5,778	636	0		3,850,378
375.80	30	0	30	0	0	0		8,102
376.00	3,706,029	121,642	3,827,671	2,119,447	211,945	0		281,521,150
378.00	429,481	24,252	453,734	243,786	63,384	0		16,865,514
379.10	760	1,272	2,032	0	0	0		64,459
380.00	1,676,059	233,983	1,910,042	812,732	292,584	0		141,272,195
381.00	80,529	(5,338)	75,192	12,433	0	1,492		17,871,776
381.10	128,506	0	128,506	0	0	0		16,285,909
382.00	67,487	0	67,487	16,888	0	0		14,685,972
383.00	29,098	0	29,098	2,225	0	0		7,741,128
385.00	34,144	8,993	43,138	10,056	4,726	0		3,021,658
387.00	443	0	443	0	0	0		78,319
387.40	42,807	157	42,964	0	0	0		2,598,362
387.50	20,198	0	20,198	0	0	0		1,439,368
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,078,726
391.11	488	0	488	0	0	0		44,588
391.12	40,265	0	40,265	0	0	0		2,651,162
392.00	83	(233)	(149)	0	0	0		16,856
394.00	53,822	(36)	53,786	0	0	0		7,322,660
395.00	1,137	0	1,137	0	0	0		78,149
396.00	1,652	(2,935)	(1,283)	0	0	0		871,736
397.50	5,344	413	5,756	13,486	4,316	0		634,607
398.00	4,798	0	4,798	0	0	0		448,733
303.00	443,327	0	443,327	83,500	0	0		18,093,117
303.60	242,230	0	242,230	0	0	0		3,679,028
362.10	0	4,496	4,496	0	0	0		(119,941)
375.71	68,534	0	68,534	5,551	0	0		2,887,222
389.20	0	0	0	0	0	0		0
Total	**7,172,846**	**390,336**	**7,563,182**	**3,331,614**	**580,256**	**1,492**	**0**	**553,788,054**

	2021							
	JULY							
Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,224,792
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		388,967
354.00	2,837	0	2,837	0	0	0		816,694
355.00	0	0	0	0	0	0		104,477
374.40	5,005	1,080	6,084	1,914	1,570	0		792,232
374.50	2,910	0	2,910	0	0	0		1,783,163
375.34	10,473	2,101	12,574	4,094	1,310	0		1,483,242
375.60	45	9	54	0	0	0		75,283
375.70	46,107	107	46,215	5,481	603	0		3,890,509
375.80	30	0	30	0	0	0		8,132
376.00	3,730,892	121,642	3,852,535	2,034,847	203,485	0		283,135,353
378.00	434,910	24,252	459,163	235,939	61,344	0		17,027,393
379.10	760	1,272	2,032	0	0	0		66,491
380.00	1,689,287	233,983	1,923,271	788,426	283,833	0		142,123,206
381.00	80,673	(5,338)	75,336	12,544	0	1,505		17,936,073
381.10	128,584	0	128,584	0	0	0		16,414,494
382.00	67,682	0	67,682	17,377	0	0		14,736,277
383.00	29,127	0	29,127	2,384	0	0		7,767,871
385.00	34,407	8,993	43,400	9,810	4,611	0		3,050,637
387.00	443	0	443	0	0	0		78,762
387.40	42,807	157	42,964	0	0	0		2,641,326
387.50	20,198	0	20,198	0	0	0		1,459,566
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,085,829
391.11	488	0	488	0	0	0		45,077
391.12	40,265	0	40,265	0	0	0		2,691,428
392.00	83	(233)	(149)	0	0	0		16,706
394.00	54,071	(36)	54,035	0	0	0		7,376,696
395.00	1,137	0	1,137	0	0	0		79,287
396.00	1,652	(2,935)	(1,283)	0	0	0		870,454
397.50	5,592	413	6,005	12,779	4,089	0		623,744
398.00	4,798	0	4,798	0	0	0		453,531
303.00	443,327	0	443,327	28,300	0	0		18,508,144
303.60	242,230	0	242,230	0	0	0		3,921,258
362.10	0	4,496	4,496	0	0	0		(115,445)
375.71	68,534	0	68,534	5,266	0	0		2,950,490
389.20	0	0	0	0	0	0		0
Total	**7,217,890**	**390,336**	**7,608,225**	**3,159,160**	**560,845**	**1,505**	**0**	**557,677,781**

Account	2021							
	AUGUST							
	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,246,568
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		388,991
354.00	2,837	0	2,837	0	0	0		819,531
355.00	0	0	0	0	0	0		104,477
374.40	5,027	1,080	6,107	2,460	2,017	0		793,861
374.50	2,910	0	2,910	0	0	0		1,786,073
375.34	10,530	2,101	12,631	4,519	1,446	0		1,489,908
375.60	45	9	54	0	0	0		75,337
375.70	46,093	107	46,200	6,227	685	0		3,929,797
375.80	30	0	30	0	0	0		8,163
376.00	3,758,540	121,642	3,880,182	2,103,914	210,391	0		284,701,231
378.00	440,938	24,252	465,190	246,809	64,170	0		17,181,604
379.10	760	1,272	2,032	0	0	0		68,524
380.00	1,703,968	233,983	1,937,951	827,544	297,916	0		142,935,698
381.00	80,832	(5,338)	75,495	13,893	0	1,667		17,999,341
381.10	128,669	0	128,669	0	0	0		16,543,163
382.00	67,895	0	67,896	19,733	0	0		14,784,440
383.00	29,159	0	29,159	2,841	0	0		7,794,188
385.00	34,699	8,993	43,692	10,379	4,878	0		3,079,072
387.00	443	0	443	0	0	0		79,205
387.40	42,807	157	42,964	0	0	0		2,684,290
387.50	20,198	0	20,198	0	0	0		1,479,763
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,092,932
391.11	488	0	488	0	0	0		45,565
391.12	40,265	0	40,265	0	0	0		2,731,693
392.00	83	(233)	(149)	0	0	0		16,557
394.00	54,344	(36)	54,308	0	0	0		7,431,004
395.00	1,137	0	1,137	0	0	0		80,424
396.00	1,652	(2,935)	(1,283)	0	0	0		869,171
397.50	5,870	413	6,282	12,956	4,146	0		612,924
398.00	4,798	0	4,798	0	0	0		458,329
303.00	443,327	0	443,327	2,971,100	0	0		15,980,370
303.60	242,230	0	242,230	0	0	0		4,163,488
362.10	0	4,496	4,496	0	0	0		(110,949)
375.71	68,534	0	68,534	5,982	0	0		3,013,042
389.20	0	0	0	0	0	0		0
Total	**7,267,642**	**390,336**	**7,657,977**	**6,228,358**	**585,650**	**1,667**	**0**	**558,523,416**

	2021							
	SEPTEMBER							
Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,268,344
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		389,015
354.00	2,837	0	2,837	0	0	0		822,368
355.00	0	0	0	0	0	0		104,477
374.40	5,052	1,080	6,131	2,335	1,915	0		795,742
374.50	2,910	0	2,910	0	0	0		1,788,983
375.34	10,592	2,101	12,693	4,295	1,374	0		1,496,933
375.60	45	9	54	0	0	0		75,391
375.70	64,010	107	64,117	6,081	669	0		3,987,164
375.80	30	0	30	0	0	0		8,193
376.00	3,788,883	121,642	3,910,526	2,000,639	200,064	0		286,411,053
378.00	447,548	24,252	471,801	234,668	61,014	0		17,357,723
379.10	760	1,272	2,032	0	0	0		70,556
380.00	1,720,065	233,983	1,954,048	786,809	283,251	0		143,819,685
381.00	81,006	(5,338)	75,669	13,203	0	1,584		18,063,391
381.10	128,762	0	128,762	0	0	0		16,671,925
382.00	68,129	0	68,129	18,748	0	0		14,833,821
383.00	29,193	0	29,193	2,698	0	0		7,820,683
385.00	35,018	8,993	44,011	9,868	4,638	0		3,108,578
387.00	443	0	443	0	0	0		79,648
387.40	42,807	157	42,964	0	0	0		2,727,255
387.50	20,198	0	20,198	0	0	0		1,499,961
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,100,035
391.11	488	0	488	0	0	0		46,054
391.12	40,265	0	40,265	0	0	0		2,771,958
392.00	83	(233)	(149)	0	0	0		16,408
394.00	54,641	(36)	54,604	0	0	0		7,485,608
395.00	1,137	0	1,137	0	0	0		81,561
396.00	1,652	(2,935)	(1,283)	0	0	0		867,888
397.50	6,174	413	6,587	12,323	3,943	0		603,245
398.00	4,798	0	4,798	0	0	0		463,127
303.00	443,327	0	443,327	14,800	0	0		16,408,897
303.60	242,230	0	242,230	0	0	0		4,405,719
362.10	0	4,496	4,496	0	0	0		(106,452)
375.71	68,534	0	68,534	5,843	0	0		3,075,733
389.20	0	0	0	0	0	0		0
Total	**7,340,151**	**390,336**	**7,730,486**	**3,112,309**	**556,868**	**1,584**	**0**	**562,586,311**

	2021							
	OCTOBER							
Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,290,120
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		389,039
354.00	2,837	0	2,837	0	0	0		825,205
355.00	0	0	0	0	0	0		104,477
374.40	5,092	1,080	6,171	2,341	1,919	0		797,653
374.50	2,910	0	2,910	0	0	0		1,791,893
375.34	10,693	2,101	12,794	4,243	1,358	0		1,504,126
375.60	45	9	54	0	0	0		75,446
375.70	81,927	107	82,035	5,707	628	0		4,062,864
375.80	30	0	30	0	0	0		8,223
376.00	3,838,096	121,642	3,959,738	1,962,975	196,297	0		288,211,519
378.00	458,272	24,252	482,524	230,544	59,942	0		17,549,761
379.10	760	1,272	2,032	0	0	0		72,588
380.00	1,746,180	233,983	1,980,163	773,268	278,376	0		144,748,204
381.00	81,292	(5,338)	75,954	13,049	0	1,566		18,127,862
381.10	128,905	0	128,905	0	0	0		16,800,830
382.00	68,508	0	68,508	18,577	0	0		14,883,751
383.00	29,249	0	29,249	2,686	0	0		7,847,246
385.00	35,536	8,993	44,530	9,706	4,562	0		3,138,840
387.00	443	0	443	0	0	0		80,091
387.40	42,807	157	42,964	0	0	0		2,770,219
387.50	20,198	0	20,198	0	0	0		1,520,158
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,107,137
391.11	488	0	488	0	0	0		46,542
391.12	40,265	0	40,265	0	0	0		2,812,223
392.00	83	(233)	(149)	0	0	0		16,259
394.00	55,100	(36)	55,064	0	0	0		7,540,672
395.00	1,137	0	1,137	0	0	0		82,699
396.00	1,652	(2,935)	(1,283)	0	0	0		866,605
397.50	6,668	413	7,081	12,064	3,861	0		594,401
398.00	4,798	0	4,798	0	0	0		467,925
303.00	443,327	0	443,327	214,500	0	0		16,637,724
303.60	242,230	0	242,230	0	0	0		4,647,949
362.10	0	4,496	4,496	0	0	0		(101,956)
375.71	68,534	0	68,534	5,483	0	0		3,138,784
389.20	0	0	0	0	0	0		0
Total	**7,446,596**	**390,336**	**7,836,931**	**3,255,143**	**546,943**	**1,566**	**0**	**566,622,724**

	2021							
	NOVEMBER							
Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,311,895
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		389,063
354.00	2,837	0	2,837	0	0	0		828,042
355.00	0	0	0	0	0	0		104,477
374.40	5,131	1,080	6,211	2,506	2,055	0		799,304
374.50	2,910	0	2,910	0	0	0		1,794,803
375.34	10,794	2,101	12,895	3,731	1,194	0		1,512,096
375.60	45	9	54	0	0	0		75,500
375.70	81,913	107	82,021	5,271	580	0		4,139,034
375.80	30	0	30	0	0	0		8,253
376.00	3,887,102	121,642	4,008,744	1,543,171	154,317	0		290,522,776
378.00	468,944	24,252	493,196	185,199	48,152	0		17,809,607
379.10	760	1,272	2,032	0	0	0		74,620
380.00	1,772,163	233,983	2,006,147	624,990	224,996	0		145,904,365
381.00	81,575	(5,338)	76,237	11,536	0	1,384		18,193,947
381.10	129,047	0	129,047	0	0	0		16,929,877
382.00	68,883	0	68,883	17,048	0	0		14,935,587
383.00	29,305	0	29,305	2,632	0	0		7,873,919
385.00	36,052	8,993	45,045	7,957	3,740	0		3,172,189
387.00	443	0	443	0	0	0		80,535
387.40	42,807	157	42,964	0	0	0		2,813,183
387.50	20,198	0	20,198	0	0	0		1,540,356
390.10	0	0	0	0	0	0		49,821
391.10	7,103	0	7,103	0	0	0		1,114,240
391.11	488	0	488	0	0	0		47,031
391.12	40,265	0	40,265	0	0	0		2,852,488
392.00	83	(233)	(149)	0	0	0		16,110
394.00	55,554	(36)	55,518	0	0	0		7,596,189
395.00	1,137	0	1,137	0	0	0		83,836
396.00	1,652	(2,935)	(1,283)	0	0	0		865,323
397.50	7,160	413	7,573	9,129	2,921	0		589,924
398.00	4,798	0	4,798	0	0	0		472,723
303.00	443,327	0	443,327	86,300	0	0		16,994,750
303.60	242,230	0	242,230	0	0	0		4,890,180
362.10	0	4,496	4,496	0	0	0		(97,460)
375.71	68,534	0	68,534	5,065	0	0		3,202,253
389.20	0	0	0	0	0	0		0
Total	**7,534,700**	**390,336**	**7,925,036**	**2,504,533**	**437,954**	**1,384**	**0**	**571,606,657**

Account	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Acquisitions	Ending Balance
	2021							
	DECEMBER							
350.20	0	0	0	0	0	0		1,931
351.20	21,419	357	21,776	0	0	0		2,333,671
352.01	0	0	0	0	0	0		738,926
352.02	0	0	0	0	0	0		168,032
352.10	0	0	0	0	0	0		206,932
353.00	10	14	24	0	0	0		389,087
354.00	2,837	0	2,837	0	0	0		830,879
355.00	0	0	0	0	0	0		104,477
374.40	5,179	1,080	6,259	2,526	2,072	0		800,965
374.50	2,910	0	2,910	0	0	0		1,797,713
375.34	10,917	2,101	13,018	3,582	1,146	0		1,520,387
375.60	45	9	54	0	0	0		75,554
375.70	82,159	107	82,266	4,127	454	0		4,216,720
375.80	30	0	30	0	0	0		8,284
376.00	3,947,523	121,642	4,069,166	1,431,805	143,180	0		293,016,956
378.00	482,097	24,252	506,349	173,032	44,988	0		18,097,936
379.10	760	1,272	2,032	0	0	0		76,653
380.00	1,804,184	233,983	2,038,167	585,059	210,621	0		147,146,852
381.00	81,924	(5,338)	76,586	11,090	0	1,331		18,260,775
381.10	129,218	0	129,218	0	0	0		17,059,095
382.00	69,345	0	69,345	16,557	0	0		14,988,375
383.00	29,373	0	29,373	2,599	0	0		7,900,693
385.00	36,687	8,993	45,680	7,481	3,516	0		3,206,871
387.00	443	0	443	0	0	0		80,978
387.40	42,807	157	42,964	0	0	0		2,856,147
387.50	20,198	0	20,198	0	0	0		1,560,554
390.10	0	0	0	0	0	0		49,821
391.10	6,833	0	6,833	173,687	0	0		947,386
391.11	488	0	488	0	0	0		47,519
391.12	30,998	0	30,998	1,495,727	0	0		1,387,760
392.00	83	(233)	(149)	0	0	0		15,961
394.00	55,277	(36)	55,240	552,198	0	0		7,099,231
395.00	1,137	0	1,137	0	0	0		84,973
396.00	1,652	(2,935)	(1,283)	0	0	0		864,040
397.50	7,767	413	8,180	8,363	2,676	0		587,065
398.00	4,777	0	4,777	8,228	0	0		469,273
303.00	443,327	0	443,327	461,200	0	0		16,976,877
303.60	242,230	0	242,230	0	0	0		5,132,410
362.10	0	4,496	4,496	0	0	0		(92,964)
375.71	68,534	0	68,534	3,965	0	0		3,266,822
389.20	0	0	0	0	0	0		0
Total	**7,633,170**	**390,336**	**8,023,506**	**4,941,225**	**408,654**	**1,331**	**0**	**574,281,617**

CPA PLANT BRINGFORWARD

	2020	2020			2021		
	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	3,220,858.29			3,220,858.29			3,220,858.29
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	948,272.21			948,272.21			948,272.21
355.00	104,476.92			104,476.92			104,476.92
374.40	3,434,803.99	53,449.71	2,297.24	3,485,956.46	4,325.36	1,674.70	3,488,607.12
374.50	3,233,171.42			3,233,171.42			3,233,171.42
375.34	5,562,420.97	104,672.35	4,498.77	5,662,594.55	8,470.51	2,849.48	5,668,215.58
375.60	86,227.87			86,227.87			86,227.87
375.70	17,884,877.63	204,000.00	4,126.56	18,084,751.07		2,553.40	18,082,197.67
375.80	16,515.17			16,515.17			16,515.17
376.00	1,930,890,960.24	44,039,460.08	1,105,996.75	1,973,824,423.57	4,060,607.13	1,276,200.82	1,976,608,829.88
378.00	114,338,019.45	5,766,068.11	279,630.14	119,824,457.42	473,832.51	150,795.20	120,147,494.73
379.10	135,966.90			135,966.90			135,966.90
380.00	637,465,204.96	17,096,053.53	559,723.14	654,001,535.35	1,586,318.97	506,658.22	655,081,196.10
381.00	40,103,640.54	258,395.94	13,065.57	40,348,970.91	22,102.40	8,777.40	40,362,295.91
381.10	24,731,741.62	45,599.29		24,777,340.91	3,900.43		24,781,241.34
382.00	42,002,191.28	429,156.64	18,444.95	42,412,902.97	36,532.35	12,639.17	42,436,796.15
383.00	17,433,228.84	53,469.31	2,298.08	17,484,400.07	5,152.14	1,865.78	17,487,686.43
385.00	8,157,871.91	244,977.85	10,529.03	8,392,320.73	19,824.59	6,385.29	8,405,760.03
387.00	136,698.14			136,698.14			136,698.14
387.40	10,526,342.87			10,526,342.87			10,526,342.87
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	2,381,980.24		90,789.14	2,291,191.10			2,291,191.10
391.11	91,303.67			91,303.67			91,303.67
391.12	4,191,295.25		941,918.01	3,249,377.24			3,249,377.24
392.00	25,616.89			25,616.89			25,616.89
394.00	17,581,806.31	267,248.56	162,417.47	17,686,637.40	21,626.82		17,708,264.22
395.00	269,029.81		2,990.39	266,039.42			266,039.42
396.00	948,698.04			948,698.04			948,698.04
397.50	1,340,832.67	178,165.70	7,657.48	1,511,340.89	25,231.29	7,761.77	1,528,810.41
398.00	971,182.92		17,913.22	953,269.70			953,269.70
303.00	35,867,794.52	3,575,209.24	296,400.00	39,146,603.76		117,100.00	39,029,503.76
303.60	5,722,223.16	292,794.49		6,015,017.65	181,173.30		6,196,190.95
375.71	6,113,135.39	196,000.00	3,964.73	6,305,170.66		2,453.27	6,302,717.39
Total Plant	**2,939,674,774.68**	**72,804,720.80**	**3,524,660.67**	**3,008,954,834.81**	**6,449,097.80**	**2,097,714.50**	**3,013,306,218.11**

Account	2021 FEBRUARY Additions	2021 FEBRUARY Retirements	2021 FEBRUARY Ending Balance	2021 MARCH Additions	2021 MARCH Retirements	2021 MARCH Ending Balance
350.20			1,932.08			1,932.08
351.00			3,220,858.29			3,220,858.29
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			948,272.21			948,272.21
355.00			104,476.92			104,476.92
374.40	7,936.87	1,424.34	3,495,119.65	12,211.85	1,318.20	3,506,013.30
374.50			3,233,171.42			3,233,171.42
375.34	15,543.04	3,043.22	5,680,715.40	23,914.87	3,575.75	5,701,054.52
375.60			86,227.87			86,227.87
375.70		3,371.44	18,078,826.23		4,077.40	18,074,748.83
375.80			16,515.17			16,515.17
376.00	7,451,055.27	1,511,858.47	1,982,548,026.68	11,464,358.34	1,921,701.49	1,992,090,683.53
378.00	869,464.13	175,312.07	120,841,646.79	1,337,776.73	219,908.84	121,959,514.68
379.10			135,966.90			135,966.90
380.00	2,910,833.26	585,844.51	657,406,184.85	4,478,672.40	732,016.81	661,152,840.44
381.00	40,557.06	9,324.37	40,393,528.60	62,401.97	10,907.47	40,445,023.10
381.10	7,157.13		24,788,398.47	11,012.12		24,799,410.59
382.00	67,035.44	12,918.68	42,490,912.91	103,142.21	14,613.58	42,579,441.54
383.00	9,453.98	1,772.76	17,495,367.65	14,546.09	1,868.45	17,508,045.29
385.00	36,377.34	7,289.87	8,434,847.50	55,970.98	9,024.58	8,481,793.90
387.00			136,698.14			136,698.14
387.40			10,526,342.87			10,526,342.87
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,291,191.10			2,291,191.10
391.11			91,303.67			91,303.67
391.12			3,249,377.24			3,249,377.24
392.00			25,616.89			25,616.89
394.00	39,684.37		17,747,948.59	61,059.26		17,809,007.85
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	46,298.44	9,493.43	1,565,615.42	71,235.80	12,329.47	1,624,521.75
398.00			953,269.70			953,269.70
303.00		111,700.00	38,917,803.76		269,800.00	38,648,003.76
303.60	239,216.75		6,435,407.70	289,306.48		6,724,714.18
375.71		3,239.23	6,299,478.16		3,917.50	6,295,560.66
Total Plant	**11,740,613.08**	**2,436,592.39**	**3,022,610,238.80**	**17,985,609.10**	**3,205,059.54**	**3,037,390,788.36**

	2021			2021		
	APRIL			MAY		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,220,858.29			3,220,858.29
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			948,272.21			948,272.21
355.00			104,476.92			104,476.92
374.40	13,116.31	1,270.96	3,517,858.65	15,328.62	1,538.55	3,531,648.72
374.50			3,233,171.42			3,233,171.42
375.34	25,686.10	3,381.75	5,723,358.87	30,018.54	3,605.66	5,749,771.75
375.60			86,227.87			86,227.87
375.70		4,598.32	18,070,150.51		5,308.46	18,064,842.05
375.80			16,515.17			16,515.17
376.00	12,313,452.24	1,807,513.67	2,002,596,622.10	14,390,347.77	1,852,206.12	2,015,134,763.75
378.00	1,436,857.56	207,026.75	123,189,345.49	1,679,210.63	213,550.29	124,655,005.83
379.10			135,966.90			135,966.90
380.00	4,810,379.88	689,318.76	665,273,901.56	5,621,741.01	712,427.62	670,183,214.95
381.00	67,023.70	10,319.01	40,501,727.79	78,328.51	11,027.33	40,569,028.97
381.10	11,827.71		24,811,238.30	13,822.68		24,825,060.98
382.00	110,781.31	13,859.39	42,676,363.46	129,466.67	15,069.06	42,790,761.07
383.00	15,623.44	1,781.74	17,521,886.99	18,258.62	2,010.44	17,538,135.17
385.00	60,116.41	8,503.59	8,533,406.72	70,256.17	8,829.70	8,594,833.19
387.00			136,698.14			136,698.14
387.40			10,526,342.87			10,526,342.87
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,291,191.10			2,291,191.10
391.11			91,303.67			91,303.67
391.12			3,249,377.24			3,249,377.24
392.00			25,616.89			25,616.89
394.00	65,581.54		17,874,589.39	76,643.10		17,951,232.49
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	76,511.79	11,580.27	1,689,453.27	89,416.95	11,740.66	1,767,129.56
398.00			953,269.70			953,269.70
303.00		144,700.00	38,503,303.76		478,600.00	38,024,703.76
303.60	326,268.11		7,050,982.29	376,655.85		7,427,638.14
375.71		4,418.00	6,291,142.66		5,100.29	6,286,042.37
Total Plant	**19,333,226.10**	**2,908,272.21**	**3,053,815,742.25**	**22,589,495.12**	**3,321,014.18**	**3,073,084,223.19**

Account	2021 JUNE Additions	2021 JUNE Retirements	2021 JUNE Ending Balance	2021 JULY Additions	2021 JULY Retirements	2021 JULY Ending Balance
350.20			1,932.08			1,932.08
351.00			3,220,858.29			3,220,858.29
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			948,272.21			948,272.21
355.00			104,476.92			104,476.92
374.40	15,754.68	1,663.73	3,545,739.67	17,563.14	1,914.09	3,561,388.72
374.50			3,233,171.42			3,233,171.42
375.34	30,852.91	4,068.39	5,776,556.27	34,394.49	4,094.18	5,806,856.58
375.60			86,227.87			86,227.87
375.70	204,000.00	5,777.70	18,263,064.35		5,480.74	18,257,583.61
375.80			16,515.17			16,515.17
376.00	14,790,328.12	2,119,447.00	2,027,805,644.87	16,488,095.93	2,034,846.73	2,042,258,894.07
378.00	1,725,884.36	243,786.08	126,137,104.11	1,923,997.00	235,939.09	127,825,162.02
379.10			135,966.90			135,966.90
380.00	5,777,997.55	812,732.38	675,148,480.12	6,441,248.43	788,426.06	680,801,302.49
381.00	80,505.66	12,432.61	40,637,102.02	89,746.82	12,544.20	40,714,304.64
381.10	14,206.88		24,839,267.86	15,837.68		24,855,105.54
382.00	133,065.20	16,887.87	42,906,938.40	148,339.62	17,376.68	43,037,901.34
383.00	18,766.12	2,224.83	17,554,676.46	20,920.26	2,383.69	17,573,213.03
385.00	72,208.95	10,056.18	8,656,985.96	80,497.74	9,810.16	8,727,673.54
387.00			136,698.14			136,698.14
387.40			10,526,342.87			10,526,342.87
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,291,191.10			2,291,191.10
391.11			91,303.67			91,303.67
391.12			3,249,377.24			3,249,377.24
392.00			25,616.89			25,616.89
394.00	78,773.39		18,030,005.88	87,815.72		18,117,821.60
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	91,902.29	13,486.26	1,845,545.59	102,451.67	12,779.02	1,935,218.24
398.00			953,269.70			953,269.70
303.00	3,972,454.71	83,500.00	41,913,658.47		28,300.00	41,885,358.47
303.60	409,950.14		7,837,588.28	388,878.61		8,226,466.89
375.71	196,000.00	5,551.13	6,476,491.24		5,265.80	6,471,225.44
Total Plant	**27,612,650.96**	**3,331,614.16**	**3,097,365,259.99**	**25,839,787.11**	**3,159,160.44**	**3,120,045,886.66**

	2021			2021		
	AUGUST			SEPTEMBER		
Account	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,220,858.29			3,220,858.29
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			948,272.21			948,272.21
355.00			104,476.92			104,476.92
374.40	18,973.07	2,460.24	3,577,901.55	20,659.03	2,335.06	3,596,225.52
374.50			3,233,171.42			3,233,171.42
375.34	37,155.59	4,518.99	5,839,493.18	40,457.26	4,294.55	5,875,655.89
375.60			86,227.87			86,227.87
375.70		6,226.64	18,251,356.97	14,204,000.00	6,081.24	32,449,275.73
375.80			16,515.17			16,515.17
376.00	17,811,716.92	2,103,913.67	2,057,966,697.32	19,394,477.60	2,000,639.42	2,075,360,535.50
378.00	2,078,450.42	246,809.23	129,656,803.21	2,263,142.88	234,667.91	131,685,278.18
379.10			135,966.90			135,966.90
380.00	6,958,334.93	827,543.89	686,932,093.53	7,576,657.06	786,809.09	693,721,941.50
381.00	96,951.46	13,893.31	40,797,362.79	105,566.64	13,202.86	40,889,726.57
381.10	17,109.08		24,872,214.62	18,629.40		24,890,844.02
382.00	160,247.95	19,732.95	43,178,416.34	174,487.68	18,748.11	43,334,155.91
383.00	22,599.69	2,840.81	17,592,971.91	24,607.92	2,697.91	17,614,881.92
385.00	86,959.89	10,379.17	8,804,254.26	94,687.20	9,867.52	8,889,073.94
387.00			136,698.14			136,698.14
387.40			10,526,342.87			10,526,342.87
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,291,191.10			2,291,191.10
391.11			91,303.67			91,303.67
391.12			3,249,377.24			3,249,377.24
392.00			25,616.89			25,616.89
394.00	94,865.33		18,212,686.93	103,295.13		18,315,982.06
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	110,676.22	12,956.17	2,032,938.29	120,510.98	12,322.55	2,141,126.72
398.00			953,269.70			953,269.70
303.00		2,971,100.00	38,914,258.47	3,972,454.71	14,800.00	42,871,913.18
303.60	441,803.30		8,668,270.19	431,487.21		9,099,757.40
375.71		5,982.45	6,465,242.99	196,000.00	5,842.76	6,655,400.23
Total Plant	**27,935,843.85**	**6,228,357.52**	**3,141,753,372.99**	**48,741,120.70**	**3,112,308.98**	**3,187,382,184.71**

Account	2021 OCTOBER			2021 NOVEMBER		
	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20			1,932.08			1,932.08
351.00			3,220,858.29			3,220,858.29
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			948,272.21			948,272.21
355.00			104,476.92			104,476.92
374.40	40,750.18	2,340.61	3,634,635.09	19,931.18	2,505.67	3,652,060.60
374.50			3,233,171.42			3,233,171.42
375.34	79,802.43	4,243.11	5,951,215.21	39,031.90	3,731.09	5,986,516.02
375.60			86,227.87			86,227.87
375.70		5,706.52	32,443,569.21		5,271.26	32,438,297.95
375.80			16,515.17			16,515.17
376.00	38,255,840.93	1,962,974.96	2,111,653,401.47	18,711,184.69	1,543,170.77	2,128,821,415.39
378.00	4,464,076.61	230,544.48	135,918,810.31	2,183,409.38	185,198.82	137,917,020.87
379.10			135,966.90			135,966.90
380.00	14,945,047.42	773,267.93	707,893,720.99	7,309,721.48	624,989.56	714,578,452.91
381.00	208,231.45	13,049.31	41,084,908.71	101,847.38	11,535.83	41,175,220.26
381.10	36,746.72		24,927,590.74	17,973.07		24,945,563.81
382.00	344,179.05	18,576.92	43,659,758.04	168,340.25	17,047.62	43,811,050.67
383.00	48,539.40	2,685.83	17,660,735.49	23,740.94	2,631.86	17,681,844.57
385.00	186,771.64	9,706.04	9,066,139.54	91,351.25	7,956.80	9,149,533.99
387.00			136,698.14			136,698.14
387.40			10,526,342.87			10,526,342.87
387.50			2,201,371.95			2,201,371.95
390.10			49,821.42			49,821.42
391.10			2,291,191.10			2,291,191.10
391.11			91,303.67			91,303.67
391.12			3,249,377.24			3,249,377.24
392.00			25,616.89			25,616.89
394.00	203,750.88		18,519,732.94	99,655.90		18,619,388.84
395.00			266,039.42			266,039.42
396.00			948,698.04			948,698.04
397.50	237,709.37	12,064.16	2,366,771.93	116,265.22	9,129.16	2,473,907.99
398.00			953,269.70			953,269.70
303.00		214,500.00	42,657,413.18		86,300.00	42,571,113.18
303.60	404,899.69		9,504,657.09	374,015.07		9,878,672.16
375.71		5,482.74	6,649,917.49		5,064.54	6,644,852.95
Total Plant	**59,456,345.77**	**3,255,142.61**	**3,243,583,387.87**	**29,256,467.71**	**2,504,532.98**	**3,270,335,322.60**

Account	2021 DECEMBER Additions	Retirements	Ending Balance
350.20			1,932.08
351.00			3,220,858.29
352.01			738,941.36
352.02			168,031.87
352.10			206,940.78
353.00			389,345.13
354.00			948,272.21
355.00			104,476.92
374.40	53,449.71	2,526.27	3,702,984.04
374.50			3,233,171.42
375.34	104,672.35	3,581.50	6,087,606.87
375.60			86,227.87
375.70	204,000.00	4,126.56	32,638,171.39
375.80			16,515.17
376.00	50,178,031.05	1,431,804.71	2,177,567,641.73
378.00	5,855,277.75	173,031.63	143,599,266.99
379.10			135,966.90
380.00	19,602,576.62	585,058.90	733,595,970.63
381.00	273,125.47	11,089.86	41,437,255.87
381.10	48,198.61		24,993,762.42
382.00	451,440.27	16,556.84	44,245,934.10
383.00	63,666.40	2,599.42	17,742,911.55
385.00	244,977.85	7,481.39	9,387,030.45
387.00			136,698.14
387.40			10,526,342.87
387.50			2,201,371.95
390.10			49,821.42
391.10		173,686.96	2,117,504.14
391.11			91,303.67
391.12		1,495,726.59	1,753,650.65
392.00			25,616.89
394.00	267,248.56	552,198.39	18,334,439.01
395.00			266,039.42
396.00			948,698.04
397.50	311,789.98	8,362.92	2,777,335.05
398.00		8,228.13	945,041.57
303.00	3,972,454.71	461,200.00	46,082,367.89
303.60	292,794.49		10,171,466.65
375.71	196,000.00	3,964.73	6,836,888.22
Total Plant	**82,119,703.82**	**4,941,224.80**	**3,347,513,801.62**

COLUMBIA STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

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

April 24, 2020

Table of Contents

I. Introduction

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 the 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. No, I have not testified before this Commission or any other state commission.

II. <u>Statement of Purpose</u>

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, 2021, 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. Additionally, I will describe a change in the presentation of Cloud Computing investments within the rate case exhibits, as well as address capital investment reporting requirements agreed to from prior rate case approved Settlements. The following are the exhibits I support:

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)	FERC Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract
Exhibit NMS-2 (Attached hereto)	Update of Ex. 108, Schedule 1 from Docket No. R-2018-2647577 (Updated through Dec. 31, 2018)

Exhibit NMS-3 (Attached hereto)	Update of Ex. 108, Schedule 1 from Docket No. R-2018-2647577 (Updated through Dec. 31, 2019)
Exhibit NMS-4 (Attached hereto)	Property, Plant & Equipment - Budget to Actual Comparison from Docket No. R-2018-2647577 (Updated through Dec. 31, 2019)

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

A. I will be addressing the twelve month period ending November 30, 2019 as the Historic Test Year (Exhibit 8), the twelve month period ended November 30, 2020 as the Future Test Year (Exhibit 108), and the twelve month period ended December 31, 2021 as the FPFTY (Exhibit 108).

III. <u>Rate Base</u>

Q. Please explain the development of rate base at November 30, 2019 for the Historic Test Year, November 30, 2020 for the Future Test Year and December 31, 2021 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 1-11.

A. The Company's Plant in Service includes plant in service per books as of November

30, 2019. Accounts 101 and 106 are detailed in Lines 2 through 5. Note, the plant detail for Leases (Line 5) and Cloud Computing (Line 4) are separately provided as Leases are removed from rate base and Cloud Computing has a new accounting presentation as noted in Section IV of this testimony. 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 6. The Historic Test Year also includes per books Gas Stored Underground – Non-Current, Account 117 on Exhibit 8, Page 3, Line 7. Reductions are included for the reserve for depreciation, per Company witness Spanos (Columbia Statement No. 5) on Line 8. The reserve related to Cloud Computing is detailed on Line 9. Finally, gas lost in underground storage is on Line 10.

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, 2021, as shown on Exhibit 108, Schedule 1, Column 5, was developed beginning from Column 2 of Page 1 with Gas Plant in Service at November 30, 2019 (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 2019 through December 2021 per the Company's forecasted budget are shown in Exhibit 108, Schedule 1, columns 3-5. The forecasted plant additions were provided based on the Company's current capital plan, Column 3. Forecasted retirements from December 2019 to December 2021, as supported by Company witness Spanos (Columbia

Statement No. 5) are shown in Exhibit 108, Schedule 1, column 4. 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, 2021, column 6.

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, 2019.

Q. Please explain the credits to Gas Plant in Service on Exhibit 8, Page 3, Lines 8-10 and Exhibit 108, Page 3, Lines 7-9.

A. Line 8, Depreciation Reserve, Accounts 108-111 in Exhibit 8, Page 3 for the Historic Test Year and Line 7, 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. Amortization for Cloud Computing has been added on Line 9 in Exhibit 8 for the Historic Test Year; Line 8 in Exhibit 108 for the FPFTY and supplied by Company witness Spanos, by plant account, in Exhibit 105 in the FPFTY. Exhibit 8, Page 3, Line 10 and Exhibit 108, Page 3, Line 9 Accumulated Provision for Gas Lost – Underground Storage, Account 117, is per books as of November 30, 2019 for the Historic Test Year and December 31, 2021 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 2019 actual balances (most recently available), with January 2020 through November 2020 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 23, to the actual balances of January 2019 through November 2019. 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; Medical Long Term Disability Insurance, Account 16500010; Prepaid Insurance I/C, Account 1652000; and Regulatory Commission Fees, Office of Consumer Advocate ("OCA") fees, and Office of Small Business Advocate ("OSBA") fees, Account 16503600. 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. There were no prepayments included for Cloud based assets as those were included in Property Plant and Equipment as shown on Exhibit 8 Page 3, line 4.

Exhibit 108, Schedule 6 for the FPFTY shows prepayments for: Prepaid Leases, Account 16500000; Corporate Insurance, Account 16521000; Medical Long Term Disability Insurance, Account 16500010; Prepaid Insurance I/C, Account 1652000; and Regulatory Commission Fees, OCA, and OSBA fees, Account 16503600. 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 19 to the January 2019 through November 2019 actual balances to reflect expected new prepayments as of December 2021. Again, there were no prepayments shown in the FPFTY for Cloud based assets as those were included in Property Plant and Equipment on Exhibit 108 Page 3, line 3.

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 2018 through November 2019 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 2019, 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 2019 through December 2021. 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, 2019 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, 2020 and December 31, 2021 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, Pages 5 and 5a.

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 2019 through December 2021, with entries for November and December of each year based on actual data for November and December of 2019. The balances for the months of January 2021 through October 2021 are the same as the balances in the month of January 2020 through October 2020 following the trend that deposits gradually go up in the winter and down in the summer. The balances for January 2020 – October 2021 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 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 Aid of Construction and remains as a credit to the Capital asset.

Customer Advances for Construction are reflected on Exhibit 8 Page 3, line 26 for the HTY and Exhibit 108 Page 3, line 25 for the FTY and FPFTY.

IV. <u>Cloud Based Computing</u>

Q. Please describe Cloud Based Computing.

A. Cloud Based Computing is an arrangement where the IT provider (e.g. SAP, PeopleSoft) maintains the software and data on their own hardware and the user (e.g. Columbia) accesses the IT providers system to perform work functions. This is a growing trend in the Information Technology space and differs from traditional arrangements where the IT user loaded the software on its own hardware.

Q. Please describe the Company's use of cloud based assets.

A. Many cloud based services offer advantages over traditional on-premises software such as greater flexibility for the workforce, improved productivity, and higher efficiency at lower costs relative to certain on-premises solutions. As a result of these benefits, Cloud based technologies are becoming more prevalent. In 2018, Columbia began investing in Cloud Based arrangements and as of the end of the historic test year has Cloud arrangements in service for AP, Treasury, and IT management.

Q. How does the Company treat the investments related to cloud based assets?

A. Prior to 2020, Columbia recorded the investment costs associated with Cloud Computing in Account 165-Prepayments. The costs were amortized to O&M expense based on the life of the Cloud Computing arrangement; generally 5 years. Based on FERC guidance issued on December 20, 2019 at Docket No. AI20-1-000 (Attachment NMS-1), Columbia will be changing the accounting to record the investments as Plant Property & Equipment accounts in 2020. The in-service assets will be included in Account 303 – Intangible plant, and the costs incurred but not yet in-Service will be included in Account 107 – Construction Work in Progress. Additionally, the amortization expense related to the in-service investments will be charged to Account 404 – Amortization of Limited-Term Gas Plant.

Q. How has the Company reflected the Cloud investments in this proceeding?

A. The Cloud investments and expenses have been adjusted to reflect the new going forward accounting practice in the Historic as well as Future and Fully Projected Future test periods. Specifically, Exhibit 8 and Exhibit 108 include new lines that reflect Cloud based in-service assets. Also note, the Cloud investments that were recorded in Account 165 - Prepayments are not included in Exhibit 8, Schedule 6 which details the various prepayments included in rate base.

Q. How were Cloud investments detailed in the last rate case?

A. In the prior rate filing, these investments were included in rate base as part of the Prepayment 165 accounts on Exhibit 8, Schedule 6 and Exhibit 108, Schedule 6. While the presentation differs between the cases, the Company's inclusion of Cloud based investments in rate base has not changed.

Q. Has any other Pennsylvania utility made a claim for cloud based assets in rate base?

A. Yes, at Docket No. R-2016-2580030, UGI PNG included cloud based information services in its rate base, and at Docket No. R-2018-3000124, Duquesne Light Company included cloud based information systems in its rate base. Both utilities were permitted to include its cloud based assets into rate base by Commission-approved settlements. These Commission rulings, augmented by the FERC accounting guidance on Cloud Assets as Plant, Property and Equipment, support the Company's inclusion of Cloud Computing Investments in rate base.

V. <u>Rate Base Reporting Requirements</u>

Q. Is the FPFTY utilized by Columbia in this case similar to that used in its prior base rate case?

A. Yes. Columbia elected to use the FPFTY provided for in Act 11 of 2012 in Docket Nos. R-2012-2321748, R-2014-2406274, R-2015-2468056, R-2016-2529660 and R-2018-2647577. The Company has made the same election in the current case. Also note, with the exception of the Cloud Computing presentation as explained in Section IV of my testimony, the presentation of rate base in this case is the same as the prior cases.

Q. Are there any current requirements arising from the use of a FPFTY in those prior cases?

A. Yes. There are several current requirements from the approved Settlement in Docket No. R-2018-2647577.

Pursuant to paragraph 36 of the approved Settlement in Docket No. R-2018-

2647577, Columbia was required to, and did provide the Commission and other parties by April 1, 2019, an update of Columbia Exhibit 108, Schedule 1, which included actual capital expenditures, plant additions and retirements by month for the twelve months ending December 31, 2018. See Exhibit NMS-2.

Paragraph 36 also requires Columbia to provide the Commission and other parties, on or before April 1, 2020, an update of Columbia Exhibit 108, Schedule 1, which includes actual capital expenditures, plant additions and retirements by month for the twelve months ending December 31, 2019. See Exhibit NMS-3. Also pursuant to paragraph 36 of the approved settlement in Docket No. R-2018-2647577, Columbia is required to provide a comparison of its actual revenue, expenses and rate base additions for the 12 months ended December 31, 2019 to the projections in the case. See Exhibit NMS-4 for this comparison. See Exhibit NMS-3 and NMS-4 for a comparison of projections to actuals updated through December 31, 2019.

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. When will the Company be eligible to include plant additions in the DSIC?

A. Pursuant to Paragraph 29 of the approved Settlement in Docket No. R-2018-2647577, the Company will be eligible to include plant additions in the DSIC once eligible account balances exceed the levels projected by the Company at December 31, 2019. As of December 31, 2019 the Company has not exceeded these levels; however, Columbia is expecting to exceed levels by early 2020. Please refer to Exhibit NMS-4 for a comparison of projections to actual additions.

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.

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. AI20-1-000
December 20, 2019

TO ALL JURISDICTIONAL PUBLIC UTILITIES AND LICENSEES, NATURAL GAS COMPANIES, AND CENTRALIZED SERVICE COMPANIES

Subject: Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract

The Financial Accounting Standards Board (FASB) has issued Accounting Standards Update (ASU) No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement,* to reduce potential diversity in practice in accounting for the costs of implementing cloud computing arrangements that are service contracts. ASU No. 2018-15 aligns the accounting for costs incurred to implement a cloud computing arrangement that is a service contract with the guidance on capitalizing costs associated with developing or obtaining internal-use software. Specifically, ASU No. 2018-15 clarifies that an entity obtaining a service contract in a cloud computing arrangement should follow the existing guidance in Accounting Standards Codification (ASC) 350-40 to determine which implementation costs can be capitalized and which costs must be expensed, and further provides that the capitalized implementation costs shall be amortized over the term of the associated arrangement. In addition, ASU No. 2018-15 requires the capitalized implementation costs to be reported on the balance sheet in the same line item as any prepayment of the service fees for the associated cloud computing arrangements. The related amortization expense is required to be reported in the same expense line item on the income statement as the expense for the service fees of the associated cloud computing arrangement. For most jurisdictional entities, ASU No. 2018-15 is effective January 1, 2020 for accounting and financial reporting under generally accepted accounting principles (GAAP).

Commission staff received many inquiries from industry participants regarding clarification on how to apply ASU No. 2018-15 within the framework and regulatory intent of the Commission's existing accounting requirements. As discussed herein, for regulatory accounting and reporting to the Commission, jurisdictional entities will be permitted to capitalize certain implementation costs and to amortize those costs over the term of the associated cloud computing arrangement. However, in capitalizing these costs, jurisdictional entities must adhere to the regulations related to plant construction costs set forth under Part 101, Part 201, and Part 367 of the Commission's regulations.[1] Jurisdictional entities must also follow the guidance provided herein with regards to the accounts they should use to record the capitalized costs and the related amortization expense. Service fees and other non-capital costs for the cloud computing arrangement are generally recorded as an expense.

The accounting guidance included herein is intended to result in consistent accounting for the same types of costs incurred for cloud computing arrangements and internal-use software projects for accounting and financial reporting to the Commission. The Commission's accounting requirements are not intended to automatically reflect changes in FASB's Accounting Standards Codification, and FASB updates should not be construed as required for regulatory accounting and reporting to the Commission. However, upon analysis, the Commission may issue accounting guidance to clarify how provisions of an ASU can be reflected within the Commission's existing accounting and financial reporting requirements. Accordingly, this accounting guidance is intended to provide clarity and certainty on how jurisdictional entities should apply the Commission's accounting and reporting requirements related to cloud computing arrangements in response to ASU No. 2018-15.

1. **Question:** How should jurisdictional entities capitalize implementation costs related to cloud computing arrangements?

Response: Implementation costs related to cloud computing arrangements are similar to the costs incurred to develop internal-use software and should be accounted for on the same basis. Jurisdictional entities have historically determined capitalizable internal-use software costs in a manner consistent with the requirements of ASC 350-40, which is an acceptable approach for accounting and financial reporting to the Commission. Accordingly, it is also appropriate for jurisdictional entities to determine capitalized implementation costs related to cloud computing consistent with ASC 350-40. Examples of implementation costs that may be capitalized include upfront costs to integrate with on-premise software, coding, configuration, and customization.

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[1] *See* 18 C.F.R. Part 101, Electric Plant Instructions No. 3 (Components of Construction) and No. 4 (Overhead Construction Costs). *See also* 18 C.F.R. Part 201, Gas Plant Instructions No. 3 (Components of Construction) and No. 4 (Overhead Construction Costs). *See also* 18 C.F.R. Part 367, Service Company Property Instructions No. 367.51 (Components of Construction) and No. 367.52 (Overhead Construction Costs).

2. **Question:** What accounts should jurisdictional entities use to record capitalized implementation costs related to cloud computing arrangements for Commission accounting and reporting purposes?

Response: Jurisdictional entities should record capitalized implementation costs associated with cloud computing arrangements as a utility plant asset, consistent with the Commission's accounting requirements for internal-use software. Accordingly, jurisdictional entities should record capitalized implementation costs in Account 303 (Miscellaneous Intangible Plant), provided such costs are not specifically provided for in other utility plant accounts. For example, public utilities are required to record software used to support regional transmission and market operations in Account 383 (Computer Software). Accordingly, a public utility's capitalized cost related to cloud computing arrangements for regional transmission and market operations should be recorded in Account 383.

3. **Question:** What accounts should jurisdictional entities use to record the amortization or depreciation of capitalized implementation costs related to cloud computing arrangements for Commission accounting and reporting purposes?

Response: Jurisdictional entities should amortize or depreciate capitalized cloud computing costs consistent with the requirements of the utility plant accounts in which they are recorded. Specifically, the amortization of capitalized cloud computing costs recorded as intangible utility plant should be recorded in Account 404 (Amortization of Limited-Term Electric Plant)[2] for public utilities and centralized service companies, and Account 404.3 (Amortization of Other Limited-Term Gas Plant) for natural gas companies.[3] The amortization of capitalized cloud computing costs not classified as intangible utility plant should be recorded in Account 403 (Depreciation Expense).

If a jurisdictional entity believes that its facts and circumstances warrant the use of alternative accounts other than those prescribed herein to record the capitalized costs and related amortization, the jurisdictional entity should request clarification or approval from the Chief Accountant to use the alternative accounting treatment.

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[2] *See* 18 C.F.R. Parts 101 and 367 (2019).

[3] *See* 18 C.F.R. Part 201 (2019).

The Commission delegated authority to act on this matter to the Director of the Office of Enforcement or his designee under 18 C.F.R. § 375.311 (2019). The Director has designated this authority to the Chief Accountant. This letter constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2019).

Sincerely,

Steven D Hunt

Steven D. Hunt
Chief Accountant and Director
Division of Audits and Accounting
Office of Enforcement

Columbia Gas of Pennsylvania
Schedule 108 - Case R-2018-2647577
Updated for Actuals Through December 31, 2018

Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 11/30/2017 1/ (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2017 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 1/31/2018 (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	26,489	0	0	26,489	0	0	26,489
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	22,230,329	399,532	(31,257)	22,598,605	170,192	(1,471,768)	21,297,029
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,287,123	0	0	3,287,123	0	0	3,287,123
10	Wells Construction	352.01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,543	0	0	399,543	0	0	399,543
15	Compressor Station Equipment	354.00	864,752	0	0	864,752	0	0	864,752
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,102	0	0	477,102	0	0	477,102
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,574,965	30,461	(1,038)	2,604,389	61	(2,637)	2,601,813
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,143	0	0	3,233,143	0	0	3,233,143
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,775,247	27,345	(18,885)	4,783,707	4,203	0	4,787,909
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,387,713	81,239	0	7,468,952	0	0	7,468,952
29	Structures, Other Distribution System, Leased	375.71	2,830,323	214,171	0	3,044,494	0	0	3,044,494
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,319,721,756	50,306,071	(3,096,870)	1,366,930,957	1,475,010	(1,577,391)	1,366,828,576
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	66,998,019	0	(353,215)	66,644,804	0	(85,111)	66,559,693
35	Cast Iron	376.80	406,130	0	(5,334)	400,795	0	(45,950)	354,845
36	Measuring & Regulating Equipment General	378.10	1,371,450	0	0	1,371,450	0	0	1,371,450
37	Measuring & Regulating Equipment Regulating	378.20	58,638,449	2,500,657	(106,386)	61,032,720	801,885	(92,567)	61,742,038
38	Measuring & Regulating Equipment Local Gas	378.30	471,962	0	0	471,962	7,281	(2,081)	477,161
39	Measuring & Regulating Equipment City Gate	379.10	140,677	0	0	140,677	0	0	140,677
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	484,373,791	5,414,140	(715,528)	489,072,404	2,131,872	(1,479,370)	489,724,905
42	Meters	381.00	37,708,686	138,839	0	37,847,526	69,485	(45,603)	37,871,407
43	Auto Meter Reading Devices	381.10	23,950,869	0	0	23,950,869	0	0	23,950,869
44	Meter Installations	382.00	38,336,244	59,139	(6,232)	38,389,151	86,965	(4,185)	38,471,930
45	House Regulators	383.00	12,036,518	51,831	(606)	12,087,743	54,062	(325)	12,141,481
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,037,782	136,303	(83,746)	6,090,340	0	(1,114)	6,089,226
48	Industrial M&R Equipment. Large Volume	385.10	1,085,273	0	0	1,085,273	0	(421)	1,084,852
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,109	0	0	627,109	0	0	627,109
53	Other Equipment, Telemetering	387.45	7,015,504	206,365	0	7,221,869	392,472	(5,796)	7,608,545
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,053,366	0	0	2,053,366	0	0	2,053,366
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,275,011	0	(334,483)	2,940,528	0	0	2,940,528
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	3,117,086	1,254,075	0	4,371,161	0	0	4,371,161
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	85,691	0	(37,066)	48,625	0	0	48,625
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	13,435	0	0	13,435	0	0	13,435
65	Tools, Garage & Service Equipment	394.10	94,327	0	0	94,327	0	0	94,327
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	63,653	0	0	63,653	0	0	63,653
69	Tools, Tools and Other	394.30	15,207,766	176,912	(980)	15,383,697	34,637	(19,442)	15,398,893
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	273,740	0	0	273,740	0	0	273,740
72	Power Operated Equipment	396.00	1,216,922	0	(180,818)	1,036,104	0	(40,178)	995,926
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	1,219,845	8,370	0	1,228,216	0	0	1,228,216
					0				
79	**Total Gas Plant in Service**		2,171,126,344	61,005,451	(4,972,444)	2,227,159,351	5,228,123	(4,873,939)	2,227,513,535

1/ Exhibit 8, Schedule 1.

Line No.	Description	Account No. (1)	Plant Beginning Balance 1/31/2018 (2) $	Additions (3) $	Retirements (4) $	Balance as of 2/28/2018 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 3/31/2018 (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	26,489	0	0	26,489	0	0	26,489
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	21,297,029	98,103	0	21,395,132	298,033	0	21,693,165
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,287,123	21,547		3,308,670	(16,085)	(9,062)	3,283,523
10	Wells Construction	352.01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,543	0	0	399,543	0	0	399,543
15	Compressor Station Equipment	354.00	864,752	0	0	864,752	0	0	864,752
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,102	0	0	477,102	0	0	477,102
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,601,813	0	0	2,601,813	218,835	(25)	2,820,624
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,143	0	0	3,233,143	0	0	3,233,143
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,787,909	27,840	(11,153)	4,804,597	17,067	(10,528)	4,811,136
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,468,952	149,136	(3,994)	7,614,093	(1,802)	0	7,612,292
29	Structures, Other Distribution System, Leased	375.71	3,044,494	39,943	0	3,084,437	(900)	0	3,083,537
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,366,828,576	5,398,308	(361,720)	1,371,865,163	4,288,940	(178,503)	1,375,975,599
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	66,559,693	0	(89,499)	66,470,195	0	(11,969)	66,458,226
35	Cast Iron	376.80	354,845	0	0	354,845	0	(140)	354,705
36	Measuring & Regulating Equipment General	378.10	1,371,450	0	0	1,371,450	0	0	1,371,450
37	Measuring & Regulating Equipment Regulating	378.20	61,742,038	162,617	(31,803)	61,872,852	(123,218)	(425,578)	61,324,056
38	Measuring & Regulating Equipment Local Gas	378.30	477,161	245	0	477,406	0	0	477,406
39	Measuring & Regulating Equipment City Gate	379.10	140,677	0	0	140,677	0	(3,578)	137,099
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	489,724,905	2,890,204	(393,688)	492,221,422	3,907,553	(1,042,818)	495,086,157
42	Meters	381.00	37,871,407	48,008	(50,428)	37,868,988	77,733	(51,812)	37,894,909
43	Auto Meter Reading Devices	381.10	23,950,869	0	0	23,950,869	0	0	23,950,869
44	Meter Installations	382.00	38,471,930	150,369	(6,556)	38,615,744	132,894	(7,324)	38,741,314
45	House Regulators	383.00	12,141,481	50,163	(464)	12,191,180	51,009	(468)	12,241,722
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,089,226	83	0	6,089,308	327,943	(44,554)	6,372,696
48	Industrial M&R Equipment. Large Volume	385.10	1,084,852	0	(1,043)	1,083,809	0	(2,472)	1,081,337
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,109	589	0	627,699	0	0	627,699
53	Other Equipment, Telemetering	387.45	7,608,545	37,088	0	7,645,634	249,813	(11,059)	7,884,387
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,053,366	0	0	2,053,366	0	0	2,053,366
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,940,528	0	(84,269)	2,856,260	0	0	2,856,260
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,371,161	29,204	0	4,400,365	0	0	4,400,365
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	48,625	0	0	48,625	0	0	48,625
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	13,435	0	0	13,435	0	0	13,435
65	Tools, Garage & Service Equipment	394.10	94,327	0	0	94,327	0	(28,566)	65,761
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	63,653	0	0	63,653	0	0	63,653
69	Tools, Tools and Other	394.30	15,398,893	31,229	(96,587)	15,333,535	84,482	(10,787)	15,407,230
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	273,740	0	0	273,740	0	0	273,740
72	Power Operated Equipment	396.00	995,926	0	0	995,926	0	0	995,926
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	1,228,216	0	0	1,228,216	0	(3,175)	1,225,041
79	**Total Gas Plant In Service**		2,227,513,535	9,134,677	(1,131,202)	2,235,517,010	9,512,298	(1,842,418)	2,243,186,890

Line No.	Description	Account No. (1)	Plant Beginning Balance 3/31/2018 (2) $	Additions (3) $	Retirements (4) $	Balance as of 4/30/2018 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 5/31/2018 (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	26,489	0	0	26,489	0	(273)	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	21,693,165	121,217	0	21,814,382	112,435	0	21,926,817
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,283,523	(86,590)	0	3,196,933	45,435	0	3,242,367
10	Wells Construction	352.01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,543	0	0	399,543	0	0	399,543
15	Compressor Station Equipment	354.00	864,752	84,296	0	949,047	0	0	949,047
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,102	0	0	477,102	0	(2)	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,820,624	8,500	0	2,829,124	0	0	2,829,124
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,143	0	0	3,233,143	0	0	3,233,143
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,811,136	17,654	0	4,828,790	14,717	0	4,843,507
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,612,292	0	0	7,612,292	3,755	0	7,616,046
29	Structures, Other Distribution System, Leased	375.71	3,083,537	88,126	0	3,171,663	56,871	0	3,228,534
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,375,975,599	7,726,904	(577,694)	1,383,124,809	11,656,196	(232,755)	1,394,548,250
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	66,458,226	0	(21,253)	66,436,972	0	(14,958)	66,422,014
35	Cast Iron	376.80	354,705	0	(2,117)	352,588	0	(7,108)	345,480
36	Measuring & Regulating Equipment General	378.10	1,371,450	0	(1,847)	1,369,603	0	0	1,369,603
37	Measuring & Regulating Equipment Regulating	378.20	61,324,056	1,804,170	(45,617)	63,082,608	103,764	(21,289)	63,165,083
38	Measuring & Regulating Equipment Local Gas	378.30	477,406	3,144	0	480,550	63	0	480,613
39	Measuring & Regulating Equipment City Gate	379.10	137,099	0	0	137,099	0	(683)	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	495,086,157	3,972,255	(10,643)	499,047,769	4,372,988	(691,095)	502,729,662
42	Meters	381.00	37,894,909	98,633	0	37,993,542	48,517	(66,085)	37,975,974
43	Auto Meter Reading Devices	381.10	23,950,869	0	0	23,950,869	0	0	23,950,869
44	Meter Installations	382.00	38,741,314	143,293	(3,398)	38,881,209	83,263	(24,984)	38,939,488
45	House Regulators	383.00	12,241,722	55,775	(293)	12,297,204	44,495	(593)	12,341,106
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,372,696	11,633	(20,382)	6,363,948	10,986	(7,747)	6,367,188
48	Industrial M&R Equipment. Large Volume	385.10	1,081,337	0	(2,987)	1,078,350	0	0	1,078,350
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,699	0	0	627,699	(101)	0	627,598
53	Other Equipment, Telemetering	387.45	7,884,387	(31,579)	(14,740)	7,838,068	217,131	0	8,055,199
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,053,366	0	0	2,053,366	0	0	2,053,366
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,856,260	0	(4,266)	2,851,993	0	(9,004)	2,842,989
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,400,365	0	0	4,400,365	0	0	4,400,365
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	48,625	0	0	48,625	0	0	48,625
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	13,435	0	0	13,435	0	0	13,435
65	Tools, Garage & Service Equipment	394.10	65,761	0	0	65,761	0	(850)	64,911
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	63,653	0	0	63,653	0	0	63,653
69	Tools, Tools and Other	394.30	15,407,230	67,867	(28,853)	15,446,244	169,955	(37,985)	15,578,214
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	273,740	0	0	273,740	0	0	273,740
72	Power Operated Equipment	396.00	995,926	0	0	995,926	0	0	995,926
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	1,225,041	0	0	1,225,041	0	0	1,225,041
79	**Total Gas Plant In Service**		**2,243,186,890**	**14,085,296**	**(734,091)**	**2,256,538,096**	**16,940,468**	**(1,115,412)**	**2,272,363,152**

Line No.	Description	Account No. (1)	Gas Plant in Service Plant Beginning Balance 5/31/2018 (2) $	Additions (3) $	Retirements (4) $	Balance as of 6/30/2018 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 7/31/2018 (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	21,926,817	39,234	0	21,966,052	4,081	(251,732)	21,718,401
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,242,367	(21,506)	0	3,220,861	0	0	3,220,861
10	Wells Construction	352.01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,543	0	0	399,543	0	0	399,543
15	Compressor Station Equipment	354.00	949,047	0	0	949,047	0	0	949,047
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	0	0	477,100	0	0	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,829,124	0	0	2,829,124	0	0	2,829,124
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,143	0	0	3,233,143	0	0	3,233,143
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,843,507	22,741	0	4,866,248	14,699	(2,554)	4,878,392
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,616,046	(18,175)	0	7,597,872	106,079	0	7,703,951
29	Structures, Other Distribution System, Leased	375.71	3,228,534	1,122,771	0	4,351,304	359,066	0	4,710,371
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,394,548,250	11,462,891	(701,841)	1,405,309,299	18,677,006	(515,673)	1,423,470,632
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	66,422,014	854	(63,213)	66,359,655	0	(62,459)	66,297,196
35	Cast Iron	376.80	345,480	0	(1,302)	344,178	0	(1,525)	342,653
36	Measuring & Regulating Equipment General	378.10	1,369,603	0	0	1,369,603	0	0	1,369,603
37	Measuring & Regulating Equipment Regulating	378.20	63,165,083	7,597	(16,512)	63,156,168	754,271	(856)	63,909,582
38	Measuring & Regulating Equipment Local Gas	378.30	480,613	0	0	480,613	0	(23,916)	456,697
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	502,729,662	4,896,928	(918,098)	506,708,491	5,215,500	(967,803)	510,956,188
42	Meters	381.00	37,975,974	80,188	(27,763)	38,028,399	91,882	(40,031)	38,080,250
43	Auto Meter Reading Devices	381.10	23,950,869	0	0	23,950,869	0	0	23,950,869
44	Meter Installations	382.00	38,939,488	96,368	(4,161)	39,031,694	44,350	(10,983)	39,065,061
45	House Regulators	383.00	12,341,106	36,875	(390)	12,377,590	71,502	(686)	12,448,406
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,367,188	4,632	(5,582)	6,366,238	(352)	(4,430)	6,361,456
48	Industrial M&R Equipment. Large Volume	385.10	1,078,350	0	(604)	1,077,746	0	0	1,077,746
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,598	0	0	627,598	0	0	627,598
53	Other Equipment, Telemetering	387.45	8,055,199	(585,871)	(15,673)	7,453,655	51,541	0	7,505,196
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,053,366	0	0	2,053,366	148,006	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,842,989	0	(2,140)	2,840,849	0	(34,084)	2,806,765
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,400,365	0	(299,110)	4,101,255	0	0	4,101,255
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	48,625	0	0	48,625	0	(3,312)	45,313
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	13,435	0	0	13,435	0	0	13,435
65	Tools, Garage & Service Equipment	394.10	64,911	0	0	64,911	0	(2,400)	62,511
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	63,653	0	0	63,653	0	0	63,653
69	Tools, Tools and Other	394.30	15,578,214	61,834	(33,421)	15,606,626	68,849	(10,873)	15,664,602
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	273,740	0	(1,385)	272,355	0	0	272,355
72	Power Operated Equipment	396.00	995,926	0	0	995,926	0	(47,228)	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	1,225,041	(212,478)	0	1,012,563	0	(7,200)	1,005,363
79	**Total Gas Plant in Service**		2,272,363,152	16,994,881	(2,091,195)	2,287,266,838	25,606,480	(1,987,746)	2,310,885,571

Line No.	Description	Account No.	Gas Plant in Service: Plant Beginning Balance 7/31/2018	Additions	Retirements	Balance as of 8/31/2018	Additions	Retirements	Balance as of 9/30/2018
		(1)	(2)	(3)	(4)	(5 = 2+3+4)	(6)	(7)	(8)=(5+6+7)
			$	$	$	$	$	$	$
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	21,718,401	224,570	0	21,942,971	83,648	0	22,026,619
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,861	0	0	3,220,861	0	0	3,220,861
10	Wells Construction	352.01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,543	0	(55)	399,487	0	0	399,487
15	Compressor Station Equipment	354.00	949,047	0	0	949,047	0	0	949,047
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	0	0	477,100	0	0	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,829,124	11,868	0	2,840,992	0	0	2,840,992
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,143	0	0	3,233,143	0	0	3,233,143
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,878,392	24,098	(7,462)	4,895,028	0	0	4,895,028
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,703,951	0	0	7,703,951	22,000	0	7,725,951
29	Structures, Other Distribution System, Leased	375.71	4,710,371	0	0	4,710,371	249,388	0	4,959,759
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,423,470,632	17,807,151	(718,945)	1,440,558,838	10,024,734	(93,568)	1,450,490,005
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	66,297,196	0	(114,530)	66,182,665	0	(8,454)	66,174,211
35	Cast Iron	376.80	342,653	0	(15,796)	326,858	0	(1,841)	325,016
36	Measuring & Regulating Equipment General	378.10	1,369,603	0	0	1,369,603	0	0	1,369,603
37	Measuring & Regulating Equipment Regulating	378.20	63,909,582	2,249,015	(50,250)	66,108,347	3,045,744	0	69,154,091
38	Measuring & Regulating Equipment Local Gas	378.30	456,697	0	0	456,697	0	0	456,697
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	510,956,188	3,858,239	(856,609)	513,957,818	4,527,814	(1,063,405)	517,422,227
42	Meters	381.00	38,080,250	121,195	(65,284)	38,136,161	47,225	0	38,183,386
43	Auto Meter Reading Devices	381.10	23,950,869	0	0	23,950,869	0	0	23,950,869
44	Meter Installations	382.00	39,065,061	59,914	(3,665)	39,121,310	107,353	(9,774)	39,218,889
45	House Regulators	383.00	12,448,406	48,285	(473)	12,496,218	57,079	(1,015)	12,552,282
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,361,456	507	(36,690)	6,325,273	25,908	0	6,351,181
48	Industrial M&R Equipment. Large Volume	385.10	1,077,746	0	(2,406)	1,075,340	0	(143)	1,075,197
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,598	0	0	627,598	0	0	627,598
53	Other Equipment, Telemetering	387.45	7,505,196	234,161	(18,855)	7,720,502	98,667	0	7,819,169
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,806,765	0	0	2,806,765	0	(10,912)	2,795,853
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,101,255	0	0	4,101,255	0	0	4,101,255
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	45,313	0	0	45,313	0	0	45,313
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	13,435	0	0	13,435	0	0	13,435
65	Tools, Garage & Service Equipment	394.10	62,511	0	(969)	61,542	0	0	61,542
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	63,653	0	0	63,653	0	(12,316)	51,337
69	Tools, Tools and Other	394.30	15,664,602	49,304	(24,076)	15,689,830	80,748	(102,701)	15,667,877
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	272,355	0	0	272,355	0	0	272,355
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	1,005,363	0	0	1,005,363	12,626	0	1,017,989
79	**Total Gas Plant in Service**		2,310,885,571	24,688,307	(1,916,065)	2,333,657,813	18,382,933	(1,304,127)	2,350,736,619

Line No.	Description	Account No. (1)	Gas Plant In Service: Plant Beginning Balance 9/30/2018 (2)	Additions (3)	Retirements (4)	Balance as of 10/31/2018 (5 = 2+3+4)	Additions (6)	Retirements (7)	Balance as of 11/30/2018 (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	22,026,619	117,631	0	22,144,250	683,051	(72,865)	22,754,436
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,861	0	0	3,220,861	(3)	0	3,220,858
10	Wells Construction	352.01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,487	0	0	399,487	0	0	399,487
15	Compressor Station Equipment	354.00	949,047	0	0	949,047	0	0	949,047
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	0	0	477,100	0	0	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,840,992	0	0	2,840,992	(10)	0	2,840,981
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,143	0	0	3,233,143	0	0	3,233,143
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,895,028	0	0	4,895,028	69	(7,554)	4,887,543
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,725,951	0	0	7,725,951	37	0	7,725,987
29	Structures, Other Distribution System, Leased	375.71	4,959,759	0	0	4,959,759	4,030	0	4,963,789
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,450,490,005	20,476,343	(2,203,825)	1,468,762,522	11,196,152	(1,057,046)	1,478,901,628
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	66,174,211	(854)	(54,952)	66,118,405	0	(59,380)	66,059,026
35	Cast Iron	376.80	325,016	0	(5,294)	319,722	0	(2,902)	316,820
36	Measuring & Regulating Equipment General	378.10	1,369,603	0	0	1,369,603	(20)	0	1,369,583
37	Measuring & Regulating Equipment Regulating	378.20	69,154,091	4,859,417	(77,492)	73,936,015	6,353,861	(6,276)	80,283,601
38	Measuring & Regulating Equipment Local Gas	378.30	456,697	0	(339)	456,358	(1)	0	456,357
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	517,422,227	5,005,214	(848,816)	521,578,625	2,940,221	(769,738)	523,749,108
42	Meters	381.00	38,183,386	140,821	(77,268)	38,246,939	144,349	(54,895)	38,336,392
43	Auto Meter Reading Devices	381.10	23,950,869	0	0	23,950,869	0	0	23,950,869
44	Meter Installations	382.00	39,218,889	221,555	(3,699)	39,436,745	83,216	(65,855)	39,454,107
45	House Regulators	383.00	12,552,282	90,034	(615)	12,641,701	55,422	(715)	12,696,407
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,351,181	134,075	(22,721)	6,462,535	10,742	(22,938)	6,450,339
48	Industrial M&R Equipment. Large Volume	385.10	1,075,197	0	(1,488)	1,073,710	0	(751)	1,072,959
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,598	0	0	627,598	(38)	0	627,560
53	Other Equipment, Telemetering	387.45	7,819,169	97,976	0	7,917,145	509,057	0	8,426,202
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,795,853	0	(120,728)	2,675,125	0	0	2,675,125
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,101,255	0	0	4,101,255	0	0	4,101,255
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	45,313	0	0	45,313	0	0	45,313
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	13,435	0	(1,550)	11,885	0	0	11,885
65	Tools, Garage & Service Equipment	394.10	61,542	0	0	61,542	0	0	61,542
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	51,337	0	0	51,337	0	0	51,337
69	Tools, Tools and Other	394.30	15,667,877	223,117	(2,191)	15,888,802	127,634	(15,538)	16,000,899
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	272,355	0	(728)	271,627	0	(2,597)	269,030
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	1,017,989	0	0	1,017,989	0	0	1,017,989
79	**Total Gas Plant In Service**		2,350,736,619	31,365,329	(3,421,708)	2,378,680,239	22,107,769	(2,139,050)	2,398,648,958

Line No.	Description	Account No. (1)	Plant Beginning Balance 11/30/2018 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2018 (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	22,754,436	117,498	(154,512)	22,717,421
6	**Underground Storage Plant**					
7	Land	350.10	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858
10	Wells Construction	352.01	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498
14	Lines	353.00	399,487	0	0	399,487
15	Compressor Station Equipment	354.00	949,047	0	0	949,047
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477
17	**Distribution Plant**					
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	0	0	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,840,981	12,466	0	2,853,447
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
23	Rights of Way	374.50	3,233,143	18	0	3,233,161
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,887,543	7,478	(8,208)	4,886,813
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,725,987	0	0	7,725,987
29	Structures, Other Distribution System, Leased	375.71	4,963,789	127,138	0	5,090,928
30	Structures, Communication	375.80	16,515	0	0	16,515
31	Mains:					
32	Mains	376.00	1,478,901,628	30,941,791	(1,231,514)	1,508,611,904
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	66,059,026	0	(95,429)	65,963,597
35	Cast Iron	376.80	316,820	0	(17,217)	299,603
36	Measuring & Regulating Equipment General	378.10	1,369,583	25,865	0	1,395,448
37	Measuring & Regulating Equipment Regulating	378.20	80,283,601	(267,707)	(49,963)	79,965,931
38	Measuring & Regulating Equipment Local Gas	378.30	456,357	0	0	456,357
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)
41	Services	380.00	523,749,108	8,529,450	(712,152)	531,566,406
42	Meters	381.00	38,336,392	124,099	(37,956)	38,422,535
43	Auto Meter Reading Devices	381.10	23,950,869	497,032	0	24,447,901
44	Meter Installations	382.00	39,454,107	241,999	(10,260)	39,685,845
45	House Regulators	383.00	12,696,407	148,713	(1,686)	12,843,434
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,450,339	11,201	(20,278)	6,441,262
48	Industrial M&R Equipment. Large Volume	385.10	1,072,959	0	0	1,072,959
49	Other Equipment	387.10	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,560	0	0	627,560
53	Other Equipment, Telemetering	387.45	8,426,202	399,230	(13,512)	8,811,920
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372
56	**General Plant**					
57	Structures, Communications	390.10	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,675,125	0	(215,553)	2,459,573
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,101,255	0	0	4,101,255
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	45,313	0	0	45,313
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
64	Stores Equipment	393.00	11,885	0	(11,885)	0
65	Tools, Garage & Service Equipment	394.10	61,542	0	0	61,542
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	51,337	0	0	51,337
69	Tools, Tools and Other	394.30	16,000,899	163,447	(5,303)	16,159,043
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	269,030	0	0	269,030
72	Power Operated Equipment	396.00	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	1,017,989	0	0	1,017,989
79	**Total Gas Plant In Service**		2,398,648,958	41,079,718	(2,585,429)	2,437,143,247

SUMMARY

Line No.	Description	Account No. (1)	Plant Beginning Balance 11/30/2017 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2018 (5 = 2+3+4) $
1	Intangible Plant					
2	Organization Costs	301.00	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,489	0	(273)	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	22,230,329	2,469,226	(1,982,134)	22,717,421
				0	0	
6	Underground Storage Plant			0	0	
7	Land	350.10	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,287,123	(57,202)	(9,062)	3,220,858
10	Wells Construction	352.01	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498
14	Lines	353.00	399,543	0	(55)	399,487
15	Compressor Station Equipment	354.00	864,752	84,296	0	949,047
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477
				0	0	
17	Distribution Plant			0	0	
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,102	0	(2)	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,574,965	282,181	(3,700)	2,853,447
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
23	Rights of Way	374.50	3,233,143	18	0	3,233,161
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,775,247	177,910	(66,344)	4,886,813
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,387,713	342,269	(3,994)	7,725,987
29	Structures, Other Distribution System, Leased	375.71	2,830,323	2,260,605	0	5,090,928
30	Structures, Communication	375.80	16,515	0	0	16,515
31	Mains:			0	0	
32	Mains	376.00	1,319,721,756	201,437,493	(12,547,345)	1,508,611,904
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	66,998,019	0	(1,034,422)	65,963,597
35	Cast Iron	376.80	406,130	0	(106,526)	299,603
36	Measuring & Regulating Equipment General	378.10	1,371,450	25,845	(1,847)	1,395,448
37	Measuring & Regulating Equipment Regulating	378.20	58,638,449	22,252,071	(924,589)	79,965,931
38	Measuring & Regulating Equipment Local Gas	378.30	471,962	10,732	(26,337)	456,357
39	Measuring & Regulating Equipment City Gate	379.10	140,677	0	(4,261)	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)
41	Services	380.00	484,373,791	57,662,377	(10,469,763)	531,566,406
42	Meters	381.00	37,708,686	1,230,974	(517,126)	38,422,535
43	Auto Meter Reading Devices	381.10	23,950,869	497,032	0	24,447,901
44	Meter Installations	382.00	38,336,244	1,510,678	(161,077)	39,685,845
45	House Regulators	383.00	12,036,518	815,245	(8,329)	12,843,434
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,037,782	673,661	(270,182)	6,441,262
48	Industrial M&R Equipment. Large Volume	385.10	1,085,273	0	(12,314)	1,072,959
49	Other Equipment	387.10	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,109	451	0	627,560
53	Other Equipment, Telemetering	387.45	7,015,504	1,876,052	(79,635)	8,811,920
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,053,366	148,006	0	2,201,372
				0	0	
56	General Plant			0	0	
57	Structures, Communications	390.10	49,821	0	(334,483)	(284,662)
58	Office Furniture & Equipment, Unspecified	391.10	3,275,011	0	(480,955)	2,794,056
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	1,254,075	0	1,345,379
60	Office Furniture & Equipment, Information Systems	391.12	3,117,086	29,204	(299,110)	2,847,180
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	(37,066)	(34,059)
62	Transportation Equipment, Trailers > $1,000	392.20	85,691	0	(3,312)	82,379
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
64	Stores Equipment	393.00	13,435	0	(13,435)	0
65	Tools, Garage & Service Equipment	394.10	94,327	0	(32,786)	61,542
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	63,653	211,549	(32,738)	242,464
69	Tools, Tools and Other	394.30	15,207,766	1,128,465	(368,315)	15,967,916
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	273,740	0	(225,706)	48,034
72	Power Operated Equipment	396.00	1,216,922	0	(47,228)	1,169,694
73	Communication Equipment	397.00	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	8,370	0	800,634
78	Miscellaneous Equipment	398.00	1,219,845	(199,852)	(10,375)	1,009,618
79	Total Gas Plant in Service		2,171,126,344	296,131,730	(30,114,827)	2,437,143,247

Columbia Gas of Pennsylvania
Schedule 108 - Case R-2018-2647577
Updated for Actuals Through December 31, 2019

			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 11/30/2018 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2018 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 1/31/2019 (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	22,754,436	117,498	(154,512)	22,717,421	1,255,846.67	(920,643.51)	23,052,624
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858	0	0	3,220,858
10	Wells Construction	352.01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352.02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,487	0	0	399,487	0	0	399,487
15	Compressor Station Equipment	354.00	949,047	0	0	949,047	0	0	949,047
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	0	0	477,100	0	0	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,840,981	12,466	0	2,853,447	37,375.73	(0.06)	2,890,822
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,143	18	0	3,233,161	0	0	3,233,161
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,887,543	7,478	(8,208)	4,886,813	38,492.35	(6,956.22)	4,918,349
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,725,987	0	0	7,725,987	0	0	7,725,987
29	Structures, Other Distribution System, Leased	375.71	4,963,789	127,138	0	5,090,928	(1,494.25)	0	5,089,433
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,478,901,628	30,941,791	(1,231,514)	1,508,611,904	9,423,504	(427,368)	1,517,608,041
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	66,059,026	0	(95,429)	65,963,597	0	(15,669)	65,947,928
35	Cast Iron	376.80	316,820	0	(17,217)	299,603	0	(827)	298,776
36	Measuring & Regulating Equipment General	378.10	1,369,583	25,865	0	1,395,448	0	0	1,395,448
37	Measuring & Regulating Equipment Regulating	378.20	80,283,601	(267,707)	(49,963)	79,965,931	112,728	(53,097)	80,025,561
38	Measuring & Regulating Equipment Local Gas	378.30	456,357	0	0	456,357	0	0	456,357
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	523,749,108	8,529,450	(712,152)	531,566,406	4,089,941	(807,790)	534,848,557
42	Meters	381.00	38,336,392	124,099	(37,956)	38,422,535	56,924	(47,595)	38,431,863
43	Auto Meter Reading Devices	381.10	23,950,869	497,032	0	24,447,901	0	0	24,447,901
44	Meter Installations	382.00	39,454,107	241,999	(10,260)	39,685,845	89,629	(12,205)	39,763,269
45	House Regulators	383.00	12,696,407	148,713	(1,686)	12,843,434	92,932	(825)	12,935,540
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,450,339	11,201	(20,278)	6,441,262	11,620	(5,552)	6,447,330
48	Industrial M&R Equipment. Large Volume	385.10	1,072,959	0	0	1,072,959	0	0	1,072,959
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,560	0	0	627,560	0	0	627,560
53	Other Equipment, Telemetering	387.45	8,426,202	399,230	(13,512)	8,811,920	52,659	(5,757)	8,858,823
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,675,125	0	(215,553)	2,459,573	0	0	2,459,573
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,101,255	0	0	4,101,255	433,644	0	4,534,899
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	45,313	0	0	45,313	0	0	45,313
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	11,885	0	(11,885)	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	61,542	0	0	61,542	0	0	61,542
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	51,337	0	0	51,337	0	0	51,337
69	Tools, Tools and Other	394.30	16,000,899	163,447	(5,303)	16,159,043	28,781	0	16,187,824
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	269,030	0	0	269,030	0	0	269,030
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	1,017,989	0	0	1,017,989	0	0	1,017,989
79	**Total Gas Plant in Service**		2,398,648,958	41,079,718	(2,585,429)	2,437,143,247	15,722,582	(2,304,285)	2,450,561,544

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Line No.	Description	Account No. (1)	Gas Plant in Service Plant Beginning Balance 1/31/2019 (2) $	Additions (3) $	Retirements (4) $	Balance as of 2/28/2019 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 3/31/2019 (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	23,052,624	77,645.33	(131,519.53)	22,998,750	115,137	0	23,113,887
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858	0	0	3,220,858
10	Wells Construction	352.01	799,134	0	(60,192.37)	738,941	0	0	738,941
11	Wells Equipment	352.02	168,680	0	(647.80)	168,032	0	0	168,032
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,487	0	0	399,487	0	0	399,487
15	Compressor Station Equipment	354.00	949,047	0	(774.99)	948,272	0	0	948,272
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	0	0	477,100	0	0	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,890,822	38.81	0	2,890,861	112,130	0	3,002,991
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,161	0	0	3,233,161	0	0	3,233,161
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,918,349	39,007.67	(1,131.19)	4,956,225	53,623	(1,775)	5,008,073
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	7,725,987	202,636.03	0	7,928,623	40,709	0	7,969,332
29	Structures, Other Distribution System, Leased	375.71	5,089,433	235,632.90	0	5,325,066	14,916	0	5,339,982
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,517,608,041	9,462,492.21	(47,790.13)	1,527,022,743	8,860,973	(305,192)	1,535,578,523
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	65,947,928	0	(64,324.21)	65,883,604	(11,629)	(38,384)	65,833,592
35	Cast Iron	376.80	298,776	0	(780.49)	297,995	0	(1,191)	296,805
36	Measuring & Regulating Equipment General	378.10	1,395,448	0	0	1,395,448	0	0	1,395,448
37	Measuring & Regulating Equipment Regulating	378.20	80,025,561	1,491,272.69	(38,845.60)	81,477,988	1,149,687	(97,143)	82,530,531
38	Measuring & Regulating Equipment Local Gas	378.30	456,357	0	(226.60)	456,130	0	(90)	456,040
39	Measuring & Regulating Equipment City Gate	379.10	136,417			136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)			(450)	0	0	(450)
41	Services	380.00	534,848,557	3,189,047.89	(511,298.15)	537,526,307	5,157,934	(457,163)	542,227,078
42	Meters	381.00	38,431,863	95,576.62	(5,178.42)	38,522,261	82,271	(47,550)	38,556,983
43	Auto Meter Reading Devices	381.10	24,447,901	14,033.50	0	24,461,934	0	0	24,461,934
44	Meter Installations	382.00	39,763,269	90,178.87	(5,820.61)	39,847,627	123,852	(4,003)	39,967,476
45	House Regulators	383.00	12,935,540	59,433.10	(508.53)	12,994,465	65,417	(267)	13,059,615
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,447,330	85,740.38	(12,682.04)	6,520,389	1,878	(3,638)	6,518,628
48	Industrial M&R Equipment. Large Volume	385.10	1,072,959	0	(2,712.75)	1,070,247	0	(4,730)	1,065,516
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,560	0	0	627,560	0	0	627,560
53	Other Equipment, Telemetering	387.45	8,858,823	314,964.85	(14,172.29)	9,159,616	(26,997)	0	9,132,619
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,459,573	0	0	2,459,573	0	0	2,459,573
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,534,899	0	0	4,534,899	0	0	4,534,899
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	45,313	0	0	45,313	0	(9,843)	35,470
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	61,542	0	0	61,542	0	0	61,542
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	51,337	0	0	51,337	0	0	51,337
69	Tools, Tools and Other	394.30	16,187,824	124,421.95	0	16,312,246	85,078	0	16,397,323
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	269,030	0	0	269,030	0	0	269,030
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	1,017,989	0	0	1,017,989	(35,619)	0	982,370
79	**Total Gas Plant in Service**		**2,450,561,544**	**15,482,123**	**(898,606)**	**2,465,145,061**	**15,789,357**	**(970,967)**	**2,479,963,451**

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Line No.	Description	Account No. (1)	Plant Beginning Balance 3/31/2019 (2) $	Additions (3) $	Retirements (4) $	Balance as of 4/30/2019 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 5/31/2019 (8)=(5+6+7) $
			Gas Plant in Service						
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099			100,099			100,099
3	Franchises/Consent, Perpetual	302.10	26,216			26,216			26,216
4	Intangible Plant, General	303.00	4,809,062			4,809,062			4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	23,113,887	245,947.46	(401,799.95)	22,958,035	712,218.48	(204,486.20)	23,465,767
6	**Underground Storage Plant**								
7	Land	350.10	23,882			23,882			23,882
8	Rights of Way	350.20	1,932			1,932			1,932
9	Compressor Station Structures	351.20	3,220,858			3,220,858			3,220,858
10	Wells Construction	352.01	738,941			738,941			738,941
11	Wells Equipment	352.02	168,032			168,032			168,032
12	Storage Leasehold and Rights	352.10	139,442			139,442			139,442
13	Other Leases	352.12	67,498			67,498			67,498
14	Lines	353.00	399,487			399,487			399,487
15	Compressor Station Equipment	354.00	948,272			948,272			948,272
16	Measuring & Regulating Equipment	355.00	104,477			104,477			104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944			21,944			21,944
19	Land, Other Distribution System	374.20	477,100			477,100			477,100
20	Land Rights, City Gate/Main Line	374.30	95,361			95,361			95,361
21	Land Rights, City Other Distribution System	374.40	3,002,991	6,118.68		3,009,110	(735.39)	(206.57)	3,008,168
22	Land Rights, City Other Distribution System, Loc	374.41	13			13			13
23	Rights of Way	374.50	3,233,161			3,233,161			3,233,161
24	Structures, City Gate Measurement & Regulating	375.20	7,026			7,026			7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012			4,012			4,012
26	Structures, Regulating	375.40	5,008,073	86,277.01	(4,619.52)	5,089,731	50,750.70	(7,516.08)	5,132,965
27	Structures, Distribution Industrial M&R	375.60	87,670			87,670			87,670
28	Structures, Other Distribution System	375.70	7,969,332	28,182.35		7,997,514	62,990.51	-	8,060,505
29	Structures, Other Distribution System, Leased	375.71	5,339,982	5,999.89		5,345,982	39,600.25	-	5,385,582
30	Structures, Communication	375.80	16,515			16,515			16,515
31	Mains:								
32	Mains	376.00	1,535,578,523	17,729,354.51	(1,204,403.13)	1,552,103,475	12,427,798.23	(655,768.06)	1,563,875,505
33	Mains - CSL Replacements	376.08	23,760,169			23,760,169	-	-	23,760,169
34	Bare Steel	376.30	65,833,592		(152,282.37)	65,681,309	-	(81,021.25)	65,600,288
35	Cast Iron	376.80	296,805		(9,726.47)	287,078	-	(5,642.27)	281,436
36	Measuring & Regulating Equipment General	378.10	1,395,448			1,395,448	59,167.64	(1,961.37)	1,452,654
37	Measuring & Regulating Equipment Regulating	378.20	82,530,531	362,159.50	(15,330.54)	82,877,360	148,590.78	(16,092.16)	83,009,859
38	Measuring & Regulating Equipment Local Gas	378.30	456,040	-	(529.00)	455,511	-	(594.32)	454,917
39	Measuring & Regulating Equipment City Gate	379.10	136,417			136,417			136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)			(450)			(450)
41	Services	380.00	542,227,078	5,441,057.24	(740,635.96)	546,927,499	4,486,401.53	(710,955.03)	550,702,946
42	Meters	381.00	38,556,983	61,078.78	(41,944.01)	38,576,118	258,528.66	(36,221.64)	38,798,425
43	Auto Meter Reading Devices	381.10	24,461,934	3,028.99	-	24,464,963	54,602.75	-	24,519,566
44	Meter Installations	382.00	39,967,476	123,813.22	(4,438.88)	40,086,851	81,351.48	(7,769.82)	40,160,432
45	House Regulators	383.00	13,059,615	76,948.16	(503.92)	13,136,059	50,417.15	(900.72)	13,185,575
46	House Regulators Installations	384.00	3,864,772			3,864,772	-	-	3,864,772
47	Industrial M&R Equipment. Station Equipment	385.00	6,518,628	145.03	(5,748.15)	6,513,025	(55,678.02)	(19,619.54)	6,437,727
48	Industrial M&R Equipment. Large Volume	385.10	1,065,516	-	(241.14)	1,065,275	-	(343.76)	1,064,931
49	Other Equipment	387.10	19,450			19,450	-	-	19,450
50	Other Equipment, Odorization	387.20	117,248			117,248	-	-	117,248
51	Other Equipment, Radio	387.42	119,609			119,609	-	-	119,609
52	Other Equipment, Other Communications	387.44	627,560			627,560	-	-	627,560
53	Other Equipment, Telemetering	387.45	9,132,619	(24,396.72)		9,108,222	108,471.98	(21,554.85)	9,195,139
54	Other Equipment, Customer Information Service	387.46	259,436			259,436	-	-	259,436
55	GPS Pipe Locators	387.50	2,201,372			2,201,372	-	-	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821			49,821			49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,459,573			2,459,573			2,459,573
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304			91,304			91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,534,899			4,534,899	(1,580.19)		4,533,319
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007			3,007			3,007
62	Transportation Equipment, Trailers > $1,000	392.20	35,470			35,470			35,470
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830			10,830			10,830
64	Stores Equipment	393.00	0			0			0
65	Tools, Garage & Service Equipment	394.10	61,542			61,542			61,542
66	Tools, CNG Equipment, Stationary	394.11	1,774,190			1,774,190			1,774,190
67	Tools, CNG Equipment, Portable	394.12	179,308			179,308			179,308
68	Tools, Shop Equipment	394.20	51,337			51,337			51,337
69	Tools, Tools and Other	394.30	16,397,323	(116,070.71)		16,281,253	44,966.50		16,326,219
70	Tools, High Pressure Stopping	394.31	10,847			10,847			10,847
71	Laboratory Equipment Gas	395.00	269,030			269,030			269,030
72	Power Operated Equipment	396.00	948,698			948,698			948,698
73	Communication Equipment	397.00	0			0			0
74	Communication Equipment, Telephone	397.10	0			0			0
75	Communication Equipment, Radio	397.20	0			0			0
76	Communication Equipment, Other	397.40	0			0			0
77	Communication Equipment, Telemetering	397.50	792,264			792,264			792,264
78	Miscellaneous Equipment	398.00	982,370			982,370			982,370
79	**Total Gas Plant in Service**		**2,479,963,451**	**24,029,643**	**(2,582,203)**	**2,501,410,891**	**18,527,863**	**(1,770,654)**	**2,518,168,101**

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Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 5/31/2019 (2) $	Additions (3) $	Retirements (4) $	Balance as of 6/30/2019 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 7/31/2019 (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	23,465,767	165,050	0	23,630,817	628,905	(319,371)	23,940,351
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858	0	0	3,220,858
10	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
11	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,487	0	0	399,487	0	0	399,487
15	Compressor Station Equipment	354.00	948,272	0	0	948,272	0	0	948,272
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	0	0	477,100	0	0	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	3,008,168	(12)	0	3,008,155	14,650	-	3,022,805
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,161	0	0	3,233,161	0	0	3,233,161
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	5,132,965	100	0	5,133,066	360	0	5,133,426
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375.70	8,060,505	0	0	8,060,505	1,854,931	0	9,915,436
29	Structures, Other Distribution System, Leased	375.71	5,385,582	70,313	0	5,455,895	31,797	0	5,487,692
30	Structures, Communication	375.80	16,515		0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,563,875,505	18,905,467	(719,650)	1,582,061,321	10,394,540	(577,411)	1,591,878,451
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	65,600,288	0	(76,765)	65,523,523	0	(97,615)	65,425,908
35	Cast Iron	376.80	281,436	0	(1,016)	280,420	0	0	280,420
36	Measuring & Regulating Equipment General	378.10	1,452,654	78	0	1,452,732	(42)	0	1,452,690
37	Measuring & Regulating Equipment Regulating	378.20	83,009,859	442,937	(9,963)	83,442,832	593,124	(12,072)	84,023,884
38	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	0	454,917	0	0	454,917
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	550,702,946	4,895,708	(673,760)	554,924,893	5,099,383	(528,114)	559,496,163
42	Meters	381.00	38,798,425	87,558	(54,402)	38,831,581	135,962	(64,792)	38,902,751
43	Auto Meter Reading Devices	381.10	24,519,566	473	0	24,520,039	4,998	0	24,525,037
44	Meter Installations	382.00	40,160,432	68,592	(6,531)	40,222,493	94,107	(6,449)	40,310,151
45	House Regulators	383.00	13,185,575	62,721	(745)	13,247,552	79,703	(734)	13,326,521
46	House Regulators Installations	384.00	3,864,772	0	0	3,864,772	0	(379,984)	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,437,727	5,941	(28,746)	6,414,922	2,868	607	6,418,397
48	Industrial M&R Equipment. Large Volume	385.10	1,064,931	0	(400)	1,064,531	0	(768)	1,063,763
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,560	0	0	627,560	0	0	627,560
53	Other Equipment, Telemetering	387.45	9,195,139	105,614	(33,027)	9,267,727	16,714	(8,929)	9,275,511
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,459,573	0	0	2,459,573	0	0	2,459,573
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,533,319	0	0	4,533,319	24,811	0	4,558,130
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	35,470	0	0	35,470	0	0	35,470
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	61,542	0	0	61,542	0	0	61,542
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	0	1,774,190	0	474,551	2,248,741
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	51,337	0	0	51,337	0	0	51,337
69	Tools, Tools and Other	394.30	16,326,219	138,370	0	16,464,589	86,029	0	16,550,618
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	269,030	0	0	269,030	0	0	269,030
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	0	792,264
78	Miscellaneous Equipment	398.00	982,370	0	0	982,370	0	0	982,370
79	**Total Gas Plant in Service**		**2,518,168,101**	**24,948,911**	**(1,605,005)**	**2,541,512,006**	**19,062,840**	**(1,521,081)**	**2,559,053,766**

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Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 7/31/2019 (2) $	Additions (3) $	Retirements (4) $	Balance as of 8/31/2019 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 9/30/2019 (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	23,940,351	31,964	(96,993)	23,875,322	73,514	0	23,948,837
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858	0	0	3,220,858
10	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
11	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	399,487	0	0	399,487	0	(10,142)	389,345
15	Compressor Station Equipment	354.00	948,272	0	0	948,272	0	0	948,272
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	0	0	477,100	0	0	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	3,022,805	224		3,023,029	0	0	3,023,029
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,161	0	0	3,233,161	0	0	3,233,161
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	5,133,426	743	0	5,134,169	38,780	(6,558)	5,166,391
27	Structures, Distribution Industrial M&R	375.60	87,670	0	0	87,670	0	(1,442)	86,228
28	Structures, Other Distribution System	375.70	9,915,436	0	0	9,915,436	0	(1,476)	9,913,960
29	Structures, Other Distribution System, Leased	375.71	5,487,692	0	0	5,487,692	0	0	5,487,692
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,591,878,451	15,981,312	(632,054)	1,607,227,708	28,226,034	(578,210)	1,634,875,533
33	Mains - CSL Replacements	376.08	23,760,169	0	0	23,760,169	0	0	23,760,169
34	Bare Steel	376.30	65,425,908	0	(53,624)	65,372,284	0	(166,968)	65,205,316
35	Cast Iron	376.80	280,420	0	(1,309)	279,112	0	(2,044)	277,067
36	Measuring & Regulating Equipment General	378.10	1,452,690	0	0	1,452,690	0	0	1,452,690
37	Measuring & Regulating Equipment Regulating	378.20	84,023,884	292,916	(4,342)	84,312,459	2,579,729	(44,416)	86,847,771
38	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	0	454,917	0	0	454,917
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	559,496,163	5,216,417	(818,914)	563,893,666	6,174,204	(2,049,118)	568,018,751
42	Meters	381.00	38,902,751	197,458	(35,620)	39,064,589	71,384	(119,147)	39,016,826
43	Auto Meter Reading Devices	381.10	24,525,037	6,007	0	24,531,044	592	0	24,531,637
44	Meter Installations	382.00	40,310,151	47,875	(5,861)	40,352,165	83,336	(13,185)	40,422,316
45	House Regulators	383.00	13,326,521	74,093	(474)	13,400,140	112,777	(1,140)	13,511,777
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,418,397	3,918	(46,356)	6,375,959	83,459	(55,590)	6,403,828
48	Industrial M&R Equipment. Large Volume	385.10	1,063,763	0	0	1,063,763	0	(3,303)	1,060,460
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,560	0	0	627,560	0	0	627,560
53	Other Equipment, Telemetering	387.45	9,275,511	88,838	(41,544)	9,322,805	5,343	(5,398)	9,322,750
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,459,573	0	(33,853)	2,425,719	0	(14,337)	2,411,382
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,558,130	0	(60,853)	4,497,277	0	0	4,497,277
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	35,470	0	0	35,470	0	(20,683)	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	61,542	0	(3,087)	58,454	0	0	58,454
66	Tools, CNG Equipment, Stationary	394.11	2,248,741	0	0	2,248,741	0	0	2,248,741
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	51,337	0	(15,884)	35,454	0	0	35,454
69	Tools, Tools and Other	394.30	16,550,618	161,016	(359,408)	16,352,226	90,843	(1,752)	16,441,317
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	269,030	0	0	269,030	0	0	269,030
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	0	792,264	0	(131)	792,133
78	Miscellaneous Equipment	398.00	982,370	0	(11,187)	971,183	0	0	971,183
79	**Total Gas Plant in Service**		**2,559,053,766**	**22,102,779**	**(2,221,361)**	**2,578,935,184**	**37,539,994**	**(3,095,040)**	**2,613,380,137**

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			Gas Plant in Service						
Line No.	**Description**	**Account No. (1)**	**Plant Beginning Balance 9/30/2019 (2) $**	**Additions (3) $**	**Retirements (4) $**	**Balance as of 10/31/2019 (5 = 2+3+4) $**	**Additions (6) $**	**Retirements (7) $**	**Balance as of 11/30/2019 (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	23,948,837	592,558	(23,419)	24,517,975	233,511	(177,062)	24,574,424
6	**Underground Storage Plant**								
7	Land	350.10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858	0	0	3,220,858
10	Wells Construction	352.01	738,941	0	0	738,941	0	0	738,941
11	Wells Equipment	352.02	168,032	0	0	168,032	0	0	168,032
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
14	Lines	353.00	389,345	0	0	389,345	0	0	389,345
15	Compressor Station Equipment	354.00	948,272	0	0	948,272	0	0	948,272
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	0	0	477,100	0	0	477,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	3,023,029	53,298	0	3,076,327	6,008	(62)	3,082,273
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
23	Rights of Way	374.50	3,233,161	0	0	3,233,161	0	0	3,233,161
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375.40	5,166,391	48,669	(24,317)	5,190,743	915	(7,202)	5,184,456
27	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228	0	0	86,228
28	Structures, Other Distribution System	375.70	9,913,960	0	0	9,913,960	3,144	0	9,917,104
29	Structures, Other Distribution System, Leased	375.71	5,487,692	0	0	5,487,692	225	0	5,487,917
30	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376.00	1,634,875,533	33,498,244	(674,065)	1,667,699,712	22,462,740	(1,298,716)	1,688,863,735
33	Mains - CSL Replacements	376.08	23,760,169	0	(185,665)	23,574,504	0	0	23,574,504
34	Bare Steel	376.30	65,205,316	0	(129,585)	65,075,731	0	(142,062)	64,933,670
35	Cast Iron	376.80	277,067	0	(10,431)	266,636	0	(3,396)	263,240
36	Measuring & Regulating Equipment General	378.10	1,452,690	656	0	1,453,346	(21)	(1,386)	1,451,939
37	Measuring & Regulating Equipment Regulating	378.20	86,847,771	5,695,900	(161,309)	92,382,362	954,879	(91,808)	93,245,433
38	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	0	454,917	0	0	454,917
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)	0	0	(450)
41	Services	380.00	568,018,751	7,517,840	(114,003)	575,422,588	6,565,839	(1,200,424)	580,788,003
42	Meters	381.00	39,016,826	103,241	(57,150)	39,062,916	116,543	(3,162)	39,176,296
43	Auto Meter Reading Devices	381.10	24,531,637	11,032	0	24,542,669	27,878	-	24,570,547
44	Meter Installations	382.00	40,422,316	88,919	0	40,511,235	84,898	(6,967)	40,589,166
45	House Regulators	383.00	13,511,777	99,338	0	13,611,115	78,880	(3,200)	13,686,795
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,403,828	5,087	(12,764)	6,396,150	(117)	(33,048)	6,362,985
48	Industrial M&R Equipment. Large Volume	385.10	1,060,460	0	(3,647)	1,056,813	531,978	(8,835)	1,579,956
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,560	0	0	627,560	0	0	627,560
53	Other Equipment, Telemetering	387.45	9,322,750	146,917	(12,871)	9,456,797	80,173	(17,782)	9,519,187
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	**General Plant**								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,411,382	0	(8,778)	2,402,604	0	(21,631)	2,380,973
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,497,277	0	0	4,497,277	1,357	0	4,498,635
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	58,454	0	(997)	57,458	0	0	57,458
66	Tools, CNG Equipment, Stationary	394.11	2,248,741	0	(13,264)	2,235,476	0	0	2,235,476
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	35,454	0	0	35,454	0	0	35,454
69	Tools, Tools and Other	394.30	16,441,317	0	(63,807)	16,377,510	0	(31,746)	16,345,764
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	269,030	0	0	269,030	0	0	269,030
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,133	0	0	792,133	0	0	792,133
78	Miscellaneous Equipment	398.00	971,183	0	0	971,183	0	0	971,183
79	**Total Gas Plant in Service**		**2,613,380,137**	**47,861,700**	**(1,496,073)**	**2,659,745,764**	**31,148,829**	**(3,048,489)**	**2,687,846,103**

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	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 11/30/2019 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2019 (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	708,668	(132,678)	25,150,414
6	**Underground Storage Plant**					
7	Land	350.10	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858
10	Wells Construction	352.01	738,941	0	0	738,941
11	Wells Equipment	352.02	168,032	0	0	168,032
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498
14	Lines	353.00	389,345	0	0	389,345
15	Compressor Station Equipment	354.00	948,272	0	0	948,272
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477
17	**Distribution Plant**					
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	2,884,000	0	3,361,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	3,082,273	92,478	(1,195)	3,173,555
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
23	Rights of Way	374.50	3,233,161	10	0	3,233,171
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012
26	Structures, Regulating	375.40	5,184,456	45,984	(3,897)	5,226,544
27	Structures, Distribution Industrial M&R	375.60	86,228	0	0	86,228
28	Structures, Other Distribution System	375.70	9,917,104	7,792,012	(177,785)	17,531,331
29	Structures, Other Distribution System, Leased	375.71	5,487,917	298,012	(12,476)	5,773,453
30	Structures, Communication	375.80	16,515	0	0	16,515
31	Mains:					
32	Mains	376.00	1,688,863,735	33,297,345	(5,884,107)	1,716,276,974
33	Mains - CSL Replacements	376.08	23,574,504	0	0	23,574,504
34	Bare Steel	376.30	64,933,670	0	(334,938)	64,598,732
35	Cast Iron	376.80	263,240	0	(30,851)	232,389
36	Measuring & Regulating Equipment General	378.10	1,451,939	0	(4,347)	1,447,592
37	Measuring & Regulating Equipment Regulating	378.20	93,245,433	2,144,924	(233,777)	95,156,580
38	Measuring & Regulating Equipment Local Gas	378.30	454,917	0	0	454,917
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)
41	Services	380.00	580,788,003	6,117,091	(2,320,491)	584,584,603
42	Meters	381.00	39,176,296	207,905	(64,825)	39,319,377
43	Auto Meter Reading Devices	381.10	24,570,547	2,044	0	24,572,591
44	Meter Installations	382.00	40,589,166	110,292	(29,106)	40,670,352
45	House Regulators	383.00	13,686,795	96,958	(1,248)	13,782,505
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,362,985	14	(9,683)	6,353,316
48	Industrial M&R Equipment. Large Volume	385.10	1,579,956	(531,978)	(3,683)	1,044,295
49	Other Equipment	387.10	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,560	0	(3,628)	623,932
53	Other Equipment, Telemetering	387.45	9,519,187	7,436	(3,258)	9,523,365
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372
56	**General Plant**					
57	Structures, Communications	390.10	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,380,973	0	(2,000)	2,378,973
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,498,635	12,140	(319,479)	4,191,295
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	14,787	0	0	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	57,458	0	(686)	56,772
66	Tools, CNG Equipment, Stationary	394.11	2,235,476	0	0	2,235,476
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	35,454	0	0	35,454
69	Tools, Tools and Other	394.30	16,345,764	289,521	(89,303)	16,545,982
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	269,030	0	0	269,030
72	Power Operated Equipment	396.00	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,133	0	(4,217)	787,916
78	Miscellaneous Equipment	398.00	971,183	0	0	971,183
79	**Total Gas Plant in Service**		2,687,846,103	53,574,856	(9,667,656) 1/	2,731,753,304

Columbia Gas of Pennsylvania
Schedule 108 - Case R-2018-2647577
Updated for Actuals Through December 31, 2019

SUMMARY

Line No.	Description	Account No. (1)	Plant Beginning Balance 11/30/2018 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2019 (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	22,754,436	4,958,463	(2,562,485)	25,150,414
			0	0	0	
6	**Underground Storage Plant**		0	0	0	
7	Land	350.10	23,882	0	0	23,882
8	Rights of Way	350.20	1,932	0	0	1,932
9	Compressor Station Structures	351.20	3,220,858	0	0	3,220,858
10	Wells Construction	352.01	799,134	0	(60,192)	738,941
11	Wells Equipment	352.02	168,680	0	(648)	168,032
12	Storage Leasehold and Rights	352.10	139,442	0	0	139,442
13	Other Leases	352.12	67,498	0	0	67,498
14	Lines	353.00	399,487	0	(10,142)	389,345
15	Compressor Station Equipment	354.00	949,047	0	(775)	948,272
16	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477
			0	0	0	
17	**Distribution Plant**		0	0	0	
18	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944
19	Land, Other Distribution System	374.20	477,100	2,884,000	0	3,361,100
20	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374.40	2,840,981	334,038	(1,464)	3,173,555
22	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13
23	Rights of Way	374.50	3,233,143	28	0	3,233,171
24	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012
26	Structures, Regulating	375.40	4,887,543	411,181	(72,180)	5,226,544
27	Structures, Distribution Industrial M&R	375.60	87,670	0	(1,442)	86,228
28	Structures, Other Distribution System	375.70	7,725,987	9,984,604	(179,261)	17,531,331
29	Structures, Other Distribution System, Leased	375.71	4,963,789	822,139	(12,476)	5,773,453
30	Structures, Communication	375.80	16,515	0	0	16,515
31	Mains:		0	0	0	
32	Mains	376.00	1,478,901,628	251,611,594	(14,236,248)	1,716,276,974
33	Mains - CSL Replacements	376.08	23,760,169	0	(185,665)	23,574,504
34	Bare Steel	376.30	66,059,026	(11,629)	(1,448,665)	64,598,732
35	Cast Iron	376.80	316,820	0	(84,431)	232,389
36	Measuring & Regulating Equipment General	378.10	1,369,583	85,703	(7,694)	1,447,592
37	Measuring & Regulating Equipment Regulating	378.20	80,283,601	15,701,138	(828,159)	95,156,580
38	Measuring & Regulating Equipment Local Gas	378.30	456,357	0	(1,440)	454,917
39	Measuring & Regulating Equipment City Gate	379.10	136,417	0	0	136,417
40	Measuring & Regulating Equipment Exchange Gas	379.11	(450)	0	0	(450)
41	Services	380.00	523,749,108	72,480,313	(11,644,817)	584,584,603
42	Meters	381.00	38,336,392	1,598,528	(615,543)	39,319,377
43	Auto Meter Reading Devices	381.10	23,950,869	621,722	0	24,572,591
44	Meter Installations	382.00	39,454,107	1,328,843	(112,597)	40,670,352
45	House Regulators	383.00	12,696,407	1,098,330	(12,232)	13,782,505
46	House Regulators Installations	384.00	3,864,772	0	(379,984)	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,450,339	156,076	(253,099)	6,353,316
48	Industrial M&R Equipment. Large Volume	385.10	1,072,959	0	(28,665)	1,044,295
49	Other Equipment	387.10	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	627,560	0	(3,628)	623,932
53	Other Equipment, Telemetering	387.45	8,426,202	1,274,968	(177,804)	9,523,365
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372
			0	0	0	
56	**General Plant**		0	0	0	
57	Structures, Communications	390.10	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	2,675,125	0	(296,152)	2,378,973
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	4,101,255	470,372	(380,332)	4,191,295
61	Office Furniture & Equipment, Air Condition Equip	391.20	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392.20	45,313	0	(30,526)	14,787
63	Transportation Equipment, Trailers $1,000 or <	392.21	10,830	0	0	10,830
64	Stores Equipment	393.00	11,885	0	(11,885)	0
65	Tools, Garage & Service Equipment	394.10	61,542	0	(4,770)	56,772
66	Tools, CNG Equipment, Stationary	394.11	1,774,190	0	461,287	2,235,476
67	Tools, CNG Equipment, Portable	394.12	179,308	0	0	179,308
68	Tools, Shop Equipment	394.20	51,337	0	(15,884)	35,454
69	Tools, Tools and Other	394.30	16,000,899	1,096,403	(551,319)	16,545,982
70	Tools, High Pressure Stopping	394.31	10,847	0	0	10,847
71	Laboratory Equipment Gas	395.00	269,030	0	0	269,030
72	Power Operated Equipment	396.00	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0
77	Communication Equipment, Telemetering	397.50	792,264	0	(4,348)	787,916
78	Miscellaneous Equipment	398.00	1,017,989	(35,619)	(11,187)	971,183
79	**Total Gas Plant in Service**		**2,398,648,958**	**366,871,195**	**(33,766,849)** **1/**	**2,731,753,304**

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.
Property, Plant & Equipment - Budget to Actual Comparison
2018 Rate Case at Docket R-2018-2647577

		Additions						
Ln.		Budget		Actuals		Month Over (Under)	Cumulative Spend Over (Under)	Over
No.	Month	Month	Cumulative	Month	Cumulative	Budget	Budget	(Under)
	(1)	(2)	(3)	(4)	(5)	(6)=(4-2)	(7)=(5-3)	(8)=(7/3)
		($)	($)	($)	($)	($)	($)	(%)
1	11/30/2018	30,585,254	293,995,887	22,107,769	255,052,013	(8,477,485)	(38,943,874.60)	-13.25%
2	12/31/2018	51,374,285	345,370,173	41,079,718	296,131,730	(10,294,568)	(49,238,442.39)	-14.26%
3	1/31/2019	3,226,426	348,596,599	15,722,582	311,854,313	12,496,156	(36,742,286)	-10.54%
4	2/28/2019	5,712,887	354,309,486	15,482,123	327,336,436	9,769,236	(26,973,050)	-7.61%
5	3/31/2019	11,643,727	365,953,213	15,789,357	343,125,792	4,145,630	(22,827,421)	-6.24%
6	4/30/2019	21,069,391	387,022,603	24,029,643	367,155,436	2,960,253	(19,867,168)	-5.13%
7	5/31/2019	29,599,089	416,621,693	18,527,863	385,683,299	(11,071,226)	(30,938,394)	-7.43%
8	6/30/2019	28,987,570	445,609,262	24,948,911	410,632,209	(4,038,659)	(34,977,053)	-7.85%
9	7/31/2019	18,905,925	464,515,187	19,062,840	429,695,049	156,915	(34,820,138)	-7.50%
10	8/31/2019	25,395,692	489,910,879	22,102,779	451,797,829	(3,292,913)	(38,113,050)	-7.78%
11	9/30/2019	29,343,961	519,254,840	37,539,994	489,337,822	8,196,033	(29,917,017)	-5.76%
12	10/31/2019	30,061,880	549,316,720	47,861,700	537,199,522	17,799,820	(12,117,197)	-2.21%
13	11/30/2019	30,818,169	580,134,888	31,148,829	568,348,351	330,661	(11,786,537)	-2.03%
14	12/31/2019	51,765,513	631,900,401	53,574,856	621,923,207	1,809,343	(9,977,194)	-1.58%

		Retirements						
Ln.		Budget		Actuals		Month (Over) Under	Cumulative (Over) Under	Over
No.	Month	Month	Cumulative	Month	Cumulative	Budget	Budget	(Under)
	(1)	(2)	(3)	(4)	(5)	(6)=(4-2)	(7)=(5-3)	(8)=(7/3)
		($)	($)	($)	($)	($)	($)	(%)
1	11/30/2018	(2,530,176)	(29,604,447)	(2,139,050)	(27,529,398)	391,127	2,075,049	-7.01%
2	12/31/2018	(3,443,598)	(33,048,045)	(2,585,429)	(30,114,827)	858,169	2,933,218	-8.88%
3	1/31/2019	(988,073)	(34,036,118)	(2,304,285)	(32,419,112)	(1,316,212)	1,617,006	-4.75%
4	2/28/2019	(1,322,012)	(35,358,130)	(898,606)	(33,317,718)	423,406	2,040,412	-5.77%
5	3/31/2019	(1,799,739)	(37,157,869)	(970,967)	(34,288,685)	828,772	2,869,184	-7.72%
6	4/30/2019	(2,022,824)	(39,180,693)	(2,582,203)	(36,870,888)	(559,379)	2,309,805	-5.90%
7	5/31/2019	(2,240,667)	(41,421,360)	(1,770,654)	(38,641,542)	470,013	2,779,818	-6.71%
8	6/30/2019	(2,694,178)	(44,115,537)	(1,605,005)	(40,246,547)	1,089,173	3,868,991	-8.77%
9	7/31/2019	(2,727,853)	(46,843,390)	(1,521,081)	(41,767,627)	1,206,772	5,075,763	-10.84%
10	8/31/2019	(2,736,713)	(49,580,103)	(2,221,361)	(43,988,988)	515,351	5,591,114	-11.28%
11	9/30/2019	(2,884,142)	(52,464,245)	(3,095,040)	(47,084,029)	(210,898)	5,380,216	-10.26%
12	10/31/2019	(2,934,352)	(55,398,597)	(1,496,073)	(48,580,102)	1,438,278	6,818,494	-12.31%
13	11/30/2019	(2,516,479)	(57,915,076)	(3,048,489)	(51,628,592)	(532,010)	6,286,484	-10.85%
14	12/31/2019	(3,319,932)	(61,235,008)	(9,667,656) **1/**	(61,296,247)	(6,347,723)	(61,239)	0.10%

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).

		Gross Plant in Service						
Ln.		Budget		Actuals		Month Over (Under)	Cululative Over (Under)	Over
No.	Month	Month	Cumulative	Month	Cumulative	Budget	Budget	(Under)
	(1)	(2)	(3)	(4)	(5)	(6)=(4-2)	(7)=(5-3)	(8)=(7/3)
		($)	($)	($)	($)	($)	($)	(%)
1	11/30/2018	28,055,078	264,391,440	19,968,719	227,522,615	(8,086,359)	(36,868,825)	-13.94%
2	12/31/2018	47,930,687	312,322,127	38,494,289	266,016,903	(9,436,399)	(46,305,224)	-14.83%
3	1/31/2019	2,238,353	314,560,481	13,418,297	279,435,201	11,179,944	(35,125,280)	-11.17%
4	2/28/2019	4,390,875	318,951,356	14,583,517	294,018,718	10,192,642	(24,932,638)	-7.82%
5	3/31/2019	9,843,988	328,795,344	14,818,389	308,837,107	4,974,401	(19,958,237)	-6.07%
6	4/30/2019	19,046,567	347,841,911	21,447,440	330,284,548	2,400,874	(17,557,363)	-5.05%
7	5/31/2019	27,358,422	375,200,333	16,757,209	347,041,757	(10,601,213)	(28,158,576)	-7.50%
8	6/30/2019	26,293,392	401,493,725	23,343,906	370,385,663	(2,949,486)	(31,108,062)	-7.75%
9	7/31/2019	16,178,072	417,671,797	17,541,759	387,927,422	1,363,687	(29,744,375)	-7.12%
10	8/31/2019	22,658,979	440,330,776	19,881,418	407,808,840	(2,777,561)	(32,521,936)	-7.39%
11	9/30/2019	26,459,818	466,790,595	34,444,953	442,253,794	7,985,135	(24,536,801)	-5.26%
12	10/31/2019	27,127,528	493,918,123	46,365,626	488,619,420	19,238,098	(5,298,703)	-1.07%
13	11/30/2019	28,301,689	522,219,812	28,100,340	516,719,760	(201,349)	(5,500,052)	-1.05%
14	12/31/2019	48,445,581	570,665,393	43,907,200	560,626,960	(4,538,380)	(10,038,433)	-1.76%

Columbia Gas of Pennsylvania, Inc.
Property, Plant & Equipment - Budget to Actual Comparison
2018 Rate Case at Docket R-2018-2647577

Additions

Ln. No.	Month (1)	Budget Month (2) ($)	Budget Cumulative (3) ($)	Actuals Month (4) ($)	Actuals Cumulative (5) ($)	Month Over (Under) Budget (6)=(4-2) ($)	Cumulative Spend Over (Under) Budget (7)=(5-3) ($)	Over (Under) (8)=(7/3) (%)
1	11/30/2018	30,585,254	293,995,887	22,107,769	255,052,013	(8,477,485)	(38,943,874.60)	-13.25%
2	12/31/2018	51,374,285	345,370,173	41,079,718	296,131,730	(10,294,568)	(49,238,442.39)	-14.26%
3	1/31/2019	3,226,426	348,596,599	15,722,582	311,854,313	12,496,156	(36,742,286)	-10.54%
4	2/28/2019	5,712,887	354,309,486	15,482,123	327,336,436	9,769,236	(26,973,050)	-7.61%
5	3/31/2019	11,643,727	365,953,213	15,789,357	343,125,792	4,145,630	(22,827,421)	-6.24%
6	4/30/2019	21,069,391	387,022,603	24,029,643	367,155,436	2,960,253	(19,867,168)	-5.13%
7	5/31/2019	29,599,089	416,621,693	18,527,863	385,683,299	(11,071,226)	(30,938,394)	-7.43%
8	6/30/2019	28,987,570	445,609,262	24,948,911	410,632,209	(4,038,659)	(34,977,053)	-7.85%
9	7/31/2019	18,905,925	464,515,187	19,062,840	429,695,049	156,915	(34,820,138)	-7.50%
10	8/31/2019	25,395,692	489,910,879	22,102,779	451,797,829	(3,292,913)	(38,113,050)	-7.78%
11	9/30/2019	29,343,961	519,254,840	37,539,994	489,337,822	8,196,033	(29,917,017)	-5.76%
12	10/31/2019	30,061,880	549,316,720	47,861,700	537,199,522	17,799,820	(12,117,197)	-2.21%
13	11/30/2019	30,818,169	580,134,888	31,148,829	568,348,351	330,661	(11,786,537)	-2.03%
14	12/31/2019	51,765,513	631,900,401	53,574,856	621,923,207	1,809,343	(9,977,194)	-1.58%

Retirements

Ln. No.	Month (1)	Budget Month (2) ($)	Budget Cumulative (3) ($)	Actuals Month (4) ($)	Actuals Cumulative (5) ($)	Month (Over) Under Budget (6)=(4-2) ($)	Cumulative (Over) Under Budget (7)=(5-3) ($)	Over (Under) (8)=(7/3) (%)
1	11/30/2018	(2,530,176)	(29,604,447)	(2,139,050)	(27,529,398)	391,127	2,075,049	-7.01%
2	12/31/2018	(3,443,598)	(33,048,045)	(2,585,429)	(30,114,827)	858,169	2,933,218	-8.88%
3	1/31/2019	(988,073)	(34,036,118)	(2,304,285)	(32,419,112)	(1,316,212)	1,617,006	-4.75%
4	2/28/2019	(1,322,012)	(35,358,130)	(898,606)	(33,317,718)	423,406	2,040,412	-5.77%
5	3/31/2019	(1,799,739)	(37,157,869)	(970,967)	(34,288,685)	828,772	2,869,184	-7.72%
6	4/30/2019	(2,022,824)	(39,180,693)	(2,582,203)	(36,870,888)	(559,379)	2,309,805	-5.90%
7	5/31/2019	(2,240,667)	(41,421,360)	(1,770,654)	(38,641,542)	470,013	2,779,818	-6.71%
8	6/30/2019	(2,694,178)	(44,115,537)	(1,605,005)	(40,246,547)	1,089,173	3,868,991	-8.77%
9	7/31/2019	(2,727,853)	(46,843,390)	(1,521,081)	(41,767,627)	1,206,772	5,075,763	-10.84%
10	8/31/2019	(2,736,713)	(49,580,103)	(2,221,361)	(43,988,988)	515,351	5,591,114	-11.28%
11	9/30/2019	(2,884,142)	(52,464,245)	(3,095,040)	(47,084,029)	(210,898)	5,380,216	-10.26%
12	10/31/2019	(2,934,352)	(55,398,597)	(1,496,073)	(48,580,102)	1,438,278	6,818,494	-12.31%
13	11/30/2019	(2,516,479)	(57,915,076)	(3,048,489)	(51,628,592)	(532,010)	6,286,484	-10.85%
14	12/31/2019	(3,319,932)	(61,235,008)	(9,667,656) 1/	(70,798,304)	(6,347,723)	(9,563,295)	15.62%

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).

Gross Plant in Service

Ln. No.	Month (1)	Budget Month (2) ($)	Budget Cumulative (3) ($)	Actuals Month (4) ($)	Actuals Cumulative (5) ($)	Month Over (Under) Budget (6)=(4-2) ($)	Cululative Over (Under) Budget (7)=(5-3) ($)	Over (Under) (8)=(7/3) (%)
1	11/30/2018	28,055,078	264,391,440	19,968,719	227,522,615	(8,086,359)	(36,868,825)	-13.94%
2	12/31/2018	47,930,687	312,322,127	38,494,289	266,016,903	(9,436,399)	(46,305,224)	-14.83%
3	1/31/2019	2,238,353	314,560,481	13,418,297	279,435,201	11,179,944	(35,125,280)	-11.17%
4	2/28/2019	4,390,875	318,951,356	14,583,517	294,018,718	10,192,642	(24,932,638)	-7.82%
5	3/31/2019	9,843,988	328,795,344	14,818,389	308,837,107	4,974,401	(19,958,237)	-6.07%
6	4/30/2019	19,046,567	347,841,911	21,447,440	330,284,548	2,400,874	(17,557,363)	-5.05%
7	5/31/2019	27,358,422	375,200,333	16,757,209	347,041,757	(10,601,213)	(28,158,576)	-7.50%
8	6/30/2019	26,293,392	401,493,725	23,343,906	370,385,663	(2,949,486)	(31,108,062)	-7.75%
9	7/31/2019	16,178,072	417,671,797	17,541,759	387,927,422	1,363,687	(29,744,375)	-7.12%
10	8/31/2019	22,658,979	440,330,776	19,881,418	407,808,840	(2,777,561)	(32,521,936)	-7.39%
11	9/30/2019	26,459,818	466,790,595	34,444,953	442,253,794	7,985,135	(24,536,801)	-5.26%
12	10/31/2019	27,127,528	493,918,123	46,365,626	488,619,420	19,238,098	(5,298,703)	-1.07%
13	11/30/2019	28,301,689	522,219,812	28,100,340	516,719,760	(201,349)	(5,500,052)	-1.05%
14	12/31/2019	48,445,581	570,665,393	43,907,200	560,626,960	(4,538,380)	(10,038,433)	-1.76%

COLUMBIA STATEMENT NO. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MICHAEL J. DAVIDSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

April 24, 2020

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I. Introduction

Q. Please state your name and business address.

A. Michael J. Davidson, 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 General Manager and Vice President.

Q. What are your responsibilities as General Manager and Vice President?

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. What is your educational background and professional experience?

A. I graduated from Pennsylvania State University, earning an Associate Degree in Electrical Engineering Technology. Following nearly five years of service in the United States Air Force, I attended Point Park College, earning a Bachelor's Degree in Electrical Engineering Technology and then earned a Master's Degree in Public Management from Carnegie Mellon University. I have also earned a Six Sigma Black Belt certification from the University of Michigan College of Engineering.

Following my military service, I joined Equitable Gas as a Communications Specialist. My primary job duties were the installation and maintenance of pipeline SCADA systems, electronic measurement equipment and microwave communication systems (1991-1996). I then joined Columbia in 1997 and have held a number of management roles of increasing responsibility. Functional areas that I have had the opportunity to lead include: operations planning, business improvement, applications support, integration center (operations workforce management), meter to cash, and customer contact centers.

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

A. Yes. I provided direct testimony in Columbia's 2015 and 2018 rate cases. I also provided direct testimony before the Maryland Public Service Commission in the

2016, 2017, 2018 and 2019 Columbia Gas of Maryland rate cases.

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

A. My industry affiliations include: Membership in the American Gas Association, and the Southern Gas Association and the Energy Association of Pennsylvania.

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. Overview of Columbia's Pipeline Distribution System

Q. Please describe Columbia's distribution system.

A. Currently, Columbia serves approximately 433,000 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 7,662 miles of distribution and transmission mains and approximately 432,278 services that it owns, operates, and maintains.[1] These facilities (as of January 1, 2019) are composed of approximately 1,203 miles of bare steel, 21 miles of cathodically protected bare steel, 14 miles of cast iron, 68 miles of wrought iron mains (in total, 1,306 miles of "first generation" main), and 45,815 bare steel services.[2] The balance of the system is comprised of cathodically protected coated steel, or plastic (polyethylene) mains and services, and 29.6 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

[1] I note that in compliance with Section 1510 of the Pennsylvania Public Utility Code, in Western Pennsylvania the Company does not own the service lines all the way to the building, but terminates its ownership at the curb valve, typically found at or near the property line. If there is no curb valve on the service line, Columbia's ownership terminates at the property line itself. The customer then installs and maintains the remainder of the service line to the building.

[2] The terms "bare steel," "unprotected coated steel," "unprotected steel," and "wrought iron" as explained further below, are used interchangeably and all refer to steel pipe without cathodic protection that is susceptible to corrosion.

[3] It should be noted that in 2011 Columbia deployed a Geographical Information System ("GIS") Mapping System to provide both mapping and data retrieval capabilities on its system and facilities. The 29.6 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.

transmission pressure to local distribution pressure, further filters the gas to remove moisture and particulates that may damage Columbia's system, and then in some cases increases the amount of odorant known as mercaptan (the "rotten egg smell") to the natural gas before it is put into the distribution system. The gas then goes into the Columbia 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 of the meter (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 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. 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. Further, since that time Columbia has retrofitted all of its unprotected coated steel facilities with cathodic protection systems.

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, typically installed between 1970 and 1981 in most distribution systems and softer than today's "418 PE" material (due to the different composition of the base plastic material), has demonstrated itself to be prone to stress propagation cracking under some circumstances. 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. Columbia has made significant progress in reducing facility damage rates. In 2007, damages per thousand locates were at 5.39. In 2019, damages per thousand locates were at 1.98. 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 system, at 57% of total damages in 2019. 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 issue that the industry has identified as "First Generation" plastic pipe, Columbia is replacing those sections of first generation plastic pipe that are uncovered in the course of executing the bare steel and cast iron replacement program, which I discuss later in my testimony. Further, 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. <u>Federal Pipeline Safety Rules and Advisories</u>

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

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

- <u>Integrity Management Program for Gas Distribution Pipelines</u> (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.

- Pipeline Safety: Operator Qualification, Cost Recovery, Accident and Incident Notification, and Other Pipeline Safety Proposed Changes (82 FR 7972) – This rule revises the federal pipeline safety regulations to modify several requirements, including adding a specific time frame for telephone and electronic incident notifications, requires Control Room training and the inspection of regulators and related components installed on a Farm Tap if not addressed by the Operator's DIMP (84 FR 11253, Pipeline Safety: Exercise of Enforcement Discretion Regarding Farm Taps). A Farm Tap is defined as a service line served by a production line, gathering line, or transmission line. In addressing this final rule, Columbia has amended its existing procedures or created new procedures to address these requirements.
- Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments (84 FR 52180) – Pursuant to National Transportation Safety Board ("NTSB") recommendations and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, PHMSA has promulgated regulations governing the safety of gas transmission pipelines. The purpose of this final rule is to increase the level of safety associated with the transportation of gas. This rule requires operators of certain onshore steel gas transmission pipeline

segments to reconfirm the maximum allowable operating pressure ("MAOP") of those segments and gather any necessary material property records they might need to do so, where the records needed to substantiate the MAOP are not traceable, verifiable, and complete. This includes previously untested pipelines, which are commonly referred to as "grandfathered" pipelines, operating at or above 30 percent of specified minimum yield strength ("SMYS"). Records to confirm MAOP include pressure test records or material property records (mechanical properties) that verify the MAOP is appropriate for the class location. Operators with missing records can choose one of six methods to reconfirm their MAOP and must keep the record that is generated by this exercise for the life of the pipeline. PHMSA has also created an opportunistic method by which 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: Plastic Pipe Rule (83 FR 58694) - PHMSA has amended the plastic pipe pipeline safety regulations (49 CFR Part 192) to address regulatory requirements to correct errors, address inconsistencies, and respond to petitions for rulemaking. This rulemaking limits these changes to new, repaired, and replaced pipelines. The changes include increasing the design factor of polyethylene pipe; new standards for risers; more stringent standards for plastic fittings and joints; stronger mechanical fitting requirements; new and expanded standards for the installation of plastic pipe; the installation of plastic pipe; new or updated consensus standards for pipe, fittings, and other components; the qualification of procedures and personnel for joining plastic pipe; and the installation of plastic pipe.

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

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

- Pipeline Safety - Safety of Gas Transmission Pipelines, Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (PHMSA-2011-0023 RIN 2137–AF39) - This rulemaking would amend the pipeline safety regulations relevant to gas transmission pipelines by adjusting the repair criteria in HCAs and creating new criteria for non-HCAs, requiring the inspection of pipelines following extreme events, requiring safety features on in-line inspection tool launchers and receivers, updating and bolstering pipeline corrosion control, codifying a management of change process, clarifying certain IM provisions, and strengthening IM assessment requirements.
- NTSB Recommendation P-12-17 Pipeline Safety Management Systems (API Recommended Practice 1173) – Conceptually, Pipeline Safety Management Systems are built on the premise that managing the safety of a complex industry requires a system of efforts to address multiple, dynamic, changing activities, and circumstances. It further reflects the PHMSA view that if the industry is to achieve the goal of zero incidents, a highly structured and comprehensive effort is required. The broad components of these plans would include:
    - Demonstrated management commitment
    - Structured pipeline safety risk management decisions
    - Increased confidence in risk prevention and mitigation

- Providing a platform for shared knowledge and lessons learned
- Promoting a pipeline safety oriented culture

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

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

Q. Will PHMSA's focus on Transmission Lines have any significant impact on Columbia operations?

A. Yes, "Transmission Line" is defined in CFR 49, Part 192 as "a pipeline, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream of a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS [System Minimum Yield Strength]; or (3) transports gas within a storage field." Columbia has 40.2 miles of transmission class pipelines (4.6 miles within HCAs) per the 2018 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. <u>Strategic O&M Safety Initiatives</u>

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

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

- **Low Pressure Program.** Columbia has initiated a Low Pressure ("LP") Program that is comprised of several actions designed to improve safety on these gas systems. The Company completed a field survey of all low pressure systems and gas regulator stations in order to enhance our data, mapping, isometric drawings and geographic information system ("GIS") information. The Company also evaluated its engineering designs in order to support both enhanced field practices as well as asset modifications. Columbia has implemented enhanced damage prevention practices to include additional station monitoring whenever excavation is occurring within proximity to regulator stations. Columbia has also established enhanced 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.

To address the potential for human error in addition to its process and procedure improvements, Columbia has developed designs to modify its low pressure systems to add an additional level of overpressure protection and redundancy such that they are equivalent to more modern elevated pressure systems. The work involves installing an automatic shut off device as 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 373 miles of sanitary and storm sewer mains, and 25,903 customer laterals since 2013. During this inspection, 406 cross bores were identified, with 278 of those involving Columbia's system. Given program results, cross bores are now identified as a high risk in Columbia's DIMP plan. As a high risk, the program should be completed in as short a period as practical. With limitations in the ramping up of resources to perform this work, a staged approach is required. The first stage is to increase the program resources in 2021 by $1.4 million dollars. This would place the program on a 31 year pace, from the current estimated 68 year pace, cutting the current timeframe in less than half. The Company intends to make future recommendations to further reduce the program timeframe as current resource constraints diminish. The annual incremental O&M cost of $1.4 million is reflected as part of the ratemaking adjustment of $3,895,910 noted on Exhibit No. 104, Schedule No. 2, Page 18, Line 11.

- **Workforce Transition – Gas Qualifications Specialists.** As Columbia works to build the pipeline of the future, the Company also finds itself in the midst of building the workforce of the future. With the ramp up of the capital program, Columbia has experienced the transfer of employees from O&M positions to capital construction positions; in addition, the Company continues to see an increase in the number of employees who are eligible to retire. Columbia sees both opportunity and risk in the current and future transition of its workforce. Columbia's historical methods of training were developed in an era of very low turnover and well-established institutional knowledge. These traditional training methods will not address the increased risk of human error to its system introduced by this large scale workforce transition. The Company has adjusted its methods of training to reduce that risk for new and existing employees. Columbia is currently conducting a formal employee training and qualification program to address its DIMP plan and system risks associated with human error in the field. These programs not only include more classroom time and far more stringent testing procedures, where appropriate, they also require hands-on demonstrations of necessary skills to validate employee or contractor qualification competency prior to work with the Company's live natural gas system. Columbia has made organizational changes to focus on training and development of employees that are vital in preparing the next generation of employees, so as to minimize risk to employees, our customers, and the general public. To support this ongoing effort, Columbia is seeking to add two Gas Qualifications Specialists to conduct hands on skill performance evaluations and proctor knowledge exams as needed. They would also participate in auditing Approved Providers working with our Contractors to ensure adherence to the operator qualification plan. The projected O&M expense is $185,000 for the two positions. The annual incremental O&M cost of $185,000 is reflected as part of the ratemaking adjustment of $3,895,910 noted on Exhibit No. 104, Schedule No. 2, Page 18, Line 11.

- **Legacy Service Line Enhancement Program.** In January 2019, Columbia implemented a legacy service line record enhancement program. This effort was established to correct inaccurate and/or incomplete data within legacy records. Accurate records are critical to ongoing maintenance of the system. Currently the program is staffed with temporary employees, which has presented challenges to the effort due to increased turnover and training. To alleviate the challenges of staffing the program with temporary employees only, Columbia intends to add seven full-time employees, and supplement with temporary employees to accelerate the program. This would result in an additional $491,000 in O&M expense. The annual incremental O&M cost of $491,000 is reflected as part of the ratemaking adjustment of $3,895,910 noted on Exhibit No. 104, Schedule No. 2, Page 18, Line 11.

- **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. Columbia noted in its 2018 rate case that its budget did not include any amounts dedicated to replacement of customer-owned field assembled risers. To expand the program on customer-owned facilities, Columbia is including an additional $1.7 million for the program in 2021. The annual incremental O&M cost of $1.7 million is reflected as part of the ratemaking adjustment of $3,895,910 noted on Exhibit No. 104, Schedule No. 2, Page 18, Line 11.

- **Picarro Leak Detection Program.** In 2021, Columbia intends to employ 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. Specifically, the Picarro platform system will 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.

The Picarro platform system is a hardware-enabled descriptive and predictive analytics platform (which can be added to a company vehicle), that combines state of the art sensors with energy utility application focused analytics. The Picarro system will enable Columbia to leverage the data capture capability of its hardware combined with associated analytics to support a more advanced leak detection approach.

Columbia will equip two of its vehicles with Picarro platform systems. These two platforms will cost approximately $3.1 million dollars in total which will include: two platform systems, annual maintenance and 24/7 support for the platform systems and the cost of the vehicles which will be equipped with the platforms. Of the $3.1 million dollars, the Company plans to capitalize $2.5 million dollars for the platform systems and expense the remaining $0.6 million as annual incremental O&M of the next five years. The annual incremental O&M cost of $120,000 per year is reflected as part of the ratemaking adjustment of $3,895,910 noted on Exhibit No. 104, Schedule No. 2, Page 18, Line 11.

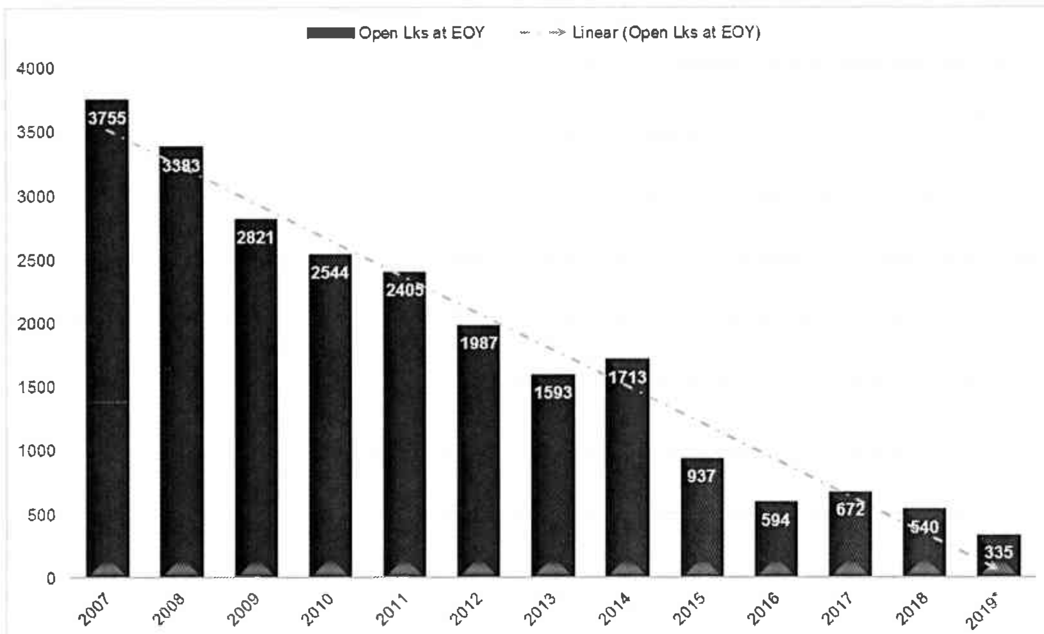
- **Safety Management System (SMS).** As previously noted in my testimony, Columbia is pursuing the adoption and implementation of a Safety Management System (SMS). As an early adopter of deploying an SMS, Columbia has aggressively educated the entire workforce and key contractor resources on what it 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 bare steel, cast iron, and wrought iron 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:

- *Reduction of Type-2 leaks.* Columbia reduced the number of open Type-2 leaks in the Columbia distribution system as measured by the annual Federal DOT report. It is worth noting that corrosion on bare steel is identified as a high level DIMP plan risk in the Columbia system, and that roughly 60% of leaks in the system are caused by corrosion on bare steel. Further, this is a significant undertaking in assuring safe and reliable service to customers, as the greater the number of leaks in a system and the longer they are left unattended, the greater the potential risk of gas migrating into a structure or other underground facility. The result of this focused effort was that at the end of 2007 (the first full year of Columbia's annual system wide bare steel survey), Columbia reported a total of 3,755 open Type-2 leaks in its distribution system. As you can see from the table below, as of December 31, 2019, Columbia has reduced that number to 335[4] open Type-2 leaks, which equates to a nearly 91% reduction in open Type-2 leaks over the last 13 years.



In addition, as indicated in its DIMP plan, Columbia intends to continue to aggressively manage its Type-2 open leaks.

- *Excavator Damage Efforts.* Columbia continues to routinely conduct face-to-face meetings with excavators who are frequent damagers and has added

[4] 2019 represents a preliminary total with final numbers expected to be available in March 2020 as required by 49 CFR Part 191 for the U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration Annual Report.

resources to accelerate this activity. Damage prevention coordinators educate contractor employees in safe excavating practices and the coordinators remind contractors of the potential consequences of damaging natural gas facilities. These efforts have contributed to the 63% reduction in the damage rate on Columbia's system between 2007 and 2019, from a damage per thousand (locate requests) rate of 5.39 in 2007 to a damage per thousand rate of 1.98 through December 31, 2019.

- *Training Center*. Columbia constructed a new training center that opened in mid-2016 which provides the facilities needed to conduct classroom training and enhanced hands on training. The facility is currently being used for multiple training purposes, including: new employee training, employees transitioning into higher skilled positions, and annual refresher training for the existing workforce. 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 five 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 2019 as follows:

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

**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[5]. As more and more customers need to take time off from work to provide access to their homes for routine meter turn-on, turn-off, and other service related activities, it is incumbent upon the Company to be as efficient as possible with the customers' time. Therefore, in 2007, Columbia began to focus specific attention on improving its percentage of on-time appointments. It did so by tasking the Integration Center (Columbia's 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 98.7% in 2019.

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 and has achieved top decile performance in OSHA Recordable Injuries, as measured by American Gas

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

Association benchmarking. For comparison, at the end of 2006, Columbia had 48 OSHA recordable injuries, and in 2019 that number was 14 OSHA recordable injuries. 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 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, and managers. These teams make recommendations on, and implement, safety improvement opportunities.
- Columbia undertakes a root cause analysis of every OSHA recordable injury and preventable vehicle accident that involves a Columbia employee. Near miss discussions are also conducted.
- Columbia delivers safety training to all employees. This training spans skills from driving maneuverability to office ergonomics.
- Columbia conducts an employee safety audit program in which leaders perform safety audits on field activities, and provide feedback to employees' on their safety performance.

- Columbia employees evaluate the hazards at each jobsite prior to beginning work and complete a safety check list which is reviewed with each employee.

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.

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-2020-3018835

April 24, 2020

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 and the superior performance of its management, as described in the testimony of witness Huwar, President of the Company (Columbia Statement No. 1), it is my opinion that the rate of return on common equity should be set at 10.95%. 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, 2021 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	42.22%	4.70%	1.98%
Short-Term Debt	3.59%	2.06%	0.07%
Total Debt	45.81%		2.05%
Common Equity	54.19%	10.95%	5.93%
Total	100.00%		7.98%

The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

Q. **What background information have you considered in reaching a conclusion concerning the Company's cost of capital?**

A. The Company is a wholly-owned subsidiary of NiSource Gas Distribution Group, which is a wholly-owned subsidiary of NiSource Inc. ("NiSource"). NiSource is a holding company under the Public Utility Holding Company Act of 2005 ("PUHCA") and also owns Northern Indiana Public Service Company (a combination gas and electric utility), Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, and other energy investments.

The Company provides natural gas distribution service to approximately 433,000 customers located in south-central and western Pennsylvania. Throughput to its customers for the twelve-months ended December 31, 2018 was represented by approximately 47% to sales customers and approximately 53% to transportation customers. CPA obtains its gas supplies from producers and marketers and has transportation arrangements through connections with six interstate pipelines. The Company has storage arrangements with three suppliers to supplement flowing gas.

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

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a gas distribution utility, such as the Company. In this regard, I have considered four (4) well-recognized models. These methods include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's rate of return on common equity is 10.95%, including a provision for the exemplary performance of the Company's management.

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

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

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

[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).

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 electric generation. The companies in the Gas Group are identified on page 2 of Schedule 3. These are the same companies that were used to apply the cost of equity models in the recent Quarterly Earnings Report approved by the Commission on November 14, 2019.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

	Gas Group
DCF	11.91%
Risk Premium	10.50%
CAPM	10.19%
Comparable Earnings	12.75%

From these measures, I recommend a cost of equity of 10.95% including recognition of the exemplary performance of the Company's management. Witness Huwar has shown that the Company ranks high in customer service and management efficiency. In recognition of its outstanding performance, the Company should be granted an opportunity to earn an 10.95% rate of return on common equity. The 10.95% rate of return on common equity, which includes 20 basis points in recognition of the exemplary performance of the Company's management, is well with the range of the market-based measures (i.e., DCF, RP and CAPM) of the cost of equity. 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 more 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 Huwar 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. 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. Description of the

Company's WNA is contained in Company witness Bell's testimony. I also understand that the Company is proposing a second mechanism, called a RNA, that is a revenue normalization adjustment applicable only to residential customers.

Q. Does your cost of equity analysis and recommendation take into account the normalization rate design that the Company is proposing?

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 continue with its WNA rate design and is not authorized to adopt 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 80 of the Company's major account customers, i.e., those with large volume usage and/or those with competitive alternatives. This throughput to these 80 customers represents approximately 25% (22,298,621 Dth ÷ 89,320,801 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. Third, in addition to the bypass threat, a material portion of the large customer throughput can be exposed to fuel switching to coal, oil, propane, or other 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 1284.9 miles (or approximately 17%) of its distribution mains as of year-end 2018. The Company also has 45,815 (or approximately 11%) of its services constructed of unprotected steel. For the future, the Company expects its net capital expenditures to be:

Year	Capital Expenditures
2020	$ 318,761,000
2021	$ 375,604,000
2022	$ 365,281,000
2023	$ 423,083,000
2024	$ 436,024,000
Total	$ 1,918,753,000

The Company's total capital expenditures over the next five years will represent approximately 93% ($1,918,753,000 ÷ $2,054,429,000) of the net utility plant in service at December 31, 2018.

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 2018. 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 2014-2018. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, the Company is smaller than the average size of the Gas Group, and smaller still than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity.

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

There are no market ratios available for the Company because its stock is owned by NiSource. The five-year average price-earnings multiple was similar for the Gas Group and the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio was somewhat 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

[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).

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 55.5% for CPA, 53.2% for the Gas Group, and 43.0% for the S&P Public Utilities. The Company's common equity ratio was fairly similar to the Gas Group, thereby indicating similar financial risk.

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 0.132 (1.5% ÷ 11.4%) for the Company, 0.086 (0.8% ÷ 9.3%) for the Gas Group, and 0.050 (0.5% ÷ 10.0%) for the S&P Public Utilities. The variability of the Company's rates of return was higher than the Gas Group and the S&P Public Utilities, thereby signifying higher risk for the Company.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[3] The five-year average operating ratios were 75.5% for the Company, 84.7% for the Gas Group, and 79.0% for the S&P Public Utilities. The Company's operating ratios were somewhat 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

[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.

grades of creditworthiness. Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 4.64 times for the Company, 4.41 times for the Gas Group, and 3.32 times for the S&P Public Utilities. The interest coverages were fairly similar for the Company and the Gas Group, thereby indicating similar risk.

<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, the effective income tax rate declined 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 66.5% for the Company, 66.6% for the Gas Group and 78.6% 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 similar to that of the Gas Group, thereby signifying similar risk. The IGF to construction has declined for the Gas Group in 2018 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 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.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.66 as the average for the Gas Group (see page 2 of Schedule 3) and 0.62 as the average for the S&P Public Utilities (see page 3 of Schedule 4).

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, points to similar risk for CPA and the Gas Group. On balance, the cost of equity measured with the Gas Group data will provide a reasonable representation of the Company's cost of equity.

Capital Structure Ratios

Q. Please explain the selection of capital structure ratios for CPA.

A. In this case, the capital structure ratios of CPA have been proposed to calculate the rate of return. Furthermore, consistency requires that the embedded cost rate of the Company's senior securities also be employed.

[4]Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

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

A. Yes. Schedule 5 presents the Company's capitalization and related capital structure ratios. The November 30, 2019 capitalization corresponds with the end of the HTY in this case. The November 30, 2020 capital structure is estimated at the end of the FTY, and the December 31, 2021 capital structure is estimated at the end of the FPFTY. The Company will receive an equity infusion of $55 million in the FTY (March 2020). Prior to the end of the FPFTY, the Company expects to issue $210 million of new long-term debt, consisting of an issue in the FTY (March 2020) amounting to $110 million, and an issue in the FPFTY (March 2021) amounting to $100 million. Pursuant to Paragraph 26 of the approved settlement in Columbia's 2018 base rate case (Docket No. R-2018-2647577), I am including, as Exhibit PRM-1 to my testimony, the methodology used for the pricing of the Company's most recent debt issues in June 30, 2019 and November 2019. Exhibit PRM-1 describes the procedure that was adopted for the pricing of these issues using comparable yields reported by Bloomberg.

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 42.22% long-term debt, 3.59% short-term debt, and 54.19% common equity at December 31, 2021. For short-term debt, I have used a twelve-month average for the FPFTY. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

Costs of Senior Capital

Q. What cost rate have you assigned to the debt portion of CPA's capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of debt at November 30, 2019. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of debt at November 30, 2020. And on page 3 of Schedule 6, the embedded cost of debt is shown at December 31, 2021. For the new issues of long-term debt, I have used a cost of 3.6245% for the issue in March 2020 and 3.8645% for the issue in March 2021. 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 4.70% 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 42.22% 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 2.06%, 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 4.49% for the FPFTY.

Cost of Equity – General Approach

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among CPA, the Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models 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, which includes recognition of strong management performance.

Discounted Cash Flow Analysis

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 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 and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k= D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[5] My DCF results are provided on page 2 of Schedule 1 for the Gas Group. The DCF return is 11.91% 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 dividend receipts. 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 2019, the monthly dividend yields are shown on Schedule 7 and reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price

[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.

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 2019 the average dividend yield was 2.59% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month period were 2.59% and 2.67%, respectively, for each group. I have used, for the purpose of the DCF model, the six-month average dividend yield of 2.59% 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 ten basis points to the six-month average historical yield, thus producing the 2.69% 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 earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of 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 stabilizes 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. What investor-expected growth rate is appropriate in a DCF calculation?

A. 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. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner.

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 using a variety of techniques must be evaluated 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 have considered the growth in the financial variables shown on Schedules 8 and 9. In this regard, I have considered both historical and projected growth rates 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, it is earnings per share growth that influences directly the expectations of investors for utility stocks. Forecasts of earnings growth are required within the context of the DCF because the model is a forward-looking concept, and with a constant price-earnings multiple and payout ratio, all other measures of growth will mirror earnings growth. So, with the assumptions underlying the DCF, all forward-looking projections should be similar with a constant price-earnings multiple, earned return, and payout ratio. The historical growth rates were taken from the Value Line publication that provides this data. As to the issue of historical data, investors cannot purchase past earnings of a utility, rather they are only entitled to future earnings. In addition, when significant weight is assigned to historical performance results, the historical data is double counted. While history cannot be ignored, it is already factored into the analysts' forecasts of earnings growth. In developing a forecast of future earnings growth, an analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance. The historical growth of earnings per share are shown on Schedule 8.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes. The constant form of the DCF assumes an infinite stream of cash flows, but 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 investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings ("P-E") multiple -- a necessary assumption of the DCF. 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 the actual total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication suggests that there is no market for this information because investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

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, Morningstar, and Value Line. IBES/First Call, Zacks and Morningstar, represent reliable authorities of projected growth upon which investors rely. The IBES/First Call and Zacks growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Zacks and Morningstar estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. 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, Zacks and Morningstar, 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 have also been included on Schedule 9 for the Gas Group.

Q. What are the projected growth rates published by the sources you discussed?

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Gas Group are 5.24% by IBES/First Call, 6.59% by Zacks, 7.00% by Morningstar and 10.17%% by Value Line. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate rather than lower rates of growth in dividends per share and book value per share, thus producing the capital gains yield expected by investors.

Q. What other factors did you consider in developing a growth rate?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. From the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). 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 this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[6] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as

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

those published by IBES/First Call, Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations.

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

A. The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of average growth rates of 5.24% to 10.17% for the Gas Group. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 7.50% is a reasonable estimate of investor expected growth for the Gas Group and is within the array of earnings per share growth rates shown by the analysts' forecasts. Indeed, my 7.50% growth rate is obtained from the analysts' growth forecasts that cover a five-year period, which are the growth rates that investors employ for DCF purposes. Continued gas utility infrastructure spending argues for a DCF growth rate near the high end of the range.

Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Gas Group, those average capital structure ratios are 32.24% long-term debt, 0.00% preferred stock, and 67.76% 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. Where a firm's capitalization as measured by its stock price diverges from its book value capitalization, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value. A leverage adjustment accounts for this difference 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 than 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 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 a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the 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 8.34% 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 indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that 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. The adjustment that I label as 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), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to 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 8.34%, which is the return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 3.57% compensation for having a 47.93% debt ratio, plus 0.00% for having a 0.00% preferred stock ratio. The sum of the parts is 11.91% (8.34% + 3.57% + 0.00%) 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 2.69% dividend yield, the 7.50% growth rate, and the 1.72% for the leverage adjustment in order to arrive at the same 11.91% (2.69% + 7.50% + 1.72%) return. I know of no means to mathematically solve for the 1.72% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.72%

adjustment is merely a convenient way to compare the 11.91% return computed directly with the Modigliani & Miller formulas to the 10.19% return generated by the DCF model (i.e., $D_1/P_0 + g$, or the traditional form of the DCF -- see page 1 of Schedule 7) based on a market value capital structure. A 10.19% 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 ratesetting process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is:

	D_1/P_0	+	g	+	*lev.*	=	k
Gas Group	2.69%	+	7.50%	+	1.72%	=	11.91%

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 other model results when determining a company's cost of equity.

Risk Premium Analysis

Q. Please describe your use of the risk premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 10.50%.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 4.00% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data is 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 page 1 of Schedule 11. For the twelve months ended December 2019, the average monthly yield on Moody's index of A-rated public utility bonds was 3.77%. For the six and three-month periods ended December 2019, the yields were 3.43% and 3.41%, respectively. During the twelve-months ended December 2019, the range of the yields on A-rated public utility bonds was 3.29% to 4.35%. 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 1.19% on a twelve-month average basis, 1.16% on a six-month average basis, and 1.15% on a three-month average basis. From these averages, 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. The 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, 2020, 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:

		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2020	First	3.2%	4.1%	2.3%	1.25%	3.55%
2020	Second	3.3%	4.2%	2.4%	1.25%	3.65%
2020	Third	3.4%	4.3%	2.4%	1.25%	3.65%
2020	Fourth	3.5%	4.4%	2.5%	1.25%	3.75%
2021	First	3.5%	4.5%	2.5%	1.25%	3.75%
2021	Second	3.6%	4.5%	2.6%	1.25%	3.85%

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, 2019 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
2021-2025	4.2%	5.2%	3.2%
2026-2030	4.7%	5.6%	3.7%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 4.00% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. In reaching my conclusion as to a prospective yield on A-rated public utility debt, I have considered the data relied upon by investors.

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

A. To develop an appropriate equity risk premium, I analyzed the results from 2017 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 page 1 of Schedule 12.

Common Equity Risk Premiums	
Low Interest Rates	6.90%
Average Across All Interest Rates	5.63%
High Interest Rates	4.34%

Based on my analysis of the historical data, the equity risk premium was 6.90% when the marginal cost of long-term government bonds was low (i.e., 2.92%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.15% on average during periods of high interest rates) the spread narrowed to 4.34%. Over the entire spectrum of interest rates, the equity risk premium was 5.63% when the average government bond yield was 5.02%. I have utilized a 6.50% equity risk premium. The equity risk premium of 6.50% that I employed is somewhat above the midpoint 6.27% (6.90% + 5.63% = 12.53% ÷ 2) for the low and average risk premiums shown above. I have taken this approach in recognition of the low interest rates that have prevailed during recent periods and the fact that long-term forecasts published by Blue Chip show a trend toward higher rates in the future. The risk premium that I established provides a balance to both factors. I rounded up to the next one-half percentage point owing to the fact that long-term government bond yields today are lower than 2.92%. This equity risk premium is between the 6.90% premium related to periods of low interest rates and the 5.63% premium related to average interest rates across all levels.

Q. What common equity cost rate did you determine based on your risk premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i"), and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

	i	+	RP	=	k
Gas Group	4.00%	+	6.50%	=	10.50%

This representation of the Risk Premium result for the Gas Group will understate somewhat the cost of equity for CPA because of the weaker credit quality rating of NiSource.

Capital Asset Pricing Model

Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 10.19% 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 0.66 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:

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

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 0.48 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 0.83 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 2019, the average yield on 30-year Treasury bonds was 2.58%. For the six- and three-months ended December 2019, the yields on 30-year Treasury bonds were 2.27% and 2.26%, respectively. During the twelve-months ended December 2019, the range of the yields on 30-year Treasury bonds was 2.12% to 3.04%. The low yields that existed during recent periods

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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.

can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist"). As noted previously, low interest rates were the product of the policy of the Federal Open Market Committee ("FOMC") in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC ended its bond purchasing program at its policy meeting on October 29, 2014. At its December 16, 2015 meeting, the FOMC increased the federal funds rate range by 0.25 percentage points. On December 14, 2016, the FOMC acted again by raising the federal funds rate by one-quarter percentage point. The FOMC also used this occasion to express a more aggressive approach to future increases in interest rates. In addition, the Fed has indicated that it will reduce the size of its balance sheet. FOMC increased the federal funds rate on three occasions in 2017 (i.e., March 15, 2017, June 14, 2017 and December 13, 2017) by one-quarter percentage point each. At its policy meetings on March 21, 2018, June 13, 2018, September 26, 2018, and December 19, 2018, the FOMC acted again to increase the federal funds rate by one-quarter percentage point in each instance. There have been nine (9) one-quarter percentage point increases in the Fed Funds rate since the FOMC began to normalize interest rates following the financial crisis and the Great Recession. Recently, the FOMC has reversed course attributed to low measures of inflation and has begun to reduce the Fed Funds rate (i.e., one-quarter percentage point reductions on July 31, 2019, September 18, 2019, and October 30, 2019), in response to a perceived weakening of the global economy due in part to the trade war with China. The FOMC has specifically noted weakness in business fixed investment and exports. Neither of these factors has an impact on the investment risk of CPA. Resolution of the trade dispute with China, when it takes place, will reduce the pressure on global economic growth. The influence of Presidential politics during the election year of 2020 may impact the trend of interest rates.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on January 1, 2020 indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.3% to 2.6% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.2% from 2021 through 2025 and 3.7% from 2026 to 2030. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 2.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

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

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 11.74% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.92% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the long-term according to Blue Chip. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 13 the average large common stock returns of 11.81% (11.74% + 11.88% = 23.62%

÷ 2) and the average yield on long-term government bonds of 3.97% (2.92% + 5.02% = 7.94% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 7.84% (11.81% - 3.97%) based on historical data, as shown on page 2 of Schedule 13. As also shown on page 2 of Schedule 13, I calculated the forecast returns, which show a 11.83% total market return from the Value Line data and a DCF return of 8.93% for the S&P 500. With the average forecast return of 10.38% (11.83% + 8.93% = 20.76% ÷ 2), I calculated a market premium of 7.63% (10.38% - 2.75%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 7.74% (7.63% + 7.84% = 15.47% ÷ 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. In this regard, the Gas Group has a market-based average equity capitalization of $4,587 million. For my CAPM analysis, I have adopted a mid-cap adjustment of 1.02%, as shown on page 3 of Schedule 13.

Q. What does your CAPM analysis show?

A. Using the 2.75% risk-free rate of return, the leverage adjusted beta of 0.83 for the Gas Group, the 7.74% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*
Gas Group	2.75%	+	0.83	x (	7.74%	) +	1.02%	=	10.19%

<u>Comparable Earnings Approach</u>

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar 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 page 3 of Schedule 14. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 14.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page

2 of Schedule 14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies 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 11.7% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return as published by Value Line is 13.8% also using values less than 20%, as provided on page 2 of Schedule 14. Using the average of these data my Comparable Earnings result is 12.75%, as shown on page 2 of Schedule 1.

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, which includes 20 basis points or 0.20% for recognition of the Company's strong management performance. 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, sustain its cash flow in the context of the its high levels of capital expenditures, and receive recognition of the significant accomplishments that management has achieved.

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 twenty-nine 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.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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 200 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).

PROMISSORY NOTE

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Issue Date: June 29, 2018
Due Date: June 29, 2048

FOR VALUE RECEIVED, the undersigned, Columbia Gas of Pennsylvania, Inc., a Pennsylvania corporation ("Borrower"), hereby unconditionally promises to pay to NiSource Inc., a Delaware corporation ("Lender"), at such place as Lender may from time to time designate in writing, in lawful money of the United States of America, the principal sum of Eighty Million Dollars ($80,000,000) together with interest on the principal balance hereof from time to time outstanding at the rate of **4.5279%** per annum from the date such principal is advanced until payment in full thereof. The principal indebtedness evidenced hereby shall be payable on June 29, 2048. Borrower may prepay the principal amount hereof in whole or in part, without premium or penalty, at any time after the first anniversary of the date hereof. Any payment on this Note shall be applied first to accrued but unpaid interest until paid in full and second to the unpaid principal amount hereof.

Interest shall be payable semi-annually in arrears on the first business day of June and December (commencing on December 1, 2018) and on the date on which the principal balance hereof is paid in full. Interest shall be calculated on the basis of a 365 day year for the actual number of days elapsed. Notwithstanding the foregoing, in no contingency or event whatsoever shall interest charged hereunder, however such interest may be characterized or computed, exceed the highest rate permissible under any law which a court of competent jurisdiction shall, in a final determination, deem applicable hereto. In the event that such a court determines that Lender has received interest hereunder in excess of the highest rate applicable hereto, Lender shall promptly refund such excess interest to Borrower.

Borrower shall be in default hereunder if: (a) any amount payable to Lender under this Note is not paid within five (5) business days of the date it is due, (b) Borrower shall make any assignment for the benefit of creditors, or (c) there shall be commenced any bankruptcy or insolvency proceedings by or against Borrower. Upon and after the occurrence of a default hereunder, this Note may, at the option of Lender, and without demand, notice or legal process of any kind, be declared, and thereupon immediately shall become, due and payable in full.

Presentment, protest and notice of nonpayment and protest are hereby waived by Borrower.

This Note has been delivered at and shall be deemed to have been made at Merrillville, Indiana, and shall be interpreted, and the rights and liabilities of the parties hereto determined, in accordance with the laws of the State of Indiana without giving effect to conflict of laws rules or principles. Whenever possible each provision of this Note shall be interpreted in such manner as to be effective and valid under applicable law, but if any provisions of this Note shall be prohibited by or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of this Note. Whenever in this Note reference is made to Lender or Borrower, such reference shall be deemed to include their respective representatives, successors and assigns. Notwithstanding anything herein to the contrary, Borrower may not assign or otherwise transfer any of its rights or obligations under this Note without the prior written consent of Lender.

IN WITNESS WHEREOF, the undersigned has executed this Note on the issue date set forth above.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Michael A. Huwar
Michael A. Huwar
President

C03830Y 4.5279 +.0189 4.5279 /4.5279

At 6/29 Op 4.5279 Hi 4.5279 Lo 4.5279 Prev 4.5090 Vol 0

C03830Y Index | 96) Export | 97) Settings | Page 1/3 | Historical Price Table

BFV USD US Utility BBB+ 30 Year

Range	12/29/2017 - 06/29/2018	Period	Daily	High	4.6412 on 05/17/18
Market	Mid Yield	Currency		Low	3.8911 on 12/29/17
View	Price Table			Average	4.3315
				Net Chg	.6368 16.37%

	Date	Mid Yield		Date	Mid Yield		Date		Mid Yield
Fr	06/29/18	4.5279	Fr	06/08/18	4.5043	Fr	05/18/18		4.5847
Th	06/28/18	4.5090	Th	06/07/18	4.4922	Th	05/17/18	H	4.6412
We	06/27/18	4.5103	We	06/06/18	4.5380	We	05/16/18		4.6120
Tu	06/26/18	4.5492	Tu	06/05/18	4.4872	Tu	05/15/18		4.5893
Mo	06/25/18	4.5447	Mo	06/04/18	4.5116	Mo	05/14/18		4.5217
Fr	06/22/18	4.5526	Fr	06/01/18	4.4607	Fr	05/11/18		4.5004
Th	06/21/18	4.5253	Th	05/31/18	4.4367	Th	05/10/18		4.5185
We	06/20/18	4.5294	We	05/30/18	4.4241	We	05/09/18		4.5473
Tu	06/19/18	4.4600	Tu	05/29/18	4.3572	Tu	05/08/18		4.5092
Mo	06/18/18	4.4938	Mo	05/28/18	4.4565	Mo	05/07/18		4.5040
Fr	06/15/18	4.4791	Fr	05/25/18	4.4565	Fr	05/04/18		4.5003
Th	06/14/18	4.4862	Th	05/24/18	4.5017	Th	05/03/18		4.4910
We	06/13/18	4.5407	We	05/23/18	4.5471	We	05/02/18		4.5147
Tu	06/12/18	4.5284	Tu	05/22/18	4.5868	Tu	05/01/18		4.5008
Mo	06/11/18	4.5312	Mo	05/21/18	4.5780	Mo	04/30/18		4.4663

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

In Re: Securities Certificate of Columbia Gas of Pennsylvania, Inc. - In the Matter of the Issuance of New Promissory Notes to Fund Construction and Other Corporate Requirements	Docket No. S-2019-______
Affiliate Interest Agreement Concerning Issuance of Promissory Notes Between Columbia Gas of Pennsylvania and NiSource Finance Corp. or NiSource Inc.	Docket No. G-2019-_______

TO THE PENNSYLVANIA PUBLIC UTILITY COMMISSION:

1. The name and address of the public utility filing this securities certificate:

Columbia Gas of Pennsylvania, Inc.
121 Champion Way, Suite 100
Canonsburg, PA 15317

2. Name and address of the public utility's attorney:

Theodore J. Gallagher (ID # 90852)
Meagan B. Moore (ID # 317975)
NiSource Corporate Services Company
121 Champion Way, Suite 100
Canonsburg, PA 15317

Amy E. Hirakis (ID #310094)
800 N Third Street, Suite 204
Harrisburg, PA 17102

3. Columbia Gas of Pennsylvania, Inc. ("Columbia") is a Pennsylvania corporation organized on June 23, 1960 under the Natural Gas Companies Act of 1885, P. L. 29, as amended, for the purpose of acquiring and operating the

distribution properties and certain other properties and assets of The Manufacturers Light and Heat Company in the Commonwealth of Pennsylvania. Columbia is currently engaged in the purchase and sale of natural gas to retail customers, as well as the transportation of customer-owned volumes of natural gas, in a service territory consisting of all or part of twenty-six counties, located principally in western and south-central Pennsylvania.

4. NiSource Gas Distribution Group, Inc. ("NGD") currently owns one hundred percent of the outstanding common stock (Exhibit 6) of Columbia. NGD is a wholly-owned subsidiary of NiSource Inc. ("NiSource"). Both NiSource and NGD are holding companies under the Public Utility Holding Company Act of 2005. The common stock has a par value of $25 per share and is the only class of stock authorized and outstanding. As of the date of this application, NGD owns 1,805,112 shares of said Common Stock (Exhibit 14). NiSource Inc. currently holds one hundred percent of the long-term debt of Columbia (Exhibit 5).

5. In this application, Columbia seeks the registration of a securities certificate, pursuant to 66 Pa.C.S.A. §§ 1901-1903, authorizing it to issue certain additional promissory notes ("New Notes"), the proceeds of which will partially reimburse Columbia's treasury for Columbia's 2019-2021 gross construction program totaling $981,242,502. Columbia currently estimates that its capital expenditures will be $319,903,029 during 2019; $327,580,030 during 2020; and $333,759,443 during 2021. These expenditures will be required for the acquisition

of property and the construction, completion, extension, and improvement of company facilities.

6. In order to finance its capital program, to refinance short-term debt, and for other corporate purposes, Columbia will require, in addition to internally generated funds, up to $270,000,000 of new long-term debt financing. Columbia therefore requests Commission authority to secure, from the issuance of New Notes to NiSource Inc. an amount not to exceed $270,000,000, as more fully described below.

7. The New Notes will be unsecured and will be dated the date of their issue. The New Notes will be issued from time to time with maturities of up to thirty years; will bear an interest rate that corresponds to the pricing being offered to companies with credit ratings equivalent to NiSource Inc. and will reflect market conditions at the time of issuance. The interest rate of the New Notes will be determined by directly referencing the prevailing yield on U.S. utility bonds as reported by Bloomberg Finance L.P., (as reported in the Bloomberg Finance L.P. "C038", or equivalent screen) for companies with credit ratings equivalent to that of NiSource Inc.[1] All of the New Notes, not to exceed $270,000,000, will be issued on or before December 31, 2021.

[1] This is the same methodology that the Commission approved in Columbia's securities certificate registration under Docket No. S-2017-2632449.

8. Since the Notes are to be sold privately, they will not be registered with the Securities and Exchange Commission under the Securities Act of 1933.

9. This Securities Certificate application is for the purpose of seeking approval of Columbia's request to issue New Notes in order to finance its 2019-2021 construction program, to refinance short-term debt, and other corporate requirements. Columbia has engaged, and continues to engage, in a construction program during 2019 which includes, inter alia, the improvement of service, the replacement of facilities due to condition, the relocation of facilities to accommodate highway construction, and the addition of new customers. Columbia's 2019 program for the construction of facilities is summarized in the following table. The various individual items making up these expenditures are listed in detail on Exhibit 13, appended hereto and made a part hereof.

Account	2019 Construction
Distribution Plant	$ 297,473,749
General Plant	22,429,280
Total Construction Costs	319,903,029
Less:	
Contributions and Reimbursements	1,919,418
Total Gross Construction Costs	317,983,611
Less: AFUDC	1,921,606
Total Net Construction	$ 316,062,005

10. Columbia also requests approval pursuant to 66 Pa. C.S.A. § 2102, to the extent that these notes are deemed to be arrangements with an affiliated interest of Columbia within the meaning of 66 Pa C.S.A. § 2101.

11. The following exhibits are appended hereto, incorporated herein by reference or omitted as stated below:

EXHIBIT 1	Balance sheet as of September 30, 2019.
EXHIBIT 2	Income statement of Columbia for the twelve months ended September 30, 2019.
EXHIBIT 3	A statement with respect to Columbia's plant accounts.
EXHIBIT 4	A statement with respect to securities of other entities that Columbia owns as of September 30, 2019.
EXHIBIT 5	Statement with respect to the outstanding funded debt of Columbia as of September 30, 2019.
EXHIBIT 6	Statement with respect to capital stock of Columbia as of September 30, 2019.
EXHIBIT 7	Registration statement with the Securities and Exchange Commission under the Securities Act of 1933 with respect to the proposed issuance of securities omitted for the reason that statement was not required to be filed by Columbia.
EXHIBIT 8	Application and declarations with the Securities and Exchange Commission with respect to the issuance of the proposed securities is omitted for the reason that the Public Utility Holding Act of 1935 has been repealed.
EXHIBIT 9	A copy of a resolution of the Board of Directors authorizing the proposed issuance of long-term debt.
EXHIBIT 10	A copy of the form of the new notes to be issued.
EXHIBIT 11	A copy of the proposed journal entries to be made by Columbia in connection with the issuance of the new notes.
EXHIBIT 12	Affidavit in the form prescribed by 52 Pa. Code §§ 1.35 and 1.36.
EXHIBIT 13	Construction program for 2019.
EXHIBIT 14	Current book value of Common Stock as of September 30, 2019.
EXHIBIT 15	Capitalization structures showing present and pro-forma capitalization structures and ratios.
EXHIBIT 16	Source and Use of Funds Statements and Income Statements for future five-year period.
EXHIBIT 17	Statement of the benefit that will accrue to the consumer in connection with this securities certificate.
EXHIBIT 18	Number of counties served and number of customers.
EXHIBIT 19	Construction Program Specific Budgets over $250,000 for 2019.
EXHIBIT 20	Construction program for future five-year period.
EXHIBIT 21	Projected 2019 and 2020 income statements.

WHEREFORE, Columbia Gas of Pennsylvania, Inc. respectfully requests this honorable Commission to (1) register this Securities Certificate Pursuant to 66 Pa.C.S.A. § 1903, authorizing Columbia to issue promissory notes as requested herein, and (2) approve the proposed issuance of such promissory notes to NiSource Inc. to the extent that those notes constitute arrangements with an affiliated interest, pursuant to 66 Pa.C.S.A. § 2102.

Respectfully submitted,

COLUMBIA GAS OF PENNSYLVANIA, INC.

Michael A. Huwar

Michael A. Huwar, President

COLUMBIA GAS OF PENNSYLVANIA, INC.
BALANCE SHEET
AS OF SEPTEMBER 30, 2019

		Amount $
Assets and Other Debits		
Utility Plant		
Utility Plant	$	2,733,793,465
Accum. Prov. for Depr., Depl. & Amort.		(497,053,923)
Net Utility Plant		2,236,739,542
Other Property and Investments		
Non-Utility Property		8,346
Accum. Prov. for Depr., Depl. & Amort.		0
Investment in Subsidiary		20,110,253
Other Investments		0
Total Other Property and Investments		20,118,599
Current and Accrued Assets		
Cash, Special Deposits		2,617,118
Working Funds		2,550
Customer Accounts Receivable		0
Other Accounts Receivable		1,508,139
Accrued Utility Revenue		0
Receivables from Associated Companies		6,999,655
Plant Materials and Operating Supplies		1,121,270
Gas Stored Underground - Current		63,573,084
Prepayments		6,283,021
Misc. Current and Accrued Assets		320,703
Regulatory Assets - Current		7,280,225
Total Current and Accrued Assets		89,705,765
Deferred Debits		
Other Special Funds		3,639,340
Interest and Dividends Receivable		0
Regulatory Assets - Non Current		280,030,204
Prelim. Survey and Investigation Chgs.		4,529,206
Clearing Accounts		2,157
Miscellaneous Deferred Debits		6,071,817
Accumulated Deferred Income Tax		125,420,810
Deferred Gas Purchase Costs		1,253,660
Total Deferred Debits		420,947,194
Total Assets and Other Debits	$	2,767,511,100

COLUMBIA GAS OF PENNSYLVANIA, INC.
BALANCE SHEET
AS OF SEPTEMBER 30, 2019

		Amount $
Liabilities and Other Credits		
Proprietary Capital		
Common Stock	$	45,127,800
Paid-in-Capital		52,889,827
Other Comprehensive Income		0
Retained Earnings		847,274,586
Total Proprietary Capital		945,292,213
Long Term Debt		
Advances from Associated Companies		805,515,000
Other Long Term Debt		0
Total Long Term Debt		805,515,000
		1,750,807,213
Current Accrued Liabilities		
Accounts Payable		40,442,086
Notes Payable to Assoc. Companies		0
Accounts Payable to Assoc. Companies		79,373,882
Customer Deposits		3,226,014
Taxes Accrued		14,441,164
Interest Accrued		284,260
Tax Collections Payable		20,423
Misc. Current and Accrued Liabilities		55,137,383
Obligations Under Capital Leases - Current		2,409,029
Regulatory Liabilities - Current		10,989,254
Total Current and Accrued Liabilities		206,323,495
Deferred Credits		
Other Deferred Credits		5,684,128
Regulatory effect of Adopting SFAS 96		238,828,235
Accumulated Deferred Investment Credits		1,604,654
Accum. Def. Taxes: Liberalized Depreciation		511,884,943
Accum. Def. Taxes: Other		5,753,656
Total Deferred Credits		763,755,616
Other Noncurrent Liabilities		
Obligations Under Capital Leases-Noncurrent		35,383,818
Accumulated Provision for Injuries & Damages		6,381,622
Long-Term Taxes Payable		0
Customer Advances for Construction		4,859,336
Total Other Noncurrent Liabilities		46,624,776
Total Liabilities and Other Credits	$	2,767,511,100

COLUMBIA GAS OF PENNSYLVANIA, INC.
INCOME STATEMENT FOR 12 MONTHS ENDED AS OF SEPTEMBER 30, 2019

	Amount $
Operating Revenues	$ 612,956,821
Operating Expenses:	
Products Purchased - Natural Gas	178,310,308
Operation Expense	160,487,250
Maintenance Expense	24,617,600
Depreciation, Depletion and Amortization Expense	69,195,979
Taxes Other than Income Taxes	3,436,443
Income Taxes	25,019,844
Total Operating Expenses	461,067,424
Utility Operating Income	151,889,397
Other Income(Deductions)	
Income from Investment in Subsidiary	273,641
Other Non-utility and Miscellaneous	(866,410)
Interest Income	515,072
Total Other Income	(77,697)
Total Income	151,811,700
Interest Charges	
Interest on Long Term Debt	37,143,817
Other Interest Charges	457,733
Total Interest Charges	37,601,550
NET INCOME	$ 114,210,150

EXHIBIT 2

COLUMBIA GAS OF PENNSYLVANIA, INC.

Columbia Gas of Pennsylvania, Inc., as of January 1, 1962, acquired all of the gas distribution property of The Manufacturers Light and Heat Company in Pennsylvania, together with certain other property and assets. Said property was purchased at original cost from The Manufacturers Light and Heat Company less accrued depreciation (Docket No. A 87616) and was recorded on the books of Columbia Gas of Pennsylvania, Inc. at said original cost.

With respect to The Manufacturers Light and Heat Company, this Commission, by its Order No. 55, dated February 15, 1937, required Original Cost Studies to be filed by the several companies whose properties were later acquired by the present company of that name. Those Original Cost Studies, as of January 1, 1939, were filed with the Commission as follows:

The Manufacturers Light and Heat Company (old) on October 30, 1942;

Greensboro Gas Company on November 8, 1944;

Fayette County Gas Company on September 20, 1945;

Pennsylvania Fuel Supply Company on March 29, 1945;

Manufacturers Gas Company on July 17, 1945;

Gettysburg Gas Corporation on October 1, 1945.

The studies were supplemented by a Supplemental Report filed November 23, 1953, which brought the original cost study of the present The Manufacturers Light and Heat Company and its predecessors down to December 31, 1947. Since that date, The Manufacturers Light and Heat Company had kept its accounts in accordance with the Commission's Uniform Rules and Columbia Gas of Pennsylvania is keeping its accounts in accordance with those rules, so that there should be no deviation between Original Cost and Book Cost in the accounts of Columbia Gas of Pennsylvania, Inc.

STATEMENT OF SECURITIES OF OTHER ENTITIES OWNED BY COLUMBIA GAS OF PENNSYLVANIA, INC.

Name of Issuer	Type of Security	Number of Shares	Date Acquired	Price Paid	Book Value
Columbia Gas of Pennsylvania Receivables Corporation	Common Stock	100	3/2/2010	$1.00	$100.00

COLUMBIA GAS OF PENNSYLVANIA, INC.

FUNDED DEBT AS OF SEPTEMBER 30, 2019

NAME AND DESCRIPTION OF OBLIGATION (A)	INTEREST RATE (B)	DATE OF MATURITY (C)	TOTAL PRINCIPAL AMOUNT OUTSTANDING (D)	TOTAL PRINCIPAL AMOUNT HELD BY THE PUBLIC UTILITY: REACQUIRED AND HELD IN TREASURY (E)	PLEDGED (F)	IN SINKING OR OTHER FUNDS (G)
Installment Promissory Notes	6.015%	November 1, 2021	$20,000,000	None	None	None
Negotiable and Unsecured	5.920%	November 28, 2025	$54,515,000	None	None	None
	6.865%	December 14, 2027	$58,000,000	None	None	None
	6.020%	December 16, 2030	$28,000,000	None	None	None
	5.355%	March 26, 2032	$30,000,000	None	None	None
	5.890%	March 26, 2042	$35,000,000	None	None	None
	5.260%	November 28, 2042	$65,000,000	None	None	None
	5.530%	June 19, 2043	$23,000,000	None	None	None
	6.290%	December 18, 2043	$32,000,000	None	None	None
	4.430%	December 16, 2044	$30,000,000	None	None	None
	4.150%	March 24, 2045	$60,000,000	None	None	None
	4.505%	September 28, 2035	$60,000,000	None	None	None
	4.186%	March 30, 2046	$45,000,000	None	None	None
	4.439%	January 31, 2047	$85,000,000	None	None	None
	4.528%	June 29, 2048	$80,000,000	None	None	None
	3.687%	November 22, 2049*	$80,000,000	None	None	None

* Reflected in September 30, 2019 long-term debt balances.

COLUMBIA GAS OF PENNSYLVANIA, INC.

CAPITAL STOCK AS OF SEPTEMBER 30, 2019

DESIGNATION OF KIND AND CLASS (A)	NUMBER OF SHARES AUTHORIZED (B)	PAR VALUE PER SHARE (C)	AMOUNT AUTHORIZED (D)	AMOUNT OUTSTANDING (NOT HELD BY THE PUBLIC UTILITY) (E)	REACQUIRED AND HELD IN TREASURY (F)	PLEDGED (G)	IN SINKING OR OTHER FUNDS (H)	STATED BOOK VALUE OF OUTSTANDING STOCK HAVING NO PAR VALUE AS OF BALANCE SHEET DATE (I)
COMMON	3,850,000	$25.00	$96,250,000	$45,127,800	None	None	None	Not Applicable
TOTALS	3,850,000	$25.00	$96,250,000	$45,127,800	None	None	None	Not Applicable

NOTE: NiSource Gas Distribution owns all outstanding capital stock.

**UNANIMOUS WRITTEN CONSENT
OF THE DIRECTORS OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

The undersigned, being all of the directors of Columbia Gas of Pennsylvania, Inc., a Pennsylvania corporation (the "Corporation"), do hereby consent and agree to the adoption of the following resolutions in lieu of a special meeting pursuant to Section 1727(b) of the Business Corporation Law of the Commonwealth of Pennsylvania:

INTERCOMPANY BORROWINGS

RESOLVED, that the Corporation is hereby authorized, subject to the limitations set forth below, to borrow in the form of one or more long term promissory notes ("Debt Security") from NiSource Inc., or one or more of its affiliates (collectively "NiSource"), an aggregate principal amount of not more than $270,000,000, with a maturity date of between one and thirty years, at interest rates reflective of market conditions at the time of issuance, with the proceeds of such borrowings to be used to finance the Corporation's construction program and other corporate requirements, on such terms and conditions as shall be determined by the President or Treasurer as prudent;

FURTHER RESOLVED, that the President, any Vice President or the Treasurer, consistent with the Pennsylvania Public Utility Commission ("PPUC") order issued in conjunction with this financing authorizing the Corporation's issuance of up to $270,000,000 of long term notes to NiSource is hereby authorized and empowered to execute and deliver on behalf of the Corporation any Debt Security authorized hereunder (including any supplements thereto) under its corporate seal to be thereto affixed and attested by its Corporate Secretary or Assistant Corporate Secretary in such form and content and bear such date as may be approved by the officer executing the same, such approval to be conclusively evidenced by the execution of said Debt Security;

FURTHER RESOLVED, that the appropriate officers of the Corporation and/or their designees be, and each of them hereby is, authorized in the name and on behalf of the Corporation, to execute and deliver such other agreements, documents, certificates and instruments as may be required by the PPUC or NiSource in connection with the Debt Security or as may be necessary or appropriate in connection with the issuance and sale of the Debt Security; and

FURTHER RESOLVED, that NiSource be, and it hereby is, authorized to rely and act upon, and shall be fully protected in so relying and acting upon, any instructions received by it and signed by any officer of the Corporation or by counsel for the Corporation, and to rely and act upon, and shall be fully protected in so relying and acting upon, any Debt Security, assignment, power of attorney, certificate, order, instruction, notice or other instrument or paper believed by it to be genuine and duly authorized and properly executed.

MISCELLANEOUS

RESOLVED, that this consent may be signed by one or more counterpart signatures, each of which signature shall be deemed an original, and all of which together shall constitute one and the same instrument. Furthermore, delivery of a copy of such signature by facsimile transmission or other electronic methodology shall constitute a valid and binding execution and delivery of this consent by the signatory thereof, and such electronic copy shall constitute an enforceable original instrument; and

FURTHER RESOLVED, that this consent shall be effective as of Decembe 3, 2019.

Pablo A. Vegas

Michael A. Huwar

Michael J. Davidson

Being all of the directors of the Corporation be genuine and duly authorized and properly executed.

MISCELLANEOUS

RESOLVED, that this consent may be signed by one or more counterpart signatures, each of which signature shall be deemed an original, and all of which together shall constitute one and the same instrument. Furthermore, delivery of a copy of such signature by facsimile transmission or other electronic methodology shall constitute a valid and binding execution and delivery of this consent by the signatory thereof, and such electronic copy shall constitute an enforceable original instrument; and

FURTHER RESOLVED, that this consent shall be effective as of December 3, 2019.

____
Pablo A. Vegas

Michael A. Huwar

Michael A. Huwar

Michael J. Davidson

Michael J. Davidson

Being all of the directors of the Corporation

PROMISSORY NOTE

$xx,xxx,xxx

Issue Date: Month, Day, 20XX
Due Date: Month, Day, 20XX

FOR VALUE RECEIVED, the undersigned, Columbia Gas of Pennsylvania, Inc., a Pennsylvania corporation ("Borrower"), hereby unconditionally promises to pay to NiSource Inc., a Delaware corporation ("Lender"), at such place as Lender may from time to time designate in writing, in lawful money of the United States of America, the principal sum of xx Million Dollars ($xx,000,000) together with interest on the principal balance hereof from time to time outstanding at the rate of x.xx% per annum from the date such principal is advanced until payment in full thereof. The principal indebtedness evidenced hereby shall be payable on Month, Day, Year. Borrower may prepay the principal amount hereof in whole or in part, without premium or penalty, at any time after the first anniversary of the date hereof. Any payment on this Note shall be applied first to accrued but unpaid interest until paid in full and second to the unpaid principal amount hereof.

Interest shall be payable semi-annually in arrears on the first business day of June and December (commencing on Month, Day, Year) and on the date on which the principal balance hereof is paid in full. Interest shall be calculated on the basis of a 365 day year for the actual number of days elapsed. Notwithstanding the foregoing, in no contingency or event whatsoever shall interest charged hereunder, however such interest may be characterized or computed, exceed the highest rate permissible under any law which a court of competent jurisdiction shall, in a final determination, deem applicable hereto. In the event that such a court determines that Lender has received interest hereunder in excess of the highest rate applicable hereto, Lender shall promptly refund such excess interest to Borrower.

Borrower shall be in default hereunder if: (a) any amount payable to Lender under this Note is not paid within five (5) business days of the date it is due, (b) Borrower shall make any assignment for the benefit of creditors, or (c) there shall be commenced any bankruptcy or insolvency proceedings by or against Borrower. Upon and after the occurrence of a default hereunder, this Note may, at the option of Lender, and without demand, notice or legal process of any kind, be declared, and thereupon immediately shall become, due and payable in full.

Presentment, protest and notice of nonpayment and protest are hereby waived by Borrower.

This Note has been delivered at and shall be deemed to have been made at Merrillville, Indiana, and shall be interpreted, and the rights and liabilities of the parties hereto determined, in accordance with the internal laws (as opposed to conflicts of law provisions) and decisions of the State of Indiana. Whenever possible each provision of this Note shall be interpreted in such manner as to be effective and valid under applicable law, but if any provisions of this Note shall be prohibited by or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of this Note. Whenever in this Note reference is made to Lender or Borrower, such reference shall be deemed to include their respective representatives, successors and assigns. Notwithstanding anything herein to the contrary, Borrower may not assign or otherwise transfer any of its rights or obligations under this Note without the prior written consent of Lender.

IN WITNESS WHEREOF, the undersigned has executed this Note on the issue date set forth above.

COLUMBIA GAS OF PENNSYLVANIA, INC.

By: ______________________________
Michael A. Huwar

Title: President

Exhibit 10

COLUMBIA GAS OF PENNSYLVANIA, INC.

PROPOSED ENTRIES TO BE MADE IN
CONNECTION WITH ISSUANCE OF INSTALLMENT PROMISSORY NOTES

General Ledger Account		Debit	Credit
146	Accounts Receivable From Associated Companies - NiSource Inc.	$135,000,000	
223	Advances From Associated Companies - Promissory Notes Payable - New Issue NiSource Inc.		($135,000,000)
146	Accounts Receivable From Associated Companies - NiSource Inc.	$135,000,000	
223	Advances From Associated Companies - Promissory Notes Payable - New Issue NiSource Inc.		($135,000,000)

To record the Issuance and Sale of Installment Promissory Notes to NiSource Inc.

AFFIDAVIT

Commonwealth of Pennsylvania)
) ss:
County of Washington)

I, Michael A. Huwar, being duly sworn according to law, depose and say that I am authorized to make this affidavit on behalf of Columbia Gas of Pennsylvania, Inc., being the holder of the office of President with that corporation, and that the facts set forth are true and correct to the best of my knowledge, information, and belief, and I expect to be able to prove the same at any hearing hereof.

Michael A. Huwar

Michael A. Huwar

Sworn to and subscribed before me this 3rd day of December, 2019.

Tracy L. Schrock

Notary Public
My Commission Expires: 11/13/21

Commonwealth of Pennsylvania - Notary Seal
Tracy L. Schrock, Notary Public
Washington County
My commission expires November 13, 2021
Commission number 1147123
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

COLUMBIA GAS OF PENNSYLVANIA, INC.

CONSTRUCTION PROGRAM - 2019

	2019 Total Est.
Distribution	
Blanket Budgets	
Mains	125,774,133
Service Lines	68,095,411
Meters	1,298,000
Meter Installation	2,696,000
House Regulators	560,000
Plant Regulators	1,910,000
Regulator Sites	240,000
Regulator Structures	409,000
Large Volume Excess Pressure Stations	1,098,000
Cathodic Protection Systems	120,000
Service Regulators-New	20,200
Service Regulators Replace	20,000
Specific Budgets	
New Business	3,962,000
Betterment	15,041,564
Public Improvement	1,500,000
Automatic Meter Reading	0
Replacement	74,729,441
Total Distribution	297,473,749
General	
Blanket Budgets	
Office Furniture and Equip	0
General Structures	11,150,000
Misc Buildings and Equip	0
Misc Motrorized Equip	0
Communications Equip	1,165,000
EDP Equipment	0
EDP Software	0
Miscellaneous	1,390,000
Specific Budgets	
IT (NiFit)	8,724,280
Other/GPS	0
Total General	22,429,280
TOTAL GROSS CONSTRUCTION	319,903,029

COLUMBIA GAS OF PENNSYLVANIA, INC.

CURRENT BOOK VALUE OF COMMON STOCK AS OF SEPTEMBER 30, 2019

	Total Equity as of September 30, 2019	$945,292,213
(A)	Total Shares Outstanding as of September 30, 2019	1,805,112
	Current Book Value per Share Outstanding	$523.68

(A) 100% of the Outstanding Common Stock is Owned by NiSource Gas Distribution.

COLUMBIA GAS OF PENNSYLVANIA, INC.

CAPITALIZATION STRUCTURES SHOWING PRESENT STRUCTURES AND PRO FORMA STRUCTURES

As of September 30, 2019	Amount ($000)		Ratio %
Short-Term Debt^	48,680		2.7
Long-Term Debt	785,515		44.1
Common Equity	945,292		53.1
Total	1,779,487		100.0

Pro Forma As of December 31, 2019	Amount ($000)		Ratio %
Short-Term Debt^	43,140		2.4
Long-Term Debt	785,515	*	43.4
Common Equity	981,231		54.2
Total	1,809,886		100.0

Pro Forma As of December 31, 2020	Amount ($000)		Ratio %
Short-Term Debt^	79,959		3.7
Long-Term Debt	920,515	**	43.1
Common Equity	1,136,602		53.2
Total	2,137,076		100.0

Pro Forma As of December 31, 2021	Amount ($000)		Ratio %
Short-Term Debt^	76,812		3.2
Long-Term Debt	1,035,515	***	43.2
Common Equity	1,283,668		53.6
Total	2,395,995		100.0

^Short-Term Debt Amounts are a 12 Month Average

	($000)
*Long-Term Debt @ 9/30/2019	785,515
2019 Payment of Current Maturities	0
2019 Current Maturities	0
2019 Proposed New Financing	0
	785,515

	($000)
**Long-Term Debt @ 12/31/2020	765,515
2020 Payment of Current Maturties	0
2020 Current Maturities	20,000
2020 Proposed New Financing	135,000
	920,515

	($000)
***Long-Term Debt @ 12/31/2021	920,515
2021 Payment of Current Maturities	(20,000)
2021 Current Maturities	0
2021 Proposed Financing	135,000
	1,035,515

COLUMBIA GAS OF PENNSYLVANIA, INC.

PROJECTED SOURCE AND USE OF FUNDS
2019-2023
($000)

Description	2019	2020	2021	2022	2023
Source of Funds					
Internal					
Net Income	$ 93,287	$ 121,096	$ 132,066	$ 148,030	$ 166,331
Depr. & Amort.	73,292	76,591	86,116	95,169	105,423
Deferred Taxes & Credits	16,675	15,751	12,097	15,585	23,131
Total Internal	183,254	213,439	230,279	258,784	294,886
Funds From Financing					
Long-Term Debt	100,000	125,000	125,000	125,000	125,000
Equity	-	45,000	15,000	-	-
Short-Term Debt Change	13,456	(41,288)	(30,788)	(2,707)	26,642
Total From Financing	113,456	128,712	109,212	122,293	151,642
Total Source of Funds	$ 296,710	$ 342,150	$ 339,491	$ 381,077	$ 446,528
Use of Funds					
Repayment of LTD	(705)	-	-	-	-
Payment of Dividends	-	-	-	10,000	10,000
Construction and Other Capex	315,686	341,136	341,034	372,556	438,884
Change in Working Capital	(18,270)	1,015	(1,543)	(1,479)	(2,356)
Total Use of Funds	$ 296,710	$ 342,151	$ 339,491	$ 381,077	$ 446,528
	-	(1)	-	-	-
1) Ratio of Net Internally Generated Funds to Construction and Other Capital Expenditures (%)	58.0	62.6	67.5	66.8	64.9

Ratio = Total Internal less Payment of Dividends divided by
Construction and Other Capex (capital expenditures)

COLUMBIA GAS OF PENNSYLVANIA, INC.

PROJECTED INCOME STATEMENTS
2019-2023
($000)

	2019	2020	2021	2022	2023
Operating Revenue	$ 436,049	$ 465,168	$ 499,313	$ 533,570	$ 574,171
Operating Expenses					
Oper. & Maint.	194,436	177,686	180,841	178,850	179,596
Depreciation	73,292	76,591	86,116	95,169	105,423
Taxes Other Than Income Taxes	3,525	3,270	3,359	3,430	3,510
Total Operating Expenses	271,252	257,547	270,316	277,449	288,529
Other Income & Deductions Net	(560)	(422)	(1,177)	(1,153)	(1,131)
Income Before Income Taxes & Interes	164,236	207,199	227,820	254,968	284,511
Income Taxes					
Federal	23,716	30,910	33,469	37,661	42,595
State	3,554	3,397	4,019	4,475	3,201
411 Tax Repairs	0	0	0	0	0
ITC Net	0	0	0	0	0
Total Income Taxes	27,270	34,307	37,489	42,135	45,796
Income Before Interest Expense	136,966	172,891	190,331	212,833	238,715
Interest Expense					
Long-Term	39,628	48,731	52,905	59,610	66,485
Short-Term	2,446	2,220	4,515	4,349	5,055
Other	1,708	845	845	845	845
Total Interest Expense	43,782	51,795	58,265	64,803	72,384
Net Income From Subsidiaries	103	0	0	0	0
NET INCOME	$ 93,287	$ 121,096	$ 132,066	$ 148,030	$ 166,331

Columbia Gas of Pennsylvania, Inc.
Securities Certificate – Statement of Consumer Benefit

The financing for which Columbia Gas of Pennsylvania, Inc. seeks the issuance of a Securities Certificate will benefit consumers and the public by providing facilities to serve new customers, by replacing unserviceable facilities, as necessary, and by replacing infrastructure that is nearing the end of its useful life, to assure safe and reliable service to all customers.

Columbia Gas of Pennsylvania, Inc.
Number of Counties and Number of Customers

Columbia Gas of Pennsylvania, Inc. furnishes utility service in the following 26 counties:

Adams County
Allegheny County
Armstrong County
Beaver County
Bedford County
Butler County
Centre County
Chester County
Clarion County
Clearfield County
Elk County
Fayette County
Franklin County
Fulton County
Greene County
Indiana County
Jefferson County
Lawrence County
McKean County
Mercer County
Somerset County
Venango County
Warren County
Washington County
Westmoreland County
York County

Columbia's total number of customers as of September 30, 2019 was 430,297.

COLUMBIA GAS OF PENNSYLVANIA, INC.

CONSTRUCTION PROGRAM - 2019

SPECIFIC BUDGETS OVER $250,000

Distribution		Total Expenditures	Age of Pipe Replaced
New Business			
3708837	Centre Hall Project	3,962,000	N/A
Total New Business Specifics		3,962,000	
Betterment			
3708649	PM D-10132 Dreibelbis	8,616,000	N/A
3708759	2231 - Glen Mitchel Road Capacity Betterment	293,564	N/A
3709801	2231 - D-82 Phase II (12-inch HDPE)	5,432,000	N/A
18-0222932-01	2231 - Roosevelt Road Betterment	700,000	N/A
Total Betterment Specifics		15,041,564	
Public Improvement			
3708843	2231 - SR 18 Turnpike Relocation (12"HDPE)	1,500,000	N/A
Total Public Improvement Specifics		1,500,000	
Replacement			
3701003	2171 - 1962 CS Falling Spring	800,000	N/A
3701011	2231 - Casteel Drive Regulator Rebuild	800,000	N/A
3707439	2391 - Latimer Avenue	835,000	N/A
3707445	2391 - Avella LP	1,450,000	N/A
3707449	2391 - D-36 (Peters Twp)	1,100,000	N/A
3707463	2221 - Tropical Avenue	3,000,000	N/A
3707737	2232 - Six Points Regulator Replacement	850,000	N/A
3707745	2231 - Hamilton St AMRP	1,100,000	N/A
3707761	37 Customer Service Lines	9,888,132	N/A
3707781	2391 - Canonsburg Phase 2	575,000	N/A
3707785	2391 - North Wade Street	375,000	N/A
3707815	2231 - 2nd Street Area AMRP - Beaver Borough	1,500,000	N/A
3707817	2231 - Ben Avon Heights Replacement and Upgrade	700,000	N/A
3707821	2231 - Oak Ave Replacement - Harmony Twp	700,000	N/A
3707835	2231 - Croton Avenue Area	261,245	N/A
3707845	2221 - Hays Avenue (Mt. Oliver)	465,000	N/A
3707853	2231 - D-1447 Replacement Phase I	3,500,000	N/A
3707863	2321 - D-7090 Palmer Road	1,250,000	N/A
3707865	2231 - Beechwood Blvd AMRP	740,000	N/A
3707871	2421 - E. King St	545,000	N/A
3707879	2231 - Mooncrest Village Betterment	850,000	N/A
3707881	2231 - D-1395 Phase 1 (12"HDPE)	3,532,000	N/A
3707885	2221 - Linnview (Pittsburgh)	2,919,465	N/A
3707891	2421 - South Adams St	865,000	N/A
3707911	2321 D-7090 Polk Lane	1,100,000	N/A
3707917	Baltimore Pike, Phase 3	1,100,000	N/A
3707921	E Maiden Street Replacement Project	1,500,000	N/A
3707925	Dewey St, Washington	1,500,000	N/A
3707937	2231 - Winter Road Replacment Project - New Castle	471,399	N/A
3707941	2391 - Line 1570 M&R	2,100,000	N/A
3708637	2221 - Brentview Road (Baldwin)	1,300,000	N/A
3708731	2221 - Bon Air Regulator (Pittsburgh)	1,250,000	N/A
3708733	2221 - McCoy Street (McKees Rocks)	1,650,000	N/A
3708737	2231 - 3rd Avenue, 13th to 16th Street - New Brighton	565,575	N/A
3708743	2421-Littlestown HP Repl	710,000	N/A
3708751	2421 - Manor Ph II	360,000	N/A
3708755	2321 - Altman Road	466,500	N/A
3708783	2421 - Knoll	1,200,000	N/A
3708803	2321 - Altman Road	1,805,000	N/A
3708805	2321 - Chestnut Street	696,833	N/A
3708819	2321 - Perry Circle	300,000	N/A
3708821	2391- D-36 Phase 2 (Peters Twp)	849,000	N/A
3708827	2221 - Fairhaven Station Reg (Pittsburgh)	350,000	N/A
3708829	2221 - Arden (Mt. Lebanon)	1,495,292	N/A
3708841	2221 - South Side Phase 5 (Pittsburgh)	665,000	N/A
3708851	2421 - Poplar	1,370,000	N/A
3709607	PM South York POD	451,000	N/A
3709615	2238 - Lewis Run POD	1,473,000	N/A
Various	LP OPP	11,400,000	N/A
		74,729,441	
Total Specifics		95,233,005	

EXHIBIT 19

COLUMBIA GAS OF PENNSYLVANIA, INC.

5 YEAR PROJECTED CONSTRUCTION PROGRAM
($000)

Plant Account	2019	2020	2021	2022	2023
Distribution	297,474	311,943	313,333	344,705	411,034
Storage	0	0	0	0	0
Production & Gas Supply	0	0	0	0	0
General	22,429	15,637	20,426	20,576	20,576
Total Gross Construction	319,903	327,580	333,759	365,281	431,610
Non-Cash & Net Salvage	1,919	1,965	2,003	2,192	2,590
Total Net Construction	317,984	325,615	331,757	363,090	429,020

Note: Please note that actual capital budgets for the following year are approved in the fourth quarter of the current year. Thus, the figures provided in this exhibit for years beyond 2019 are projections that are based, among other things, upon current capital markets, and Columbia's projected revenue under its current rate structure.

COLUMBIA GAS OF PENNSYLVANIA, INC.

PROJECTED 2019 INCOME STATEMENT

($000)

	2019 Amount ($000)
Operating Revenue	436,049
Operating Expenses	
Operation & Maintenance	194,436
Depreciation	73,292
Taxes Other Than Income Taxes	3,525
Total Operating Expenses	271,252
Other Income & Deductions Net	(560)
Income Before Income Taxes & Interest	164,236
Income Taxes	
Federal	23,716
State	3,554
Total Income Taxes	27,270
Income Before Interest Expense	136,966
Interest Expense	
Long-Term	39,628
Short-Term	2,446
Other	1,708
Total Interest Expense	43,782
Income From Subsidiaries	103
NET INCOME	93,287

COLUMBIA GAS OF PENNSYLVANIA, INC.

PROJECTED 2020 INCOME STATEMENT

($000)

	2020 Amount ($000)
Operating Revenue	465,168
Operating Expenses	
Operation & Maintenance	177,686
Depreciation	76,591
Taxes Other Than Income Taxes	3,270
Total Operating Expenses	257,547
Other Income & Deductions Net	(422)
Income Before Income Taxes & Interest	207,199
Income Taxes	
Federal	30,910
State	3,397
Total Income Taxes	34,307
Income Before Interest Expense	172,891
Interest Expense	
Long-Term	48,731
Short-Term	2,220
Other	845
Total Interest Expense	51,795
Income From Subsidiaries	0
NET INCOME	121,096

COLUMBIA STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
NANCY J.D. KRAJOVIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

April 24, 2020

I. INTRODUCTION

Q. Please state your name and business address.

A. Nancy J. D. Krajovic, 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 State Finance Director.

Q. What are your responsibilities as State Finance Director?

A. I am responsible for analysis and support in the financial planning, forecasting and O&M and capital budgeting processes for Columbia and coordination with the NiSource Corporate Services Company ("NCSC") financial planning and budgeting processes.

Q. What is your educational and professional background?

A. I hold a Bachelor's of Science Degree in Accounting from Duquesne University and a Master of Business Administration from the University of Pittsburgh's Katz Graduate School of Business. I was employed by the Pennsylvania Public Utility Commission ("Commission") from 1984 through 1987 as an auditor. From 1988 through 2007, I held various regulatory positions at Duquesne Light Company, including Regulatory Analyst, Rate Design Coordinator, Project Manager, Director of Regulatory Affairs and Manager of Regulatory Affairs. In those positions I acted as the primary interface with the Commission in the conduct of financial and management audits of Duquesne Light. Additionally, I was responsible for the interpretation and administration of Duquesne's retail and supplier tariffs. In 2007, I assumed the role of Manager, Commercial and Industrial Customers for Duquesne Light and held that position until May 2009. In November of 2009, I joined Columbia as Senior Regulatory Analyst and was promoted to Director of Rates and Regulatory Affairs in June of 2011. In July of 2015, I transferred to my current role as State Finance Director.

Q. Have you previously testified before this Commission?

A. Yes, I have submitted written testimony before the Commission on Duquesne's behalf at the following dockets: I-900005, M-00930404C001, R-00016854C001, M-FACE0302, R-00061346 and P-00072247. I also presented oral testimony in several formal customer complaint actions and at en banc hearings sponsored by the Commission on energy conservation issues. Additionally, I have submitted written testimony before the Commission on behalf of Columbia at the following dockets: R-2011-2215623, R-2012-2293303, R-2012-2321748, R-2013-2351073, R-2014-2406274, R-2014-2408268, R-2015-2468056, R-2015-2469665, R-2016-2529660, R-2018-2647577, P-2012-2338282 and C-2011-2248370/A-2011-2276780.

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

A. Basis for Forecasted 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?

A. The O&M expense budgeting methodology used by Columbia is a combination of a "top down" and "grass roots" approach. 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 Inc.'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.

Annually, 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 NCSC Chief Financial Officer ("CFO") and Chief Executive Officer ("CEO"). 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 January.

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 and NCSC CFO 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. 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 6.5%, 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. During the last four months of 2018, many NCSC employees and resources were reassigned to support Columbia Gas of Massachusetts' Merrimack Valley recovery efforts. The reassignment of employees and resources resulted in more NCSC costs being billed to Columbia Gas of Massachusetts and fewer costs billed to the remaining affiliates, including Columbia. 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%).

Notably, in eight of the last eleven 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. Please refer to Exhibit NJDK-1 accompanying this testimony for a comparison of actual results versus the annual original O&M budget for the years 2009 through 2019. Overall, Exhibit NJDK-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.

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.

B. 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 822 active full-time employees for 2020 and 839 employees for 2021, 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 763 active full-time employees. Additional positions and associated costs discussed in Company witness Davidson's testimony are not included in the budgeted O&M labor expense but rather are reflected in "Other Adjustments" in ratemaking adjustments in the FPFTY.

C. 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 Future Test Year ("FTY") and the Fully Projected Future Test Year Outside Services budgets reflect planned work activities and work volume based on historical information and inflationary cost increases.

D. 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 2019 and completed in January 2020.

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.

E. 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. O&M expense before ratemaking adjustments is $151,565,323 for the Historic Test Year ended November 30, 2019, $157,441,000 for the Future Test Year ending November 30, 2020 and $164,650,000 for the Fully Projected Future Test Year ending December 31, 2021, increases of \$5,875,677 and \$7,209,000, respectively, before pro forma ratemaking adjustments.[1]

E (1) Key Variances Between HTY and FTY

Q. Please explain the key variances in O&M expense levels between the Historic Test Year and the budgeted amounts for the Future Test Year.

A. Please refer to Exhibit 104, Schedule 1, Page 3, for a breakdown of the O&M expense variances from the Historic Test Year to the budgeted Future Test Year ended November 30, 2020. The methodology for how labor is budgeted has been covered in my earlier testimony. Please refer to Exhibit 104, Schedule 10, Page 1, for an illustration of the \$866,810 increase in labor from the Historic Test Year to the budgeted Future Test Year.

Incentive compensation increases from the Historic Test Year to the Future Test Year, are driven by the increase in headcount. The budget anticipates that any short term vacancies will be covered through increases in overtime or outside labor. Additionally, the 59 additional employees discussed in the Company's response to Standard Data Request GASRR-020 are included in the budget for the Future Test Year. As mentioned previously, the budgeted amount for benefit expenses such as pension, other post-employment benefits ("OPEB") and other benefits, is based on actuarial estimates provided by NiSource's independent actuary AON Hewitt. The change in benefits from the Historic Test Year amount to the Future Test Year budget

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

is driven by an increase in Other Employee Benefits, specifically for increases in medical expenditures and in 401(k) cost increases commensurate with merit increases and additional headcount.

The increase in Outside Services from the Historic Test Year to the Future Test Year, as described earlier in my testimony, is illustrated in Exhibit 104, Schedule 11, Page 1.

Rent and Lease Expense has decreased by virtue of the elimination of lease payments for the Monaca Operations Center, offset to some extent for contractual increases in monthly lease payments at the Company's various other leased facilities. The Company's purchase of the Monaca Operations Center facility in 2019 was approved by the Commission on September 19, 2019 at Docket No. A-2019-3012088. The decrease in Rents and Lease Expense is illustrated in Exhibit 104, Schedule 12, Page 1.

Corporate Insurance is increasing from the HTY to the FTY. Beginning in late 2018 and through 2019 the insurance market has seen significant rate increases. This is due to several factors, including mergers and acquisitions amongst insurers and higher frequency and severity of events, including natural catastrophes and high jury awards well beyond historical averages that have resulted in underwriting losses. Many insurers who have historically underwritten in the utility space are either significantly reducing available capacity or withdrawing from the market entirely. Due to the high risk exposure of the utility industry, there are very few new carriers willing to write U.S. utility insurance and, those that are have very limited capacity. The decrease in available capacity has significantly impacted insurance premiums.

Injuries and Damages expense increase follows historical trends for budgeting purposes but is normalized to an inflation-based increase for ratemaking purposes.

Employee Expense increase reflects increased headcount in the FTY.

The decrease in Materials and Supplies in the FTY reflects a more normalized level than experienced in the HTY, when expenses were driven higher than budgeted primarily because of the unplanned additional headcount during the year and increased material costs associated with higher than planned leak repair activity. The other O&M increase reflects the summation of several small variances with no significant drivers.

The budgeted increase in PUC/OCA/OSBA/DPA fees reflect an expense in line with historic experience.

The NCSC Expense decrease is explained in Exhibit 104, Schedule 13, Page 1.

E (2) Key Variances Between FTY and FPFTY

Q. Please explain the key variances in O&M expense levels between the Future Test Year and the budgeted Fully Projected Future Test Year.

A. Please refer to Exhibit 104, Schedule 1, Page 4, for a breakdown of the O&M expense variances from the Future Test Year to the budgeted Fully Projected Future Test Year. The methodology for how labor is budgeted has been covered in my earlier testimony. Please refer to Exhibit 104, Schedule 10, Page 2, for an illustration of the increase in labor from the normalized Future Test Year to the budgeted Fully Projected Future Test Year.

Incentive compensation increases from the Future Test Year to the Fully Projected Future Test Year, reflective of the increased labor costs and headcount.

As mentioned previously, the budgeted amount for benefit expenses, such as OPEB and other benefits, are based on actuarial estimates provided by NiSource's independent actuary AON Hewitt. The change in benefits from the Future Test Year amount to the Fully Projected Future Test Year budget is driven by an increase in Other Employee Benefits, as described for the Future Test Year budget.

The increase in Outside Services from the Future Test Year to the Fully Projected Future Test Year, as described earlier in my testimony, is illustrated at Exhibit 104, Schedule 11, Page 2. Note that the annual Operations Work Plan, which accounts for the majority of Outside Service expense, is developed in detail during the fourth quarter of the preceding year based upon field intelligence gathered in the prior year, current conditions and risk prioritization at that point. Therefore, it is impossible to identify precise budgets for individual work streams two years in advance.

The decrease in Rent and Lease Expense reflects complete elimination of the Monaca Operations Center lease. The additional decrease illustrated at Exhibit 104, Schedule 12, Page 2 is the net of contractual increases in monthly lease payments and changes in allocations at the Company's various facilities.

The increase in NCSC Expense is explained in detail at Exhibit 104, Schedule 13, Page 2.

Q. On Exhibit No. 104, Schedule 2, Page 18 witness Miller refers to your testimony for details on FPFTY adjustments for costs associated with compensation adjustments. Please explain.

A. The amount of $431,000 represents anticipated expenses related to two compensation issues that had not been addressed at the time of the FPFTY budget development, but have since been quantified and included in plans for appropriate action.

The first compensation issue deals with comparison of the salaries of Field Operations Leaders ("FOLs") against market rates. It was determined that 54 of the current 68 FOL incumbents are below market value. An adjustment of $461,000, with an O&M/Capital allocation of 70/30 applied, will remediate the salary gap and increase O&M labor expense by $322,700.

The second planned adjustment for compensation will provide additional compensation for salaried Leaders who are required to be on standby on a rotational basis for Emergency Response, but who do not receive overtime pay in the instances that they are called out for service. The current lack of incremental compensation for emergency call-out service acts as a disincentive for employees to move into leadership positions, because such a promotion would effectively eliminate potential overtime pay. Addressing the potentially punitive nature of the shift from non-exempt to exempt compensation will enhance the Company's ability to promote and retain qualified individuals into leadership positions. The Company estimates the cost of this adjustment to be an incremental $109,200 in O&M labor expense.

Q. Does that conclude your testimony?

A. Yes.

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense Budget vs. Actual

CE	Budget 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Labor	23,873	23,108	22,910	23,693	25,709	25,251	28,309	29,646	31,181	31,534	32,271
Incentive Compensation	293	1,171	1,149	1,249	1,238	1,333	1,584	1,642	1,742	2,150	1,133
Pension	2,119	6,005	6,598	-	3	1,137	-	6	549	-	-
OPEB	715	1,065	492	(154)	(284)	(550)	(1,378)	(810)	(514)	(1,109)	(730)
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
Outside Services	15,636	15,175	13,094	12,123	12,104	22,311	26,079	23,977	25,458	22,634	23,453
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
Corporate Insurance	3,116	3,574	3,413	3,048	3,004	3,087	4,516	3,481	3,705	3,495	3,631
Injuries and Damages	1,209	944	795	630	630	500	500	400	-	400	400
Employee Expenses	1,109	1,046	1,163	1,142	1,295	1,305	1,640	1,452	1,501	1,584	1,483
Company Memberships	347	345	249	292	262	256	256	332	491	491	563
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
Advertising	500	185	170	170	470	170	170	170	170	170	174
Fleet	4,663	4,104	4,421	5,046	5,452	5,708	5,728	5,797	5,879	6,255	5,673
Materials & Supplies	4,929	4,767	4,775	4,899	4,649	5,024	5,067	5,962	5,366	5,865	5,568
Other O&M	(3,987)	(3,780)	(116)	(783)	60	(1,906)	(434)	393	1,050	646	1,381
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
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
Amortization	82	75	(243)	(1,446)	(1,455)	185	267	496	511	409	845
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-	-	-	-	-
Total Operation and Maintenance Expense	95,231	106,443	106,498	99,407	108,941	121,516	134,890	143,604	157,656	154,193	154,233

CE	Actuals 2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Labor	23,153	23,577	22,845	23,996	25,124	25,818	27,980	29,093	30,019	32,461	36,471
Incentive Compensation	1,303	1,628	1,649	1,690	1,845	1,816	1,791	1,981	2,590	1,381	1,246
Pension	392	5,799	13,088	91	2,489	1,131	14	21	8,538	(8,417)	12
OPEB	1,683	775	(213)	88	(454)	(1,298)	(1,336)	(583)	(410)	(843)	(325)
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
Outside Services	15,180	15,440	13,244	12,133	14,113	22,070	22,951	25,361	28,246	21,352	22,850
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
Corporate Insurance	3,045	3,241	2,926	2,763	2,734	2,796	2,899	3,024	3,176	3,239	4,363
Injuries and Damages	605	545	340	241	305	(185)	381	363	337	270	512
Employee Expenses	1,405	1,450	1,553	1,465	1,376	1,264	1,415	1,381	1,545	1,383	1,713
Company Memberships	295	250	293	262	249	313	479	563	599	527	569
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
Advertising	389	281	167	133	243	236	207	226	283	146	224
Fleet	4,650	4,726	5,092	5,357	5,780	6,106	5,956	6,206	6,320	6,338	6,906
Materials & Supplies	4,741	4,967	4,412	4,353	5,171	5,343	5,873	5,461	6,327	5,627	6,320
Other O&M	(3,527)	(3,005)	157	(63)	31	512	306	367	647	1,074	1,242
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
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
Amortization	82	0	(489)	(1,446)	(594)	185	267	396	511	845	845
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-	-	-	-	-
Total Operation and Maintenance Expense	95,892	106,766	113,356	101,209	111,952	127,057	134,044	142,299	170,532	141,304	161,271

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

COLUMBIA STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	)	

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

April 24, 2020

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 Staff 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 tax CAP ("Compliance Assurance Process") audit program. Constellation was acquired by Exelon Corporation in 2012, and I became the Tax Manager for Commonwealth Edison responsible for income tax accounting, forecasting income taxes, and income tax and non-income tax return filings. In 2014, I joined Mead Johnson Nutrition BV as the Tax Manager for the European region with responsibility for all income tax and non-income tax accounting, tax research and tax return filings for the region. In 2016, I joined Cardinal Health as the Director of International Tax Operations with responsibility for income tax accounting, forecasting, mergers & acquisitions, tax research and income and non-income 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 tax matters. 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 its subsidiaries, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"). My responsibilities include oversight and review of the preparation of income tax accounting, 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 not previously testified before this or any other regulatory agency.

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 recently enacted Tax Cuts and Jobs Act ("TCJA") of 2017. The income tax calculations are included in Exhibit 7 for the Historic Test Year (the twelve month period ending November 30, 2019) and Exhibit 107 for the Future Test Year (the twelve month period ending November 30, 2020) and Fully Projected Future Test Year (the twelve month period ending December 31, 2021).

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 tax laws. The federal tax rate in effect for the Historic Test Year is 21%. A federal tax rate of 21% is also being reflected for the Future Test Year and the Fully Projected Future Test Year. The Historic Test Year tax calculations have been impacted by certain items that have been historically treated as flow-through or deferred in rate making proceedings.

Q. Can you explain the flow-through items included in the tax provision, including 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 deferred 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"). This method requires that excess deferred income taxes be used to reduce revenue requirements and revenue no sooner than would occur as the book versus tax difference reverses and flow-through the amortization of the excess 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. The Company projects to record lower tax expense by $4,317,856 in its federal tax provision related to the excess deferred taxes on asset vintages 1981-2021 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 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. 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, employee stock purchase plan compensation, and a portion of lease expense on vehicles.

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 bonus depreciation deductions in the Pennsylvania corporate tax computation in the test years, 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 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 cap of 40% in the Future Test Year and the Fully Projected Future Test Year. The Pennsylvania NOL carryforward is reflected on Exhibit 7, Page 23.

Q. Was a Consolidated Tax Adjustment included in the claim in this case?

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

[1] *Nextel Communications of the Mid-Atlantic, Inc. v. Commonwealth*, 171 A.3d 682 (Pa. 2017).
[2] *Nextel Communications of the Mid-Atlantic, Inc., v. Commonwealth*, 129 A.3d 1 (Pa. Commw. 2015).

parent or affiliated companies should not be included in computation of income tax expense to reduce rates.

Q. Section 1301.1(b) also contains provisions related to the treatment of revenues resulting from the elimination of the consolidated tax adjustment. Is this provision applicable to Columbia in this case?

A. No. Even without the passage of Act 40, the Company would not include a consolidated tax adjustment because Columbia was a loss company on average for the three year period 2016-2018 as a result of repairs deductions, 50-100% bonus depreciation allowed under federal tax law[3], and accelerated depreciation. Under these circumstances, and consistent with Columbia's presentations in prior base rate cases, it is inappropriate to apply a consolidated income tax adjustment. Nevertheless, Exhibit No. 7, Pages 2 through 4 provides computation method of the Section 1301.1 differential and details of the income and losses of affiliated companies for the periods 2012 to 2016, since Act 40 was passed in 2016 which eliminated the consolidated tax savings adjustment.

Q. Can you summarize the impact of your testimony on historic and proposed income tax expense?

A. Yes, for the Historic Test Year, Page 19 of Exhibit 7 delineates total pro forma tax expense of $29,855,968. This total includes $3,745,880 of state income taxes, which is based on $161,501,713 of operating income less $37,936,024 of interest expense on debt for total pre-tax income of $123,565,689 resulting in an effective state

[3] The Tax Increase and Prevention Act of 2014 and the Protecting Americans from Tax Hikes Act of 2015.

income tax rate of 3.03%. 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 $26,110,088 resulting in an effective tax rate of 21.13%. The increased federal effective tax rate, as compared to the federal statutory rate of 21%, is largely attributable to the flow through items included in rates.

Q. Please continue with respect to the Fully Projected Future Test Year.

A. For the Fully Projected Future Test Year, Page 16 of Exhibit 107 delineates total tax expense of $16,511,958. This total includes $42,372 of state income taxes, which is based on $132,898,363 of operating income less $49,229,254 of interest expense on debt for total pre-tax income of $83,669,109 resulting in an effective state income tax rate of .05%. 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. The expense for federal income taxes is $16,469,586 resulting in an effective tax rate of 19.68%. 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 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 9, Line 19.

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 $34,820,033 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 5, of $32,483,078 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(b).

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 $12,597,949.

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 $216,652 is reflected in the annualized Historic Test Year. Please see 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 $171,047. Please see 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, 2018. The West Virginia tax for gas stored underground was developed using the December 31, 2017 assessed value and the 2017 tax rate. This annualized level of $516,357 is equal to the Historic Test Year level of $516,357, as shown on Exhibit 6, Schedule 2, Page 4. The detail supporting this calculation for the Fully Projected Future Test Year is provided on Exhibit 106, Schedule 2, Page 4. The pro forma Fully Projected Future Test Year reflects an upward adjustment of $13,526 from the annualized level as a result of using the December 31, 2018 assessed value and the 2018 tax rate which is the latest available at this time.

Q. Please explain the License and Franchise Tax adjustment.

A. The License and Franchise tax annualized level of $100 is the same as the Historic Test Year level. This amount reflects liability license tax for the city of Uniontown, Pennsylvania for the Company. The pro forma Fully Projected Future Test Year was not adjusted from this level.

Q. Please explain the Other Tax adjustment on Exhibit 106, Schedule 2, Page 2.

A. Other taxes are primarily comprised of sales tax for uncollectible amounts. The annualized level of $126 was not adjusted for the Historic Test Year. The pro forma Fully Projected Future Test Year was also not adjusted from this level.

Q. Does this conclude your direct testimony?

A. Yes.

COLUMBIA STATEMENT NO. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	

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

April 24, 2020

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 Manager of Regulatory Accounting 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 assumed my current position in 2015. 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. No. However, I have 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 in this matter. As required by Section 53.53IV[1], Items 1 and 9 of the Commission's regulations, I prepared ACOS studies by rate class at present and proposed rates (Item 1) and a cost analysis supporting minimum charges for all rate schedules (Item 9). The studies and cost analysis are presented in Exhibit 111. Item 10 of Section 53.53 IV requires a cost analysis supporting demand charges. I did not prepare a cost analysis for demand charges because Columbia's present and proposed tariffs do not contain distribution demand charges.

Q. Please describe Exhibit No. 11.

A. Exhibit No. 11 addresses the Commission's filing requirements regarding ACOS studies as required by Section 53.53IV. The Company's ACOS studies are presented in Exhibit No. 111 and a detailed description of the methodologies are included in this testimony. The ACOS studies are based on the fully projected future test year ending December 31, 2021.

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?

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[1] 52 Pa Code § 53.51, et. seq.

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 recognizes that no one allocated cost of service study is the "right" study and 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.

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. Columbia continues to submit that the customer-demand study and the peak and average study provide a reasonable range, and that the average study with its equal weighting of the two studies, provides the Company, the parties and the Commission with a set of returns that can be used as a benchmark or guide in revenue allocation. In other words, the average study is another tool that is used in setting rates based on the cost to serve.

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

A. Yes. For purposes of clarity, 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
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

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

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

FERC account, based on allocation percentages representative of the historic test year data (twelve months ending November 30, 2019).

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. Before its 2012 rate case (Docket No. R-2012-2321748), Columbia did not identify and separate mains before applying allocation factors beyond identifying and separating mains directly assigned to the MLS/MLDS class. Beginning with the 2012 rate case, 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 recognized that the remaining intermediate pressure ("IP"), medium pressure ("MP") and high pressure ("HP") systems greater than two inches may or may not be required to serve those customers served directly from a low pressure system. Without a detailed analysis of each of Columbia's IP, MP, and HP systems, the Company did not know which customers were served from those systems and, therefore, Columbia allocated the IP, MP, and HP systems as it had in previous rate cases, to all rate classes except the MLS/MLDS class. In its 2014 rate case (Docket No. R-2014-2406274), 2015 rate case (Docket No. R-2015-2468056), 2016 rate case (Docket No. R-2016-2529660) and its 2018 rate case (Docket No. R2018-2647577), Columbia performed a detailed analysis of each of its IP, MP, and HP systems, 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 IP, MP, and HP systems in this case?

A. Yes. In this case, as in the previous four rate cases, a detailed analysis of each of the Company's IP, MP, and HP systems was performed, resulting in a refined mains allocation method. After identifying and directly assigning the actual inventory of mains for the MLS/MLDS rate class, Columbia is again assigning its remaining mains to one of four allocation categories:

Category	Definition
Transmission	Includes transmission class pipe.
Low Pressure	Includes pipe that is normally operated at 7 to 14 inches of water column.
Regulated non-low pressure	Includes Intermediate Pressure ("IP") pipe that is normally operated at 2 to 10 psig, Medium Pressure ("MP") pipe that is normally operated at 10 to 60 psig, and High Pressure ("HP") pipe that is normally operated at over 60 psig. This category does not feed low pressure systems down-stream.
Remaining regulated pressure	Includes Intermediate Pressure ("IP") pipe that is normally operated at 2 to 10 psig, Medium Pressure ("MP") pipe that is normally operated at 10 to 60 psig, and High Pressure ("HP") pipe that is normally operated at over 60 psig. This category does feed low pressure systems down-stream.

Each of these groupings of mains is then being separately allocated using Columbia's traditional allocation methods.

Q. How has Columbia identified and separated Account 376 – Mains in its current rate case?

A. Using the same method that Columbia used in the past four rate cases, Columbia identified and separated, based on operating pressures, its transmission, low pressure, and regulated non-low pressure mains. The physical system data was then analyzed alongside the Company's plant accounting system records and its customer billing system ("DIS") records to identify customers served by the different categories of mains. A fourth category, remaining regulated pressure mains, was arrived at by subtracting, from the company totals (excluding direct assignment MLS/MLDS), the quantities separately identified as 'transmission',' low pressure', or 'regulated non-low pressure'. The residual was, by default, 'remaining regulated pressure mains.' This fourth category represents upstream mains that serve both regulated pressure and low pressure customers.

Q. Did Columbia change its allocation method for Account 376 – Mains in its current case?

A. No. Columbia's allocation method in its current case follows the same approach as used in its previous four rate cases. That is, Peak & Average, Customer/Demand, and Average Studies were prepared, incorporating the same allocation factor drivers (i.e., design day volumes, customer counts, throughput). The specific allocation methods used for each of these categories are explained later in my testimony.

Q. What allocation approach is being applied to 'transmission' mains?

A. In both the Customer-Demand (Exhibit 111, Schedule No. 1) and the Peak and Average (Exhibit 111, Schedule No. 2) studies, transmission mains, because they are generally not designed to serve individual or small groups of customers, are typically viewed as being designed to meet the peak demand of the entire geographical area which they serve. For this reason, transmission mains are being allocated using the Company's total design day volumes (excluding MLS/MLDS).

Q. What allocation approach is being applied to 'low pressure' mains?

A. In the Customer-Demand Study, low pressure mains were split into customer and demand components, based on the average cost per foot of a two-inch main. The customer component was calculated by dividing the hypothetical cost of the Company's two-inch low pressure system into the total cost of the Company's low pressure system. This customer component of the low pressure mains was then allocated to rate classes based on the total number of customers (by rate class) served from Columbia's low pressure mains (excluding MLS/MLDS). The demand component was arrived at by calculating the cost of mains, other than the hypothetical cost of the Company's two-inch low pressure systems, and dividing that result into the total cost of the low pressure systems. The demand portion was allocated to rate classes based on the design day volumes for customers served from Columbia's low pressure mains.

In the Peak and Average Study, low pressure mains were allocated using historic test year throughput volumes applicable only to the low pressure customers (excluding MLS/MLDS), and design day volumes applicable only to the low pressure customers (excluding MLS/MLDS), and weighing each of the volumes equally.

Q. What are "regulated non-low pressure" mains?

A. Regulated non-low pressure mains are IP, MP and HP systems that do not serve low pressure systems. Customers served from regulated non-low pressure mains do not receive any gas directly or indirectly from a low pressure system. Conversely, customers served from low pressure system mains do not receive any gas directly or indirectly from a regulated non-low pressure system.

Q. What allocation approach is being applied to the regulated non-low pressure mains?

A. In the Customer-Demand Study and as with the low pressure mains, the regulated non-low pressure mains were split into customer and demand components and then allocated to the rate classes, using the same methodology. That is, only the customer counts and design day volumes for Columbia's regulated non-low pressure customers were used in the allocation process.

Similarly, in the Peak and Average Study, the regulated non-low pressure mains were allocated using average throughput volumes (based on historical test-year throughput volumes) and design day volumes (both applicable only to the regulated non-low pressure customers and excluding MLS/MLDS), and weighing each of the volumes equally.

Q. What are "remaining regulated pressure" mains?

A. Remaining regulated pressure mains are IP, MP and HP systems that serve two purposes: 1) to deliver gas to customers that require IP, MP or HP pressure; and 2) to also deliver gas into downstream low pressure systems and regulated non-low pressure systems. Because these upstream distribution mains are required to serve customers directly tied to both downstream low pressure and regulated non-low pressure systems, Columbia allocates the costs of remaining regulated pressure mains to all customers (except MLS/MLDS customers, which are directly assigned).

Q. What allocation approach is being applied to the remaining regulated pressure mains?

A. For the Customer-Demand Study, as with the low pressure and the regulated non-low pressure mains, the remaining regulated pressure mains were split into customer and demand components, using the same methodology as previously discussed. However, for these mains, total Company (excluding MLS/MLDS) customer counts and design day volumes were used to allocate the mains cost to the rate classes.

For the Peak and Average Study, the same 50-50 split was used to allocate the total mains cost based upon historical test year throughput and design day volumes. However, for this allocation, total Company volumes (throughput and design day) were used. Again, for this allocation, the MLS/MLDS class volumes were excluded from the allocation factor because this class is directly assigned.

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 approximately 87% of the Company's gross plant investment and approximately 56% of 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 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, 2019 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. The Company does not agree with this approach, and continues to support its traditional customer cost study, which includes 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.

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. At the request of Company witness Bell, 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. Does this complete your direct testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.
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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, 2021 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 31,2021. See Exhibit CEN-2, Page 2.

Factor No. 4- Gas Purchase Expense

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Factor No. 4 is based on gas cost assigned to each rate schedule for the twelve months ending December 31, 2021 using the applicable Gas Cost Recovery ("GCR") rates. See Exhibit CEN-2, Page 3.

Factor No. 5 - Composite of Factors No. 1 and Throughput

The determination of the total cost of transmission pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit CEN-2,Page 6. The allocation of transmission pipe was calculated by applying Allocator No. 1 (total Company design day volumes, excluding MLS/MLDS) to the total cost, recognizing that transmission mains are designed to serve an entire geographic area, as shown on Exhibit CEN-2,Page 12.

The determination of the total cost of the low pressure only pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit CEN-2 ,Pages 7 & 8. The allocation of low pressure pipe was calculated by applying, on a 50-50 basis, historical throughput (low pressure only) by rate class and design day volumes (low pressure only) by rate class to the total cost, as shown on Exhibit CEN-2,Page 13.

The determination of the total cost of the regulated non-low pressure pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit CEN-2, Page 9. The allocation of regulated non-low pressure pipe was calculated by applying, on a 50-50 basis, historical throughput

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(regulated non-low pressure only) by rate class and design day volumes (regulated non-low pressure only) by rate class to the total cost, as shown on Exhibit CEN-2,Page 14.

The determination of the total cost of the remaining regulated pressure pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit CEN-2, Pages 10 & 11. The allocation of remaining regulated pressure pipe was calculated by applying, on a 50-50 basis, historical throughput (total Company excluding MLS/MLDS) by rate class and Allocator No. 1 (total Company design day volumes) to the total cost, as shown on Exhibit CEN-2, Page 14.

For each of these four categories of allocated cost for each rate class, the aggregated amounts were converted to percentages, as shown on Exhibit CEN-2, Page 14, Line 21, which formed Allocation Factor No. 5.

Factor No. 5 combines design day quantities included in Factor No. 1 and throughput quantities for the historic test year ended November 30, 2019 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 -14 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, 2021 were averaged and used to develop Factor No. 6. See Exhibit CEN-2, Page 15.

Factor No. 7 – Current DIS Revenue

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Factor No. 7 reflects gross charge-offs recorded during the twelve months ending November 30, 2019 to small usage customers through the Company's Distributive Information System ("DIS"). See Exhibit CEN-2, Page 16.

Factor No. 8 – Current GMB/GTS

Factor No. 8 reflects revenue to be billed during the twelve months ending December 31, 2021 to larger sales usage and transportation customers through the Company's Gas Measurement Billing and General Transportation Systems. See Exhibit CEN-2, Page17.

Factor No. 9 – Customer Deposits

Factor No. 9 represents customer security deposits collected from customers by class as of November 30, 2019. See Exhibit CEN-2, Page 18.

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, 2019. See Exhibit CEN-2, Page 19.

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 20.

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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 23.

Factor No. 13 – Mains – Account 376

Factor No. 13 reflects the relationship based on the spread of dollars in account 376 Mains among all customer classes that resulted from allocating the Mains using composite Factor No. 5 for the Demand-Commodity Study and Factor No. 20 for the Customer-Demand Study for classes that could not be directly assigned. The dollars are aggregated and reduced to percentages to produce Factor No. 13. See Exhibit CEN-2, Page 24.

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 25.

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 29.

Factor No. 16 – Direct Assignment – Meters

Meters were assigned to the various classes of customers based on meters installed on customers' premises. Columbia recognizes four separate pressure groups for meters. Each varies in cost as the size changes. Individually installed meters as identified in DIS were summarized by the four pressure groups. The capitalized property investment, as identified on the Company's books and records for the four pressure groups, was divided by the number of installed meters as reflected on the Company's books and records to develop a cost per meter for each group of meters. The costs per meter were multiplied by the identified installed meters in DIS to determine the investment for each customer class. The percentages were developed for account 381 and used for assigning account 381 Meters as well as the investment in account 382 Meter Installations since these costs are incurred in direct relation with meters. See Exhibit CEN-2, Page 30.

Factor No. 17 – Direct Assignment - Ind M&R

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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 39.

Factor No. 18 - Other Distribution Expense

Factor No. 18 is based on the spread of dollars to the various classes of customers within the following distribution expense accounts:

Page 7 - Distribution Expense Allocation

Line 19 Account 871 - Distribution Load Dispatch

Line 20 Account 874 - Mains & Services

Line 21 Account 875 - M & R - General

Line 22 Account 876 - M & R - Industrial

Line 23 Account 878 - Meters & House Regulators

Line 24 Account 879 - Customer Installation

Line 29 Account 886 - Structures & Improvements

Line 30 Account 887 - Mains

Line 31 Account 889 - M & R - General

Line 32 Account 890 - M & R - Industrial

Line 33 Account 892 - Services

Line 34 Account 893 - Meters & House Regulators

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See Exhibit CEN-2, Page 40.

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 41.

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, Pages 42 to 53..

As with Factor No. 5, the total historical cost of the mains, the quantity of mains, and the directly assigned mains were all obtained from the Company's plant accounting system and Geographic Information System (" GIS") system. Likewise, this data was used to calculate the average cost per foot of each unique combination of kind and size of pipe. Again, the mains were further grouped into one of the following four allocation categories: 'transmission pipe', 'low pressure pipe', 'regulated pressure pipe only' and 'remaining regulated pressure pipe', as explained in Statement No. 11. The allocation of each of these categories is further explained in Statement No. 11.

The determination of the total cost of the transmission pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit CEN-2,Page 44. The allocation of transmission pipe was

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calculated by applying Allocator No. 1 (total Company design day volumes, excluding MLS/MLDS) to the total cost, recognizing that transmission mains are designed to serve an entire geographic area, as shown on Exhibit CEN-2,Page 50.

For the remaining categories of pipe, a minimum 2" system approach is used. 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.

The already determined total cost for the low pressure only pipe was allocated by applying the customer component percentage of 49.473% (Exhibit CEN-2, Page 51) to the average number of low pressure customers, and the demand component percentage 50.527% (Exhibit CEN-2, Page 51) to design day volumes (low pressure only). Finally, these two results are added together to form the minimum system percentages as shown on Exhibit CEN-2,Page 51.

As with the method for determining the low pressure minimum system percentage,

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the total cost of the regulated pressure pipe only was allocated by applying the customer component percentage of 58.831% (Exhibit CEN-2, Page 52) to the average number of regulated pressure only pipe customers, and the demand component percentage 41.169% (Exhibit CEN-2, Page 52) to design day volumes (regulated non-low pressure only). Finally, these two results are added together to form the minimum system percentages as shown on Exhibit CEN-2, Page 52.

Again, following the same method for determining the low pressure and regulated pressure pipe only minimum system percentages, the total cost of the remaining regulated pressure pipe was allocated by applying the customer component percentage of 31.472% (Exhibit CEN-2, Page 53) to the average number of Company customers (excluding MLS/MLDS), and the demand component percentage 68.528% (Exhibit CEN-2, Page 53) to total Company design day volumes (excluding MLS/MLDS). Finally, these two results are added together to form the minimum system percentages as shown on Exhibit CEN-2, Page 53.

Each of these four categories of allocated costs were aggregated, to arrive at a total cost for each rate class. These aggregated amounts were then converted to percentages, as shown on Exhibit CEN-2, Page 53, which formed Allocation Factor No. 20.

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

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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 54.

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

Factor No. 22 is based on the average of Factor Nos. 5 and 20 on an equal basis and is used to average the Customer-Demand Study and the Peak and Average Study. See Exhibit CEN-2, Page 55.

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 56.

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 57.

Factor No. 25 – Sales and CHOICE Transportation

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Factor No. 25 is based on the sales and CHOICE transportation activity for the twelve months ending December 31, 2021. See Exhibit CEN-2, Page 2.

Factor No. 26 – Other Automated Metering Devices

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 58.

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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.

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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.

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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.

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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

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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.

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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.

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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.

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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

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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

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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, 2021

Ln. No.	Item	Total	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	Account 117	(163,467)	(120,611)	(19,037)	(19,847)	(3,730)	-	(242)
2	Account 164	33,812,288	24,947,720	3,937,779	4,105,150	771,596	-	50,042
3	Allocated Storage Per ACOS Study using Allocation Factor #25	33,648,821	24,827,110	3,918,742	4,085,303	767,866	-	49,800
4	Sales & CHOICE Transportation (Dth)	46,955,249.2	34,645,192.4	5,468,484.9	5,700,784.4	1,071,487.5	0.0	69,300.0
5	Factor 25 Allocation of Storage	100%	73.783%	11.646%	12.141%	2.282%	0.000%	0.148%
6	Pre-Tax as Filed	15.10%	15.10%	15.10%	15.10%	15.10%	15.10%	15.10%
7	Revenue Requirement related to storage assigned to rate schedule (Ln. 6 * Ln. 7)	5,080,972	3,748,894	591,730	616,881	115,948	-	7,520
8	Rate Per Dth	0.1082						

Ln. No.	Item	Total DTH	% of Total	Included In Proposed Rates	Ratio	Redistributed Per Settlement
9						
10						
11						
12						
13	SGSS1 - Subject to Storage	4,118,413.4	72.270%	427,643	0.7531	18,004
14	SCD1 - Subject to Storage	1,350,071.5	23.690%	140,181	0.2469	5,902
15	SGDS1 - Not Subject to Storage	229,931.3	4.040%	23,906		(23,906)
		5,698,416.2	100.000%	591,730		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	4,308,373.4	45.750%	282,223	0.7558	184,024
21	SCD2 - Subject to Storage	1,392,411.0	14.780%	91,175	0.2442	59,459
22	SGDS2 - Not Subject to Storage	3,716,985.0	39.470%	243,483		(243,483)
		9,417,769.4	100.000%	616,881		0

Columbia Gas of Pennsylvania, Inc.
Pre-Tax Rate of Return
For the 12 Months ending December 31, 2021

	Ratio	Cost	Effective Cost	Gross Up	Pre Tax
Long Term Debt	42.22%		4.70%		
Short Term DebT	3.59%		2.06%		
Total	45.81%		6.76%		6.76%
Equity	54.19%	10.95%	5.93%	71.11%	8.34%
Total	100.00%		12.69%		15.10%

Federal	21.00%
State	9.99%
Fed. Benefit of SIT	2.100%
Effective Rate	28.8900%
Gross up	71.1100%

COLUMBIA STATEMENT NO. 12

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
SHIRLEY BARDES HASSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

April 24, 2020

I. Introduction

Q. Please state your name and business address.

A. Shirley Bardes Hasson, 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, Regulatory Policy.

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

A. I am responsible for managing regulatory activity before the Pennsylvania Public Utility Commission ("Commission"). This responsibility includes ensuring timely, accurate 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"), and regulations affecting Natural Gas Distribution Companies ("NGDC") within this Commonwealth. I also monitor cases before the Commission, recommend Company participation and develop comments for filing when warranted.

Q. What is your professional experience with the Company?

A. I have been an employee of Columbia since 1987 when I accepted a position in the Company's customer service department. In 1989, I was promoted to Office Operations Training Instructor where I provided customer service and compliance training to telephone representatives and field service technicians. My customer service and training experience required comprehensive knowledge of Chapter 56 of the Commission's regulations and Columbia's tariff. From 1995 until 2003, I held various positions working with the CHOICE®[1] program and large commercial and industrial transportation, initially as a Distribution Gas Transportation Coordinator, and progressing to Manager, Gas Transportation in 2001. I was significantly involved in the original development, expansion, and modification of the Columbia Choice program ("Choice Program"). I supervised employees who provided billing, collections and customer service to Columbia's largest commercial and industrial distribution service customers, and I acted as liaison between the Natural Gas Suppliers and the Company. In 2004, I joined the Regulatory Department as Manager, Regulatory Policy. Since 2004, I have been the company liaison and coordinator for the Commission's Bureau of Audits Purchased Gas Adjustment and Universal Service Plan audits, and in 2019 I held the same role for the Management and Operations Audit.

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

A. Yes, I have provided testimony before this Commission in several formal customer complaint cases and in Columbia's last seven base rate cases at Docket Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748, R-2014-2406274, R-2015-2468056, R-2016-2529660 and R-2018-2647577. I have also testified before the Maryland Public Service Commission on several occasions.

Q. What is the purpose of your testimony?

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[1] Customer CHOICE℠ is a service mark of Columbia Gas of Ohio, Inc. and its use has been licensed by Columbia Gas of Pennsylvania, Inc. CHOICE® is a registered mark of Columbia Gas of Ohio, Inc. and its use has also been licensed by Columbia Gas of Pennsylvania, Inc.

A. My testimony lists the exhibits I am sponsoring which include Exhibit 14, Schedule 2 (6), Columbia's tariff. Attachment B to that exhibit includes Columbia's proposed tariff changes. The main purpose of my testimony is to review at a high level, those proposed tariff revisions.

Q. What exhibits are you sponsoring?

A. I am sponsoring the following exhibits:

Exhibit No.:	**Description:**
Exhibit No. 10, Schedule 4 (39)	Company policy with respect to relationship with potential customers.
Exhibit No. 14, Schedule 1 (26)	List of information provided to the Commission.
Exhibit No. 14, Schedule 2 (6)	Present and proposed tariff pages.
Exhibit No. 15, Schedule 1 (01)	Corporate history, list of counties and municipalities served and total population in areas served.
Exhibit No. 15, Schedule 2 (02)	System map.
Exhibit No. 114, Schedule 1 (26) (6)	List of information provided to the Commission and tariffs, both present and proposed.
Exhibit No. 115 (01) (02) (24)	Corporate history, system map and affiliate relationships.

II. Tariff Changes Summary

Q. Please provide a brief description of Columbia's proposed tariff changes.

A. The substantive tariff changes proposed in Supplement No. 307 include rate revisions and revisions to Columbia's existing Weather Normalization Adjustment ("Rider WNA"). In addition to those revisions, Columbia is proposing a Revenue Normalization Adjustment ("Rider RNA"). All substantive changes reflect a "(C)" in the right margin of the page. Various non-substantive changes such as formatting, spelling corrections and text that has been moved from one page to the next, also are included.

Q. Is there a listing of all the tariff changes available?

A. Yes, Tariff pages 2 through 2b present the List of Changes to the Tariff proposed in this base rate case. As noted above, the Tariff is included as Exhibit 14, Schedule 2, Attachment B.

III. Non-Substantive Tariff Changes

Q. Begin by describing the formatting changes.

A. The headers on each Tariff page have been updated to reflect Supplement No. 307 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 "April 24, 2020" and "June 23, 2020", respectively.

In the Table of Contents, on Tariff page 4, the "174-176" and "177-180a" page references were revised to reflect only "174" and "177" for Rider NAS – New Area Service and Rider DSIC – Distribution System Improvement Charge respectively, to match the page numbering for other sections of the Tariff.

Q. On what pages has text been moved to the subsequent page?

A. The following describes the text that currently exists in the Tariff and the page it was moved from and to. Edits were not made to the text; the text was simply moved from one page to the next.

Item "3.17 NGS's Discontinuation of its Provision of Natural Gas Supply Services on the Company's System" was removed from page 5 of the Table of Contents and added to page 6.

Subparagraph "(iv)" from newly renumbered paragraph 2.20.1.14 on page 198 was moved to page 197.

IV. Substantive Tariff Changes

Q. Please explain the changes to rates within Supplement No 307.

A. 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 and Pass-through Charge. A column for the newly proposed RNA has been added to page 16. The DSIC has decreased.

Commercial and industrial accounts using less than or equal to 64,400 therms per year normally fall into one of three rate schedules depending on their choice of service. Rate Small General Sales Service ("SGSS") reflects the rates for customers purchasing their gas supply from the Company, while Rate Small Commercial Distribution ("SCD") and Rate Small General Distribution Service ("SGDS") are tariffed rate schedules for the mandatory firm capacity Choice program and the Gas Distribution Service program respectively, which are for customers choosing to purchase their gas from a natural gas supplier. Rate Summary page 17, which contains the rates for these rate schedules, reflects an increase to the Customer Charge and the Distribution Charge for customers on these rate schedules. The DSIC has decreased.

Q. What rate changes are reflected on page 18?

A. 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. Page 18 reflects an increase to customer and distribution charges for all rate schedules. The DSIC has decreased.

Q. How are the Rate Schedules on page 19 affected by the base rate case filing?

A. 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 change to the main line service Customer Charge and Distribution Charge rates however, the DSIC is decreasing for these customers.

Q. Explain the changes on the remaining "Summary" pages.

A. The Other Rates Summary, page 20, shows decreases to the Price-to-Compare for both residential and commercial gas supply. Those decreases are a direct result of the decreases to the Gas Procurement Charge ("Rider GPC") and the Merchant Function Charge ("Rider MFC") rates. The Price-to-Compare Summary page 21c includes these decreases too.

Page 21, which is the Rider Summary, reflects an increase to the Rider Universal Service Plan ("Rider USP") rate and decreases to the Distribution System Improvement Charge rider ("Rider DSIC") percentage, the Rider GPC rate and the Rider MFC rate. The Rider Summary also includes a new line labeled Revenue Normalization Adjustment ("Rider RNA").

Decreases to the Rider GPC and Rider MFC also impact page 21a, the Gas Supply Charge Summary.

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 Price-to-Compare Summary, page 21c, reflects the decrease to the Riders GPC and MFC.

I also note that the rate change for the 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 the RNA however, a rate is not indicated. Please explain.

A. As indicated in the description of the RNA on pages 144 and 145 of the Tariff, the first time the Company is proposing to bill an RNA is October 2021. Columbia has filed the proposed Tariff with an effective date of June 23, 2020, and at that time a rate for the RNA will not be billed. Therefore, it is appropriate that an RNA rate is not specified in the Tariff at this time.

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 were obtained from Exhibit No. 103, Schedule No. 8 pages 5 through 9. The rate change to the USP Rider was obtained from page 5 of that same schedule. Exhibit No. 103, Schedule No. 7, pages 6 and 7, were the source for the rate change to the GPC and the MFC. The percentages for the MFC are identified in Exhibit MJB-1 attached to Company witness Bell's testimony which is Columbia Statement No. 3. The rate design contained in Exhibit No. 103 is also discussed in Columbia Statement No. 3.

Q. The Table of Contents on page 4 reflects a new Rider RNA. Please explain.

A. Company witness Bell's testimony which is Statement No. 3 introduces and explains the Rider RNA in detail. The Rider RNA has been added to the Tariff on pages 144 and 145.

Q. What changes are proposed to the WNA?

A. Currently, Rider WNA has a deadband of 3%. Supplement No. 307 proposes to reduce the deadband from 3% to 0% effective with the February 2021 cycle billing. This change is reflected on pages 162 and 163 of proposed Supplement No. 307.

Further information regarding the proposed changes to Rider WNA may be found in Statement No. 3, which is Company witness Bell's testimony.

Q. Does Supplement No. 307 include clarifications or corrections to the currently effective Tariff contained in Exhibit 14, Schedule 2, Attachment A?

A. Yes. Rate Schedule SGSS - Small General Sales Service, assigned to Tariff page 86, was added to page 4. The Table of Contents in the current Tariff does not identify Rate Schedule SGSS.

Page 4 of the Tariff assigns page 164 to the Federal Tax Adjustment Credit ("FTAC"). This labeling was omitted when the FTAC was added to the Tariff in Docket No. R-2018-2647577.

Throughout the Tariff the word "premise" was changed to "premises". This affects Tariff pages 29, 40a, 43a, 44, 46, 58, 60, 65 and 139.

Page 43, section 5.7 Responsibility for Material or Workmanship, has a change to the last sentence. The word "into" has been changed to "on to".

Page 65, subparagraph 18.10.1 Timing of Reconnection, has the word "calendar" inserted before the word "days" in items "c.", "d." and "e." to further clarify how soon service shall be reconnected to a residential dwelling once all applicable conditions have been met and to align the tariff with PA. Code Title 52 §56.191 (b) (iii), (iv) and (v). By adding the word "customer" to the first sentence, the Company has further clarified the applicability of this subparagraph.

Page 140 of the Tariff currently specifies that security deposits will not be charged to Customer Assistance Plan ("CAP") customers and if a customer who previously paid a security deposit later joins the CAP, that security deposit will be credited to the pre-CAP arrears. In Supplement No. 307, the Company is adding clarification that accrued interest on the existing security deposit will also be credited to the pre-CAP arrears.

During a review of the Tariff, a duplication of numbering was discovered in Chapter 2 of the Rules Applicable to Distribution Service. Page 193 had "Special Services" labeled as section "2.16" and page 194 had "Duties Under Force Majeure" also labeled as section "2.16". Included in the proposed Tariff Supplement No. 307 is a section and paragraph renumbering on pages 194 through 200b to eliminate the duplication. The section renumbering is also reflected in the Tariff Table of Contents on page 5 and "2.16 Special Services" has been added to page 5, where it previously did not exist.

Q. Is there any text in the Tariff that is being revised to coincide with recently updated regulations?

A. Page 60 reflects a change to Paragraph 17.4 Payment of Cash Deposits. The last sentence of this paragraph suggests that an applicant for service may be required to pay a security deposit in full prior to obtaining service. In June 2019 the *Pennsylvania Bulletin* published revisions to the Commission's Chapter 56 regulations to comply with the amended provisions of 66 Pa. C.S. Chapter 14 as approved in a Final Rulemaking Order by the Commission on February 28, 2019, at Docket No. L-2015-2508421. In this proceeding, one of the revisions made to Section 56.38 "Payment period for deposits by applicants" eliminates the potential requirement to pay the security deposit in full prior to obtaining utility service. Paragraph 17.4 has been revised to comply with Section 56.38 by deleting the last sentence in the paragraph that suggests the Company may require an applicant to pay the full amount of a deposit prior to connection.

Q. Explain the background for the change to Tariff Page No. 233.

A. Supplement No. 307 corrects the cash-out calculation for "off-cycle" reconciliations that occur when a Natural Gas Supplier's ("NGS") Choice aggregation group decreases by 10% or 1,000 customers.

Paragraph 4.7.4.2 describes the annual reconciliation when the NGS's annual deliveries are less than the total annual customer consumption in the aggregation group and the NGS has to purchase the deficient amount of gas supply from the Company. Paragraph 4.7.4.3 describes the annual reconciliation when the NGS's customer aggregation uses less than what the NGS delivered during the annual period causing the Company to purchase the excess quantity from the NGS.

Paragraphs 4.7.4.2 and 4.7.4.3 both address the annual reconciliation of natural gas in Choice aggregation groups. Paragraph 4.7.4.4 differs in that it addresses reconciliations that happen outside the annual reconciliation period, or “off-cycle”.

The reconciliation cash-out rate calculation described on page 233 in the current subparagraph 4.7.4.4 conflicts with the two previous subparagraphs, 4.7.4.2 and 4.7.4.3, which address cash-outs at the time of the annual reconciliation. Docket No. R-2012-2321748 revised the calculation for reconciliation cash-outs in subparagraph 4.7.4.2 by changing the reconciliation rate from the Company’s weighted average commodity cost of gas to the average price as reported in Platt’s Inside FERC’s Gas Market Report (“Platt’s IFGMR”) in the monthly report titled “Prices of Spot Gas Delivered to Pipelines” under the column heading “Index for Columbia Gas Transmission Corporation, Appalachia”.

Docket No. R-2016-2529660 further revised the calculation of the reconciliation rate in subparagraph 4.7.4.2 by changing the referenced column heading in Platt’s IFGMR to “Index” for “Columbia Gas, App”. Docket No. R-2016-2529660 also aligned the cash-out rate calculation in subparagraph 4.7.4.3 with the new reconciliation rate calculation in subparagraph 4.7.4.2.

Current paragraph 4.7.4.4 specifies an outdated cash-out calculation using the Company’s weighted average commodity cost of gas that dates back to December 1, 2001. The change proposed in Supplement No. 307 aligns the calculation of the reconciliation rate used for an off cycle cash-out with the same rate calculation used for the annual reconciliation by referencing subparagraphs 4.7.4.2 and 4.7.4.3 in subparagraph 4.7.4.4.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 13

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
v.	)	Docket No. R-2020-3018835
	)	
Columbia Gas of Pennsylvania, Inc.	)	

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

April 24, 2020

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 27-year career at Columbia.

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

A. Pursuant to Columbia's 2018 rate case Joint Petition for Partial Settlement ("2018 Settlement", paragraph 48[1], I will provide an update on Columbia's efforts to raise

[1] Docket No. R-2018-2647577 (Order Entered December 6, 2018).

voluntary contributions for Columbia's Hardship Fund. I will also provide a history of Columbia's fundraising activities for the Hardship Fund. Finally, I will present results of Columbia's research in response to Office of Consumer Advocate's ("OCA") witness Colton's budget billing proposals in the 2018 rate case.

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 (0-200% of Federal Poverty Level), 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 $380 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.

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. Currently, Columbia has funding remaining from pipeline credits and supplier refunds that is used to supplement the Hardship Fund up to $375,000 annually.

Q. Please explain why Columbia is using pipeline credits and refunds to supplement its Hardship Fund.

A. On February 28, 2018, Columbia filed a petition at Docket No. P-2018-3000160 seeking approval to use federal pipeline penalty credits and refunds to permanently support its residential Hardship Fund. On June 14, 2018, the Commission approved Columbia's petition authorizing Columbia to use the residential portion of federal pipeline penalty credits and refunds to fund its Hardship Fund. Further, the Commission's order allows Columbia to maintain a Hardship Fund balance of up to $750,000. If Columbia's penalty credit and refund balance is more than $750,000, Columbia will flow the residential portion of the credits and refunds to its residential customers. Columbia will continue to seek opportunities to raise funds to support its Hardship Fund.

Q. What is the current balance of the penalty credits and supplier refunds that have been identified for use to supplement the funds needed to fully fund the Hardship Fund?

A A check for $375,000 was provided to Columbia's Hardship Fund administrator in January 2020, lowering the remaining balance to $422,000 for Hardship Fund use. Since February 2018, the Company has received a total of $907,489 in penalty credits and supplier refunds. These funds have been passed back to customers through the gas cost rates because the balance at the time of receipt was more than the $750,000 Hardship Fund cap. In addition, the Company received a penalty credit in the amount of $50,080 in December 2019, which will be passed back to customers through gas cost rates. Going forward, because the current Hardship Fund balance is below $750,000, any future residential portions of pipeline credits and supplier refunds received will be credited to the Hardship Fund balance up to a maximum of $750,000. Any funds received that will push the balance over the $750,000 cap will be passed back to customers through the gas cost rates. For example, if the Company were to receive $350,000 this year from the residential portion of supplier refunds, the Company would credit $328,000 to the Hardship Fund balance to bring that balance up to $750,000. The remaining $22,000 would be passed back to residential customers.

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

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

Year	Total Customer Bill contribution
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

As the chart demonstrates, these donations have been decreasing. Therefore, the Company's efforts to find other funding avenues have increased.

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. In 2019, $11,916 was raised through this effort, with TSO and the Company shareholders matching this amount.

- 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.

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 sixth year, Columbia's President has participated for two years, Columbia's Assistant General Counsel participated in 2017 and in the past three years, a unique 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
- Annual Thank you letter 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. In 2018 Columbia initiated a fundraising opportunity at Top Golf in Bridgeville, PA. Held in the fall, this fundraiser capitalizes 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 has raised a combined total of $26,980, resulting from sponsorships, participants and gift baskets generously donated by Company employees.

The Company continues its partnership with the Tran Siberian Orchestra. As part of Columbia's sponsorship, 50 cents of every ticket sold is donated to the Dollar Energy Fund.

Q. Do you have any additional issues you would like to raise?

A. Yes. I would like to address issues related to Budget Billing that were raised by OCA's witness Roger Colton in the Company's 2018 rate case.

Q. Please summarize Mr. Colton's proposals with respect to Budget Billing in the 2018 rate case.

A. Mr. Colton proposed that Columbia (1) engage in targeted outreach to accounts that experience short-term arrears during high-cost months; (2) offer residential customers levelized Budget Billing plans that are fewer than 12 months; (3) make Budget Billing enrollment available on a "year-round rolling enrollment basis"; and (4) implement a closer connection between deferred payment arrangements and enrollment of customers in Budget Billing.

Q. Did Columbia agree to implement any of these proposals?

A. Yes. In the 2018 Settlement, Columbia agreed to allow year-round rolling enrollment for its Budget Billing program. Columbia also agreed to engage in specific Budget Billing outreach to accounts that experience short-term arrears during high-cost months and to promote the budget plan to each customer upon successful completion of a deferred payment plan.

Q. What is the status of these three proposals?

A. Columbia allows year-round rolling enrollment for its Budget Billing Program. Regarding its commitment to engage in outreach to accounts that experience short-term arrears during high-cost months and to promote the budget plan to each customer upon successful completion of a deferred payment plan, the Company held two meetings in 2019 with interested stakeholders from the existing Universal Service Advisory Council including representatives from the Office of Consumer Advocate, PA Utility Law Project, Dollar Energy Fund, and the Bureau of Consumer Services to discuss budget billing outreach and promotions. The results of those meetings will be presented to the Universal Service Advisory Council at its next meeting, scheduled in April 2020, with subsequent implementation on the agreed upon recommendations.

Q. Did the Company make any other commitments in the 2018 Settlement that relate to Budget Billing?

A. Yes. Columbia agreed to further review Mr. Colton's other Budget Billing proposals to offer ten and eleven month budget billing plans in addition to a rolling twelve month budget and present an analysis in its next base rate case.

Q. Has the Company complied with this provision?

A. Yes.

Q. Please explain the analysis and the Company's recommendation.

A. In reviewing the options of offering a twelve month, eleven month and ten month budget billing plan, the Company determined that offering a twelve month budget billing plan provides the best opportunity for customers to levelize their monthly utility bills over the course of a year, as the higher cost of winter heating can be spread out over the lower cost months. The twelve month budget billing plan provides a long term solution that can be extended year after year. Company personnel researched the ability to modify existing programming to calculate a budget bill payment equal to the estimate of the average of one full year's billing, to offer customers year round. It was determined that such a modification is possible. Under the new twelve month budget billing design, a true up for all customers would still continue to occur in April of each year, which complies with existing policies that a true up cannot occur during a winter period. The bills would also be reviewed and adjusted up to four times during the first year to ensure their current payment amount is within ten dollars of the current estimated average annual bill, which is meant to reduce any under-or-overpayment during the twelve month budget billing period. For customers newly enrolled in the twelve month budget bill plan, the first April true up will be skipped, but then they will fall into the traditional budget billing cycle in which their budget bill will be trued-up every April and adjusted four times based on the number of months remaining in the cycle and their expected billing. In addition, in order to promote the budget billing plan to customers not enrolled in budget billing, the new programming will provide non-budget billing customers with their current budget billing monthly payment on each monthly bill.

Q. How much would it cost to program the proposed budget billing plan modification?

A. Approximately $280,000. This includes the cost to program the automated, monthly and revision calculations, update the bill format, update bill messages, change the on-line customer information system, update the interactive voice response unit and conduct all required testing before implementation. The Company is projecting more than 3,000 hours of information technology resources to develop this program. Additional hours are needed to design, manage and test the program before implementation.

Q. Is the Company willing to make this modification?

A. Yes.

Q. Please outline the timeline for implementation of this modification.

A. Time will be needed for programming, testing, modifying communication materials, updating call scripts, and training contact center representatives. The Company anticipates the new budget billing program could be offered within twelve months of approval.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 14

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
v.	)	Docket No. R-2020-3018835
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
ROBERT M. KITCHELL
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

April 24, 2020

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I. Introduction

Q. Please state your name and business address.

A. Robert M. Kitchell, 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 Vice President of Construction Services for Columbia and Columbia Gas of Maryland, Inc.

Q. What are your responsibilities as Vice President of Construction Services?

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; and
- Building and maintaining a network of contract resources that have the capacity and capability to execute on Columbia's capital program.

Q. What is your educational and professional background?

A. I began my career with the Northern Indiana Public Service Company ("NIPSCO"), a subsidiary of NiSource Inc. ("NiSource") in 1977 where I held a variety of operational and leadership roles of increasing responsibility. I joined NiSource's gas distribution segment in 2004 as Operations Center Manager for Columbia's Northern service area and then became the Operations Center Manager of Columbia's Central service area in 2007 prior to being named Director of Operations Integration in 2009. In 2012, I became the Vice President/General Manager for Columbia before transitioning into the Vice President, Operations for Columbia Pipeline Group ("CPG") in 2013 through 2016. In 2017, I returned to NiSource as an Executive Consultant before taking on the responsibilities of Vice President of Construction Services and Major Projects across the NiSource footprint. Lastly, I assumed my current responsibilities when I was named Vice President of Construction Services for Columbia in August 2019. I hold an Associate's degree in supervision from Purdue University and a Bachelor's degree in organization management from Calumet College of St. Joseph.

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

A. Yes. I provided direct testimony in Columbia's 2012 rate case.

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

A. My industry affiliations include: Membership in the Southern Gas Association ("SGA"), American Gas Association ("AGA") and the Energy Association of Pennsylvania.

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

A. I will provide an overview of 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, 2021).

II. Columbia's Pipeline Replacement Efforts

Q. How many feet of bare steel, wrought iron, and cast iron main has been eliminated from the Columbia 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 2019, 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
Total Actual (Through YE 2019)	**5,690,833**	feet

*Please note, some historical footages have been updated to reflect Columbia's system of record which may differ from Columbia's previous rate case testimonies.

From 2007 through 2019, Columbia's replacement program eliminated an average of 437,756 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 Huwar's testimony (Statement No. 1), Columbia was unable to complete all of its projected 2018 replacement work as a result of the Company contributing to the restoration efforts in Massachusetts and due to changes in the Company's policies and procedures relative to work on low pressure systems[1], As a result, the Company retired 302,606 feet of priority pipe. However, as part of its 2019 infrastructure replacement program, the Company did complete replacement work that had been originally projected for 2018 in addition to completing the majority of its planned 2019 infrastructure replacement program.

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 2019 actuals, is $235.00 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

[1] Columbia is implementing the following improvements: installing automatic pressure control equipment on every low-pressure system and remote monitoring capabilities, conducting a survey of all low-pressure regulator stations on its system, reviewing the engineering design of its low-pressure regulator stations, implementing a process to make observation of excavation near regulator stations a top priority and enhancing procedures for identifying potential risks and developing responses for and to replacing, reconfiguring or abandoning gas distribution mains.

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, nine 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 seven 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.

Q. Do municipal standards continue to impact Columbia's aggressive pipeline replacement program?

A. Yes. Columbia serves approximately 433,000 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 Gas of Pennsylvania, Inc.
- 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 a Manager of Municipal Affairs to work directly with municipalities and review proposed or passed local public policies that may impact Columbia's proposed work. Specifically, the Manager of Municipal Affairs 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 2020.
- 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, 2019?

A. Yes. In 2019, the Communications, Municipal Affairs and Community Relations team participated in the following discussions:

- **CONNECT Spring Utilities Meetup:** On March 26, 2019, Columbia participated in the CONNECT Spring Utilities Meetup, which brought together 14 municipalities and utility representatives in the Peoples Gas Central Construction Division office in Etna, Pa. Attendees heard permitting updates from utilities, *Coordinate PA* outreach plan update and had an opportunity for networking following the meeting.
- **Allegheny League of Municipalities Spring 2019 Conference:** In April 2019, Columbia participated in a panel discussion during the Allegheny League of Municipalities Spring 2019 Conference about the challenges municipalities and utilities face in replacing aging infrastructure and the challenges with ordinances governing street openings and restoration.

- **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.
- **Pennsylvania Municipal League Annual Summit:** In October 2019, Columbia participated in the league's 2019 Annual Summit in Gettysburg Borough. As part of a panel, Columbia addressed the importance of utility/municipal project coordination, and the challenges posed by, and limitations on, municipal ordinances governing street openings and restoration.
- **Beaver County Regional COG Public Works Officials Workshop:** Columbia participated in the Beaver County Regional Council of Government (COG) annual meeting of public works officials from across Beaver County on November 20, 2019 at Geneva College in Beaver Falls, Pa. The workshop included a presentation by a Columbia Damage Prevention Specialist and a discussion about building relationships between municipalities and utilities like Columbia on infrastructure projects.
- **Marshall Township D-82 Phase 2 Project, Allegheny County:** Columbia officials met with township officials and the zoning board to discuss the D-82 Phase 2 project along State Route 19. In addition to replacing mainline pipe, the project also included a new regulator station and building

and the abandonment of the existing regulator station along Warrendale-Bayne Road. The team was able to address concerns the zoning board raised about the new regulator station building, concerns from several residents about road closures and impact to their properties, and concerns from the board of commissioners about traffic control and restorations. Columbia satisfied those concerns and received approval from the township's zoning board and the board of commissioners to move forward with the project. Restoration on a small section of Warrendale-Bayne Rd. still remains with an anticipated completion date of Spring 2020.

- **Pine Township, Allegheny County:** Columbia met with Pine Township officials and representatives from the Pine-Richland school district to review plans for a new business development project to serve the Pittsburgh Cut Flowers senior community development in Richland Township. Columbia was able to develop a plan to address concerns raised by the officials about potential lane closures, impact on the nearby Pine-Richland High School and subsequent road restorations when the project is completed.
- **City of Warren, Warren County:** Columbia met with city officials to discuss the PA One Call law, Commission enforcement and the AVR (alleged violation report) process. The city had been upset with Columbia and its contractors for submitting AVRs for unmarked sewer laterals. Columbia

explained the law, how it works and what is required and worked with the city to address concerns about compliance with the PA One Call law.

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 early 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. Columbia and Beaver officials met again late last year to review the 2019 projects and restoration efforts and reached 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.

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 54% of all hazardous or potentially hazardous leakage cleared on mains in the Columbia distribution system as of year ending 2018. 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.

As a result, Columbia plans to maintain or increase its capital expenditures in the 2020 to 2024 timeframe, with a planned spending program of over $265 million budgeted[2] annually for replacement work, inclusive of mains, services, and measurement and regulation stations, over the 5-year period. This budget includes but is not limited to the replacement of bare steel, cast iron, and wrought iron pipelines.

Q. **Please explain Columbia's capital additions claimed for the Future Test Year and Fully Projected Future Test Year.**

A. A detailed description of Columbia's Age and Condition actuals for 2019, and the budgeted amount for 2020 and 2021 are provided in the following table.

Gas Plant Account ("GPA")	Description	Total 2019 Actual	Total 2020 Projected	Total 2021 Projected
354	Compressor Stations	8,815	0	0
376	Mains - Leakage Elimination	147,146,181	161,462,598	167,687,884
380	Service Lines – Replaced	50,290,969	48,750,000	56,250,000
376	Customer Service Lines Replaced	12,157,863	16,250,000	18,750,000
381	Meters / 998 Int. Co. Meters	882,711	850,000	900,000
382	Meter Install – Replace	700,626	1,000,000	1,050,000
383	House Regulators - Replace	22,909	57,000	70,000
378	Plant Regulators – Replace	13,877,042	20,894,161	13,481,380
375	Reg Structures Replace	267,691	300,000	300,000
385	LV Excess Press Meas Sta	109,681	900,000	900,000
376	Corrosion Mitigation Ins	176,388	150,000	150,000
383	Service Regulators - Replacement	21,656	20,000	20,000
		225,662,532	**250,633,759**	**259,559,264**

Taken in total, Columbia has made enormous progress since 2006 in delivering and maintaining a safe and reliable distribution system for its customers.

[2] Includes the following capital budget classes: Age and Condition, Betterment and Public Improvement.

The progress that I refer to is defined in more detail throughout Columbia witness Michael J. Davidson'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 14 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.

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. 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 Michael J. Davidson's testimony 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 said, 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.

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.[3] The EFVs will shut off gas to a residence or business in the event of a large pressure differential, which is indicative of a major gas leak or a service damaged by excavation. Over time, this results in a system where services are much less vulnerable to safety risks from third-party damage.

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

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

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3 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.

replaced continues to degrade, which continues to drive Type 1 and Type 2 leakage repair activities. In 2019, 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 335[4], a 91% 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. 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

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[4] 2019 represents a preliminary total with final numbers expected to be available in March 2020 as required by 49 CFR Part 191 for the U.S Department of Transportation Pipeline and Hazardous Materials Safety Administration Annual Report.

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 2019 Columbia had approximately 140 construction crews which employed approximately 1400 contractor employees and subcontractors (e.g. restoration, flaggers, drillers, plumbers, etc.)

Q. Does this conclude your direct testimony?

A. Yes, it does.