OCC EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of	)	
Columbia Gas of Ohio, Inc. for Approval	)	Case No. 16-2422-GA-ALT
of an Alternative Form of Regulation.	)	

DIRECT TESTIMONY OF DANIEL J. DUANN, Ph.D.

OPPOSING THE JOINT STIPULATION AND RECOMMENDATION

On Behalf of
The Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485

September 28, 2017

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I. INTRODUCTION

Q1. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION.

A1. My name is Daniel J. Duann. My business address is 10 West Broad Street, Suite 1800, Columbus, Ohio, 43215. I am a Principal Regulatory Analyst with the Office of the Ohio Consumers' Counsel ("OCC").

Q2. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. I received my Ph.D. degree in Public Policy Analysis from the Wharton School, University of Pennsylvania. I also have a M.S. degree in Energy Management and Policy from the University of Pennsylvania, and a M.A. degree in Economics from the University of Kansas. I completed my undergraduate study in Business Administration at the National Taiwan University, Taiwan, Republic of China. I have been a Certified Rate of Return Analyst by the Society of Utility and Regulatory Financial Analysts since 2011.

I was a Utility Examiner II in the Forecasting Section of the Ohio Division of Energy, Ohio Department of Development, from 1983 to 1985. The Forecasting Section was later transferred to the Public Utilities Commission of Ohio ("PUCO"). From 1985 to 1986, I was an Economist with the Center of Health Policy Research at the American Medical Association in Chicago. In late 1986, I joined the Illinois Commerce Commission as a Senior Economist at its Policy

Analysis and Research Division. From 1987 to 1995, I was employed as a Senior Institute Economist at the National Regulatory Research Institute ("NRRI") at The Ohio State University. NRRI has been a policy research center funded by state public utilities commissions since 1976. NRRI is currently located in Silver Spring, Maryland and no longer a part of The Ohio State University. My work at NRRI involved research, the authoring of publications, and public services in many areas of utility regulation and energy policy. I was an independent consultant from 1996 to 2007.

I joined the OCC in January 2008 as a Senior Regulatory Analyst. I was promoted to my current position in November 2011. My primary responsibility is to assist the OCC by participating in various regulatory proceedings before the PUCO. These proceedings include rate cases, cost of capital, alternative regulation, fuel cost recovery, and other types of cases filed by Ohio's electric, gas, and water utilities.

Q3. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY OR TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO?

A3. Yes. I have submitted expert testimony or testified on behalf of the OCC before the PUCO in a number of cases. A list of these cases is included in Attachment DJD-1.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE OTHER REGULATORY AGENCIES AND LEGISLATURES?

A4. Yes. I have testified before the Illinois Commerce Commission and the California Legislature on the restructuring and deregulation of electric utilities.

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A5. The purpose of my testimony is to explain and support OCC's position regarding the Joint Stipulation and Recommendation ("Settlement") filed by Columbia Gas of Ohio, Inc. ("Columbia" or "Utility") on August 18, 2017.[1] My testimony addresses mainly those issues related to the 10.95 percent pre-tax rate of return on rate base proposed in the Application[2] and recommended for approval in the Settlement.[3] I am also responding to certain issues discussed in the prepared supplemental direct testimony filed by Columbia supporting the Settlement on September 8, 2017.[4] Other OCC witnesses will address other aspects of OCC's positions regarding the Settlement and Columbia's Application such as those

[1] See *In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation to Extend and Increase Its Infrastructure Replacement Program*, Case No. 16-2422-GA-ALT, Joint Stipulation and Recommendation (August 18, 2017) ("Settlement").

[2] See *In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation,* Case No. 16-2422-GA-ALT, Application, Exhibit A at 9 (February 27, 2017).

[3] See PUCO Case No. 16-2422-GA-ALT, Joint Stipulation and Recommendation, Paragraph 1 (August 18, 2017).

[4] See PUCO Case No. 16-2422-GA-ALT, Prepared Supplemental Direct Testimony of Melissa L. Thompson (September 8, 2017).

identified and explained in OCC's Objections to the Staff Report and Application filed on August 14, 2017.[5] OCC's Objections are included as Attachment DJD-2.

III. EVALUATION OF THE SETTLEMENT

Q6. WHAT IS YOUR EVALUATION OF THE SETTLEMENT FILED BY COLUMBIA ON AUGUST 18, 2017?

A6. Based on my experience and knowledge as a regulatory economist and my participation in many proceedings before the PUCO, I conclude that the Settlement is not reasonable and should not be adopted by the PUCO. The Settlement does not satisfy the three-prong test used by the PUCO in evaluating and approving a settlement.

Specifically, the 10.95 percent pre-tax rate of return on rate base proposed in the Application and recommended for approval in the Settlement is excessive and unreasonable. By allowing Columbia to use an excessive and unreasonably high rate of return to calculate the revenue requirements of the Infrastructure Replacement Program ("IRP") Rider, the Settlement neither benefits customers nor the public interest. By allowing Columbia to earn a rate of return on its IRP investments that is significantly higher than those currently authorized for

[5] See PUCO Case No. 16-2422-GA-ALT, Objections to Columbia's Application and The PUCO Staff's Report of Investigation By The Office of the Ohio Consumers' Counsel (August 14, 2017) (OCC's Objections).

comparable gas utilities, the Settlement violates important regulatory principles and practices regarding the setting of rates and the rate of return authorized for utility services.

In addition, based on my participation in this proceeding, it appears that the Settlement is largely a product of negotiations between Columbia and the PUCO Staff prior to the participation of other interested parties in the negotiation process. It has not been demonstrated by the Signatory Parties that the Settlement is a product of serious bargaining by knowledgeable and experienced parties. The Settlement does not represent a meaningful compromise of a broad range of interests and is not a reasonable resolution of the many issues in this proceeding.

Q7. WHAT IS THE STANDARD OF REVIEW THAT THE PUCO COMMONLY USES IN EVALUATING AND ADOPTING A SETTLEMENT?

A7. I understand that the PUCO typically evaluates a proposed settlement using a three-prong test.[6] Specifically, the PUCO will apply the following three tests in deciding whether to adopt a proposed settlement:

1. Is the proposed settlement a product of serious bargaining among capable, knowledgeable parties?

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[6] See, for example, *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and, if Their Proposed Merger is Approved, as a Merged Company (collectively, AEP Ohio) for an Increase in Electric Distribution Rates,* PUCO Case No. 11-351-EL-AIR et al. Opinion and Order at 8-10 (December 14, 2011).

2. Does the proposed settlement, as a package, benefit customers (ratepayers) and the public interest?

3. Does the proposed settlement package violate any important regulatory principle or practice?

Only when the PUCO determines that a proposed settlement, as a package, satisfies each of the three prongs identified above will the PUCO adopt the settlement or in many instances adopt it with significant modifications.

Q8. HAS COLUMBIA PROVIDED AN EXPLANATION OR JUSTIFICATION WHY ITS CUSTOMERS SHOULD FUND THE PROPOSED RATE OF RETURN OF 10.95 PERCENT ON ITS IRP INVESTMENTS?

A8. No. There is nothing in the Application, the Settlement, or other filings made by Columbia that explains or justifies Columbia's proposed rate of return on rate base for its IRP investments. Even though Columbia has the burden of proof in this proceeding, Columbia provides no adequate data and information regarding the selection and reasonableness of this pre-tax rate of return of 10.95 percent. There is only one paragraph in the filings provided by Columbia that mentions the pre-tax rate of return of 10.95 percent. At page 9, Exhibit A of the Application, it states:

> "This revenue requirement will provide for a return on rate base of 10.95% (an 8.12% rate of return plus a tax gross-up factor) and the return of all program costs."

However, there is no accompanying explanation or justification for that specific rate**.**

Q9. ***HAS THE PUCO STAFF PROVIDED AN EXPLANATION OR JUSTIFICATION REGARDING WHY IT IS REASONABLE FOR CUSTOMERS TO FUND THE PROPOSED RATE OF RETURN OF 10.95 PERCENT?***

A9. No. I am unable to identify any items in the Staff Report,[7] the Settlement, or the Staff work papers that explains or demonstrates why the proposed rate of return of 10.95 percent is reasonable, and therefore should be adopted, in calculating the revenue requirement of Rider IRP.

Q10. ***WHAT IS YOUR UNDERSTANDING REGARDING THE PRE-TAX RATE OF RETURN OF 10.95 PERCENT PROPOSED BY COLUMBIA IN ITS APPLICATION?***

A10. Based on my review of the Application and other related Columbia proceedings, specifically Columbia's most recent application to adjust Rider IRP and Rider DSM (PUCO Case No. 16-2236-GA-RDR),[8] it appears that the proposed pre-tax rate of return of 10.95 percent is derived from the Joint Stipulation &

[7] See PUCO Case No. 16-2422-GA-ALT, A Report by the Staff of the Public Utilities Commission of Ohio (July 10, 2017) ("Staff Report").

[8] See PUCO Case No. 16-2236-GA-RDR, Application, Schedule AMRP-1 (February 27, 2017).

Recommendation approved in Columbia's last rate case (the "2008 Rate Case").[9] In the 2008 Rate Case, the PUCO approved a return on equity of 10.39 percent, an after-tax rate of return of 8.12 percent, a tax gross-up factor of 2.84 percent, and a pre-tax rate of return of 10.95 percent for Columbia's IRP investments.[10] By adopting a tax gross-up factor of 2.84 percent, it was imputed that Columbia would pay a federal income tax rate of approximately 35 percent.[11]

Q11. IS IT REASONABLE TO USE THE 10.95 PERCENT RATE OF RETURN THAT WAS ADOPTED TEN YEARS AGO TO CALCULATE RIDER IRP FOR IRP INVESTMENTS TO BE MADE IN THE NEXT FIVE YEARS?

A11. No. It is unreasonable and contrary to sound regulatory principles in the current proceeding to continue using a pre-tax rate of return of 10.95 percent that was approved by the PUCO ten years ago. By the end of the five-year extension, 2022, the 10.95 percent pre-tax rate of return will be in use for almost 15 years. Given the drastic decline in both the cost of capital and the authorized rate of returns and returns on equity for regulated gas utilities nationwide over the last ten years, Columbia should propose an updated and lower rate of return in

[9] See *In the Matter of the Application of Columbia Gas of Ohio, Inc., for Authority to Amend Filed Tariffs to Increase the Rates and Charges for Gas Distribution Service,* Case No. 08-72-GA-AIR, et al., ("2008 Rate Case").

[10] See PUCO Case No. 08-72-GA-AIR et al., Opinion and Order at 7-8, 25-26 (Dec. 3, 2008). In the 2008 Rate Case, Staff witness Jeffrey P. Hecker proposed a cost of debt of 5.78 percent, a capital structure of 49.29 percent debt and 50.71 percent equity, and a range of return on equity of 9.88 percent to 10.89 percent. See PUCO Case No. 08-72-GA-AIR et al., Prefiled Testimony of Jeffrey P. Hecker at 3 (October 8, 2008).

[11] 2.84% = (10.39% * 0.5071) / (1- 0.35) – (10.39% * 0.5071).

calculating the revenue requirement of Rider IRP associated with the IRP investments to be made from 2018 to 2022. The PUCO can and should set an updated and lower rate of return for Columbia's proposed IRP in this proceeding.

It is also unreasonable and contrary to sound regulatory principles to continue using an outdated and unreasonable rate of return that will unreasonably increase the financial burden on Columbia's customers, in particular the residential customers. To continue using this excessive pre-tax rate of return of 10.95 percent will result in unjust and unreasonable rates to be collected from Columbia's customers. It will only unjustifiably enrich the shareholders of Columbia. Doing so serves no public interest.

The 10.95 percent pre-tax rate of return was never intended to be used indefinitely to calculate Rider IRP. In fact, the PUCO-approved settlement in the 2008 Rate Case states:

> "The IRP shall be in effect for **the lesser of five years** from the effective date of rates approved in this proceeding or until new rates become effective as a result of Columbia's filing of an application for an increase in rates pursuant to section 4909.18, Revised Code, or Columbia's filing of a proposal to establish base

> rates pursuant to an alternative method of regulation pursuant to Section 4929.05, Revised Code."[12]

It has been more than five years from the effective date of the rates approved in the 2008 Rate Case. Therefore, the pre-tax rate of return should be re-evaluated and lowered to reflect current financial market conditions. In addition, it is reasonable to expect that when Columbia requests an extension of its IRP for the second time, which is the subject of this proceeding, all facets (including the pre-tax rate of return on rate base) of Columbia's IRP should be reviewed and, subsequently, modified or terminated as necessary.

Q12. WHAT IS YOUR UNDERSTANDING OF THE REGULATORY PRINCIPLES AND PRACTICES IN SETTING A REASONABLE RATE OF RETURN FOR A REGULATED UTILITY?

A12. The regulatory principles and practices for setting a reasonable rate of return for a regulated utility in the United States are well-established and recognized. A public utilities commission, such as the PUCO, will typically set a reasonable rate of return for a regulated utility (which in turn will be used in setting the rates paid by customers) by considering the following objectives:

(1) The resulting rates paid by the customers of the regulated utility should be just and reasonable;

[12] See PUCO Case No. 08-72-GA-AIR et al., Opinion and Order at 8 (emphasis added).

(2) The regulated utility should have funds available to continue its normal course of business;

(3) The regulated utility should have access to capital (both equity and debt) at a reasonable cost in comparison to other businesses with comparable risks under current market conditions; and

(4) The shareholders of the regulated utility should be provided the opportunity to earn a fair return on their invested capital in comparison to other investments available.

Q13. HAVE THE AUTHORIZED RATE OF RETURN AND RETURN ON EQUITY FOR REGULATED GAS UTILITIES NATIONWIDE DECLINED SIGNIFICANTLY IN RECENT YEARS?

A13. Yes. Both the rate of return and the return on equity authorized for regulated gas utilities have declined significantly in recent years. This significant decline in the authorized returns for regulated utilities is not surprising given the very drastic decline in the cost of capital worldwide and the significant appreciation of the equity prices of regulated utilities in general. A summary of the after-tax rate of return and return on equity for gas utilities authorized nationwide from 2007 to 2016 is shown in Table 1.[13] The original report by S&P Global Market Intelligence is hereby included as Attachment DJD-3.

[13] See S&P Global Market Intelligence, *Regulatory Focus* at 5 (January 18, 2017).

Table 1
Summary Table of Rate of Return and Return on Equity Authorized For Gas Utilities (2007 to 2016)

Period	After-Tax Rate of Return %	# of Cases	Return on Equity %	# of Cases
2007	8.11%	(31)	10.22%	(35)
2008	8.49%	(33)	10.39%	(32)
2009	8.15%	(29)	10.22%	(30)
2010	7.99%	(40)	10.15%	(39)
2011	8.09%	(18)	9.92%	(16)
2012	7.98%	(30)	9.94%	(35)
2013	7.39%	(20)	9.68%	(21)
2014	7.65%	(27)	9.78%	(26)
2015	7.34%	(16)	9.60%	(16)
2016	**6.95%**	(24)	**9.50%**	(24)
Proposed by Columbia	**8.12%**		**10.39%**	

Q14. DOES THE 10.95 PERCENT PRE-TAX RATE OF RETURN PROPOSED BY COLUMBIA SIGNIFICANTLY EXCEED THE RATE OF RETURNS AUTHORIZED FOR REGULATED GAS UTILITIES NATIONWIDE IN RECENT YEARS?

A14. Yes. The proposed 10.95 percent pre-tax rate of return is much higher than those authorized for other regulated gas utilities nationwide in recent years. It should be noted that the pre-tax rate of return was not widely used and directly reported in the financial and regulatory publications. However, as discussed earlier, the 10.95 percent pre-tax rate of return proposed by Columbia was derived from an 8.12 percent after-tax rate of return and a tax gross-up factor of 2.84 percent (which was imputed assuming a federal income tax rate of 35 percent). So, comparing the 10.39 percent return on equity and the 8.12 percent after-tax rate of return (which were both approved in the 2008 Rate Case and underlie the pre-tax rate of return of 10.95 percent), with the returns on equity and after-tax rate of returns authorized for regulated gas utilities nationwide in recent years can demonstrate whether the pre-tax rate of return of 10.95 percent proposed by Columbia is overstated and unreasonable.

This proposed 10.95 percent pre-tax rate of return is indeed overstated and unreasonable. For example, in 2016, the average after-tax rate of return authorized for gas utilities nationwide was 6.95 percent (for a total of 24 rate cases).[14] For the same time period, the average return on equity authorized for gas utilities nationwide was 9.50 percent (for a total of 24 different rate cases).[15] If the same federal income tax rate of 35 percent is applied to the 6.95 percent average after-tax rate of return, and assuming the same cost of debt and capital structure as proposed by the Staff in the 2008 Rate Case, the imputed tax gross-up factor would be 2.21 percent and the pre-tax rate of return would be 9.16 percent.[16] The 6.95 percent after-tax rate of return would also impute a much lower authorized return on equity of 8.09 percent, assuming the same cost of debt and capital structure of the 2008 Rate Case were used.[17]

[14] See Table 1.

[15] Id.

[16] 2.21% = (6.95% - 2.85%) / (1- 0.35) – (6.95% - 2.85%), and 9.16% = 6.95% + 2.21%.

[17] 8.09% = (6.95% - 2.85%) / 0.5071.

Q15. DO COLUMBIA'S BUSINESS AND FINANCIAL RISKS JUSTIFY A MUCH HIGHER RATE OF RETURN IN COMPARISON TO OTHER REGULATED GAS UTILITIES NATIONWIDE?

A15. No. I am not aware any specific business or financial risks associated with Columbia at this time that would justify a much higher rate of return than those authorized for regulated gas utilities nationwide. And, in this proceeding, Columbia has not demonstrated that it is currently facing or expecting to face any unusual or substantially high business or financial risks that could cause the PUCO to authorize a rate of return for Columbia's IRP that is much higher than those being authorized for other gas utilities in recent years.

I have reviewed financial presentations made by Columbia and its parent company, NiSource Inc., as well as various trade publications and I did not identify any such unusual or substantially high business and financial risks that Columbia or its parent company is facing. Specifically, in a news release by NiSource Inc. announcing 2017 Second Quarter Earnings (it is included here as Attachment DJD-4), it states:[18]

> "Consistent with plans outlined in its Investor Day in March 2017, NiSource expects to grow its net operating earnings per share (non-GAAP) and dividend at 5 to 7 percent each year –based off the revised 2017 guidance – through 2020....With this robust

[18] See News Release, *NiSource Reports Second Quarter Earnings, Increase 2017 Guidance*, (August 2, 2017).

> investment and steady earnings and dividend growth projected. NiSource continues its commitment to maintain investment grade credit ratings. Standard & Poor's rates NiSource at BBB+, Moody's at Baa2 and Fitch at BBB, all with stable outlooks. As of June 30, 2017, NiSource maintained $1.25 billion in net available liquidity, consisting of cash and available capacity under its credit facility."

Q16. WILL COLUMBIA'S FINANCIAL INTEGRITY OR ABILITY TO ACCESS CAPITAL AT REASONABLE COSTS BE ADVERSELY AFFECTED IF THE PROPOSED RATE OF RETURN OF 10.95 PERCENT FOR ITS IRP WERE NOT ADOPTED BY THE PUCO?

A16. No. I do not believe Columbia's financial integrity (that is the availability of financial resources to conduct its normal business) or ability to access capital at reasonable costs would be adversely affected if a lower pre-tax rate of return (such as the 10.17% proposed by OCC) is adopted for its IRP. In this proceeding, Columbia has not demonstrated that its financial integrity or access to capital at reasonable costs would be adversely affected if the proposed rate of return of 10.95% for the IRP program were not adopted.

In addition, my own review does not indicate that Columbia's financial integrity or access to capital at reasonable costs will be adversely affected, either. For example, as discussed in the recent news release, it is clear that Columbia and its parent company, NiSource Inc., are fully committed to a robust capital investment strategy and are confident about obtaining all necessary financing for this capital-intensive investment strategy.[19] Another example is a recent proposed agreement between an affiliate of Columbia, the Columbia Gas of Maryland Inc., with other parties in a distribution base rate case in Maryland. In that case, Columbia Gas of Maryland Inc. accepted, pending approval by the Maryland Public Service Commission, an authorized 9.7 percent return on equity and a 7.352 percent rate of return.[20] These authorized returns in another jurisdiction are well below those (a rate of return of 8.12 percent and a return on equity of 10.39 percent) proposed by Columbia in this proceeding.

Q17. WHAT WOULD YOU RECOMMEND FOR THE PRE-TAX RATE OF RETURN FOR RIDER IRP IF THE PROPOSED IRP PROGRAM WERE AUTHORIZED FOR THE NEXT FIVE YEARS?

A17. If Columbia's IRP program were authorized to continue for the next five years (which OCC is not conceding), I will recommend a pre-tax rate of return on rate base of 10.17 percent in calculating the revenue requirement of Rider IRP. This pre-tax rate of return of 10.17 percent is calculated on a return on equity of 9.39 percent, a cost of debt of 5.78 percent, and a capital structure of 50.71 percent equity and 49.29 percent debt. The calculation of my proposed pre-tax rate of

[19] See Attachment DJD-4.

[20] See Public Service Commission of Maryland, *In the Matter of the Application of Columbia Gas of Maryland, Inc. for Adjustment to Its Gas Base Rates*, Case No. 9447, Joint Motion for Approval of Agreement of Unanimous Stipulation and Settlement (July 28, 2017).

return is shown in Table 2. This proposed pre-tax rate of return of 10.17 percent is more reflective of those rates of return and return on equity recently authorized for regulated gas utilities nationwide. This 10.17 percent pre-tax rate of return, if adopted by the PUCO, along with other OCC-proposed modifications to Columbia's IRP, will result in rates that are reasonable and just to the customers and a rate of return fair to the shareholders of Columbia.[21]

Table 2
Recommended Pre-Tax Rate of Return

	% of Total	**% Cost Rate**	**Weighted Cost (After-Tax)**	**Weighted Cost (Pre-Tax)**
Long Term Debt	49.29%	5.78%	2.85%	2.85%
Common Equity	50.71%	9.39%	4.77%	7.32%
Total Capital	100.00%		7.62%	10.17%

Q18. WILL THE FINANCIAL BURDEN BORNE BY COLUMBIA'S CUSTOMERS FOR RIDER IRP BE SIGNIFICANTLY HIGHER THAN JUSTIFIED IF COLUMBIA'S PROPOSED RATE OF RETURN OF 10.95 PERCENT WERE ADOPTED?

A18. Yes. My analysis indicates that the financial burden borne by Columbia's customers will likely be significantly higher (approximately $62 million higher over the five-year period) if the pre-tax rate of return of 10.95 percent proposed by Columbia is adopted instead of the 10.17 percent rate of return proposed by

[21] In the Staff Report of a pending rate case, the Staff recommended a range of return on equity of 9.22 percent to 10.24 percent and a range of after-tax rate of return of 7.20 percent to 7.74 percent. These recommended ROEs and RORs are far below those proposed by Columbia (10.39 percent to 8.12 percent, respectively). They are largely aligned with my recommendation of 9.32 percent and 7.32 percent, respectively. See PUCO Case No. 17-0032-EL-AIR., Staff Report at 18-19 (September 26, 2017).

OCC. This estimation is based on the work papers (in Excel spreadsheet) provided by the PUCO Staff titled **Estimated Rate Impact of Proposed IRP Program (1018-2022)**. The relevant part of the original PUCO Staff work paper is attached as Attachment DJD-5.

It should be emphasized that I do not agree with all the assumptions, input data, and methodology used in the Staff's work papers. More importantly, the estimated total revenue requirements and the Rider IRP rates presented here do not represent OCC's positions or recommendations on these subjects. Another OCC witness will provide a more detailed analysis and specific recommendations regarding the proper rates of Rider IRP or the total revenue requirements if Columbia's IRP were to continue for the next five years. I am using this particular model provided by the PUCO Staff to highlight the difference in the total revenue requirements and Rider IRP to be collected from customers resulting solely and entirely from the difference in the pre-tax rate of return used in the analysis.

A summary of the estimated total revenue requirement over the five-year period under the two pre-tax rates of return using the Staff's model is summarized in Table 3. The Excel spreadsheets supporting Table 3 are attached as Attachment DJD-6.

Table 3
Estimated Total Revenue Requirement of Columbia IRP Program
(2018-2022)

	2018 (million)	**2019** (million)	**2020** (million)	**2021** (million)	**2022** (million)	**2018-2022 Total** (million)
Revenue Requirement (At 10.95% ROR)	$196.9	$225.5	$253.5	$279.9	$305.5	$1,261.4
Revenue Requirement (At 10.17% ROR)	$187.3	$214.5	$241.1	$266.2	$290.6	$1,199.7
Difference	$9.7	$11.1	$12.4	$13.7	$14.9	$61.7

I have also reviewed the **<u>Infrastructure Replacement Program Rider Rate Analysis</u>** provided by Columbia supporting the Settlement in response to OCC's discovery.[22] However, the information provided by Columbia is not sufficient for me to conduct a separate and different analysis regarding the increase of financial burden to Columbia's customers as a result of the higher pre-tax rate of return. The $62 million additional total revenue requirement over the five-year period is a reasonable and probably the best available estimate of the increase in customers' financial burden if the pre-tax rate of return of 10.95 percent were adopted.

[22] See PUCO Case No. 16-2422-GA-ALT, Discovery Response of Columbia in OCC RPD Set 6, No. Attachment A.

Q19. WILL THE RATES OF RIDER IRP PAID BY COLUMBIA'S SGS (MOSTLY RESIDENTIAL) CUSTOMERS BE SIGNIFICANTLY HIGHER THAN JUSTIFIED IF COLUMBIA'S PROPOSED RATE OF RETURN OF 10.95 PERCENT WERE ADOPTED?

A19. Yes. The Rider IRP paid by Columbia's SGS customers, which are mostly residential, will be significantly higher than that is justified if the proposed pre-tax rate of return of 10.95 percent were adopted by the PUCO. Currently, SGS customers pay about 72.36 percent of the total cost (or total revenue requirement) of Columbia's IRP. This cost allocation is not expected to change. Furthermore, Rider IRP is collected as a fixed monthly charge per customer regardless of the amount of gas used. A summary of the estimated monthly cost of Rider IRP for each SGS customer over the five-year period under the two pre-tax rates of return proposed by Columbia and OCC is summarized in Table 4. The Excel spreadsheets supporting Table 4 are attached as Attachment DJD-6. Once again, these estimated monthly costs presented here are to highlight the effects of a higher and unreasonable pre-tax rate of return. They are presented here to demonstrate the unreasonable and unnecessary increase in the financial burden to the SGS customers. The results here may also be considered, along with recommendations by other OCC witnesses, in lowering the annual caps of Rider IRP for SGS customers. As discussed earlier, the results here should not be viewed as OCC's recommendation on what the Rider IRP should be if Columbia's IRP were authorized for the next five years.

Table 4
Estimated Monthly Cost of Rider IRP for SGS Customer
(2018-2022)

	2018	2019	2020	2021	2022	Cumulative Difference In Monthly Cost (2018 – 2022)
Monthly Cost (At 10.95% ROR)	$11.48	$12.76	$14.02	$15.18	$16.28	
Monthly Cost (At 10.17% ROR)	$11.07	$12.29	$13.49	$14.61	$15.66	
Difference	$0.41	$0.47	$0.53	$0.57	$0.62	$2.50

Q20. WILL THE ADOPTION OF THE PROPOSED RATE OF RETURN OF 10.95 PERCENT AS PROPOSED IN THE APPLICATION AND RECOMMENDED FOR APPROVAL IN THE SETTLEMENT HARM THE CUSTOMERS AND THE PUBLIC INTEREST?

A20. Yes. As discussed above, the adoption of the proposed pre-tax rate of return of 10.95 percent will result in unjust and unreasonable rates collected from Columbia's 1.45 million customers.[23] The customers of Columbia will be forced to pay approximately $62 million more solely as a result of using an outdated and unreasonably high rate of return. This results in unnecessary and unreasonable harm to Columbia's customers who have already paid billions in the past for the IRP and may continue paying a more costly Rider IRP in the future. There is also no demonstration of any public policy justification to allow Columbia to collect from customers more money than is just and reasonable for its IRP.

[23] See PUCO Case No. 16-2236-GA-RDR, Application, Schedule AMRP-11 (February 27, 2017). Columbia has approximately 1,450,917 customers that pay Rider IRP in 2017.

Q21. WILL THE ADOPTION OF THE PROPOSED RATE OF RETURN OF 10.95 PERCENT VIOLATE IMPORTANT REGULATORY PRINCIPLES AND PRACTICES?

A21. Yes. As discussed above, the pre-tax rate of return of 10.95 percent proposed in the Application and recommended for approval in the Settlement is significantly higher than the rate of returns authorized for regulated gas utilities in recent years, and the reasonable rate of return supported by current financial market conditions and the state of the economy. If the PUCO adopts this excessive and unreasonable pre-tax rate of return of 10.95 percent, it will violate those fundamental and well-established regulatory principles that I have identified above. Specifically, the resulting rates (that is the Rider IRP) paid by the customers of the regulated utility (Columbia) would not be just and reasonable. Also, the shareholders of the regulated utility (Columbia) would be provided the opportunity to earn a much higher (thus unfair and unreasonable) return on their invested capital in comparison to other investments available.

Q22. DID YOU PARTICIPATE IN ANY FORMAL DISCUSSIONS WITH THE PARTIES BEFORE THE SETTLEMENT WAS FILED AT THE PUCO?

A22. Yes. I attended the one and only all-party settlement meeting on August 9, 2017. I also attended a telephone conference between OCC and Staff and the intervenors on August 15, 2017, before the Settlement was filed on August 18, 2017.

Q23 WAS THE SETTLEMENT A PRODUCT OF SERIOUS BARGAINING AMONG CAPABLE, KNOWLEDGEABLE PARTIES?

A23. No. The alleged "serious bargaining" process in this proceeding took just nine days, included just two counter offers (of which one was completely ignored) to the utility settlement offer, and substantively involved just two parties out of five—Columbia and Staff. Indeed, the Settlement was largely presented as a "take-it or leave-it" offer by Columbia to other parties in this proceeding. After an initial all-party negotiation session on August 9, 2017, there were no more negotiation sessions attended by all parties.

In addition, the single negotiation session was scheduled on just two days' notice before parties had even filed their Objections to the Staff Report and Application, and did not include a draft settlement offer before or during the negotiation session to facilitate or assist in any meaningful bargaining among parties. When OCC provided its counter-offer to the initial settlement offer (that was given by Columbia on August 10, 2017, one day after the all-party negotiation session), it was immediately rejected in full and the final settlement document was filed that same day, August 18, 2017, without any further "bargaining." OCC was essentially denied the chance of any serious bargaining.

Consequently, a large majority of the issues raised in OCC's counter settlement offer and in its Objections filed with the PUCO (see Attachment DJD-2) were not addressed at all in the Settlement or the settlement process. It is clear to me that this Settlement was not the product of any serious bargaining.

Q24. DOES THE SETTLEMENT REPRESENT A COMPROMISE OF ISSUES BY PARTIES WITH A BROAD RANGE OF INTERESTS?

A24. No. As discussed earlier, this Settlement is largely a take-it or leave-it offer from Columbia. At best, it may represent an agreement between Columbia and the PUCO Staff. However, the Settlement failed to address the large majority of the issues in OCC's and the Ohio Partners for Affordable Energy's ("OPAE") Objections to the Staff Report and Application filed with the PUCO.

In addition, the Settlement only has the support of one intervening party—OPAE. The Industrial Energy users of Ohio ("IEU-Ohio") agreed not to oppose the Settlement and OCC opposes the Settlement. It appears to me that OPAE, the applicant Utility, and the PUCO Staff (which represents the staff of the regulatory agency itself) do not necessarily create a broad range of interests. Indeed, this represents a narrow range of interests in this proceeding.

Q25. DOES THE SETTLEMENT SERVE AS A REASONABLE RESOLUTION OF ISSUES RELATED TO COLUMBIA'S IRP PROGRAM?

A25. No. This Settlement only specifically addresses two issues related to Columbia's IRP program (the Maximum Rider IRP for SGS customers[24] and the Minimum AMRP O&M Savings[25]), and unfortunately both issues were resolved unreasonably in the Settlement. A wide range of issues related to Columbia's IRP programs are not addressed at all in the Settlement. For example, as discussed extensively earlier in my testimony, the 10.95 percent pre-tax rate of return proposed in the Application and recommended for approval in the Settlement is unreasonable and violates important regulatory principles and practices. An updated and lower pre-tax rate of return should be adopted in any settlement of this proceeding. This issue was not even mentioned in the Settlement.

Another example of the issues not addressed or resolved is the need for a prudency audit and/or independent review of the efficiency and effectiveness of the IRP before the program be renewed with customers paying even more money (see OCC Objection 1).[26] The third example of issues not resolved is the reasonableness of Columbia's request to charge customers $125 million over five years for an accelerated service line replacement program that Columbia calls the

[24] See PUCO Case No. 16-2422-GA-ALT, Joint Stipulation and Recommendation, 3 (August 18, 2017).

[25] Id.

[26] See Attachment DJD-2 at 2.

"Hazardous Customer Service Line" ("HCSL") program (see OCC Objection 4).[27] There are many other issues or objections raised by OCC and OPAE not addressed or resolved in the Settlement. There is no doubt that this Settlement has failed to reasonably resolve many important issues associated with Columbia's IRP.

Q26. DOES THIS CONCLUDE YOUR TESTIMONY?

A26. Yes. However, I reserve the right to supplement my testimony in the event that additional testimony is filed, or if new information or data in connection with this proceeding becomes available.

[27] See Attachment DJD-2 at 5.

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that a true copy of the foregoing *Direct Testimony of Daniel J. Duann, Ph.D. on Behalf of the Office of the Ohio Consumers' Counsel* was served via electronic transmission to the persons listed below on this 28th day of September 2016.

<u>/s/ Kevin Moore</u>
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Daniel J. Duann, Ph.D.
List of Testimonies Filed Before PUCO

1. *Application of The Dayton Power and Light Company for Approval of Its Electric Security Plan*, Case No. 08-1094-EL-SSO (January 26, 2009).

2. *Application of Ohio American Water Company to Increase Its Rates for Water and Sewer Service Provided to Its Entire Service Area*, Case No. 09-391-WS-AIR (January 4,2010).

3. *Application of Aqua Ohio, Inc. for Authority to Increase its Rates and Charges in its Masury Division*, Case No. 09-560-WW-AIR (February 22, 2010).

4. *Application of Aqua Ohio, Inc. for Authority to increase its Rates and Charges in its Lake Erie Division*, Case No. 09-1044-WW-AIR (June 21, 2010).

5. *In the Matter of the Fuel Adjustment Clauses for Columbus Southern Power Company and Ohio Power Company*, Case Nos. 09-872-EL-FAC and 09-873-EL-FAC (August 16, 2010).

6. *In the Matter of the Application of Columbus Southern Power Company for Approval of an Electric Security Plan; an Amendment to its Corporate Separation Plan; and the Sale or Transfer of Certain Generating Asset (Remand)*, Case Nos. 08-917-EL-SSO et al (June 30, 2011).

7. *In the Matter of the Application of The East Ohio Gas Company d/b/a Dominion East Ohio for Approval of Tariffs to Modify and further Accelerate its Pipeline Infrastructure Replacement Program and to Recover the Associated Costs et al.*, Case Nos. 11-2401-GA-ALT and 08-169-GA-ALT (July 15, 2011).

8. *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to 4928.143, Ohio Rev. Code in the Form of an Electric Security Plan (ESP)*, Case Nos. 11-346-EL-SSO, et al (July 25,2011).

9. *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Merge and Related Approval (ESP Stipulation)*, Case Nos. 10-2376-EL-UNC, et al (September 27, 2011).

10. *In the Matter of the 2010 Annual Filing of Columbus Southern Power Company and Ohio Power Company Required by Rule 4901:1-35-10, Ohio Administrative Code*, Case Nos. 11-4571-EL-UNC and 11-4572-EL-UNC (October 12, 2011).

11. *In the Matter of the Application of Ohio American Water Company to Increase Its Rates for Water and Sewer Service Provided to Its Entire Service Area*, Case No. 11-4161-WS-AIR (March 1, 2012).

12. *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to 4928.143, Ohio Rev. Code in the Form of an Electric Security Plan (Modified ESP),* Case Nos. 11-346-EL-SSO, et al (May 4, 2012).

13. *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company For Authority to Establish a Standard Service Offer Pursuant to R.C. § 4928.143 in the Form Of an Electric Security Plan,* Case No. 12-1230-EL-SSO (May 21, 2012).

14. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Electric Distribution Rates, et al.* Case Nos. 12-1682-EL-AIR (February 19, 2013).

15. *In the Matter of the Application of Duke Energy Ohio, Inc., for an Increase in Gas Rates,* Case Nos. 12-1685-GA-AIR, et al (February 25, 2013).

16. *In the Matter of the Application of Dayton Power & Light Company for Authority to Establish a Standard Service Offer in the Form Of an Electric Security Plan Pursuant to R.C. 4928.143,* Case No. 12-426-EL-SSO et al. (March 1, 2013).

17. *In the Matter of the Application of The Dayton Power and Light Company for Authority to Recover of Certain Storm-related Service Restoration Costs,* Case Nos. 12-3062-EL-RDR, et al. (January 31, 2014).

18. *In the Matter of the Application of The Dayton Power and Light Company for Authority to Recover of Certain Storm-related Service Restoration Costs,* Case Nos. 12-3062-EL-RDR, et al. (May 23, 2014).

19. *In the Matter of the Application of Aqua Ohio, Inc. to Increase Its Rates and Charges for Its Waterworks Service,* Case No. 13-2124-WW-AIR (August 4, 2014).

20. *In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Ride,* Case No. 14-1693-EL-RDR, et al. (September 11, 2015).

21. *In the matter of the Application of Duke Energy Ohio, Inc. for Approval of an Alternative Rate Plan Pursuant to R.C. 4929.05, Revised Code, for an Accelerated Service Line Replacement Program,* Case No. 14-1622-GA-ALT (November 6, 2015).

22. *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.141 in the Form of an Electric Security Plan,* Case No. 14-1297-EL-SSO (June 22, 2016).

23. *In the Matter of the Application of Ohio Power Company for Administration of the Significantly Excessive Earnings Test for 2014 Under Section 4928.143 (F), Revised Code, and Rule 4901:1-35-10, Ohio Administration Code.* 15-1022-EL-UNC et al. (August 15, 2016).
24. *In the Matter of the Application of Ohio Power Company for Administration of the Significantly Excessive Earnings Test for 2014 Under Section 4928.143 (F), Revised Code, and Rule 4901:1-35-10, Ohio Administration Code.* 15-1022-EL-UNC et al. (September 19, 2016).
25. *In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company.* 10-2929-EL-UNC et al. (October 18, 2016).
26. *In the Matter of the Application of Aqua Ohio, Inc. for Authority to Increase Its Rates and Charges for Its Waterworks Service*. 16-907-WW-AIR (December 19, 2016).

BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation.	)))	Case No. 16-2422-GA-ALT

OBJECTIONS TO COLUMBIA'S APPLICATION AND THE PUCO STAFF'S REPORT OF INVESTIGATION BY THE OFFICE OF THE OHIO CONSUMERS' COUNSEL

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BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation.	)))	Case No. 16-2422-GA-ALT

OBJECTIONS TO
COLUMBIA'S APPLICATION AND
THE PUCO STAFF'S REPORT OF INVESTIGATION
BY
THE OFFICE OF THE OHIO CONSUMERS' COUNSEL

I. INTRODUCTION

This case involves the request of Columbia Gas of Ohio, Inc. ("Columbia" or "Utility") to extend its pipeline replacement program for another five-year period, and increase a monthly charge to consumers from $10.20 (in 2017) to approximately $16.70 (in 2022).[1] The Office of the Ohio Consumers' Counsel ("OCC")[2] submits these objections to Columbia's Application (filed on February 27, 2017) and the Public Utilities Commission of Ohio's ("PUCO") Staff Report of Investigation ("Staff Report"), as filed in this case on July 10, 2017.[3]

OCC asks the PUCO to adopt these objections to Columbia's Application and the Staff Report when deciding how much Columbia's customers should pay for gas distribution service. OCC's Objections pertain to rates and issues under the Utility's Application and the Staff Report that are not just and reasonable. These objections meet the specificity requirement of Ohio Admin. Code 4901-1-28.

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[1] Application at 11.

[2] Under R.C. Chapter 4911, the OCC is the statewide representative for all of Duke's 382,000 residential electric utility customers.

[3] See R.C. 4909.19 and Ohio Admin. Code 4901-1-28(B).

Lack of an objection to any aspect of the Staff Report or Application should not preclude OCC from filing further pleadings or comments in this docket. Nor should it limit OCC's cross-examination or introduction of evidence or argument on any issue contained in the Staff Report in the event the PUCO Staff reverses, modifies, or withdraws its position on the issue. OCC reserves the right to amend and/or to supplement its objections in the event that the PUCO Staff reverses, modifies, or withdraws its position on any issue contained in the Staff Report. OCC also reserves the right to file expert testimony, produce fact witnesses, and introduce additional evidence in the event the PUCO schedules an evidentiary hearing.

II. OBJECTIONS TO COLUMBIA'S APPLICATION AND THE PUCO STAFF REPORT

OBJECTION 1: OCC objects to the Staff's failure to recommend that a prudency audit and/or independent review of the efficiency and effectiveness of Columbia's Infrastructure Replacement Program ("IRP") be conducted before proposing that the program be renewed, with customers paying even more money.

The Utility asks its customers to pay an estimated additional $1.3 billion over the next five years to renew the program; however, there has been no demonstration by Columbia that the customer benefits will outweigh or even be commensurate with this large investment. The intent of the IRP is to improve the safety of the Utility's distribution infrastructure by upgrading bare steel and cast iron pipelines that are prone to corrosion and leaking.[4] However, in the program's most recent years, the leak rates have not improved by any significant

[4] Application at 2, 6-7.

amount.[5] In addition, the costs to implement the program have steadily increased.[6]

Because actual leak rates on the Utility's distribution system are not improving and the costs to implement the program are increasing, an independent audit should be performed to ensure that safety of the infrastructure is improving as intended. Specifically, such an audit will aid the PUCO in determining whether the program is efficiently and effectively reducing leaks, improving safety, and minimizing costs per mile and costs per leak avoided. The results of the audit should also assist the PUCO in determining whether the rates consumers are paying under this program are just and reasonable.

OBJECTION 2: OCC objects to Columbia's request to increase the Rider IRP customer charge cap (to $1.30 per month each year from 2018 to 2022). (Application at 11).

Columbia has not provided evidence that shows that increasing the annual rate cap that customers fund from $1.00 to $1.30 per year (which can potentially increase the monthly charge by $6.50 over the five-year period) is necessary, just, reasonable, or in the public interest. The analysis and assumptions that Columbia relied on to justify its proposed rate cap increases were found by the Staff to be faulty and unreliable.[7] Columbia's estimates of the amount of total pipe that needs to be replaced and the costs per mile to replace the pipe are overstated.[8] Further, the rate of return used in determining the rate cap is excessive and unjust

[5] See OCC INT set 2 No. 2 Att. A. Leaks declined from a high of 4462 in 2009 to 3796 in 2010, with a low of 3465 in 2014, but main leaks cleared in 2015 and 2016 was above 3700 and leaks cleared per mile increased. Attachment 1.

[6] See Columbia Direct Testimony of Diana Beil at 6-7, Attach. DMB-1 and Donald Ayers at 5-9.

[7] See Staff Report at 9-12 (Staff states that Columbia's analysis supporting the estimated capital investment that Columbia states it will need to install new pipeline is unreliable. The Staff Report also states that Columbia's analysis of historical costs to support the proposed increase to the annual IRP rate cap relies on an errant assumption).

[8] See Staff Report at 9-12.

and unreasonable. In addition, Columbia has not shown that it needs a rate cap increase. It has not exceeded or even reached the specified rate cap in any of the nine years of the rider's existence.[9] Columbia's requested IRP rate cap increase should not be approved before and without a prudency audit of the current IRP, as discussed in OCC Objection 1.

OBJECTION 3: OCC objects to the Staff 's recommendation to allow the Rider IRP rate cap increase of $1.00 per year from 2018 to 2020 and $1.10 per year from 2021 to 2022. (Staff Report at 12).

The PUCO Staff has not provided sufficient evidence that shows that a $1.00 or $1.10 increase in the rate cap is necessary, just, reasonable, or in the public interest. The analysis that PUCO Staff has relied on in sponsoring its rate cap increase is unsubstantiated. The Staff's estimates of the amount of total pipe that needs to be replaced and the costs per mile to replace the pipe are overstated. In addition, the rate of return used in determining the rate cap is excessive, unjust and unreasonable. Further, Columbia has not shown that it needs a rate cap increase. It has not exceeded or even reached its rate cap in any of the nine years of the program.[10] Therefore, the Staff's recommended IRP rate cap increase should not be approved before and without a prudency audit of the current IRP, as discussed in OCC Objection 1.

OBJECTION 4: OCC objects to Columbia's request to charge consumers $125 million over five years for an accelerated service line replacement program that Columbia calls the "Hazardous Customer Service Line" ("HCSL") program. (Application at 6-7). The PUCO just

[9] See Direct Testimony of Melissa Thompson at 4.

[10] See Direct Testimony of Melissa Thompson at 4.

last year denied a similar program that Duke Energy Ohio, Inc. proposed.[11] The PUCO should, consistent with its decision in the Duke ASRP case, not allow Columbia to continue the HCSL.

The Utility's request is unreasonable and unlawful because the evidence does not support the continued approval of the HCSL program. Columbia failed to provide sufficient evidence to show that the program provides benefits to public safety that are commensurate with its substantial costs ($125 million). Columbia failed to prove that it considered alternative methods or programs to mitigate the alleged risk. Columbia failed to provide any evidence regarding the level of risk to the system and/or public, addressing the likelihood of harm as well as the associated potential harm. Finally, Columbia failed to explain why the PUCO's pipeline safety regulations, codified in O.A.C. 4901:1-16-04, if followed, are not sufficient to resolve any alleged risk currently posed by customer service lines on Columbia's distribution system.

OBJECTION 5: OCC objects to the Staff's failure to deny or even address Columbia's request to charge consumers an additional $125 million over five years for an accelerated service line replacement program (HCSL program), for the reasons discussed in Objection 4.

OBJECTION 6: OCC objects to the Staff 's failure to direct Columbia to report more thoroughly on the performance metrics of the IRP (which customers pay for) over the next five years.

Specifically, the Staff Report should have directed Columbia to collect, at a minimum, the following information: (1) leak history associated with mains replaced (i.e., for each Job Order number under each Project ID for each year of the program from 2018 forward, the five-year history of leaks (by grade and year) on the mains that were replaced or retired under that job

[11] *In the Matter of the Application of Duke Energy Ohio, Inc., for Approval of an Alternative Rate Plan Pursuant to R.C. 4929.05 for an Accelerated Service Line Replacement Program*, Case No. 14-1622-GA-ALT, Opinion and Order (Oct. 26, 2016) ("Duke ASRP case").

order); (2) leak history after replacement (i.e., for each Job Order under each Project ID in each year of the program from 2018 forward, the subsequent leaks (by grade and year) on the mains that were replaced or retired under that job order); (3) cost effectiveness (i.e., for each Job Order under each Project ID in each year, the total cost of the job order, once complete, divided by the five-year average number of leaks on the mains that were replaced or retired under that job order); (4) variance explanations (i.e., for each Job Order under each Project ID in each year for which the cost per leak addressed (the ratio in the cost effectiveness report described above) is higher than a threshold number (e.g., $1,000,000 per average leak), provide an explanation of what factors might have led to the high cost or low leak rate involved).

Without such performance metrics, it is not possible to determine whether the IRP is being implemented in a just and reasonable way.

OBJECTION 7: OCC objects to the amount and calculation of Operation and Maintenance expense ("O&M") savings that Columbia guarantees will be credited to consumers. (Application at 10). The O&M savings, which are supposed to be passed back to customers, should be much higher than the $1.25 million that Columbia proposed, given the enormous amount of money that is being spent, with customers paying a return on and of such huge investment.

At this time, Columbia guarantees to pass back a paltry $1.25 million to customers in future Rider adjustment cases. If Columbia's actual savings exceed the $1.25 million, then the actual O&M savings will be credited to customers. But, since the inception of the IRP program to date, the O&M savings from the program have not been greater than the minimum $1.25 million. As pointed out by Staff, other Ohio gas utilities with IRP programs very similar to Columbia's program, have produced much greater savings.[12] OCC agrees with Staff that if Columbia's IRP program has been successful in reducing the number of leaks, as the Utility indicated,[13] the annual O&M savings should have increased considerably. OCC objects to the Utility's proposal to continue to pass through a minimal amount of savings to customers when the program has cost customers hundreds of millions of dollars.

OBJECTION 8: OCC objects to Columbia's request to collect its IRP costs from customers with a return on rate base (profits) of 10.95 percent (i.e., an 8.12 percent rate of return plus a tax gross-up factor). (Application, Exhibit A at 9).

In its Application and supporting testimonies, Columbia has not carried its burden of proof to show that charging customers for a rate of return of 10.95 percent on rate base is just and reasonable at this time. Columbia has not provided any documentation that supports this proposed rate of return. This proposed rate of return of 10.95% is apparently derived from the rate of return approved in the 2008 Columbia alternative regulation rate case.[14] Moreover, under the proposed IRP rider, shareholders of Columbia have limited risk that does not justify the requested high return. Columbia needs to explain why it is just and reasonable for customers to fund this high rate of return (approved in 2008) for the next five years (from 2018 through 2022), given the significant decline in the cost of capital over the last ten years. Columbia has not done so in its Application.

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[12] Staff Report at 9.

[13] *Id.* at 9, citing Columbia's response to OCC INT's 2-24, 26, and 28 (June 23, 2017).

[14] See *In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation and for a Change in its Rates and Charges,* Case No. 08-0073-GA-ALT, et al. Opinion and Order (Dec. 3, 2008).

OBJECTION 9: OCC objects to the Staff Report's failure to adjust the rate of return of 10.95 percent proposed by Columbia. The Staff should have recommended a lower rate of return, which would mean lower utility bills for consumers.

This proposed rate of return of 10.95 percent by Columbia is unreasonable, and would significantly increases the costs of the IRP programs borne by Columbia's customers. This 10.95 percent rate of return was approved by the PUCO in a 2008 alternative regulation rate case.[15] It was based largely on the prevailing financial market and economic conditions ten years ago. It far exceeds the average rate of return authorized for gas utilities in recent years. It should be adjusted downward based current financial market and economic conditions as well as the business and financial risks facing Columbia at this time.

OBJECTION 10: OCC objects to Columbia's request to continue the IRP because, despite the significant spending through the IRP, Columbia has failed to reduce the Maintenance of Mains expenses (Account 887) over the nine-year life of the program.

One of the objectives of the IRP was to reduce the amount of maintenance costs for Columbia's main lines by replacing older unprotected metallic lines with new plastic or protected steel lines.[16] However, over the life of the program, the annual maintenance of main lines expenses has increased not decreased. This shows that the IRP is not effective at reducing main lines expenses. This is important to consumers because reduced main line expenses should be part of the annual savings passed back to consumers.

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[15] See *In the Matter of the Application of Columbia Gas of Ohio, Inc. for Approval of an Alternative Form of Regulation and for a Change in its Rates and Charges,* Case No. 08-0073-GA-ALT, Opinion and Order (Dec. 3, 2008).

[16] Direct Testimony of Diana Beil at 3-4, Case No. 16-2422-GA-ALT.

OBJECTION 11: OCC Objects to the Staff's failure to challenge Columbia's request to continue the IRP because, despite the significant spending through the IRP, Columbia has failed to reduce Maintenance of Mains expenses (Account 887) over the nine-year life of the program.

One of the objectives of the IRP was to reduce the amount of maintenance costs for Columbia's main lines by replacing older unprotected metallic lines with new plastic or protected steel lines.[17] However, over the life of the program, the annual maintenance of main lines expenses has increased, not decreased. The Staff should have required Columbia to explain why the IRP has not been effective at reducing main line expenses, and why such expenses are increasing and not decreasing. This is important to consumers because reduced main line expenses should be part of the annual savings passed back to consumers.

OBJECTION 12: OCC Objects to Columbia's request to continue the IRP even though the IRP has failed to reduce Maintenance of Services expenses (Account 892) over the nine-year life of the program.

One of the objectives of the IRP was to reduce the amount of maintenance costs for Columbia's service lines by replacing older unprotected metallic lines with new plastic or protected steel lines.[18] However, over the life of the program, the annual maintenance of service lines expenses has increased, not decreased. This shows that the IRP is not effective at reducing service line expenses. This is important to consumers because reduced main line expenses should be part of the annual savings passed back to consumers.

[17] Direct Testimony of Diana Beil at 3-4, Case No. 16-2422-GA-ALT.

[18] Direct Testimony of Diana Beil at 3-4, Case No. 16-2422-GA-ALT.

OBJECTION 13: OCC Objects to the Staff's failure to challenge Columbia's request to continue the IRP because, despite the significant spending through the IRP, Columbia has failed to reduce Maintenance of Services expenses (Account 892) over the nine-year life of the program.

One of the objectives of the IRP was to reduce the amount of maintenance costs for Columbia's service lines by replacing older unprotected metallic lines with new plastic or protected steel lines. However, over the life of the program, the annual maintenance of service lines expenses has increased, not decreased. This shows that the IRP is not effective at reducing service line expenses. This is important to consumers because reduced main line expenses should be part of the annual savings passed back to consumers.

OBJECTION 14: OCC objects to Columbia's failure to reduce or, in the alternative, justify the amount of non-priority pipe that it is proposing to replace under the IRP. (Application at 8). The amount of non-priority pipe that Columbia is replacing appears to be excessive and may be contributing to the need to collect dramatic and unnecessary increases in IRP costs from customers. Replacing too much non-priority pipe is contributing to consumers having to pay unjust and unreasonable rates under Rider IRP. It may also be contributing to the need to increase the caps for IRP spending.

OBJECTION 15: OCC objects to the Staff 's failure to recommend that Columbia should reduce or, in the alternative, justify the amount of non-priority pipe that it is proposing to replace under the IRP. (Application at 8). The amount of non-priority pipe that Columbia is replacing appears to be excessive and may be contributing to the need to collect dramatic and unnecessary increases in IRP costs from customers. Replacing too much non-priority pipe is contributing to consumers having to pay unjust and unreasonable rates under Rider IRP. It may also be contributing to the need to increase the caps for IRP spending.

III. CONCLUSION

In conclusion, OCC objects to the above-mentioned provisions of Columbia's application and the PUCO's Staff Report because they are not just and reasonable. OCC asks the PUCO to adopt these objections to Columbia's Application and the Staff Report when deciding how much Columbia's customers should pay for gas distribution service.

Respectfully submitted,

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CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Objections* was served by electronic transmission upon the parties below this 14th day of August 2017.

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Regulatory Research Associates

REGULATORY FOCUS

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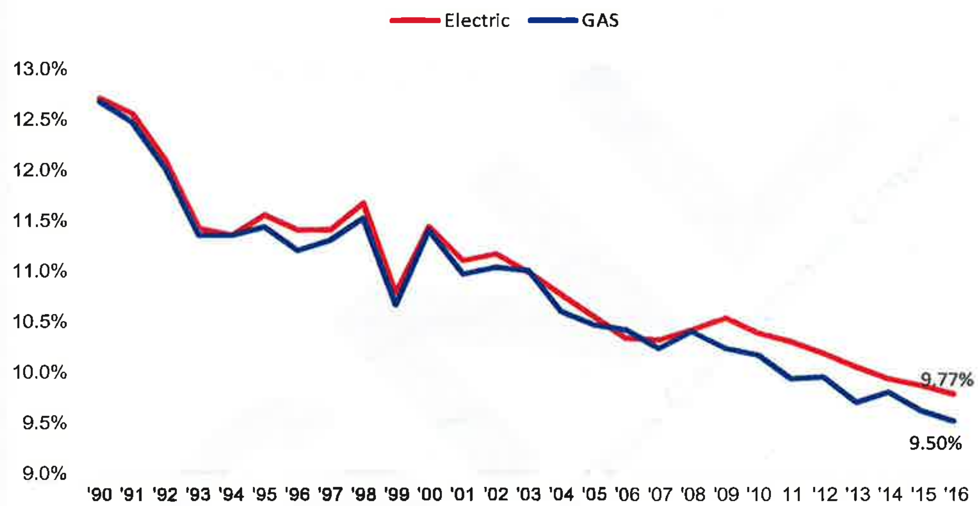
January 18, 2017

MAJOR RATE CASE DECISIONS — JANUARY-DECEMBER 2016

The average ROE authorized electric utilities was 9.77% in rate cases decided in 2016, compared to 9.85% in 2015. There were 42 electric ROE determinations in 2016, versus 30 in 2015. This data includes several limited issue rider cases; excluding these cases from the data, the average authorized ROE was 9.6% in rate cases decided in 2016, the same as in 2015. RRA notes that this differential in electric authorized ROEs is largely driven by Virginia statutes that authorize the State Corporation Commission to approve ROE premiums of up to 200 basis points for certain generation projects (see the Virginia Commission Profile). The average ROE authorized gas utilities was 9.5% in 2016 versus 9.6% in 2015. There were 24 gas cases that included an ROE determination in 2016, versus 16 in 2015.

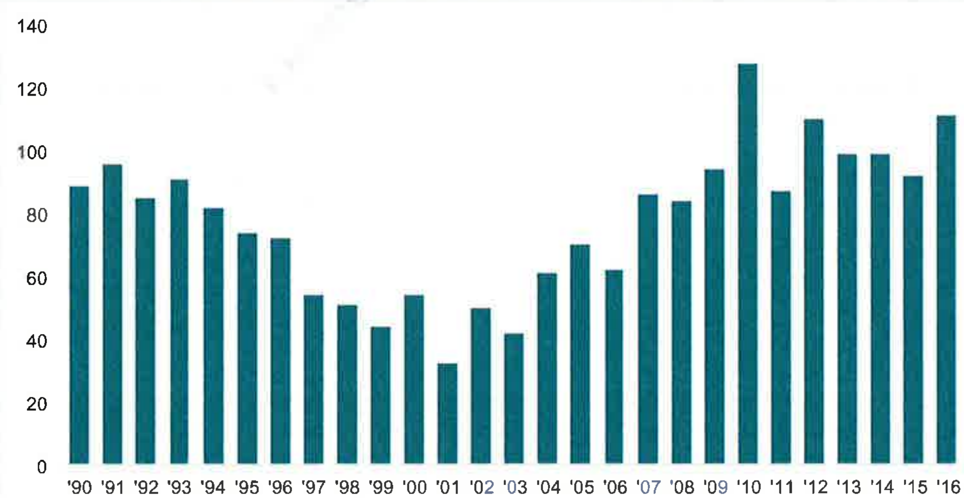
Graph 1: Average authorized ROEs — electric and gas rate decisions



Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

As shown in Graph 2 below, after reaching a low in the early-2000s, the number of rate case decisions for energy companies has generally increased over the last several years, peaking in 2010 at more than 125 cases.

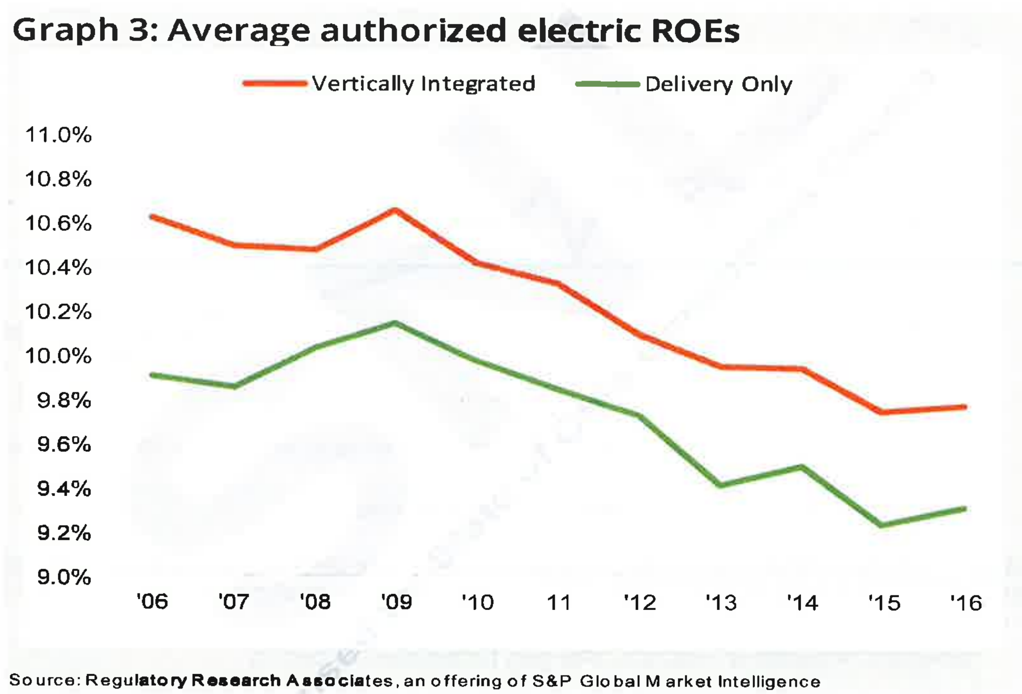
Graph 2: Volume of electric and gas rate case decisions



Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Since 2010, the number of rate cases has moderated somewhat but has been 90 or more in the last five calendar years. There were 111 electric and gas rate cases resolved in 2016, 92 in 2015, 99 in both 2014 and 2013, and 110 in 2012, and this level of rate case activity remains robust compared to the late 1990s/early 2000s. Increased costs associated with environmental compliance, including possible CO_2 reduction mandates, generation and delivery infrastructure upgrades and expansion, renewable generation mandates and employee benefits argue for the continuation of an active rate case agenda over the next few years. In addition, if the Federal Reserve continues its policy initiated in December 2015 to gradually raise the federal funds rate, utilities eventually would face higher capital costs and would need to initiate rate cases to reflect the higher capital costs in rates. However, the magnitude and pace of any additional Federal Reserve action to raise the federal funds rate is quite uncertain.

Included in tables on pages 6 and 7 of this report are comparisons, since 2006, of average authorized ROEs by settled versus fully litigated cases, general rate cases versus limited issues rider proceedings and vertically integrated cases versus delivery only cases. For both electric and gas cases, no pattern exists in average annual authorized ROEs in cases that were settled versus those that were fully litigated. In some years, the average authorized ROE was higher for fully litigated cases, in others it was higher for settled cases, and in a few years the authorized ROE was similar for fully litigated versus settled cases. Regarding electric cases that involve limited issue riders, over the last several years the annual average authorized ROEs in these cases was typically at least 100 basis points higher than in general rate cases, driven by the ROE premiums authorized in Virginia. Limited issue rider cases in which an ROE is determined have had extremely limited use in the gas industry. Comparing electric vertically integrated cases versus delivery only proceedings, RRA finds that the annual average authorized ROEs in vertically integrated cases are from roughly 40 to 70 basis points higher than in delivery only cases, arguably reflecting the increased risk associated with generation assets.



We note that this report utilizes the simple mean for the return averages. In addition, the average equity returns indicated in this report reflect the cases decided in the specified time periods and are not necessarily representative of the returns actually earned by utilities industry wide.

As a result of electric industry restructuring, certain states unbundled electric rates and implemented retail competition for generation. Commissions in those states now have jurisdiction only over the revenue requirement and return parameters for delivery operations, which we footnote in our chronology beginning on page 8, thus complicating historical data comparability. We note that from 2008 through 2015, interest rates declined significantly, and average authorized ROEs have declined modestly. We also note the increased utilization of limited issue rider proceedings that allow utilities to recover certain costs outside of a general rate case and typically incorporate previously-determined return parameters.

The table on page 4 shows the average ROE authorized in major electric and gas rate decisions annually since 1990, and by quarter since 2013, followed by the number of observations in each period. The tables on page 5 indicate the composite electric and gas industry data for all major cases summarized annually since 2002 and by quarter for the past eight quarters. The individual electric and gas cases decided in 2016 are listed on pages 8-13, with the decision date shown first, followed by the company name, the abbreviation for the state issuing the decision, the authorized rate of return, or ROR, ROE, and percentage of common equity in the adopted capital structure. Next we indicate the month and year in which the adopted test year ended, whether the commission utilized an average or a year-end rate base, and the amount of the permanent rate change authorized. The dollar amounts represent the permanent rate change ordered at the time decisions were rendered. Fuel adjustment clause rate changes are not reflected in this study.

The table below tracks the average equity return authorized for all electric and gas rate cases combined, by year, for the last 27 years. As the table indicates, since 1990 authorized ROEs have generally trended downward, reflecting the significant decline in interest rates and capital costs that has occurred over this time frame. The combined average equity returns authorized for electric and gas utilities in each of the years 1990 through 2016, and the number of observations for each year are as follows:

Composite Electric and Gas Average Annual Authorized ROEs: 1990 — 2016

Year	Average ROE (%)	Observations	Year	Average ROE (%)	Observations
1990	12.69	(75)	2004	10.67	(39)
1991	12.51	(80)	2005	10.50	(55)
1992	12.06	(77)	2006	10.39	(42)
1993	11.37	(77)	2007	10.30	(76)
1994	11.34	(59)	2008	10.42	(67)
1995	11.51	(49)	2009	10.36	(68)
1996	11.29	(42)	2010	10.28	(100)
1997	11.34	(24)	2011	10.21	(59)
1998	11.59	(20)	2012	10.08	(93)
1999	10.74	(29)	2013	9.92	(71)
2000	11.41	(24)	2014	9.86	(63)
2001	11.05	(25)	2015	9.76	(46)
2002	11.10	(43)	2016	9.67	(66)
2003	10.98	(47)			

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Please Note: Historical data provided in this report may not match data provided on RRA's website due to certain differences in presentation, including the treatment of cases that were withdrawn or dismissed.

Dennis Sperduto

Average Equity Returns Authorized January 1990 - December 2016

		Electric Utilities		Gas Utilities	
Year	**Period**	**ROE %**	**(# Cases)**	**ROE %**	**(# Cases)**
1990	Full Year	12.70	(44)	12.67	(31)
1991	Full Year	12.55	(45)	12.46	(35)
1992	Full Year	12.09	(48)	12.01	(29)
1993	Full Year	11.41	(32)	11.35	(45)
1994	Full Year	11.34	(31)	11.35	(28)
1995	Full Year	11.55	(33)	11.43	(16)
1996	Full Year	11.39	(22)	11.19	(20)
1997	Full Year	11.40	(11)	11.29	(13)
1998	Full Year	11.66	(10)	11.51	(10)
1999	Full Year	10.77	(20)	10.66	(9)
2000	Full Year	11.43	(12)	11.39	(12)
2001	Full Year	11.09	(18)	10.95	(7)
2002	Full Year	11.16	(22)	11.03	(21)
2003	Full Year	10.97	(22)	10.99	(25)
2004	Full Year	10.75	(19)	10.59	(20)
2005	Full Year	10.54	(29)	10.46	(26)
2006	Full Year	10.32	(26)	10.40	(15)
2007	Full Year	10.30	(38)	10.22	(35)
2008	Full Year	10.41	(37)	10.39	(32)
2009	Full Year	10.52	(40)	10.22	(30)
2010	Full Year	10.37	(61)	10.15	(39)
2011	Full Year	10.29	(42)	9.92	(16)
2012	Full Year	10.17	(58)	9.94	(35)
	1st Quarter	10.28	(14)	9.57	(3)
	2nd Quarter	9.84	(7)	9.47	(6)
	3rd Quarter	10.06	(7)	9.60	(1)
	4th Quarter	9.91	(21)	9.83	(11)
2013	Full Year	10.03	(49)	9.68	(21)
	1st Quarter	10.23	(8)	9.54	(6)
	2nd Quarter	9.83	(5)	9.84	(8)
	3rd Quarter	9.87	(12)	9.45	(6)
	4th Quarter	9.78	(13)	10.28	(6)
2014	Full Year	9.91	(38)	9.78	(26)
	1st Quarter	10.37	(9)	9.47	(3)
	2nd Quarter	9.73	(7)	9.43	(3)
	3rd Quarter	9.40	(2)	9.75	(1)
	4th Quarter	9.62	(12)	9.68	(9)
2015	Full Year	9.85	(30)	9.60	(16)
	1st Quarter	10.29	(9)	9.48	(6)
	2nd Quarter	9.60	(7)	9.42	(6)
	3rd Quarter	9.76	(8)	9.47	(4)
	4th Quarter	9.57	(18)	9.60	(8)
2016	Full Year	9.77	(42)	9.50	(24)

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric Utilities--Summary Table

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Cap. Struc.	(# Cases)	$ Mil.	(# Cases)
2002	Full Year	8.72	(20)	11.16	(22)	46.27	(19)	-475.4	(24)
2003	Full Year	8.86	(20)	10.97	(22)	49.41	(19)	313.8	(12)
2004	Full Year	8.44	(18)	10.75	(19)	46.84	(17)	1,091.5	(30)
2005	Full Year	8.30	(26)	10.54	(29)	46.73	(27)	1,373.7	(36)
2006	Full Year	8.32	(26)	10.32	(26)	48.54	(25)	1,318.1	(39)
2007	Full Year	8.18	(37)	10.30	(38)	47.88	(36)	1,405.7	(43)
2008	Full Year	8.21	(39)	10.41	(37)	47.94	(36)	2,823.2	(44)
2009	Full Year	8.24	(40)	10.52	(40)	48.57	(39)	4,191.7	(58)
2010	Full Year	8.01	(62)	10.37	(61)	48.63	(57)	4,921.9	(78)
2011	Full Year	8.00	(43)	10.29	(42)	48.26	(42)	2,595.1	(56)
2012	Full Year	7.95	(51)	10.17	(58)	50.69	(52)	3,080.7	(69)
2013	Full Year	7.66	(45)	10.03	(49)	49.25	(43)	3,328.6	(61)
2014	Full Year	7.60	(32)	9.91	(38)	50.28	(35)	2,053.7	(51)
	1st Quarter	7.74	(10)	10.37	(9)	51.91	(9)	203.6	(11)
	2nd Quarter	7.04	(9)	9.73	(7)	47.83	(6)	819.5	(17)
	3rd Quarter	7.85	(3)	9.40	(2)	51.08	(3)	379.6	(5)
	4th Quarter	7.22	(13)	9.62	(12)	48.24	(12)	488.7	(19)
2015	Full Year	7.38	(35)	9.85	(30)	49.54	(30)	1,891.5	(52)
	1st Quarter	7.03	(9)	10.29	(9)	46.06	(9)	311.2	(12)
	2nd Quarter	7.42	(7)	9.60	(7)	49.91	(7)	117.7	(9)
	3rd Quarter	7.23	(8)	9.76	(8)	49.11	(8)	499.1	(13)
	4th Quarter	7.38	(17)	9.57	(18)	49.93	(17)	1,421.4	(23)
2016	Full Year	7.28	(41)	9.77	(42)	48.91	(41)	2,349.4	(57)

Gas Utilities--Summary Table

	Period	ROR %	(# Cases)	ROE %	(# Cases)	Cap. Struc.	(# Cases)	$ Mil.	(# Cases)
2002	Full Year	8.80	(20)	11.03	(21)	48.29	(18)	303.6	(26)
2003	Full Year	8.75	(22)	10.99	(25)	49.93	(22)	260.1	(30)
2004	Full Year	8.34	(21)	10.59	(20)	45.90	(20)	303.5	(31)
2005	Full Year	8.25	(29)	10.46	(26)	48.66	(24)	458.4	(34)
2006	Full Year	8.44	(17)	10.40	(15)	47.24	(16)	392.5	(23)
2007	Full Year	8.11	(31)	10.22	(35)	48.47	(28)	645.3	(43)
2008	Full Year	8.49	(33)	10.39	(32)	50.35	(32)	700.0	(40)
2009	Full Year	8.15	(29)	10.22	(30)	48.49	(29)	438.6	(36)
2010	Full Year	7.99	(40)	10.15	(39)	48.70	(40)	776.5	(50)
2011	Full Year	8.09	(18)	9.92	(16)	52.49	(14)	367.0	(31)
2012	Full Year	7.98	(30)	9.94	(35)	51.13	(32)	264.0	(41)
2013	Full Year	7.39	(20)	9.68	(21)	50.60	(20)	494.9	(38)
2014	Full Year	7.65	(27)	9.78	(26)	51.11	(28)	529.2	(48)
	1st Quarter	6.41	(2)	9.47	(3)	50.41	(2)	168.9	(9)
	2nd Quarter	7.29	(3)	9.43	(3)	50.71	(3)	34.9	(8)
	3rd Quarter	7.35	(1)	9.75	(1)	42.01	(1)	103.9	(8)
	4th Quarter	7.54	(10)	9.68	(9)	50.40	(10)	186.5	(15)
2015	Full Year	7.34	(16)	9.60	(16)	49.93	(16)	494.1	(40)
	1st Quarter	7.12	(6)	9.48	(6)	50.83	(6)	120.2	(11)
	2nd Quarter	7.38	(6)	9.42	(6)	50.01	(6)	276.3	(16)
	3rd Quarter	6.59	(5)	9.47	(4)	48.44	(4)	106.3	(8)
	4th Quarter	6.71	(7)	9.60	(8)	48.74	(7)	733.1	(19)
2016	Full Year	6.95	(24)	9.50	(24)	49.56	(23)	1,235.9	(54)

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric Average Authorized ROEs: 2006 — 2016

Settled versus Fully Litigated Cases

	All Cases		Settled Cases		Fully Litigated Cases	
Year	ROE %	(# Cases)	ROE %	(# Cases)	ROE %	(# Cases)
2006	10.32	(26)	10.26	(11)	10.37	(15)
2007	10.30	(38)	10.42	(14)	10.23	(24)
2008	10.41	(37)	10.43	(17)	10.39	(20)
2009	10.52	(40)	10.64	(16)	10.45	(24)
2010	10.37	(61)	10.39	(34)	10.35	(27)
2011	10.29	(42)	10.12	(16)	10.39	(26)
2012	10.17	(58)	10.06	(29)	10.28	(29)
2013	10.03	(49)	10.12	(32)	9.85	(17)
2014	9.91	(38)	9.73	(17)	10.05	(21)
2015	9.85	(30)	10.07	(14)	9.66	(16)
2016	9.77	(42)	9.80	(17)	9.74	(25)

General Rate Cases versus Limited Issue Riders

	All Cases		General Rate Cases		Limited Issue Riders	
Year	ROE %	(# Cases)	ROE %	(# Cases)	ROE %	(# Cases)
2006	10.32	(26)	10.34	(25)	9.80	(1)
2007	10.30	(38)	10.31	(37)	9.90	(1)
2008	10.41	(37)	10.37	(35)	11.11	(2)
2009	10.52	(40)	10.52	(38)	10.55	(2)
2010	10.37	(61)	10.29	(58)	11.87	(3)
2011	10.29	(42)	10.19	(40)	12.30	(2)
2012	10.17	(58)	10.01	(52)	11.57	(6)
2013	10.03	(49)	9.81	(42)	11.34	(7)
2014	9.91	(38)	9.75	(33)	10.96	(5)
2015	9.85	(30)	9.60	(24)	10.87	(6)
2016	9.77	(42)	9.60	(32)	10.31	(10)

Vertically Integrated Cases versus Delivery Only Cases

	All Cases		Vertically Integrated Cases		Delivery Only Cases	
Year	ROE %	(# Cases)	ROE %	(# Cases)	ROE %	(# Cases)
2006	10.32	(26)	10.63	(15)	9.91	(10)
2007	10.30	(38)	10.50	(26)	9.86	(11)
2008	10.41	(37)	10.48	(26)	10.04	(9)
2009	10.52	(40)	10.66	(28)	10.15	(10)
2010	10.37	(61)	10.42	(41)	9.98	(17)
2011	10.29	(42)	10.33	(28)	9.85	(12)
2012	10.17	(58)	10.10	(39)	9.73	(13)
2013	10.03	(49)	9.95	(31)	9.41	(11)
2014	9.91	(38)	9.94	(19)	9.50	(14)
2015	9.85	(30)	9.75	(17)	9.23	(7)
2016	9.77	(42)	9.77	(20)	9.31	(12)

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Gas Average Authorized ROEs: 2006 — 2016

Settled versus Fully Litigated Cases

	All Cases		Settled Cases		Fully Litigated Cases	
Year	ROE %	(# Cases)	ROE %	(# Cases)	ROE %	(# Cases)
2006	10.40	(15)	10.26	(7)	10.53	(8)
2007	10.22	(35)	10.24	(22)	10.20	(13)
2008	10.39	(32)	10.34	(20)	10.47	(12)
2009	10.22	(30)	10.43	(13)	10.05	(17)
2010	10.15	(39)	10.30	(12)	10.08	(27)
2011	9.92	(16)	10.08	(8)	9.76	(8)
2012	9.94	(35)	9.99	(14)	9.92	(21)
2013	9.68	(21)	9.80	(9)	9.59	(12)
2014	9.78	(26)	9.51	(11)	9.98	(15)
2015	9.60	(16)	9.60	(11)	9.58	(5)
2016	9.50	(24)	9.43	(14)	9.61	(10)

General Rate Cases versus Limited Issue Riders

	All Cases		General Rate Cases		Limited Issue Riders	
Year	ROE %	(# Cases)	ROE %	(# Cases)	ROE %	(# Cases)
2006	10.40	(15)	10.40	(15)	—	(0)
2007	10.22	(35)	10.22	(35)	—	(0)
2008	10.39	(32)	10.39	(32)	—	(0)
2009	10.22	(30)	10.22	(30)	—	(0)
2010	10.15	(39)	10.15	(39)	—	(0)
2011	9.92	(16)	9.91	(15)	10.00	(1)
2012	9.94	(35)	9.93	(34)	10.40	(1)
2013	9.68	(21)	9.68	(21)	—	(0)
2014	9.78	(26)	9.78	(26)	—	(0)
2015	9.60	(16)	9.60	(16)	—	(0)
2016	9.50	(24)	9.49	(23)	9.70	(1)

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Electric Utility Decisions

Date	Company	State	ROR %	ROE %	Common Equity as % of Capital	Test Year	Rate Base	Amt. $ Mil.	Footnotes
1/5/16	MDU Resources Group	ND	7.95	10.50	50.27	12/16	—	15.1	(B,LIR,1)
1/6/16	Avista Corporation	WA	7.29	9.50	48.50	9/14	—	-8.1	(B)
1/28/16	Northern India-- Public Service Co.	IN	—	—	—	—	—	0.0	(LIR,2)
2/2/16	Kentucky Utilities Company	VA	—	—	—	12/14	—	5.5	(B)
2/23/16	Entergy Arkansas	AR	4.52	9.75	28.46	3/15	—	219.7	(B,*)
2/29/16	Virginia Electric and Power Company	VA	7.90	11.60	49.99	3/17	Average	21.0	(LIR,3)
2/29/16	Virginia Electric and Power Company	VA	7.40	10.60	49.99	3/17	Average	-9.3	(LIR,4)
2/29/16	Virginia Electric and Power Company	VA	7.40	10.60	49.99	3/17	Average	6.6	(LIR,5)
2/29/16	Virginia Electric and Power Company	VA	7.40	10.60	49.99	3/17	Average	-16.8	(LIR,6)
3/16/16	Indianapolis Power & Light Company	IN	6.51	9.85	37.33	6/14	Year-end	29.6	(*)
3/25/16	MDU Resources Group	MT	—	—	—	12/14	—	7.4	(B,Z)
3/29/16	Virginia Electric and Power Company	VA	6.90	9.60	49.99	3/17	Average	40.4	(LIR,7)
2016	1ST QUARTER: AVERAGES/TOTAL		7.03	10.29	46.06			311.2	
	OBSERVATIONS		9	9	9			12	
4/29/16	Fitchburg Gas and Electric Light Co.	MA	8.46	9.80	52.17	12/14	Year-end	2.1	(D)
6/3/16	Baltimore Gas and Electric Company	MD	7.28	9.75	51.90	11/15	Average	44.1	(D,R)
6/8/16	El Paso Electric Company	NM	7.67	9.48	49.29	12/14	Year-end	1.1	
6/15/16	New York State Electric & Gas Corp.	NY	6.68	9.00	48.00	4/17	Average	29.6	(B,D,Z,8)
6/15/16	Rochester Gas and Electric Corp.	NY	7.55	9.00	48.00	4/17	Average	3.0	(B,D,Z,8)
6/23/16	San Diego Gas & Electric Co.	CA	—	—	—	12/16	Average	3.0	(B,Z,9)
6/30/16	Appalachian Power Company	WV	—	—	—	—	—	55.1	(B,LIR,10)
6/30/16	Virginia Electric and Power Company	VA	7.40	10.60	49.99	8/17	Average	-25.7	(LIR,11)
6/30/16	Virginia Electric and Power Company	VA	6.90	9.60	49.99	8/17	Average	5.4	(LIR,12)
2016	2ND QUARTER: AVERAGES/TOTAL		7.42	9.60	49.91			117.7	
	OBSERVATIONS		7	7	7			9	
7/18/16	Northern Indiana Public Service Co.	IN	6.74	9.98	47.42	3/15	Year-end	72.5	(B,*)
8/9/16	Kingsport Power Company	TN	6.18	9.85	40.25	12/17	Average	8.6	(B)
8/10/16	Southwestern Public Service Co.	NM	—	—	—	—	—	23.5	(B)
8/10/16	Empire District Electric Company	MO	—	—	—	6/15	—	20.4	(B)
8/18/16	El Paso Electric Company	TX	—	—	—	3/15	—	40.7	(I,B)
8/18/16	UNS Electric, Inc.	AZ	7.22	9.50	52.83	12/14	Year-end	15.1	
8/22/16	Virginia Electric and Power Company	VA	—	—	—	8/17	—	21.3	(LIR, B,13)
8/24/16	Atlantic City Electric Company	NJ	7.64	9.75	49.48	12/15	Year-end	45.0	(D,B)

Electric Utility Decisions (continued)

Date	Company	State	ROR %	ROE %	Common Equity as % of Capital	Test Year	Rate Base	Amt. $ Mil.	Footnotes
9/1/16	PacifiCorp	WA	7.30	9.50	49.10	6/15	Year-end	13.7	(Z)
9/8/16	Upper Peninsula Power Company	MI	7.47	10.00	53.49	12/16	Average	4.6	(I,*)
9/28/16	Public Service Co. of New Mexico	NM	7.71	9.58	49.61	9/16	Average	61.2	
9/28/16	KCP&L Greater Missouri Operations	MO	—	—	—	—	—	3.0	(B)
9/30/16	Massachusetts Electric Company	MA	7.58	9.90	50.70	6/15	Year-end	169.7	(D)
2016	3RD QUARTER: AVERAGES/TOTAL		7.23	9.76	49.11			499.3	
	OBSERVATIONS		8	8	8			13	
10/6/16	Appalachian Power Company	VA	—	9.40	—	—	—	—	(LIR)
10/19/16	South Carolina Electric & Gas Co.	SC	8.24	—	51.35	6/16	Year-end	64.4	(LIR, 14)
10/26/16	Northern States Power Company - WI	WI	—	—	—	12/17	—	24.5	(15)
11/9/16	Madison Gas and Electric Company	WI	7.89	9.80	57.16	12/17	Average	-3.3	
11/10/16	Public Service Company of Oklahoma	OK	6.94	9.50	44.00	1/15	Year-end	14.5	
11/15/16	Potomac Electric Power Company	MD	7.49	9.55	49.55	12/15	Average	52.5	(D)
11/18/16	Wisconsin Power and Light Company	WI	7.91	10.00	52.20	12/18	Average	9.4	(B,Z)
11/29/16	Florida Power & Light Company	FL	—	10.55	—	12/18	—	811.0	(B,Z)
12/1/16	Liberty Utilities (CalPeco Electric) LLC	CA	7.51	10.00	52.50	12/16	Average	8.3	(B)
12/6/16	Commonwealth Edison Company	IL	6.71	8.64	45.62	12/15	Year-end	130.9	(D)
12/6/16	Ameren Illinois Company	IL	7.28	8.64	50.00	12/15	Year-end	-8.8	(D)
12/6/16	Entergy Arkansas, Inc.	AR	—	—	—	12/17	—	54.4	(B)
12/7/16	Duke Energy Progress, LLC	SC	7.21	10.10	53.00	12/15	Year-end	56.2	(B,Z)
12/9/16	Monongahela Power Company	WV	—	—	—	6/16	—	25.0	(B,LIR,16)
12/12/16	Jersey Central Power & Light Co.	NJ	7.47	9.60	45.00	6/16	Year-end	80.0	(B,D)
12/14/16	United Illuminating Company	CT	7.08	9.10	50.00	12/15	Average	57.4	(D,Z)
12/15/16	Avista Corporation	WA	—	—	—	—	—	0.0	(17)
12/19/16	Black Hills Colorado Electric Utility Co.	CO	7.43	9.37	52.39	12/15	Average	0.6	
12/19/16	Emera Maine	ME	7.45	9.00	49.00	12/14	Average	3.0	(D,Hy)
12/20/16	Georgia Power Company	GA	—	—	—	12/17	—	—	(LIR,W,18)
12/22/16	Sierra Pacific Power Company	NV	6.65	9.60	48.03	12/15	—	-2.9	(B)
12/22/16	Virginia Electric and Power Company	NC	7.37	9.90	51.75	12/15	Year-end	34.7	(B,I)
12/23/16	Hawaiian Electric Company, Inc.	HI	—	—	—	—	—	0.0	(19)
12/28/16	Avista Corporation	ID	7.58	9.50	50.00	12/15	Average	6.3	(B)
12/30/16	Appalachian Power Company	VA	7.30	10.00	47.22	12/17	Average	3.3	(B,LIR,20)
2016	4TH QUARTER: AVERAGES/TOTAL		7.38	9.57	49.93			1,421.4	
	OBSERVATIONS		17	18	17			23	
2016	FULL YEAR: AVERAGES/TOTAL		7.28	9.77	48.91			2,349.6	
	OBSERVATIONS		41	42	41			57	

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

Gas Utility Decisions

Date	Company	State	ROR %	ROE %	Common Equity as % of Capital	Test Year	Rate Base	Amt. $ Mil.	Footnotes
1/6/16	Oklahoma Natural Gas Company	OK	7.31	9.50	60.50	3/15	Year-end	30.0	(B)
1/6/16	Avista Corporation	WA	7.29	9.50	48.50	09/14	—	10.8	(B)
1/28/16	SourceGas Arkansas	AR	5.33	9.40	39.46	3/15	Year-end	8.0	(B,*)
2/10/16	Liberty Utilities (New England Nat. Gas)	MA	7.99	9.60	50.00	12/14	Year-end	7.8	(B)
2/16/16	Public Service Company of Colorado	CO	7.33	9.50	56.51	12/14	Average	39.2	(I,Z,R)
2/25/16	Black Hills Kansas Gas Utility Company	KS	—	—	—	10/15	Year-end	0.8	(LIR,21)
2/29/16	Avista Corporation	OR	7.46	9.40	50.00	12/16	Average	4.5	
3/17/16	Atmos Energy Corporation	KS	—	—	—	3/15	—	2.2	(B)
3/30/16	Indiana Gas Company, Inc.	IN	—	—	—	6/15	Year-end	7.0	(LIR,22)
3/30/16	Northern Indiana Public Service Co.	IN	—	—	—	6/15	Year-end	7.6	(LIR,23)
3/30/16	Southern Indiana Gas and Electric Co.	IN	—	—	—	6/15	Year-end	2.3	(LIR,22)
2016	1ST QUARTER: AVERAGES/TOTAL		7.12	9.48	50.83			120.2	
	OBSERVATIONS		6	6	6			11	
4/21/16	Consumers Energy Company	MI	—	—	—	12/16	—	40.0	(I,B)
4/29/16	Fitchburg Gas and Electric Light Company	MA	8.46	9.80	52.17	12/14	Year-end	1.6	
5/5/16	CenterPoint Energy Resources Corp.	MN	7.07	9.49	50.00	9/16	Average	27.5	(I)
5/11/16	Liberty Utilities (Midstates Nat. Gas)	MO	—	—	—	1/16	—	0.2	(LIR,24)
5/19/16	Delta Natural Gas Company	KY	—	—	—	12/15	Year-end	1.4	(LIR)
5/19/16	Laclede Gas Company	MO	—	—	—	2/16	Year-end	5.4	(LIR,25)
5/19/16	Missouri Gas Energy	MO	—	—	—	2/16	Year-end	3.6	(LIR,25)
6/1/16	Maine Natural Gas	ME	7.28	9.55	50.00	9/14	Average	2.5	(B,Z)
6/3/16	Baltimore Gas and Electric Company	MD	7.23	9.65	51.90	11/15	Average	47.9	(R)
6/15/16	New York State Electric & Gas Corporation	NY	6.68	9.00	48.00	4/17	Average	13.1	(B,Z,7)
6/15/16	Rochester Gas and Electric Corp.	NY	7.55	9.00	48.00	4/17	Average	8.8	(B,Z,7)
6/22/16	Northern Indiana Public Service Co.	IN	—	—	—	12/15	Year-end	6.7	(LIR,E,26)
6/23/16	San Diego Gas & Electric Co.	CA	—	—	—	12/16	Average	-1.6	(B,Z,27)
6/23/16	Southern California Gas Company	CA	—	—	—	12/16	Average	106.9	(B,Z,9)
6/29/16	Indiana Gas Company, Inc.	IN	—	—	—	12/15	Year-end	10.2	(LIR,28)
6/29/16	Southern Indiana Gas and Electric Co.	IN	—	—	—	12/15	Year-end	2.1	(LIR,28)
2016	2ND QUARTER: AVERAGES/TOTAL		7.38	9.42	50.01			276.3	
	OBSERVATIONS		6	6	6			16	

Gas Utility Decisions (continued)

Date	Company	State	ROR %	ROE %	Common Equity as % of Capital	Test Year	Rate Base	Amt. $ Mil.	Footnotes
7/7/16	Cascade Natural Gas Corporation	WA	7.35	—	—	—	—	4.0	(B)
7/19/16	CenterPoint Energy Resources Corp.	OK	—	—	—	12/15	—	0.0	(B,29)
8/4/16	Atmos Energy Corporation	KY	—	—	—	5/17	—	0.5	(B)
8/22/16	Questar Gas Company	UT	—	—	—	—	—	—	(30)
9/1/16	UGI Utilities, Inc.	PA	—	—	—	9/17	—	27.0	(B)
9/2/16	CenterPoint Energy Resources Corp.	AR	4.53	9.50	30.85	9/15	Year-end	14.2	(B,*)
9/23/16	New Jersey Natural Gas Company	NJ	6.90	9.75	52.50	6/16	Year-end	45.0	(B)
9/27/16	Texas Gas Service Company	TX	7.28	9.50	60.10	9/15	Year-end	8.8	
9/29/16	Minnesota Energy Resources Corp.	MN	6.88	9.11	50.32	12/16	Average	6.8	(I,E)
2016	3RD QUARTER: AVERAGES/TOTAL		6.59	9.47	48.44			106.3	
	OBSERVATIONS		5	4	4			8	
10/26/16	Northern States Power Company - WI	WI	—	—	—	12/17	—	4.8	(15)
10/27/16	Columbia Gas of Maryland, Inc.	MD	—	—	—	4/16	—	3.7	(B)
10/27/16	Columbia Gas of Pennsylvania, Inc.	PA	—	—	—	12/17	—	35.0	(B)
10/28/16	Public Service Co. of North Carolina	NC	7.53	9.70	52.00	12/15	Year-end	19.1	(B)
11/9/16	Madison Gas and Electric Company	WI	—	9.80	—	12/17	—	3.1	
11/14/16	Atmos Energy Corporation	KY	—	—	—	9/17	Year-end	5.0	(LIR,31)
11/15/16	Texas Gas Service Company	TX	—	—	—	12/15	—	6.8	(B)
11/18/16	Wisconsin Power and Light Company	WI	7.84	10.00	52.20	12/18	Average	9.4	(B,Z)
11/23/16	Baltimore Gas and Electric Company	MD	—	—	—	12/18	Average	6.1	(B,Z,LIR,32)
11/29/16	Kansas Gas Service Company	KS	—	—	—	—	—	15.5	(B)
12/1/16	Pacific Gas and Electric Company	CA	—	—	—	12/15	Average	100.0	(Tr,I, 33)
12/9/16	DTE Gas Company	MI	5.76	10.10	38.65	10/17	Average	122.3	(I,*)
12/14/16	Columbia Gas of Maryland, Inc.	MD	7.53	9.70	54.29	12/17	Average	1.2	(LIR,32)
12/15/16	KeySpan Gas East Corporation	NY	6.42	9.00	48.00	12/17	Average	112.0	(B,34)
12/15/16	Brooklyn Union Gas Company	NY	6.15	9.00	48.00	12/17	Average	272.1	(B,35)
12/15/16	Avista Corporation	WA	—	—	—	—	—	0.0	(17)
12/20/16	Columbia Gas of Virginia, Inc.	VA	—	—	—	12/17	Average	1.3	(LIR,36)
12/22/16	Columbia Gas of Kentucky, Inc.	KY	—	—	—	—	—	18.1	(B)
12/22/16	Sierra Pacific Power Company	NV	5.75	9.50	48.03	12/15	—	-2.4	(B)
2016	4TH QUARTER: AVERAGES/TOTAL		6.71	9.60	48.74			733.1	
	OBSERVATIONS		7	8	7			19	
2016	FULL YEAR: AVERAGES/TOTAL		6.95	9.50	49.56			1,235.9	
	OBSERVATIONS		24	24	23			54	

Source: Regulatory Research Associates, an offering of S&P Global Market Intelligence

FOOTNOTES

A-	Average
B-	Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body.
CWIP-	Construction work in progress
D-	Applies to electric delivery only
DCt	Date certain rate base valuation
E-	Estimated
F-	Return on fair value rate base
Hy-	Hypothetical capital structure utilized
I-	Interim rates implemented prior to the issuance of final order, normally under bond and subject to refund.
LIR	Limited-issue rider proceeding
M-	"Make-whole" rate change based on return on equity or overall return authorized in previous case.
R-	Revised
Te-	Temporary rates implemented prior to the issuance of final order.
Tr-	Applies to transmission service
U-	Double leverage capital structure utilized.
W-	Case withdrawn
YE-	Year-end
Z-	Rate change implemented in multiple steps.
*	Capital structure includes cost-free items or tax credit balances at the overall rate of return.

(1) Rate increase approved in renewable resource cost recovery rider.

(2) Case represents the company's transmission, distribution, and storage system improvement charge, or TDSIC rate adjutment mechanism. The case was dismissed by the Commission, with no rate change authorized.

(3) Proceeding determines the revenue requirement for Rider B, which is the mechanism through which the company recovers costs associated with its plan to convert the Altavista, Hopewell, and Southampton Power Stations to burn biomass fuels.

(4) Represents rate decrease associated with the company's Rider R proceeding, which is the mechanism through which the company recovers the investment in the Bear Garden generating facility.

(5) This proceeding determines the revenue requirement for Rider S, which recognizes in rates the company's investment in the Virginia City Hybrid Energy Center.

(6) Decrease authorized through a surcharge, Rider W, which reflects in rates investment in the Warren County Power Station.

(7) Proceeding involves a new gas-fired generation facility, the Greensville County project, and creation of a new rider mechanism, Rider GV, to reflect the related revenue requirement in rates.

(8) Rate increase effective 5/1/16; additional increases to be effective 5/1/17 and 5/1/18.

(9) Settlement adopted with modifications. Rate increase effective retroactive to 1/1/16; additional increases to be effective 1/1/17 and 1/1/18.

(10) Represents the company's joint expanded net energy cost, or ENEC, proceeding.

(11) Represents rate decrease associated with the company's Rider BW proceeding, which is the mechanism through which the company recovers the investment in its Brunswick County Power Station.

(12) Represents the rate increase associated with the company's Rider US-2, which is the mechanism through which the company recovers the revenue requirement associated with three new solar generation facilities.

(13) Case involves the company's request to establish Rider U for recovery of investment and costs associated with a project to underground certain distribution lines.

(14) The present case involves South Carolina Electric & Gas' request for a cash return on incremental V.C. Summer Units 2 and 3 construction work in progress (CWIP) and incorporates the 10.5% return on equity that was authorized in September 2015 for use in the Summer CWIP-related proceedings beginning in 2016.

(15) The rate case is for the limited purpose of recovering anticipated increases in: generation and transmission fixed charges and fuel and purchased power expenses related to the interchange agreement with affiliate NSP-Minnesota; and, rate base investment.

FOOTNOTES (continued)

(16) Case is a consolidated expanded net energy cost proceeding for Monongahela Power and affiliate Potomac Edison.
(17) Rate increase rejected by commission.
(18) As a result of the commission's adoption of a settlement in another proceeding, the company withrew its rate increase request in this proceeding, and no rate change was implemented.
(19) No change in base rates was sought by the company, and on 12/23/16, the commission issued an order closing this docket.
(20) Case involves the company's G-RAC rider mechanism that addresses its investment in the Dresden Generating Plant, and establishes the revenue requirement for the rider to become effective 1/1/17.
(21) Case involves the company's gas system reliabillity surcharge, or GSRS, rider and reflects investments made from July 1, 2014 through Oct. 31, 2015.
(22) Case involves company's "compliance and system improvement adjustment" mechanism, and includes compliance-related investments made between Jan. 1 and June 30, 2015, and certain other investments made between July 1, 2014 and June 30, 2015.
(23) Case establishes the rates to be charged to customers under the company's transmission, distribution and storage system improvement charge rate adjustment mechanism, and reflects investments made between July 1, 2014 and June 30, 2015.
(24) Case involves the company's infrastructure system replacement surcharge rider and reflects incremental investments made from 6/1/15 through 1/31/16.
(25) Case involves the company's infrastructure system replacement surcharge rider and reflects incremental investments made from 9/1/15 through 2/29/16.
(26) Case establishes the rates to be charged to customers under the company's transmission, distribution and storage system improvement charge rate adjustment mechanism, and reflects investments made between 7/1/15 and 12/31/15.
(27) Settlement adopted with modifications. Rate decrease effective retroactive to 1/1/16; rate increases to be effective 1/1/17 and 1/1/18.
(28) Case involves company's "compliance and system improvement adjustment" mechanism, and includes compliance-related investments made between 7/1/15 and 12/31/15.
(29) Case involves the company's performance based ratemaking plan.
(30) On 8/22/16, the PSC approved the company's petition to withdraw the rate increase request, effectively closing the case. The request to withdraw the filing comported with provisions of a settlement filed in the Questar/Dominion Resources merger proceeding.
(31) Case is an annual update to the company's pipe replacement program rider.
(32) Case involves the company's strategic infrastrucure development and enhancement, or STRIDE, rider.
(33) Case involves the company's gas transmission and storage operations. The decision also authorized attrition rate increases of $246 million for 2016, $64 million for 2017 and $105 million for 2018.
(34) Adopted joint proposal provides for the company to implement a $112 million rate increase effective 1/1/17, a $19.6 million rate increase effective 1/1/18, and a $27 million rate increase effective 1/1/19.
(35) Adopted joint proposal provides for the company to implement a $272.1 million rate increase effective 1/1/17, a $41 million rate increase effective 1/1/18, and a $48.9 million rate increase effective 1/1/19.
(36) Case involves the company's investments under the Steps to Advance Virginia's Energy Plan.

Dennis Sperduto

NEWS

FOR IMMEDIATE RELEASE

NiSource

WWW.NISOURCE.COM

August 2, 2017

FOR ADDITIONAL INFORMATION

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NiSource Reports Second Quarter Earnings, Increases 2017 Guidance

- 2017 non-GAAP net operating earnings guidance increased to a range of $1.17 to $1.20 per share
- Financial results reflect disciplined execution of core utility infrastructure investment strategy
- Successful refinancing will result in significant interest expense savings

MERRILLVILLE, Ind. - NiSource Inc. (NYSE: NI) today announced, on a GAAP basis, a loss from continuing operations for the three months ended June 30, 2017 of $44.3 million, or $0.14 per share, compared to income from continuing operations of $29.0 million, or $0.09 per share, for the same period of 2016. For the six months ended June 30, 2017, NiSource's income from continuing operations was $167.0 million, or $0.51 per share, compared to $215.6 million, or $0.67 per share, for the same period of 2016.

NiSource also reported net operating earnings (non-GAAP) of $33.3 million, or $0.10 per share, for the three months ended June 30, 2017, compared to $26.6 million, or $0.08 per share, for the same period of 2016. For the six months ended June 30, 2017, NiSource's net operating earnings (non-GAAP) were $263.9 million, or $0.81 per share, compared to $224.3 million, or $0.70 per share, for the same period of 2016.

Reflected in the GAAP results is a $111.5 million loss on early extinguishment of higher-coupon long-term debt. This $990.7 million refinancing will result in significant interest expense savings over the next several years. Schedule 1 of this press release contains a complete reconciliation of non-GAAP measures to GAAP measures.

“NiSource's team continued to execute on our long-term infrastructure investment strategy benefiting customers through enhanced safety, reliability and service," said NiSource President and CEO **Joe Hamrock**. "With this effective execution, combined with interest expense savings following the successful refinancing effort, we now expect to deliver 2017 non-GAAP net operating earnings in the range of $1.17 to $1.20 per share."

NiSource reminds investors that it does not provide a GAAP equivalent of its earnings guidance due to the impact of unpredictable factors such as fluctuations in weather, asset sales and impairments, and other items included in GAAP results.

Additional information for the quarter ended June 30, 2017 is available on the Investors section of www.nisource.com, including segment and financial information and our presentation to be discussed at our second quarter 2017 earnings conference call scheduled for Aug. 2, 2017 at 8:30 a.m. ET.

Second Quarter 2017 and Recent Business Highlights

NiSource continues to advance regulatory initiatives and customer programs in support of its ongoing infrastructure modernization, system safety and reliability enhancements, and customer growth investments.

Gas Distribution Operations

- **Columbia Gas of Ohio's** application for a five year extension of its **Infrastructure Replacement Program** remains pending before the Public Utilities Commission of Ohio (PUCO). This well-established pipeline replacement program, which is currently authorized through December 31, 2017, covers replacement of priority mainline pipe and targeted customer service lines. A PUCO order is expected by the end of the year.
- **Columbia Gas of Maryland's** base rate case remains pending before the Maryland Public Service Commission (MPSC). The request, filed April 14, 2017, seeks to adjust the company's base rates so it can continue to expedite the replacement of aging pipe as well as adopt additional pipeline safety upgrades. On July 28, 2017, all parties filed a settlement agreement with the MPSC which, if approved as filed, would result in an annual revenue increase of $2.4 million, effective in late October 2017.
- **Northern Indiana Public Service Company (NIPSCO)** continues to execute on its seven-year, $845 million **gas infrastructure modernization program** to further improve system reliability and safety. On June 28, 2017 the Indiana Utility Regulatory Commission (IURC) approved NIPSCO's latest semi-annual tracker update covering approximately $61 million of investments that were made in the second half of 2016.

Electric Operations

- NIPSCO's request, filed in November 2016, to invest in **environmental upgrades at its Michigan City Unit 12 and R.M. Schahfer Units 14 and 15 generating facilities** remains pending before the IURC. On June 9, 2017, NIPSCO, along with the Indiana Office of Utility Consumer Counselor, the Citizens Action Coalition and a group of NIPSCO industrial customers submitted a settlement agreement seeking, among other things, approval and cost recovery for the **Coal Combustion Residuals** projects and moving **Effluent Limitation Guidelines**-related investments to a later proceeding. An IURC order is expected before the end of the year.
- NIPSCO continues to execute on its **seven-year electric infrastructure modernization program**, which includes enhancements to its electric transmission and distribution system designed to further improve system safety and reliability. The IURC-approved program represents approximately $1.25 billion of electric infrastructure investments expected to be made through 2022. In February 2017, NIPSCO began recovering on approximately $46 million of these investments. On June 30, 2017, it filed with the IURC its latest tracker update request, covering $133.6 million in investments from May 2016 through April 2017.
- NIPSCO’s **two major electric transmission projects** remain on schedule with anticipated in-service dates in the second half of 2018. The 100-mile 345-kV and 65-mile 765-kV projects are designed to enhance region-wide system flexibility and reliability. Substation, line and tower construction are under way for both projects.

Long-term Earnings and Dividend Growth, Capital Investment Forecasts on Track

Consistent with plans outlined at its Investor Day in March 2017, NiSource expects to grow its net operating earnings per share (non-GAAP) and dividend at 5 to 7 percent each year - based off the revised 2017 guidance - through 2020. The company also continues to expect to invest $1.6 to $1.8 billion annually ($1.6 to $1.7 billion in 2017) in its utility infrastructure programs through 2020. These program investments are part of NiSource's more than $30 billion of identified long-term investment opportunities.

With this robust investment and steady earnings and dividend growth projected, NiSource continues its commitment to maintaining investment grade credit ratings. Standard & Poor's rates NiSource at BBB+, Moody's at Baa2 and Fitch at BBB, all with stable outlooks. As of June 30, 2017, NiSource maintained $1.25 billion in net available liquidity, consisting of cash and available capacity under its credit facility.

About NiSource
NiSource Inc. (NYSE: NI) is one of the largest fully-regulated utility companies in the United States, serving approximately 3.5 million natural gas customers and 500,000 electric customers across seven states through its local Columbia Gas and NIPSCO brands. Based in Merrillville, Indiana, NiSource's approximately 8,000 employees are focused on safely delivering reliable and affordable energy to our customers and communities we serve. NiSource has been designated a World's Most Ethical Company by the Ethisphere Institute since 2012 and is a member of the Dow Jones Sustainability - North America Index. Additional information about NiSource, its investments in modern infrastructure and systems, its commitments and its local brands can be found at www.nisource.com. Follow us at www.facebook.com/nisource, www.linkedin.com/company/nisource or www.twitter.com/nisourceinc. NI-F

Forward-Looking Statements
This press release contains forward-looking statements within the meaning of federal securities laws. Investors and prospective investors should understand that many factors govern whether any forward-looking statement contained herein will be or can be realized. Any one of those factors could cause actual results to differ materially from those projected. Examples of forward-looking statements in this press release include statements and expectations regarding NiSource's business, performance, growth, commitments, investment opportunities, and planned, identified, infrastructure or utility investments. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially. Factors that could cause actual results to differ materially from the projections, forecasts, estimates, plans, expectations and strategy discussed in this press release include, among other things, NiSource's debt obligations; any changes in NiSource's credit rating; NiSource's ability to execute its growth strategy; changes in general economic, capital and commodity market conditions; pension funding obligations; economic regulation and the impact of regulatory rate reviews; NiSource's ability to obtain expected financial or regulatory outcomes; any damage to NiSource's reputation; compliance with environmental laws and the costs of associated liabilities; fluctuations in demand from residential and commercial customers; economic conditions of certain industries; the success of NIPSCO's electric generation strategy; the price of energy commodities and related transportation costs; the reliability of customers and suppliers to fulfill their payment and contractual obligations; potential impairments of goodwill or definite-lived intangible assets; changes in taxation and accounting principles; potential incidents and other operating risks associated with our business; the impact of an aging infrastructure; the impact of climate change; potential cyber-attacks; construction risks and natural gas costs and supply risks; extreme weather conditions; the attraction and retention of a qualified work force; advances in technology; the ability of NiSource's subsidiaries to generate cash; tax liabilities associated with the separation of Columbia Pipeline Group, Inc. and other matters set forth in Item 1A, "Risk Factors" section of NiSource's Annual Report on Form 10-K for the fiscal year ended December 31, 2016 and in other filings with the Securities and Exchange Commission. NiSource expressly disclaims any duty to update, supplement or amend any of its forward-looking statements contained in this press release, whether as a result of new information, subsequent events or otherwise, except as required by applicable law.

Regulation G Disclosure Statement

This press release includes financial results and guidance for NiSource with respect to net operating earnings, which is a non-GAAP financial measure as defined by the SEC's Regulation G. The company includes this measure because management believes it permits investors to view the company's performance using the same tools that management uses and to better evaluate the company's ongoing business performance. With respect to such guidance, it should be noted that there will likely be a difference between this measure and its GAAP equivalent due to various factors, including, but not limited to, fluctuations in weather, the impact of asset sales and impairments, and other items included in GAAP results. The company is not able to estimate the impact of such factors on GAAP earnings and, as such, is not providing earnings guidance on a GAAP basis.

Schedule 1 - Reconciliation of Consolidated Net Operating Earnings (Non-GAAP) to Income (Loss) from Continuing Operations *(unaudited)*

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	**2017**	2016	**2017**	2016
Net Operating Earnings (Non-GAAP)	**$ 33.3**	$ 26.6	**$ 263.9**	$ 224.3
Items Excluded from Operating Earnings:				
Net Revenues:				
Weather - compared to normal	**(4.9)**	4.6	**(33.9)**	(12.6)
Operating Expenses:				
Plant retirement costs[1]	**—**	—	**(1.5)**	—
IT service provider transition costs[2]	**(5.1)**	—	**(5.1)**	—
Transaction costs[3]	**—**	(0.9)	**—**	(1.7)
Gain on sale of assets and impairments, net	**0.1**	0.2	**0.1**	0.3
Total items excluded from operating earnings	**(9.9)**	3.9	**(40.4)**	(14.0)
Other Income (Deductions):				
Loss on early extinguishment of long-term debt	**(111.5)**	—	**(111.5)**	—
Income Taxes:				
Tax effect of above items	**43.8**	(1.5)	**55.0**	5.3
Total items excluded from net operating earnings	**(77.6)**	2.4	**(96.9)**	(8.7)
GAAP Income (Loss) from Continuing Operations	**$ (44.3)**	$ 29.0	**$ 167.0**	$ 215.6
Basic Average Common Shares Outstanding	**325.1**	321.7	**324.4**	321.0
Non-GAAP Basic Net Operating Earnings Per Share	**$ 0.10**	$ 0.08	**$ 0.81**	$ 0.70
Items excluded from net operating earnings (after-tax)	**(0.24)**	0.01	**(0.30)**	(0.03)
GAAP Basic Earnings (Loss) Per Share From Continuing Operations	**$ (0.14)**	$ 0.09	**$ 0.51**	$ 0.67

[1] Represents employee severance costs incurred associated with the planned retirement of Units 7 and 8 at Bailly Generating Station.
[2] Represents external legal and consulting costs associated with termination of the IBM IT services agreement and the transition to a new multi-vendor strategy for IT service delivery.
[3] Represents costs incurred associated with the separation of Columbia Pipeline Group ("CPG").

Historical Cost per Mile

	Cost/Priority Mile	% Increase	Total Capital[(1)]	Miles Replaced[(2)]	Total Miles Replaced
2008	$ 406,695.32	-	$ 37,009,274.38	91	91
2009	$ 312,343.20	-23.20%	$ 34,357,752.00	100	110
2010	$ 449,029.96	43.76%	$ 31,432,097.24	63	70
2011	$ 420,089.86	-6.45%	$ 107,543,003.00	216	256
2012	$ 593,856.22	41.36%	$ 154,996,474.00	184	261
2013	$ 596,401.20	0.43%	$ 167,588,738.42	197	281
2014	$ 656,059.61	10.00%	$ 165,983,082.54	176	253
2015	$ 684,724.40	4.37%	$ 182,821,415.63	196	267
2016	$ 778,023.61	13.63%	$ 214,734,515.36	200	276

9-Year Historical Average		10.49%
4-Year Historical Average		7.11%
Estimated 2017	*$ 833,315.13*	*6.47%*

Avg. BS/CI repl. 2013-2016	192
Avg. total mi. repl. 2013-2016	269
Avg. ratio BS/CI to other 2013-2016	71.40%
Avg. ratio other to BS/CI 2013-2016	28.60%

Projected Cost per Mile

4-Year Historical Average		
2018	$ 892,536.04	7.11%
2019	$ 955,965.58	7.11%
2020	$ 1,023,902.85	7.11%
2021	$ 1,096,668.19	7.11%
2022	$ 1,174,604.72	7.11%
Average Cost per Mile	$ 1,028,735.48	
Total Cost for 1,055 Miles	$ 1,085,315,928.63	
Average Annual Spend	$ 217,063,185.73	
Average Annual Rate Increase	1.224	

9-Year Historical Average		
2018	$ 920,717.12	10.49%
2019	$ 1,017,286.23	10.49%
2020	$ 1,123,983.97	10.49%
2021	$ 1,241,872.66	10.49%
2022	$ 1,372,126.07	10.49%
Average Cost per Mile	$ 1,135,197.21	
Total Cost for 1,055 Miles	$ 1,197,633,058.17	
Average Annual Spend	$ 239,526,611.63	
Average Annual Rate Increase	1.41	

	Feet		Conversion to Miles		
	Bare Steel	**Iron**	**Bare Steel**	**Iron**	**Total Miles**
2008	428,073	54,762	81	10	91
2009	516,262	12,289	98	2	100
2010	317,311	16,050	60	3	63
2011	1,080,163	62,667	205	12	216
2012	903,228	67,442	171	13	184
2013	959,081	81,023	182	15	197
2014	856,785	70,087	162	13	176
2015	995,341	38,510	189	7	196
2016	1,003,778	52,923	190	10	200

Feet per Mile	5,280

Columbia Gas of Ohio, Inc.
Infrastructure Tracker Mechanism
Estimated Rate Impact of Proposed IRP Program (2018-2022)

Line	Capital Expenditure Year	2018	2019	2020	2021	2022	
No.	Revenue Recovery Time Period	2019/20	2020/21	2021/22	2022/23	2023/24	
1	**Return on Investment**						
2	Plant In-Service						
3	Additions	1,507,929,539	1,724,992,725	1,942,055,911	2,159,119,097	2,376,182,283	
4	Retirements	(173,102,787)	(198,994,080)	(224,885,374)	(250,776,667)	(276,667,960)	
5	Total Plant In-Service	1,334,826,752	1,525,998,645	1,717,170,537	1,908,342,430	2,099,514,323	
6	Less: Accumulated Provision for Depreciaiton						
7	Depreciation Expense	137,274,755	174,800,204	217,549,336	265,522,149	318,718,644	
8	Cost of Removal	(56,422,236)	(64,984,532)	(73,546,829)	(82,109,125)	(90,671,421)	
9	Retirements	(173,102,787)	(198,994,080)	(224,885,374)	(250,776,667)	(276,667,960)	
10	Total Accumulated Provision for Depreciation	(92,250,268)	(89,178,408)	(80,882,867)	(67,363,643)	(48,620,737)	
11	Net Deferred Depreciation	18,729,599	21,428,257	24,056,341	26,612,171	29,095,748	
12	Net Regulatory Asset - PISCC	54,532,066	62,310,016	69,848,284	77,169,219	84,759,582	
13	Net Deferred Tax Balance - Property Taxes	5,601,670	6,577,260	7,536,314	8,477,107	9,399,934	
14	Net Deferred Tax Balance - PISCC	(19,086,223)	(21,808,506)	(24,446,900)	(27,009,227)	(29,665,854)	
15	Net Operating Loss due to Bonus Depreciation	85,580,217	106,778,362	112,181,904	112,131,457	112,131,457	
16	Deferred Taxes on Liberalized Depreciation	(330,057,613)	(370,488,504)	(394,402,350)	(420,141,013)	(447,527,276)	
17	Net Rate Base	1,242,376,736	1,419,973,938	1,592,826,997	1,752,945,788	1,906,328,651	
18	Approved Pre-tax Rate of Return	10.95%	10.95%	10.95%	10.95%	10.95%	
			-	-	-	-	
19	Annualized Return on Rate Base	136,040,253	155,487,146	174,414,556	191,947,564	208,742,987	
20	**Operating Expenses**						
21	Annualized Depreciation	30,932,244	35,560,426	40,188,608	44,816,791	49,444,973	
22	Deferred Depreciation Amortization	465,205	537,458	609,712	681,965	754,219	
23	Deferred PISCC Amortization	1,351,462	1,559,954	1,767,615	1,975,059	2,193,474	
24	Annualized Property Tax Expense	29,808,407	34,003,436	38,065,761	42,018,168	45,834,905	
25	Deferred Property Tax Expense Amortization	211,040	250,163	289,557	329,208	369,134	
26	Operation & Maintenance Expense	150,000	150,000	150,000	150,000	150,000	
27	Operation & Maintenance Savings	(1,250,000)	(1,250,000)	(1,250,000)	(1,250,000)	(1,250,000)	
28	Total Revenue Requirement	197,708,611	226,298,585	254,235,810	280,668,756	306,239,693	1,265,151,453
29	Estimated Number of SGS Customers	1,414,010	1,420,829	1,427,531	1,433,829	1,439,836	
30	Estimated Number of GS Customers	40,469	40,505	40,543	40,577	40,611	
31	Estimated Number of LGS Customers	297	297	297	297	297	
32	Estimated Annual Cost Per SGS Customer	101.17	115.25	128.87	141.64	153.90	
33	Estimated Annual Cost Per GS Customer	1,079.19	1,234.15	1,385.21	1,527.95	1,665.76	
34	Estimated Annual Cost Per LGS Customer	36,945.55	42,288.12	47,508.71	52,448.20	57,226.61	
35	Estimated Cost Per Month Per SGS Customer	8.43	9.60	10.74	11.80	12.83	
36	Estimated Cost Per Month Per GS Customer	89.93	102.85	115.43	127.33	138.81	
37	Estimated Cost Per Month Per LGS Customer	3,078.80	3,524.01	3,959.06	4,370.68	4,768.88	
38	Estimated Cost Per Month SGS-AMRD	0.29	0.27	0.26	0.23	0.20	
39	Estimated Cost Per Month GS-AMRD	3.23	3.01	2.70	2.45	2.18	
40	Estimated Cost Per Month LGS-AMRD	-	-	-	-	-	
41	Estimated Cost Per Month SGS-HCSL	2.79	2.92	3.05	3.18	3.29	
42	Estimated Cost Per Month GS-HCSL	3.19	3.35	3.52	3.66	3.81	
43	Estimated Cost Per Month LGS-HCSL	-	-	-	-	-	
44	Cost Per Month SGS-Total	11.51	12.79	14.05	15.21	16.32	
45	Cost Per Month GS-Total	96.35	109.20	121.65	133.44	144.80	
46	Cost Per Month LGS-Total	3,078.80	3,524.01	3,959.06	4,370.68	4,768.88	
							Average Annual Increase
47	Annual Rate Increase*	1.31	1.28	1.26	1.16	1.11	1.224

*For estimation purposes, the estimated total capital investment for the five-year period was evenly spread over the five years. Columbia will manage the capital execution to ensure monthly SGS rates do not cumulatively exceed the approved maximum Rider IRP rates.

Columbia Gas of Ohio, Inc.
Infrastructure Tracker Mechanism
Estimated Rate Impact of Proposed IRP Program (2018-2022)

Line No.	Capital Expenditure Year / Revenue Recovery Time Period	2018 / 2019/20	2019 / 2020/21	2020 / 2021/22	2021 / 2022/23	2022 / 2023/24	
1	**Return on Investment**						
2	Plant In-Service						
3	Additions	1,530,392,965	1,769,919,577	2,009,446,189	2,248,972,801	2,488,499,413	
4	Retirements	(180,892,212)	(214,572,930)	(248,253,648)	(281,934,366)	(315,615,084)	
5	Total Plant In-Service	1,349,500,753	1,555,346,647	1,761,192,541	1,967,038,435	2,172,884,329	
6	Less: Accumulated Provision for Depreciaiton						
7	Depreciation Expense	138,060,531	177,943,306	224,621,313	278,094,553	338,363,026	
8	Cost of Removal	(58,998,213)	(70,136,485)	(81,274,758)	(92,413,030)	(103,551,303)	
9	Retirements	(180,892,212)	(214,572,930)	(248,253,648)	(281,934,366)	(315,615,084)	
10	Total Accumulated Provision for Depreciation	(101,829,894)	(106,766,109)	(104,907,092)	(96,252,843)	(80,803,361)	
11	Net Deferred Depreciation	19,216,937	22,853,233	26,400,728	29,854,231	33,213,744	
12	Net Regulatory Asset - PISCC	55,785,207	66,271,116	76,455,047	86,356,260	96,607,959	
13	Net Deferred Tax Balance - Property Taxes	5,601,670	6,909,900	8,198,755	9,463,857	10,705,587	
14	Net Deferred Tax Balance - PISCC	(19,524,822)	(23,194,891)	(26,759,267)	(30,224,691)	(33,812,786)	
15	Net Operating Loss due to Bonus Depreciation	85,580,217	106,778,362	112,181,904	112,131,457	112,131,457	
16	Deferred Taxes on Liberalized Depreciation	(343,413,878)	(395,768,184)	(426,805,129)	(460,347,619)	(496,130,736)	
17	Net Rate Base	1,254,575,978	1,445,962,294	1,635,771,673	1,810,524,774	1,976,402,915	
18	Approved Pre-tax Rate of Return	10.95%	10.95%	10.95%	10.95%	10.95%	
			-	-	-	-	
19	Annualized Return on Rate Base	137,376,070	158,332,871	179,116,998	198,252,463	216,416,119	
20	**Operating Expenses**						
21	Annualized Depreciation	32,324,638	38,345,214	44,365,790	50,386,366	56,406,942	
22	Deferred Depreciation Amortization	476,414	570,405	664,396	758,387	852,378	
23	Deferred PISCC Amortization	1,380,285	1,651,501	1,921,637	2,191,492	2,475,616	
24	Annualized Property Tax Expense	31,343,668	37,043,268	42,577,008	47,967,983	53,188,169	
25	Deferred Property Tax Expense Amortization	211,040	261,934	313,179	364,760	416,697	
26	Operation & Maintenance Expense	150,000	150,000	150,000	150,000	150,000	
27	Operation & Maintenance Savings	(1,250,000)	(1,250,000)	(1,250,000)	(1,250,000)	(1,250,000)	
28	Total Revenue Requirement	202,012,114	235,105,193	267,859,008	298,821,450	328,655,921	1,332,453,686
29	Estimated Number of SGS Customers	1,414,010	1,420,829	1,427,531	1,433,829	1,439,836	
30	Estimated Number of GS Customers	40,469	40,505	40,543	40,577	40,611	
31	Estimated Number of LGS Customers	297	297	297	297	297	
32	Estimated Annual Cost Per SGS Customer	103.38	119.73	135.77	150.80	165.17	
33	Estimated Annual Cost Per GS Customer	1,102.68	1,282.18	1,459.44	1,626.78	1,787.70	
34	Estimated Annual Cost Per LGS Customer	37,749.74	43,933.80	50,054.46	55,840.37	61,415.50	
35	Estimated Cost Per Month Per SGS Customer	8.61	9.98	11.31	12.57	13.76	
36	Estimated Cost Per Month Per GS Customer	91.89	106.85	121.62	135.56	148.97	
37	Estimated Cost Per Month Per LGS Customer	3,145.81	3,661.15	4,171.21	4,653.36	5,117.96	
38	Estimated Cost Per Month SGS-AMRD	0.30	0.28	0.26	0.23	0.20	
39	Estimated Cost Per Month GS-AMRD	3.23	3.01	2.70	2.45	2.18	
40	Estimated Cost Per Month LGS-AMRD	-	-	-	-	-	
41	Estimated Cost Per Month SGS-HCSL	2.79	2.92	3.05	3.18	3.29	
42	Estimated Cost Per Month GS-HCSL	3.19	3.35	3.52	3.66	3.81	
43	Estimated Cost Per Month LGS-HCSL	-	-	-	-	-	
44	Cost Per Month SGS-Total	11.69	13.18	14.62	15.98	17.25	
45	Cost Per Month GS-Total	98.31	113.21	127.84	141.68	154.96	
46	Cost Per Month LGS-Total	3,145.81	3,661.15	4,171.21	4,653.36	5,117.96	**Average Annual Increase**
47	Annual Rate Increase*	1.49	1.48	1.44	1.36	1.28	1.410

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Columbia Gas of Ohio, Inc.
Infrastructure Tracker Mechanism
Estimated Rate Impact of Proposed IRP Program (2018-2022)

Line No.	Capital Expenditure Year / Revenue Recovery Time Period	2018 / 2019/20	2019 / 2020/21	2020 / 2021/22	2021 / 2022/23	2022 / 2023/24	
1	**Return on Investment**						
2	Plant In-Service						
3	Additions	1,507,929,539	1,724,992,725	1,942,055,911	2,159,119,097	2,376,182,283	
4	Retirements	(173,102,787)	(198,994,080)	(224,885,374)	(250,776,667)	(276,667,960)	
5	Total Plant In-Service	1,334,826,752	1,525,998,645	1,717,170,537	1,908,342,430	2,099,514,323	
6	Less: Accumulated Provision for Depreciaiton						
7	Depreciation Expense	137,274,755	174,800,204	217,549,336	265,522,149	318,718,644	
8	Cost of Removal	(56,422,236)	(64,984,532)	(73,546,829)	(82,109,125)	(90,671,421)	
9	Retirements	(173,102,787)	(198,994,080)	(224,885,374)	(250,776,667)	(276,667,960)	
10	Total Accumulated Provision for Depreciation	(92,250,268)	(89,178,408)	(80,882,867)	(67,363,643)	(48,620,737)	
11	Net Deferred Depreciation	18,729,599	21,428,257	24,056,341	26,612,171	29,095,748	
12	Net Regulatory Asset - PISCC	54,532,066	62,310,016	69,848,284	77,169,219	84,759,582	
13	Net Deferred Tax Balance - Property Taxes	5,601,670	6,577,260	7,536,314	8,477,107	9,399,934	
14	Net Deferred Tax Balance - PISCC	(19,086,223)	(21,808,506)	(24,446,900)	(27,009,227)	(29,665,854)	
15	Net Operating Loss due to Bonus Depreciation	85,580,217	106,778,362	112,181,904	112,131,457	112,131,457	
16	Deferred Taxes on Liberalized Depreciation	(330,057,613)	(370,488,504)	(394,402,350)	(420,141,013)	(447,527,276)	
17	Net Rate Base	1,242,376,736	1,419,973,938	1,592,826,997	1,752,945,788	1,906,328,651	
18	Approved Pre-tax Rate of Return	10.95%	10.95%	10.95%	10.95%	10.95%	
			-	-	-	-	
19	Annualized Return on Rate Base	136,040,253	155,487,146	174,414,556	191,947,564	208,742,987	
20	**Operating Expenses**						
21	Annualized Depreciation	30,932,244	35,560,426	40,188,608	44,816,791	49,444,973	
22	Deferred Depreciation Amortization	465,205	537,458	609,712	681,965	754,219	
23	Deferred PISCC Amortization	1,351,462	1,559,954	1,767,615	1,975,059	2,193,474	
24	Annualized Property Tax Expense	29,808,407	34,003,436	38,065,761	42,018,168	45,834,905	
25	Deferred Property Tax Expense Amortization	211,040	250,163	289,557	329,208	369,134	
26	Operation & Maintenance Expense	150,000	150,000	150,000	150,000	150,000	
27	Operation & Maintenance Savings	(2,000,000)	(2,000,000)	(2,000,000)	(2,000,000)	(2,000,000)	
28	Total Revenue Requirement	196,958,611	225,548,585	253,485,810	279,918,756	305,489,693	1,261,401,453
29	Estimated Number of SGS Customers	1,414,010	1,420,829	1,427,531	1,433,829	1,439,836	
30	Estimated Number of GS Customers	40,469	40,505	40,543	40,577	40,611	
31	Estimated Number of LGS Customers	297	297	297	297	297	
32	Estimated Annual Cost Per SGS Customer	100.79	114.87	128.49	141.26	153.53	
33	Estimated Annual Cost Per GS Customer	1,075.10	1,230.06	1,381.13	1,523.87	1,661.68	
34	Estimated Annual Cost Per LGS Customer	36,805.40	42,147.97	47,368.56	52,308.05	57,086.46	
35	Estimated Cost Per Month Per SGS Customer	8.40	9.57	10.71	11.77	12.79	
36	Estimated Cost Per Month Per GS Customer	89.59	102.51	115.09	126.99	138.47	
37	Estimated Cost Per Month Per LGS Customer	3,067.12	3,512.33	3,947.38	4,359.00	4,757.20	
38	Estimated Cost Per Month SGS-AMRD	0.29	0.27	0.26	0.23	0.20	
39	Estimated Cost Per Month GS-AMRD	3.23	3.01	2.70	2.45	2.18	
40	Estimated Cost Per Month LGS-AMRD	-	-	-	-	-	
41	Estimated Cost Per Month SGS-HCSL	2.79	2.92	3.05	3.18	3.29	
42	Estimated Cost Per Month GS-HCSL	3.19	3.35	3.52	3.66	3.81	
43	Estimated Cost Per Month LGS-HCSL	-	-	-	-	-	
44	Cost Per Month SGS-Total	11.48	12.76	14.02	15.18	16.28	
45	Cost Per Month GS-Total	96.01	108.86	121.31	133.10	144.46	
46	Cost Per Month LGS-Total	3,067.12	3,512.33	3,947.38	4,359.00	4,757.20	
							Average Annual Increase
47	Annual Rate Increase*	1.28	1.28	1.26	1.16	1.10	1.216

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Columbia Gas of Ohio, Inc.
Infrastructure Tracker Mechanism
Estimated Rate Impact of Proposed IRP Program (2018-2022)

Line	Capital Expenditure Year	2018	2019	2020	2021	2022	
No.	Revenue Recovery Time Period	2019/20	2020/21	2021/22	2022/23	2023/24	
1	**Return on Investment**						
2	Plant In-Service						
3	Additions	1,507,929,539	1,724,992,725	1,942,055,911	2,159,119,097	2,376,182,283	
4	Retirements	(173,102,787)	(198,994,080)	(224,885,374)	(250,776,667)	(276,667,960)	
5	Total Plant In-Service	1,334,826,752	1,525,998,645	1,717,170,537	1,908,342,430	2,099,514,323	
6	Less: Accumulated Provision for Depreciaiton						
7	Depreciation Expense	137,274,755	174,800,204	217,549,336	265,522,149	318,718,644	
8	Cost of Removal	(56,422,236)	(64,984,532)	(73,546,829)	(82,109,125)	(90,671,421)	
9	Retirements	(173,102,787)	(198,994,080)	(224,885,374)	(250,776,667)	(276,667,960)	
10	Total Accumulated Provision for Depreciation	(92,250,268)	(89,178,408)	(80,882,867)	(67,363,643)	(48,620,737)	
11	Net Deferred Depreciation	18,729,599	21,428,257	24,056,341	26,612,171	29,095,748	
12	Net Regulatory Asset - PISCC	54,532,066	62,310,016	69,848,284	77,169,219	84,759,582	
13	Net Deferred Tax Balance - Property Taxes	5,601,670	6,577,260	7,536,314	8,477,107	9,399,934	
14	Net Deferred Tax Balance - PISCC	(19,086,223)	(21,808,506)	(24,446,900)	(27,009,227)	(29,665,854)	
15	Net Operating Loss due to Bonus Depreciation	85,580,217	106,778,362	112,181,904	112,131,457	112,131,457	
16	Deferred Taxes on Liberalized Depreciation	(330,057,613)	(370,488,504)	(394,402,350)	(420,141,013)	(447,527,276)	
17	Net Rate Base	1,242,376,736	1,419,973,938	1,592,826,997	1,752,945,788	1,906,328,651	
18	Approved Pre-tax Rate of Return	10.95%	10.95%	10.95%	10.95%	10.95%	
			-	-	-	-	
19	Annualized Return on Rate Base	136,040,253	155,487,146	174,414,556	191,947,564	208,742,987	
20	**Operating Expenses**						
21	Annualized Depreciation	30,932,244	35,560,426	40,188,608	44,816,791	49,444,973	
22	Deferred Depreciation Amortization	465,205	537,458	609,712	681,965	754,219	
23	Deferred PISCC Amortization	1,351,462	1,559,954	1,767,615	1,975,059	2,193,474	
24	Annualized Property Tax Expense	29,808,407	34,003,436	38,065,761	42,018,168	45,834,905	
25	Deferred Property Tax Expense Amortization	211,040	250,163	289,557	329,208	369,134	
26	Operation & Maintenance Expense	150,000	150,000	150,000	150,000	150,000	
27	Operation & Maintenance Savings	(2,000,000)	(2,000,000)	(2,000,000)	(2,000,000)	(2,000,000)	
28	Total Revenue Requirement	196,958,611	225,548,585	253,485,810	279,918,756	305,489,693	1,261,401,453
29	Estimated Number of SGS Customers	1,414,010	1,420,829	1,427,531	1,433,829	1,439,836	
30	Estimated Number of GS Customers	40,469	40,505	40,543	40,577	40,611	
31	Estimated Number of LGS Customers	297	297	297	297	297	
32	Estimated Annual Cost Per SGS Customer	100.79	114.87	128.49	141.26	153.53	
33	Estimated Annual Cost Per GS Customer	1,075.10	1,230.06	1,381.13	1,523.87	1,661.68	
34	Estimated Annual Cost Per LGS Customer	36,805.40	42,147.97	47,368.56	52,308.05	57,086.46	
35	Estimated Cost Per Month Per SGS Customer	8.40	9.57	10.71	11.77	12.79	
36	Estimated Cost Per Month Per GS Customer	89.59	102.51	115.09	126.99	138.47	
37	Estimated Cost Per Month Per LGS Customer	3,067.12	3,512.33	3,947.38	4,359.00	4,757.20	
38	Estimated Cost Per Month SGS-AMRD	0.29	0.27	0.26	0.23	0.20	
39	Estimated Cost Per Month GS-AMRD	3.23	3.01	2.70	2.45	2.18	
40	Estimated Cost Per Month LGS-AMRD	-	-	-	-	-	
41	Estimated Cost Per Month SGS-HCSL	2.79	2.92	3.05	3.18	3.29	
42	Estimated Cost Per Month GS-HCSL	3.19	3.35	3.52	3.66	3.81	
43	Estimated Cost Per Month LGS-HCSL	-	-	-	-	-	
44	Cost Per Month SGS-Total	11.48	12.76	14.02	15.18	16.28	
45	Cost Per Month GS-Total	96.01	108.86	121.31	133.10	144.46	
46	Cost Per Month LGS-Total	3,067.12	3,512.33	3,947.38	4,359.00	4,757.20	**Average Annual Increase**
47	Annual Rate Increase*	1.28	1.28	1.26	1.16	1.10	1.216

*For estimation purposes, the estimated total capital investment for the five-year period was evenly spread over the five years. Columbia will manage the capital execution to ensure monthly SGS rates do not cumulatively exceed the approved maximum Rider IRP rates.

Columbia Gas of Ohio, Inc.
Infrastructure Tracker Mechanism
Estimated Rate Impact of Proposed IRP Program (2018-2022)

Line No.	Capital Expenditure Year / Revenue Recovery Time Period	2018 / 2019/20	2019 / 2020/21	2020 / 2021/22	2021 / 2022/23	2022 / 2023/24	
1	**Return on Investment**						
2	Plant In-Service						
3	Additions	1,507,929,539	1,724,992,725	1,942,055,911	2,159,119,097	2,376,182,283	
4	Retirements	(173,102,787)	(198,994,080)	(224,885,374)	(250,776,667)	(276,667,960)	
5	Total Plant In-Service	1,334,826,752	1,525,998,645	1,717,170,537	1,908,342,430	2,099,514,323	
6	Less: Accumulated Provision for Depreciaiton						
7	Depreciation Expense	137,274,755	174,800,204	217,549,336	265,522,149	318,718,644	
8	Cost of Removal	(56,422,236)	(64,984,532)	(73,546,829)	(82,109,125)	(90,671,421)	
9	Retirements	(173,102,787)	(198,994,080)	(224,885,374)	(250,776,667)	(276,667,960)	
10	Total Accumulated Provision for Depreciation	(92,250,268)	(89,178,408)	(80,882,867)	(67,363,643)	(48,620,737)	
11	Net Deferred Depreciation	18,729,599	21,428,257	24,056,341	26,612,171	29,095,748	
12	Net Regulatory Asset - PISCC	54,532,066	62,310,016	69,848,284	77,169,219	84,759,582	
13	Net Deferred Tax Balance - Property Taxes	5,601,670	6,577,260	7,536,314	8,477,107	9,399,934	
14	Net Deferred Tax Balance - PISCC	(19,086,223)	(21,808,506)	(24,446,900)	(27,009,227)	(29,665,854)	
15	Net Operating Loss due to Bonus Depreciation	85,580,217	106,778,362	112,181,904	112,131,457	112,131,457	
16	Deferred Taxes on Liberalized Depreciation	(330,057,613)	(370,488,504)	(394,402,350)	(420,141,013)	(447,527,276)	
17	Net Rate Base	1,242,376,736	1,419,973,938	1,592,826,997	1,752,945,788	1,906,328,651	
18	Approved Pre-tax Rate of Return	10.17%	10.17%	10.17%	10.17%	10.17%	
			-	-	-	-	
19	Annualized Return on Rate Base	126,349,714	144,411,350	161,990,506	178,274,587	193,873,624	
20	**Operating Expenses**						
21	Annualized Depreciation	30,932,244	35,560,426	40,188,608	44,816,791	49,444,973	
22	Deferred Depreciation Amortization	465,205	537,458	609,712	681,965	754,219	
23	Deferred PISCC Amortization	1,351,462	1,559,954	1,767,615	1,975,059	2,193,474	
24	Annualized Property Tax Expense	29,808,407	34,003,436	38,065,761	42,018,168	45,834,905	
25	Deferred Property Tax Expense Amortization	211,040	250,163	289,557	329,208	369,134	
26	Operation & Maintenance Expense	150,000	150,000	150,000	150,000	150,000	
27	Operation & Maintenance Savings	(2,000,000)	(2,000,000)	(2,000,000)	(2,000,000)	(2,000,000)	
28	Total Revenue Requirement	187,268,072	214,472,788	241,061,759	266,245,778	290,620,329	1,199,668,727
29	Estimated Number of SGS Customers	1,414,010	1,420,829	1,427,531	1,433,829	1,439,836	
30	Estimated Number of GS Customers	40,469	40,505	40,543	40,577	40,611	
31	Estimated Number of LGS Customers	297	297	297	297	297	
32	Estimated Annual Cost Per SGS Customer	95.83	109.23	122.19	134.36	146.05	
33	Estimated Annual Cost Per GS Customer	1,022.20	1,169.66	1,313.43	1,449.43	1,580.80	
34	Estimated Annual Cost Per LGS Customer	34,994.54	40,078.25	45,046.89	49,753.00	54,307.84	
35	Estimated Cost Per Month Per SGS Customer	7.99	9.10	10.18	11.20	12.17	
36	Estimated Cost Per Month Per GS Customer	85.18	97.47	109.45	120.79	131.73	
37	Estimated Cost Per Month Per LGS Customer	2,916.21	3,339.85	3,753.91	4,146.08	4,525.65	
38	Estimated Cost Per Month SGS-AMRD	0.29	0.27	0.26	0.23	0.20	
39	Estimated Cost Per Month GS-AMRD	3.23	3.01	2.70	2.45	2.18	
40	Estimated Cost Per Month LGS-AMRD	-	-	-	-	-	
41	Estimated Cost Per Month SGS-HCSL	2.79	2.92	3.05	3.18	3.29	
42	Estimated Cost Per Month GS-HCSL	3.19	3.35	3.52	3.66	3.81	
43	Estimated Cost Per Month LGS-HCSL	-	-	-	-	-	
44	Cost Per Month SGS-Total	11.07	12.29	13.49	14.61	15.66	
45	Cost Per Month GS-Total	91.60	103.83	115.67	126.90	137.72	
46	Cost Per Month LGS-Total	2,916.21	3,339.85	3,753.91	4,146.08	4,525.65	
							Average Annual Increase
47	Annual Rate Increase*	0.87	1.22	1.20	1.12	1.05	1.092

*For estimation purposes, the estimated total capital investment for the five-year period was evenly spread over the five years. Columbia will manage the capital execution to ensure monthly SGS rates do not cumulatively exceed the approved maximum Rider IRP rates.