OCC EXHIBIT NO._______

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

DIRECT TESTIMONY
OF
DANIEL E. O'NEILL

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

September 28, 2017

TABLE OF CONTENTS

LIST OF ATTACHMENTS

I. INTRODUCTION

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

A1. My name is Daniel E. O'Neill. I am the President of O'Neill Managing Consulting, LLC, a Georgia limited liability corporation founded by me in 2005 that specializes in providing utility industry management consulting services. The firm's address is 1820 Peachtree Road, Suite 709, Atlanta, GA 30309.

Q2. PLEASE DESCRIBE YOUR EDUCATION BACKGROUND AND PROFESSIONAL EXPERIENCE.

A2. I earned a Bachelor of Arts degree in Economics from the Louisiana State University in New Orleans, now called the University of New Orleans, in 1971. From 1971 to 1975 I studied for the Ph.D. in Economics at the Massachusetts Institute of Technology (MIT), leaving there with the dissertation underway. I completed the MIT Ph.D. in 1977 while I was teaching at the Georgia Institute of Technology in Atlanta. My dissertation was written under two professors: Franco Modigliani, who was later awarded the Novel prize, and Stanley Fischer, now co-chairman of the Federal Reserve.

Q3. PLEASE DESCRIBE YOUR WORK EXPERIENCE.

A3. After leaving Georgia Tech in 1979, I served as Manager of Marketing Research for Equifax, and then became their Director of Financial Analysis. In 1982, I joined a telecommunications utility, Contel, as Director of Financial Analysis, and was later promoted to Assistant Controller of Financial Analysis. In 1987, I joined Deloitte, Haskins & Sells, now part of the firm Deloitte & Touche, LLP, in their utilities consulting practice, where I continued to focus on utility financial performance, especially activity-based accounting, budgeting and reporting systems. Because Deloitte was the major auditor of electric and gas utilities in the United States, I focused on the electric and gas industries rather than the telecommunications industry.

In 1992, I joined Electronic Data Systems' newly acquired subsidiary, Energy Management Associates, to continue my utility consulting career, still focused on methods to improve financial performance, and with an increasing emphasis on the operational drivers of such performance, including work management, electric reliability and gas system integrity. I began to publish some of the results of my work, often co-authoring with clients, and now have authored over 50 relevant articles and conference papers.

In 1997, I joined Metzler & Associates, a management consultancy dedicated to utility industry issues, which has since become Navigant Consulting and now serves many industries. In 2005, I established my current firm, continuing to focus on utility asset management and reliability. At the same time I founded and began to chair a conference on Emergency Preparedness and Service Restoration for Utilities, which continues to serve the emergency management needs of the utility industry.

Q4. HAVE YOU PREVIOUSLY TESTIFIED BEFORE OTHER REGULATORY AGENCIES?

A4. Yes, I have testified before the Philadelphia Gas Commission, the Massachusetts Department of Public Utilities (including eight electric cases and six gas cases), and the Indiana Utility Regulatory Commission (an electric case). In addition, I have performed independent studies (without testimony) for the Public Utilities Commission of Ohio ("PUCO") (FirstEnergy reliability audit) and the Pennsylvania Public Utilities Commission (FirstEnergy reliability audits), the Massachusetts DPU, and the Indiana Utility Regulatory Commission. I have also assisted numerous investor-owned utilities in preparing for and responding to regulatory investigations or audits.

II. PURPOSE OF TESTIMONY

Q5. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A5. I am appearing on behalf of Office of the Ohio Consumers' Counsel ("OCC") in this case. The purpose of this testimony is to explain and support OCC's position opposing the Joint Stipulation and Recommendation ("Settlement") filed by

Columbia on August 18, 2017.[1] Other OCC witnesses will address additional issues explaining OCC's opposition to the Settlement and Columbia's Application[2] such as those identified in OCC's Objections to the Staff Report and Application filed on August 14, 2017.[3]

III. SUMMARY OF THE APPLICATION AND SETTLEMENT

Q6. PLEASE PROVIDE A SUMMARY OF THE APPLICATION IN THIS PROCEEDING.

A6. Columbia's Application in this proceeding requested an extension of its Infrastructure Replacement Program ("IRP"), and associated rider, for another five years (from 2018 through 2022), with almost no changes in the terms of the program from the modifications made in the 2012 Settlement in PUCO Case No. 11-5515-GA-ALT ("2012 Settlement").[4] The only substantive changes include a drastic increase in the Rider IRP monthly rate cap for Small General Service ("SGS") customers (including residential customers), from the current cap of

[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 to Extend and Increase Its Infrastructure Replacement Program,* Case No. 16-2422-GA-ALT, Application (February 27, 2017).

[3] 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, OCC Objections to Staff Report and Application (August 14, 2017) ("OCC's Objections").

[4] *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. 11-5515-GA-ALT, Joint Stipulation and Recommendation (September 26, 2012) ("2012 Settlement").

$1.00 per month each year to $1.30 per month each year. The Application did not change the minimum amount of O&M savings that Columbia is required to pass back to customers every year ($1.25 Million) that was ordered in the 2012 Settlement.

Q7. PLEASE PROVIDE A SUMMARY OF THE SETTLEMENT IN THIS PROCEEDING.

A7. The Settlement responds to the Staff Report's assertion that the guaranteed minimum O&M savings should be raised. The PUCO Staff ("Staff") had suggested a collaborative study to determine the reasons why the actual O&M savings were not higher than the guaranteed minimum of $1.25 million. The Settlement, however avoids the study, instead proposing a new, higher guaranteed minimum for O&M savings as follows: $2.00 million for the first two years, $2.25 million for the middle year (2020), and $2.50 million for the last two years.

Similarly, the Settlement responds to the Staff Report's recommendation that the annual increase in the monthly rate cap be frozen at $1.00 for three years (2018, 2018, 2020) and then increased to $1.10 for the last two years of the extension (2021 and 2022), by instead agreeing that the annual increase in the monthly cap should be increased from the current $1.00 per year to $1.15 for the first two years (2018 and 2019), $1.20 for 2020, and $1.25 for the last two years (2021 and 2022).

Notably the Settlement fails to respond to OCC's numerous objections to the Staff Report.

IV. EVALUATION OF THE SETTLEMENT

Q8. WHAT IS THE PUCO'S STANDARD OF REVIEW FOR SETTLEMENTS?

A8. I understand that the PUCO typically evaluates a proposed settlement using a three-prong test.[5] 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?

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.

[5] 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).

Q9. WHAT ARE YOUR PRIMARY CONCLUSIONS AND RECOMMENDATIONS?

A9. I conclude that the Settlement, as a package, does not satisfy the three-part test considered by the PUCO for approval and should be rejected.

I do not believe that the Settlement satisfies the first prong. However, the first prong of the three-part settlement test is discussed more in other OCC testimony.

Second, the Settlement, as a whole, benefits neither customers nor the public interest.

And, the Settlement, as a package, violates important regulatory principles and practices.

In general, the Settlement, among other problems, proposes an unjust and unreasonable increase of costs to customers with no demonstration of corresponding benefits (leak reduction) over the term of the extension. Regulatory practice requires that the burden of proof that investments are prudent and used and useful belongs to the utility requesting the rate increase—not the intervening parties.

Q10. WHAT ARE YOUR GENERAL OBJECTIONS TO THE SETTLEMENT FILED IN THIS CASE?

A10. It is important to make clear that I do not oppose, and in fact am in favor of, pipeline safety measures. I do, however, object to the Infrastructure Replacement Program ("IRP") as proposed in the Settlement.

Not enough guaranteed O&M savings for customers

First, as described in the Staff Report, the O&M savings that the program has generated so far are far too low. The guaranteed minimum O&M savings should be increased to reflect the pipe already replaced and planned to be replaced over the next five-year period. Also, the O&M savings should be higher based on the performance of other similar programs. While the Settlement does increase the guaranteed minimum O&M savings somewhat, I believe that the guaranteed minimum O&M savings should be much higher, rising to at least $3.0 million by 2022.

Too much non-priority pipeline replacement

Second, the additional "non-priority" pipe that the Utility has replaced under the IRP in addition to the originally targeted bare steel and cast iron adds another 40 percent to the required investment. In my opinion this additional amount is higher than what would be deemed reasonable for cost effectiveness. It is not just and reasonable for these extra costs to be passed on to consumers especially because there is no evidence that it is warranted.

Unnecessary increases in caps that customers pay

Third, I object to the portion of the Settlement that grants Columbia an increase in the cap on the monthly charge to customers under the IRP program. Instead, to benefit consumers and avoid additional unnecessary charges, the current $10.20 per month rate cap charged to customers should be allowed to increase by no more than the $1.00 in each year of the program, or less, as I detail below.

Lack of study on cost-effectiveness of program that customers pay

Finally, the Utility has no commitment to monitor or manage the cost per leak avoided. (The Utility only commits to a 25-year replacement of the targeted pipe.) This does not serve the public interest in terms of providing greater safety at a reasonable cost, nor does it accord with regulatory practice of ensuring efficiency and cost-effectiveness of investments that lead to recovery through rates. Therefore, in light of this and also in light of the unusually low savings generated from the program itself (apart from the guarantee), I believe, as Staff originally suggested in its report,[6] that there should be a collaborative study, or a

[6] The Staff Report recommended a study focused solely on the reasons for the low O&M savings. I believe, as I detail below, the problem may be deeper, and that the scope of the study should be the cost effectiveness of the program, including why leaks have not declined further and therefore why O&M savings are not greater. 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, Staff Report at 9 (July 10, 2017) ("Staff Report").

third-party audit, of the program to investigate the reasons for the program's lack of cost effectiveness. As an ongoing aid to that end, I also recommend that the Utility be required to report certain metrics that relate to program efficiency and effectiveness.

Q11. PLEASE ELABORATE ON YOUR OPINION WITH REGARD TO THE FIRST REASON: THAT THE SETTLEMENT IS NOT IN THE PUBLIC INTEREST DUE TO THE LOW LEVEL OF O&M SAVINGS.

A11. As noted in the Staff Report, the O&M savings generated by the IRP have been very low. In fact, the O&M savings have been lower than the guaranteed minimum O&M of $1.25 million each year that have been figured into the revenue requirement.[7] As the Staff Report explains, the previously agreed upon guaranteed minimum O&M savings should at least be adjusted to reflect five more years of pipe replacement, which under normal circumstances would have been expected to increase the O&M savings accordingly.

A major part of O&M expenses is the repair of leaks. The major source of leaks for Columbia, and for other gas distribution utilities with substantial amounts of bare steel and cast iron pipe, are the leaks on priority pipe. The leaks on Columbia's main lines have decreased from 2012 to 2016.[8] As priority pipe is replaced with other, newer pipe, the leaks can be expected to decline dramatically.

---

[7] Staff Report at 8-9.

[8] See OCC INTs 24, 26, and 28 (Attachments DEO-1, DEO-2, and DEO-3).

And as the amount of leaks decline, the amount of leak repair expense should also decline. Replacing another five years' worth of pipe should be expected to produce an additional five years' worth of savings on top of what the previous five years accomplished.

As stated in the Staff Report, Columbia has consistently argued that patience is needed as O&M savings should increase as its program matures.[9] Yet, as the Staff Report notes, the amount of O&M savings for 2013 to 2017 is still below the minimum amount of $1.25 million set back in 2012. The additional patience requested by Columbia is not warranted by recent experience.

In addition, as the Staff Report also details, other companies have achieved greater O&M savings with very similar programs. For example, Dominion East Ohio Gas's similar program has realized $3.2 million in O&M savings per year, compared to Columbia's guarantee of $1.25 million.[10] And, Duke Energy Ohio Inc.'s ("Duke") similar program, which is only 33 percent complete, has already achieved $1.7 million in annual O&M savings, and is likely to save more as the program reaches the same level of completion as Columbia's 60 percent completion (by 2022).

[9] See Staff Report at 9.

[10] See Staff Report at 8-9.

Yet, the Settlement only increases the guaranteed O&M savings to $2.0 million in 2018 and $2.5 million by 2022. I find this to be a one sided, inadequate compromise. It suggests that the Utility's guarantee for the second five-year period (2013-2017) should merely be doubled ($1.25 to $2.50 million), despite the evidence that the earlier guarantee was inadequate compared to the experience of comparable programs.

As explained above, I believe the guaranteed minimum O&M savings should be at least $3.0 million by 2022, if not more, based on what should have been the reduction due to reduced leaks and inspection expenses alone from the Accelerated Main Replacement Program ("AMRP") component of the IRP. Therefore, the Settlement is not in the public interest because it will unreasonably increase customer utility bills.

Q12. PLEASE ELABORATE ON YOUR OPINION WITH REGARD TO THE SECOND REASON: THAT THE ADDITIONAL NON-PRIORITY PIPE THAT THE UTILITY HAS REPLACED IN ADDITION TO THE ORIGINALLY TARGETED BARE STEEL AND CAST IRON HAS BEEN EXCESSIVE, AND, THEREFORE, NOT IN THE PUBLIC INTEREST.

A12. The originally targeted pipe for the AMRP was approximately 4,100 miles of mostly bare steel and cast or wrought iron.[11] Part of the 2012 Settlement allowed for recovery of some "non-priority" pipe through the AMRP rider. This was based on it being 'economic' to replace some interspersed segments of non-priority pipe that were part of the same replacement project.[12] There was also some acknowledgement of replacement of other leak-prone pipe, e.g., Aldyl-A plastic, provided it did not amount to more than five percent of the project miles.

The Utility, in projecting its needs for replacement miles in the next five years, appears to be using a factor of 1.4 total miles to priority miles, or an extra 40 percent,[13] that is, 40 percent of the pipe that Columbia is proposing to replace in the next five years is "non-priority" pipe that was added to the IRP in 2012.

[11] The originally targeted 4,050 miles included 155 miles of coated but inadequately protected steel pipe. See Staff Report, n.5. It is clear, however, that it did not include other non-priority pipe. The 2012 Settlement (Case No. 11-5515-GA-ALT) that allowed for recovery through the AMRP rider of some non-priority pipe did not change the requirement that the original 4,050 (rounded to 4,100) miles be replaced in 25 years, or a rate of 164 miles per year, and that a proportionate amount, 1,640 miles, should be replaced by the end of 2017, the end of the first ten years of the program.

[12] See Case No. 11-5515-GA-ALT, Joint Stipulation and Recommendation (September 26, 2012).

[13] The average total miles replaced from 2013-2016 was 269 miles. The average priority miles replaced over the same period was 192. The ratio of 269 to 192 is 1.4. Also, see OCC RPD Set 6, RPD 20, Attachment A, page 2 (Attachment DEO-4), which shows that the expected miles of replacement for all pipe is 229, which, relative to the expected 164 miles of priority pipe is a ratio of 1.4, or 40 percent higher.

It would have been difficult to know in 2012 that the "non-priority" pipe would become such a large part of the IRP in the future. Now is the time for the PUCO to reevaluate the IRP and scale back the replacement of "non-priority" pipe in order to decrease the cost of the program to consumers. Scaling back the amount of "non-priority" pipe will not impact safety because the "non-priority" pipe is not part of the original priority pipe that the PUCO approved for replacement due to its safety risks. The "non-priority" pipe was added to the IRP in 2012 for economic reasons—not safety reasons. Based on my experience with other programs and what appeared to be the intent of the 2012 Settlement, the current amount of non-priority pipe being replaced seems excessive and not in the public interest because it will unreasonably increase customer utility bills. This may well be a factor in the next reason I give below.

Q13. PLEASE ELABORATE ON YOUR OPINION WITH REGARD TO THE THIRD REASON: THAT THE HIGH COST PER LEAK AVOIDED IMPLIES THAT THE SETTLEMENT IS NOT IN THE PUBLIC INTEREST AND VIOLATES REGULATORY PRINCIPLES AND PRACTICE.

A13. The most basic test of cost effectiveness for a priority pipe replacement program is the cost per avoided leak. When the public is asked to fund a program to improve its safety, it should be fully informed and aware of what it is giving its hard-earned money for. The cost per leak avoided should be in line with some sense of the benefit of avoiding another leak.

Yet the Columbia IRP seems to have no such requirement. In an OCC request for admission that requested Columbia to "Admit that Columbia has no analysis that projects the future level of leaks based on alternative levels of replacement of leak-prone mains and services," Columbia replied: "Admit. Columbia has a twenty-five year program to replace its Priority Pipe and it is this commitment that sets the appropriate level of pipe replacement."[14] From this admission it would appear that the Utility does not feel bound to show any specific improvement in leaks as a result of the program, i.e., the customer is 'buying a pig in a poke.' I believe this is a violation of accepted regulatory practice because a pipeline replacement program is generally only continued if it proves to be sufficiently efficient and effective. Columbia has not demonstrated that the IRP has been cost effective or will continue to be cost effective. Approving the IRP is also not in the public interest because it would unreasonably increase customer utility bills without first producing benefits for customers.

Q14. DO YOU PROPOSE A REMEDY FOR THIS SITUATION?

A14. Yes. I believe it is appropriate that the PUCO order that a collaborative study or third-party audit of the IRP program be undertaken by Staff or an independent auditor. The audit would investigate the IRP to date to determine whether the program is being implemented effectively and efficiently. Specifically, the audit would aid the PUCO in determining whether the IRP is efficiently and effectively

[14] OCC Set 3, RFA 6 (Attachment DEO-5).

reducing leaks, improving safety, and minimizing costs per mile and costs per leak avoided. Furthermore, I recommend that Columbia maintain a record of the performance of the IRP over the next five-year term. This record should, at a minimum, include:

a. 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 onward, the five-year history of leaks (by grade and year) on the mains that were replaced or retired under that job order);

b. Leak history after replacement (i.e., for each Job Order under each Project ID in each year of the program from 2018 on ward, the subsequent leaks [by grade and year] on the mains that were replaced or retired under that job order);

c. 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); and

d. Variance explanations (i.e., provide an explanation of what factors might have led to the high cost or low leak rate 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 dollar amount [e.g., $1,000,000 per average leak]).

Q15. HOW SHOULD THE PUCO DETERMINE THE COST-EFFECTIVENESS OF THE COLUMBIA AMRP SO FAR?

Q15. In determining the cost per avoided leak, the numerator is fairly straightforward: the capital cost of the pipe replacement, including all cost of all equipment (mains, services, valves, and meters) replaced or abandoned under the aegis of the program. The denominator can be estimated by a number of different ways: either by the recent history of the leaks on the pipe replaced, or perhaps with an additional increment for how those leaks might have been expected to grow over time or from the overall impact on annual leaks. For example, if replacing a mile of pipe were to cost $1 million dollars, and the pipe in question had historically leaked at an average annual rate of one per mile (a somewhat typical rate for vintage bare steel and cast iron pipe), then the cost per avoided annual leak would be $1,000,000. If the actual historical leak rate were lower, say .85 annual leaks per mile, but one assumed that they were growing at say, five percent per year, then over a five-year program the cost per avoided leak might be assumed to again be approximately $1,000,000.

Q16. WHAT HAS COLUMBIA EXPERIENCED IN ITS AMRP?

A16. Much worse results. Columbia's cost per mile has approached $1,000,000, depending on whether you count per mile of originally targeted priority pipe (as I would recommend) or you include the ancillary pipe, and has averaged over $850,000 per mile[15] in the six years after 2010 when the program ramped up to a level averaging 195 miles per year. Over the same period, the number of main leaks has bounced around an average of 3,650 leaks per year,[16] or only about 150 leaks less than the 3,796 leaks in 2010 or even the 3,852 leaks in 2007 before the program began. That translates to a cost per avoided leak of $6,630,000 per annual leak avoided.[17] In other words, over those six years, Columbia spent almost a billion dollars to reduce the annual number of leaks by 150 per year, or about four percent.

The benefits that customers have received under the IRP do not outweigh the costs. The customers' interest deserves a better accounting for the cost effectiveness of the IRP, and, in my experience, regulatory practice typically demands such accountability.

---

[15] See OCC Set 6, RPD 20, page 2, but with cost per mile computed as cost per priority mile rather than per total miles replaced (Attachment DEO-4).

[16] See OCC Set 2, INT 2 Attachment A, row 2, columns F through K (2011-2016) (Attachment DEO-6).

[17] Six years x 195 miles per year x $850,000 per mile divided by 150 annual leaks.

Q17. PLEASE ELABORATE ON YOUR OPINION WITH REGARD TO THE FOURTH REASON: THAT THE SETTLEMENT'S ANNUAL INCREASES IN THE MONTHLY IRP RATE CAP THAT CUSTOMERS PAY ARE NOT WARRANTED AND THEREFORE NOT IN THE PUBLIC INTEREST.

A17. In the 2012 Settlement, the annual increases in the monthly rate cap for residential customers was limited to $1.00, which raised the cap from $5.20 in 2012 to 10.20 in 2017. Although the actual recovery so far has been below the caps,[18] Columbia projects them to be higher in the next five years and has asked for the caps to be raised more than the annual increase of $1.00 would allow. In the application, Columbia has proposed that the caps be raised by $1.30 per year, based on a rate of inflation of 6.47 percent per year, which it says has been the historical rate of increase in its cost per mile of priority pipe in the period 2013-2016.[19] The Staff Report objected to this request, and proposed a freeze for three years, and a ten percent increase in the last two years ($1.10 per year).[20] The Settlement, in turn, proposes annual increases of the monthly rate cap for 2018-2022 period equal to $1.15, $1.15, $1.20, $1.25, and $1.25, respectively. I believe this is completely unwarranted and that the existing annual increase of $1.00 per year in the monthly rate cap is more than adequate and should be maintained or decreased.

[18] 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, Direct Testimony of Melissa Thompson at 4 (February 27, 2012).

[19] 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, Direct Testimony of Diana Beil, Attachment DMB-1 (February 27, 2017).

[20] See Staff Report at 9-12.

Q18. WHAT EVIDENCE DO YOU HAVE THAT THE EXISTING ANNUAL INCREASE IN THE MONTHLY RATE CAP THAT CUSTOMERS PAY IS MORE THAN ADEQUATE, AND THEREFORE THAT RAISING THE CAP AT THIS TIME IS NOT IN THE PUBLIC INTEREST?

A18. I have studied the potential impact of various aspects of the provisions in the Settlement, including those that leave unchanged certain parameters in the Application. I also studied the Staff work papers that were used to develop the Staff Report, in particular the worksheet on the Estimated Rate Impact of Proposed IRP 2018-2022 under the low end cost per mile.[21] Columbia states that it does not have a similar excel-type work paper showing the revenue requirements for the Settlement.[22] Some of the key drivers are the number of miles replaced, the rate of inflation in cost per mile, the O&M savings, the allowed rate of return, and the treatment of the investment in Hazardous Customer Service Lines. I find that under a reasonable set of values for these assumptions, the revenue requirement as it would translate to the monthly rate for the SGS customer need only increase by an amount that would be less than the $1.00 per year specified in the 2012 Settlement.

[21] See Staff Work Paper (Attachment DEO-7).

[22] See Columbia supplemental response to OCC Set 6, RPD 20 (Attachment DEO-8).

Q19. WHAT ARE SOME OF THE VARIATIONS IN THOSE ASSUMPTIONS THAT WOULD PRODUCE SUCH A RESULT?

A19. First, the number of total miles replaced could vary. In Columbia's response to OCC RPD No. 20, Columbia assumed that the total miles to be replaced each year would be 229 miles.[23] This was based on an assumption that there would be 164 priority miles per year replaced, and that the non-priority miles would include an additional 40 percent. I argued above that the amount of non-priority pipe should not add up to 40 percent of the priority pipe. A lower figure, such as 200 miles, would yield a much smaller capital cost and therefore lower revenue requirement and rate impact on consumers. But even if we use a figure of 229 miles, other changes in the assumptions could still lead to an increase of less than $1.00 per year for the IRP rate cap.

Q20. WHAT WOULD BE SOME OF THOSE OTHER CHANGES IN ASSUMPTIONS?

A20. As I have mentioned above, I believe the O&M savings should reach at least $3 million per year. Every dollar of extra O&M savings reduces the revenue requirement dollar for dollar. And every million dollars of lower revenue requirement reduces the SGS customer bill by about $.06 per month.[24]

[23] See OCC Set 6, RPD 20, Attach. A, page 2 (Attachment DEO-4).

[24] In the rate impact calculation, the revenue requirement is divided by the number of SGS customers (approximately 1.4 million customers), and then divided by the number of months in the year, 12. Hence every $1 million reduction in the revenue requirement results in a reduction of rate impact of $1 million / 1.4 million / 12, or $.06 per month.

Additionally, in the testimony of OCC witness Dr. Daniel J. Duann, OCC has argued for a lower pre-tax rate of return on investment, which would also lower the revenue requirement, depending on how much lower and assuming it applies to the entire IRP investment and not just post-2017 additions.

One of the largest factors to consider is the rate of inflation in cost per mile. Columbia proposed in its Application, and the Staff Report accepts, a 6.47 percent increase per year, based upon the annual increase in the cost per mile from 2013-2016. The Settlement appears to use a 7.2 percent rate of inflation.[25] I believe that costs should not, and likely will not, increase by one third as much. Given that the annual additions for the AMRP are in the $200 million range, depending on assumptions about mileage and cost per mile, every percentage point decrease in inflation yields approximately $6 million less investment per year (on average, over five years).[26] At an ROI of approximately 10 percent, that yields $0.6 million less revenue requirement (although the exact figure is complicated by depreciation and taxes as well), and therefore $0.036 less impact on the monthly SGS rate (.6 x .06). So, as I explain below, if a two percent rate of inflation is substituted for the 6.47 percent used in the Application and the Staff Report work papers (or even more so for the 7.2 percent used in the Settlement), it could lower

[25] See OCC Set 6, RPD 20, Attach. A, page 2 (Attachment DEO-4).

[26] Each year, the inflation of the previous year is carried forward in the new cost per mile, so that in five years one could expect to see a 1 percent increase per year cause increases in the cost of each subsequent year in the amount of 1, 2, 3, 4, and 5 percent (before compounding, which adds a little), or an average of about 3 percent, which times $200 million is $6 million.

the SGS rate by approximately $0.16 on average (4.47 x .036), a figure that could vary with other assumptions.

In short, the combination of fewer non-priority miles replaced, extra O&M savings, lower ROI, and lower inflation is likely to completely offset the need for the increase of up to an additional $0.25 per year in the monthly SGS rate cap proposed in the Settlement.

Q21. WHAT EVIDENCE DO YOU HAVE THAT THE RATE OF INFLATION IN THE COST PER MILE WOULD BE CLOSER TO 2.0 PERCENT THAN THE 6.47 PERCENT IMPLIED IN THE APPLICATION OR THE 7.2 PERCENT IN THE SETTLEMENT?

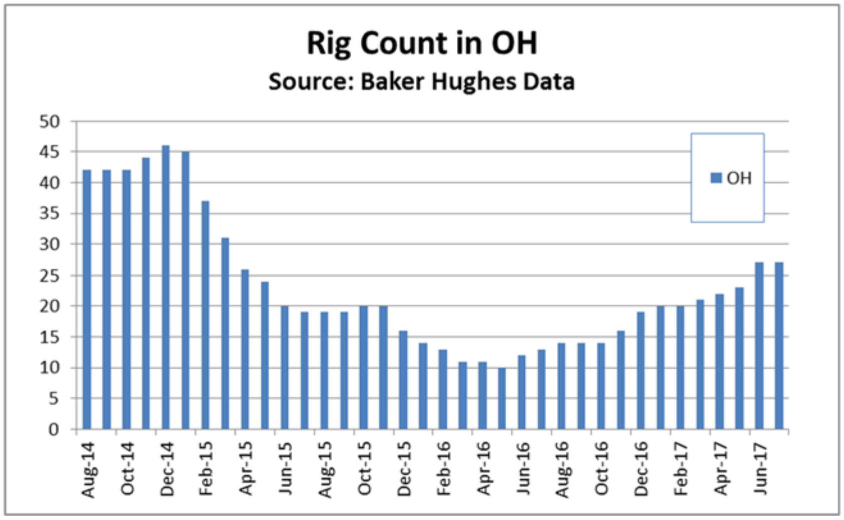
A21. There are multiple sources of evidence that point to that conclusion. I will cite three: the decline in the demand for pipe construction resources since 2015, the trend in the Handy-Whitman Gas Construction Cost index for the North Central Region, and the Federal Reserve's target for inflation for the next five years.

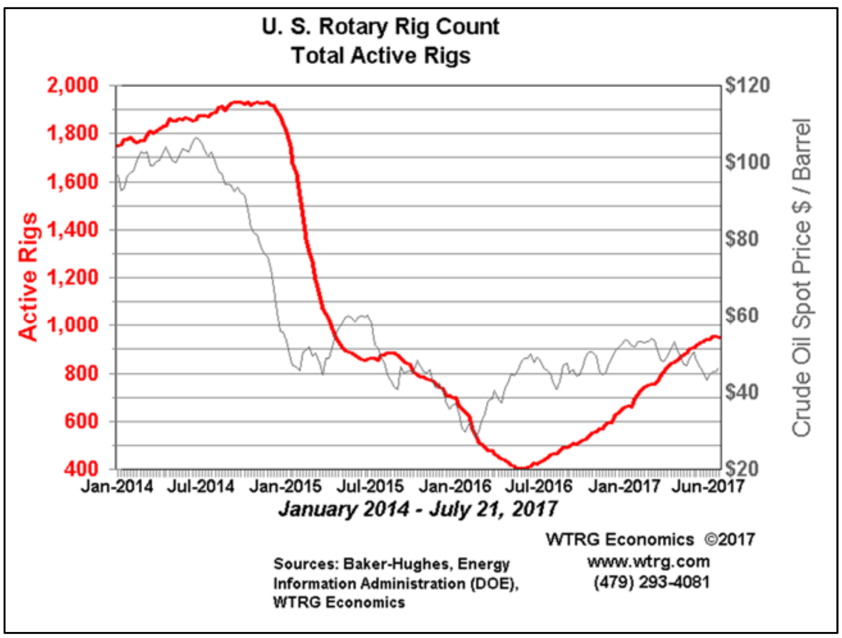
Q22. ***WHAT IS THE EVIDENCE FROM YOUR FIRST SOURCE REGARDING THE DEMAND FOR PIPE CONSTRUCTION RESOURCES?***

A22. The pace of oil and gas exploration in the Midwest (and elsewhere) has definitely declined, as reported in the August 19, 2015 Wall Street Journal[27] and demonstrated in the graphs below[28] showing the dramatic reduction in rig count in the U.S. in the last 18 months, and how this also resulted in a 78 percent reduction in the rig count in Ohio from the peak in December of 2014 through May of 2016. While the rig count in Ohio has recovered some since that trough, it is still over 40 percent below its earlier peak. The chart for the total US also shows the price of oil (the gray line on the chart), and how the rig count (the red line) directly reacts, with a lag of a few months, to the price of oil, and that even a rise of the price of oil to $60 per barrel from $40 per barrel was not a significant stimulus to return the rig count to its prior peak levels. It would appear that it would take the return of near-$100 per barrel oil pricing (which is not a reasonable forecast at this time) to return the rig count to 2012-2014 levels.

[27] Wall Street Journal, "Energy Slowdown Hits One Town Hard," August 19, 2015 about Waynesburg, PA, which cites a general slowdown through the area, viz., "The economic pain from lower oil and gas prices is spreading to small towns and businesses across Pennsylvania and parts of Ohio and West Virginia that had been riding a wave of prosperity from the natural-gas shale boom" http://www.wsj.com/articles/energy-slowdown-hits-one-town-hard-1440008970. (Attachment DEO-9.)

[28] Data are from the Baker Hughes reports http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-reportsother and http://www.energyeconomist.com/a6257783p/exploration/rotaryrigweekly.html. (Attachment DEO-10.)

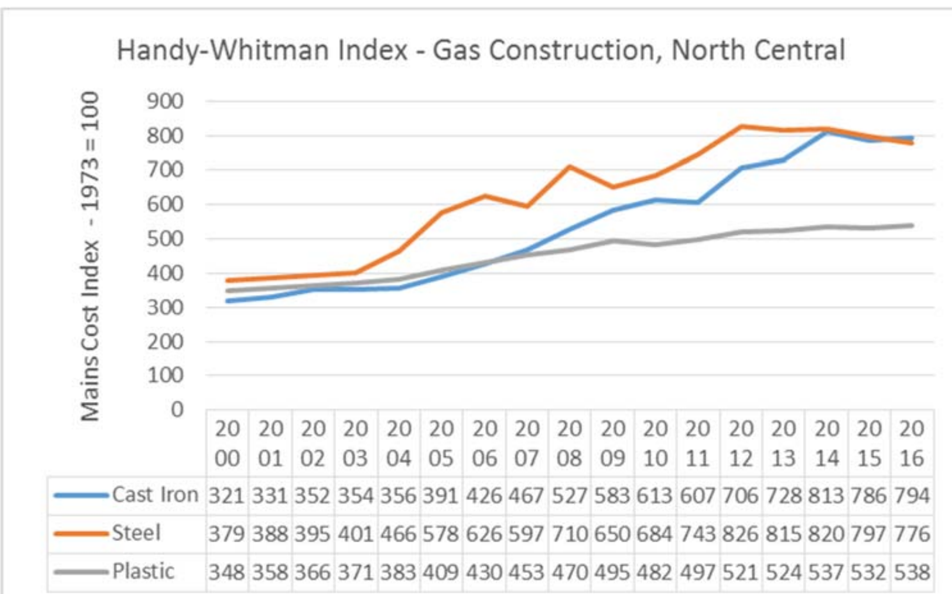




Also, a properly managed program should reap the benefits of such a less-contested labor market. It could even happen that Columbia could replace at a lower cost per mile than it has recently experienced, and so well within the existing cap of $10.20 per month. If that were to happen, it would certainly be a better use of the customers' money to fund the increase in the jobs and economic activity at more economic rates, as opposed to padding the pockets of those who might be profiteering from a temporary shortage of resources.

Q23. ***WHAT IS THE EVIDENCE FROM YOUR SECOND SOURCE REGARDING THE CONSTRUCTION COST INDEX?***

A23. The OCC has obtained data on the recent trend in the cost of gas pipe construction. The source of the data is the well-known and highly regarded Handy-Whitman index, specifically the one for Gas Distribution construction in the North Central Region, which includes Ohio and neighboring states. The chart[29] below shows the values for three different material types:



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Cast Iron	321	331	352	354	356	391	426	467	527	583	613	607	706	728	813	786	794
Steel	379	388	395	401	466	578	626	597	710	650	684	743	826	815	820	797	776
Plastic	348	358	366	371	383	409	430	453	470	495	482	497	521	524	537	532	538

[29] Handy-Whitman Index of Public Utility Construction Costs - Bulletin No. 185 (1912 to January 1, 2017), pages G-3-8 and G-3-9, Gas Distribution, lines 43-45. (Attachment DEO-11.)

Clearly, there was a strong upward trend, especially in steel and cast iron, through 2012. Yet, after 2012 the trend is <u>downward</u> for steel and likewise for cast iron after 2014. I believe this is due in part to the earlier evidence that in 2015 the demand for pipe construction due to oil and gas exploration and production dropped precipitously. Moreover, I see no developments in the near future that are likely to reverse this trend.

Q24. HOW IS THIS EVIDENCE CONSISTENT WITH THE EXPERIENCE OF COLUMBIA IN THE 2013-2016 PERIOD?

A24. It supports Columbia's finding that the 2013-2016 period showed less inflation than the 2008-2012 period, and that the year 2015 saw a significant decline in the rate of inflation in gas construction costs. But it would appear that Columbia did not manage costs to be in line with utility gas construction over the period 2008-2016, and it certainly does not support Columbia's contention that Columbia's 2013-2016 rate of inflation should be extended into the next five years. Rather, we would expect that if Columbia can manage costs comparably to the rest of the industry in the region, it can expect to see a definite flattening of the rate of inflation in IRP construction costs.

Q25. WHAT IS THE EVIDENCE FROM YOUR THIRD SOURCE REGARDING THE FEDERAL RESERVE BOARD'S TARGET RATE OF INFLATION?

A25. The Federal Open Market Committee of the Federal Reserve Board ("Board"), the governing body of the Federal Reserve Bank, meets monthly and publishes the results of its meetings with a two-month delay. The minutes of the December, 2016 meeting were particularly watched for their implications for the coming year and beyond. In that meeting the Board re-iterated its oft-stated goal of achieving and maintaining an overall rate of inflation of two percent. The relevant text from the December 2016 meeting was:

> The Committee expects that, with gradual adjustments in the stance of monetary policy, economic activity will expand at a moderate pace, labor market conditions will strengthen somewhat further, and inflation will rise to two percent over the medium term.[30]

The press release noted that the current rate of inflation was somewhat less than two percent, but the Board expected a slight rise over the course of 2017 to the two percent level, from which the Board hoped to mitigate any further rise, presumably by raising gradually the target interest rates, an intention they have stated on numerous occasions, and which is discussed in that press release. Moreover, other sources indicate that the Board is coordinating its monetary policy with those of other major countries so as to achieve its desired result. In light of this knowledge, it seems reasonable to conclude that a forecast of two percent inflation is more reasonable as a forecast than a mechanical projection of

[30] Minutes of the Federal Open Market Committee, page 11, December 13-14, 2016 https://www.federalreserve.gov/monetarypolicy/files/fomcminutes20161214.pdf.

Columbia's recent trend. Moreover, it would be advisable for Columbia to use information such as this in its negotiations with vendors whose contracts are due to expire on December 31, 2020.

Q26. DO YOU RECOMMEND THAT THE PUCO ADOPT THE SETTLEMENT FILED IN THIS CASE ON AUGUST 18, 2017?

A26. I do not believe that the PUCO should approve the Settlement because, as a package, it does not meet the PUCO's specific criteria to approve a Settlement. The Settlement it is not in the public interest in multiple ways as follows: insufficient guaranteed O&M savings, too many non-priority miles, and an unwarranted increase in the rate caps for SGS customers. Finally, it violates accepted regulatory practice in that it does not require the Utility to make a significant commitment to cost-effective reduction of leaks to achieve program benefits.

V. CONCLUSION

Q27. DOES THIS CONCLUDE YOUR TESTIMONY?

A27. Yes, however, I reserve the right to incorporate new information that may subsequently become available. I also reserve the right to supplement my testimony in the event that the Utility, Staff, or other parties submit new or corrected information related to this proceeding.

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Direct Testimony of Daniel E. O'Neill on Behalf of the Office of the Ohio Consumers' Counsel* was served via electronic transmission to the persons listed below this 28th day September 2017.

/s/ Kevin Moore
Kevin Moore
Assistant Consumers' Counsel

SERVICE LIST

William.wright@ohioattorneygeneral.gov
Steven.beeler@ohioattorneygeneral.gov
cmooney@ohiopartners.org
egallon@porterwright.com

sseiple@nisource.com
josephclark@nisource.com
fdarr@mwncmh.com
mpritchard@mwncmh.com

Attorney Examiner:
Greta.see@puc.state.oh.us

PUCO Case No. 16-2422-GA-ALT
OCC Interrogatories Set 2 No. 24
Respondent: Donald P. Ayers
As to Objections: Eric B. Gallon

**COLUMBIA GAS OF OHIO, INC.
RESPONSE TO THE OFFICE OF THE OHIO
CONSUMERS' COUNSEL'S INTERROGATORIES
DATED JUNE 2, 2017**

INT-24.

Referring to the classification for leaks indicators as outlined in Ohio Adm. Code 4901:1-16-04(H)(1), how many leaks on main lines were classified as grade-one classification in the last five years?

RESPONSE:

Columbia objects to this Interrogatory because it is ambiguous and overbroad. OCC's Interrogatory is not limited to the areas in which Columbia provides service. Columbia's response provides information regarding leaks on main lines through which Columbia provides service.

Subject to, and without waiving these objections, the number of main line leaks classified as grade 1 within the last five years are included in the table below.

# of Grade 1 Leaks	2012	2013	2014	2015	2016
Main Lines	1,107	1,000	1,223	1,048	780

PUCO Case No. 16-2422-GA-ALT
OCC Interrogatories Set 2 No. 26
Respondent: Donald P. Ayers
As to Objections: Eric B. Gallon

**COLUMBIA GAS OF OHIO, INC.
RESPONSE TO THE OFFICE OF THE OHIO
CONSUMERS' COUNSEL'S INTERROGATORIES
DATED JUNE 2, 2017**

INT-26.

Referring to the classification for leaks indicators as outlined in Ohio Adm. Code 4901:1-16-04(H)(1), how many leaks on main lines were classified as grade-two classification in the last five years?

RESPONSE:

Columbia objects to this Interrogatory because it is vague and ambiguous. Ohio Adm.Code 4901:1-16-04(H)(1) does not describe the grade-two classification; it describes the grade-one classification. Columbia's response provides information regarding leaks classified as grade-two.

Columbia further objects to this Interrogatory because it is overbroad. OCC's Interrogatory is not limited to the areas in which Columbia provides service. Columbia's response provides information regarding leaks on main lines through which Columbia provides service.

Subject to, and without waiving these objections, the numbers of main line leaks classified as grade 2 within the last five years are included in the table below.

# of Grade 2 Leaks	2012	2013	2014	2015	2016
Main Lines	3,175	3,066	3,527	3,226	2,772

PUCO Case No. 16-2422-GA-ALT
OCC Interrogatories Set 2 No. 28
Respondent: Donald P. Ayers
As to Objections: Eric B. Gallon

**COLUMBIA GAS OF OHIO, INC.
RESPONSE TO THE OFFICE OF THE OHIO
CONSUMERS' COUNSEL'S INTERROGATORIES
DATED JUNE 2, 2017**

INT-28.

Referring to the classification for leaks indicators as outlined in Ohio Adm. Code 4901:1-16-04(H)(1), how many leaks on main lines were classified as grade-three classification in the last five years?

RESPONSE:

Columbia objects to this Interrogatory because it is vague and ambiguous. Ohio Adm.Code 4901:1-16-04(H)(1) does not describe the grade-three classification; it describes the grade-one classification. Columbia's response provides information regarding leaks classified as grade-three.

Columbia further objects to this Interrogatory because it is overbroad. OCC's Interrogatory is not limited to the areas in which Columbia provides service. Columbia's response provides information regarding leaks on main lines through which Columbia provides service.

Subject to, and without waiving these objections, the number of main line leaks classified as grade 3 within the last five years are included in the table below.

# of Grade 3 Leaks	2012	2013	2014	2015	2016
Main Lines	589	491	642	393	307

PUCO Case No. 16-2422-GA-ALT
OCC Requests for Production of Documents Set 6 No. 20
Respondent: Diana M. Beil
As to Objections: Eric B. Gallon

COLUMBIA GAS OF OHIO, INC.
RESPONSE TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S REQUESTS FOR PRODUCTION OF DOCUMENTS
DATED SEPTEMBER 11, 2017

RPD-20.

Please provide all analyses, studies and reports (including workpapers, data, documentation and other information relied upon to conduct the analyses, studies and reports) that support the Stipulation that have not been filed with the PUCO.

RESPONSE:

Columbia objects to this Request for Production because the phrase "that support the Stipulation" is vague and ambiguous. Columbia further objects to this Request for Production because, to the extent it would require Columbia to search its files for every document and piece of information that would tend to support the extension of Columbia's Infrastructure Replacement Program and Rider IRP, per the terms of the Application (as modified by the Stipulation), it is overbroad and unduly burdensome.

Subject to and without waiving these objections, Columbia responds: Please see OCC RPD Set 6, No. 20 Attachment A.

FOR SETTLEMENT DISCUSSION ONLY

Columbia Gas of Ohio
Infrastructure Replacement Program
Rider Rate Analysis

Capital Investment Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	*Projected 2017*
Max Rider IRP Rate Allowed	$ 1.10	$ 2.20	$ 3.20	$ 4.20	$ 5.20	$ 6.20	$ 7.20	$ 8.20	$ 9.20	$ 10.20
Actual Rider IRP Rate	$ 0.86	$ 1.62	$ 2.63	$ 3.57	$ 4.71	$ 5.71	$ 6.71	$ 7.65	$ 8.96	*$ 10.20*
Annual Rate Increase		**$ 0.76**	**$ 1.01**	**$ 0.94**	**$ 1.14**	**$ 1.00**	**$ 1.00**	**$ 0.94**	**$ 1.31**	***$ 1.24***

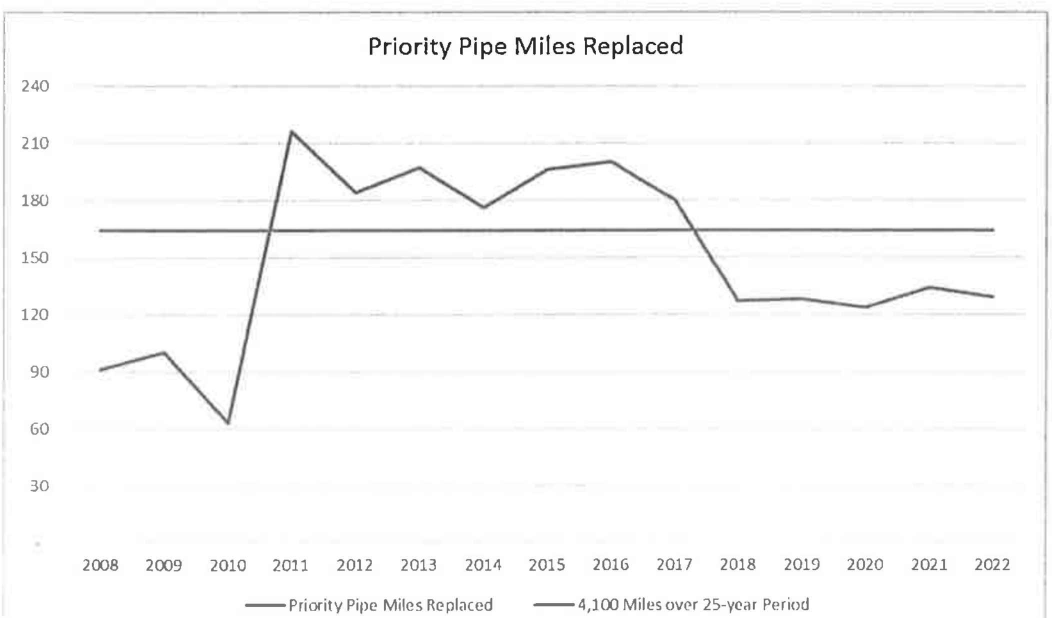
	Cost/Mile	% Increase	Total Capital	Total Miles Replaced	Miles Replaced for Bare Steel and Cast/Wrought Iron		
2008	406,695.32	-	37,009,274.38	91	91		
2009	312,343.20	-23.20%	34,357,752.00	110	100		
2010	449,029.96	43.76%	31,432,097.24	70	63		
2011	421,737.27	-6.08%	107,543,003.00	255	216		
2012	593,856.22	40.81%	154,996,474.00	261	184		
2013	598,531.21	0.79%	167,588,738.42	280	197	29.64%	
2014	658,663.03	10.05%	165,983,082.54	252	176	30.16%	
2015	687,298.56	4.35%	182,821,415.63	266	196	26.32%	
2016	780,852.78	13.61%	214,734,515.36	275	200	27.27%	
9-Year Historical Average		10.51%				*28.35%*	*Average*
4-Year Historical Average		7.20%				*164*	*Priority Pipe Miles*
2017	*837,060.89*	*7.20%*				*229*	*Total (annual)*
						1,144	*Total (5-years)*

4-Year Historical Average

2018	*897,315.02*	*7.20%*
2019	*951,906.42*	*7.20%*
2020	*1,031,147.30*	*7.20%*
2021	*1,105,372.34*	*7.20%*
2022	*1,184,940.38*	*7.20%*
	1,036,136.28	
	1,185,767,499.35	$ 237,153,499.87
	1.34	

229 = 164 / (1-.2835)

Historically, priority pipe replaced has represented approximately 72% of total pipe replaced. Using this same ratio going forward, in order for Columbia to replace 164 miles of priority pipe annually, Columbia would need to replace 229 total miles annually.



Using the estimated annual cost per mile from the table above and the Staff proposed maximum SGS customer IRP Rider rate per month, Columbia projects the annual miles replaced would be significantly below the average run rate of 164 miles of priority pipe. The excess miles replaced between 2011 and 2016 have allowed Columbia to catch up from the early years (2008-2010) of the program, where Columbia was replacing significantly less than 164 miles per year. With the Staff proposed rates, Columbia estimates it would be approximately 215 miles behind pace through 2022.

PUCO Case No. 16-2422-GA-ALT
OCC Request for Admissions Set 3 No. 6

**COLUMBIA GAS OF OHIO, INC.
RESPONSE TO THE OFFICE OF THE OHIO CONSUMERS' COUNSEL'S REQUEST FOR ADMISSIONS
DATED JUNE 23, 2017**

RFA-6.

Admit that Columbia has no analysis that projects the future level of leaks based on alternative levels of replacement of leak-prone mains and services."

RESPONSE:

Admit. Columbia has a twenty-five year program to replace its Priority Pipe and it is this commitment that sets the appropriate level of pipe replacement.

PUCO Case No. 16-2422-GA-ALT
OCC Interrogatories Set 2 No. 2
Respondent: Donald P. Ayers

**COLUMBIA GAS OF OHIO, INC.
RESPONSE TO THE OFFICE OF THE OHIO
CONSUMERS' COUNSEL'S INTERROGATORIES
DATED JUNE 2, 2017**

INT-2.

Please provide the following system wide performance and replacement rates for the ten-year period of 2007-2016. Please also indicate the source(s) of this information and any discrepancies between sources and/or data that is excluded.

System Performance- All Pipe										
***Mains* - System Performance**	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Number of leaks repaired										
Miles in service										
Mains Leak rate per mile										

System Performance - All Pipe										
***Services* - System Performance**	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Number of leaks repaired										
Miles in service										
Services Leak rate per mile										

RESPONSE:

Please find requested data included in attachment "OCC INT Set 2, No. 2 Attachment A.xlsx." Data included in the file was pulled from Columbia's Work Management System (WMS).

Mains	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Number of Leaks Cleared[1]	3,852	4,053	4,462	3,796	3,817	3,653	3,470	3,465	3,733	3,762
Miles in Service	19,706	19,690	19,733	19,763	20,002	19,779	19,829	19,880	19,900	19,999
Mains Leak Cleared per Mile[1]	0.20	0.21	0.23	0.19	0.19	0.18	0.17	0.17	0.19	0.19

Services	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Number of Leaks Cleared[1][2]	4,308	5,080	12,649	16,340	14,507	13,558	12,183	11,065	11,875	11,415
Miles in Service[3]	5,094	21,262	21,475	21,628	21,855	21,829	21,810	21,783	21,814	21,684
Services Leak Cleared per Mile[1]	0.85	0.24	0.59	0.76	0.66	0.62	0.56	0.51	0.54	0.53

[1]Columbia revised the headings included in the OCC Interrogatories to reference leaks "cleared" versus leaks "repaired." This change was made to properly identify all leaks addressed by Columbia, both those repaired and replaced. Columbia also calculated "Leak Cleared per Mile" vs "Leak Rate per Mile" to accurately reflect the data presented in the table.

[2]Excludes leaks cleared on meter settings that did not require a Distribution Property Investigation (DPI).

[3]Miles in service for service lines were estimated based on the number of services and the average service length reported in Columbia's Gas Distribution System Annual Report filed with the U.S. Department of Transportation (DOT Report).

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 No.	Capital Expenditure Year	2018	2019	2020	2021	2022
	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
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
47	Annual Rate Increase*	1.31	1.28	1.26	1.16	1.11

Average Annual Increase: 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
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
47	Annual Rate Increase*	1.49	1.48	1.44	1.36	1.28

Average Annual Increase 1.410

*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	10.95%	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	
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.

Moore, Kevin

From: Gallon, Eric B. <EGallon@porterwright.com>
Sent: Friday, September 22, 2017 12:30 PM
To: Moore, Kevin
Subject: RE: #EXT# FW: PUCO Case No. 16-2422-GA-ALT - Columbia's Responses and Objections to OCC Discovery Set 6

Kevin:

In response to your question regarding OCC Set 6, RPD 20, Columbia Gas does not have an Excel spreadsheet showing the revenue requirement for the stipulation.

Sincerely,
Eric

Eric B. Gallon | Porter Wright Morris & Arthur LLP | 41 S High St Suites 2800-3200 | Columbus, OH 43215
Direct: 614-227-2190 | Fax: 614-227-2100 | egallon@porterwright.com
porterwright

From: Kevin.Moore@occ.ohio.gov [mailto:Kevin.Moore@occ.ohio.gov]
Sent: Friday, September 22, 2017 11:06 AM
To: Gallon, Eric B.
Subject: #EXT# FW: PUCO Case No. 16-2422-GA-ALT - Columbia's Responses and Objections to OCC Discovery Set 6

#External Email#

Eric:

Do you have any updates on OCC's request for a supplemental response to OCC, Set 6, RPD 20?

Thank you.
Kevin

Kevin F. Moore
Assistant Consumers' Counsel
Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485
(614) 387-2965
kevin.moore@occ.ohio.gov

From: Moore, Kevin
Sent: Wednesday, September 20, 2017 12:59 PM

To: 'Gallon, Eric B.'
Subject: RE: PUCO Case No. 16-2422-GA-ALT - Columbia's Responses and Objections to OCC Discovery Set 6

Eric:
Just to confirm the telephone discussion we had today about Columbia's response to OCC Set 6, RPD 20.

We received Columbia's initial response consisting of OCC Set 6, RPD 20, Attachment A. OCC was wondering it there are any other work papers supporting the stipulation (e.g., an Excel spreadsheet showing the revenue requirement with formulas intact)?

Thank you.

Kevin

Kevin F. Moore
Assistant Consumers' Counsel
Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
Columbus, Ohio 43215-3485
(614) 387-2965
kevin.moore@occ.ohio.gov

From: Gallon, Eric B. [mailto:EGallon@porterwright.com]
Sent: Monday, September 18, 2017 5:28 PM
To: Moore, Kevin; Williams, Jamie
Cc: cmooney@ohiopartners.org; fdarr@mwncmh.com; mpritchard@mwncmh.com; Jones, John; Wright, William; PUCO Columbia Gas 16-2422-GA-ALT; JosephClark@nisource.com; sseiple@nisource.com; dbeil@nisource.com
Subject: PUCO Case No. 16-2422-GA-ALT - Columbia's Responses and Objections to OCC Discovery Set 6

Dear Counsel:

Columbia objects to OCC's Sixth Set of Interrogatories and Requests for Production of Document on the grounds that the majority of OCC's discovery requests are untimely. In alternative rate plan proceedings, the deadline for serving discovery requests is the same as the discovery deadline in general rate proceedings – "fourteen days after the filing and mailing of the staff report * * *." *See* Ohio Admin. Code 4901:1-19-07(G); Ohio Admin. Code 4901-1-17(B). Staff filed its report on July 10, 2017, making the discovery deadline July 24, 2017. Although the Commission's Entry of September 7, 2017, established response deadlines for "discovery requests served after the issuance of this Entry" (Entry ¶ 11), that paragraph is properly understood to apply only to discovery requests properly served after September 7th – namely, discovery requests relating to supplemental testimony in support of the Joint Stipulation and Recommendation filed August 18, 2017. The majority of OCC's Sixth Set, in contrast, relates to Columbia's application, the testimony in support of that application, and Columbia's prior responses to OCC's earlier discovery requests and Staff's data requests.

Notwithstanding this objection, and in the interests of comity and cooperation, Columbia is hereby providing its responses and objections to OCC's Sixth Set of Discovery. Although Columbia will require additional time to respond to OCC Interrogatory No. 147, it will send its response within the week.

Should you have any questions regarding this information, please do not hesitate to contact us.

Sincerely,
Eric Gallon

Eric B. Gallon | Porter Wright Morris & Arthur LLP | 41 S High St Suites 2800-3200 | Columbus, OH 43215
Direct: 614-227-2190 | Fax: 614-227-2100 | egallon@porterwright.com
porterwright

Energy Slowdown Hits One Town Hard

Businesses are slumping in a Pennsylvania community that had boomed from the gas-fracking revolution

By KRIS MAHER Aug. 19, 2015 2:29 p.m. ET

WAYNESBURG, Pa.—As fracking took off here over the past eight years, so did Gary Bowers's business supplying everything from Gatorade to replacement valves to crews drilling into natural-gas reserves a mile underground.

This year, however, the good times at his firm, Producers Supply Co., came to a screeching halt. Since January, the company's monthly sales have declined by more than half, as the number of drilling rigs operating in the Marcellus Shale has plummeted to 70 from 131 at the end of last year.

"This thing is spiraling down, and we don't know how long it's going to last," said Mr. Bowers, who expects the rig count to keep falling. "It's new territory for Appalachia."

The economic pain from lower oil and gas prices is spreading to small towns and businesses across Pennsylvania and parts of Ohio and West Virginia that had been riding a wave of prosperity from the natural-gas shale boom. Now, companies that cater to drillers, as well as hotels, restaurants and even farmers, are feeling the pinch.

A similar story is playing out in the oil fields of North Dakota, Oklahoma and Texas. U.S. energy companies have lopped off more than 150,000 jobs over the past year. But experts say many small businesses and landowners in those states have become accustomed to the boom-and-bust cycles of the industry.

Pennsylvania is now the nation's No. 2 gas producer, behind Texas. In the Marcellus Shale region, however, the gas industry's sudden rise is a relatively recent phenomenon, and this downturn is the deepest the area has experienced since the fracking boom. According to local officials, the sudden pullback has caught many small businesses that sprang up around the industry off guard.

Last month, a new round of cutbacks sent a shock wave through the region. Consol Energy Inc., based outside Pittsburgh, said it would cut 470 workers, or 10% of its total, and doesn't plan to drill a single new well until 2017. In May, Texas-based Range Resources Corp. laid off 41 employees in Pennsylvania who worked in nonshale gas operations.

The industry's growing productivity is partly to blame for a glut of gas that has kept prices depressed, leading to job cuts. In the Marcellus, a bottleneck caused by a lack of pipeline infrastructure to ship out gas has pushed supplies even higher and prices to the lowest levels in the nation.

For the week ended Aug. 12, the commonly cited "Henry Hub" spot price for natural gas in Louisiana was $2.91 per million British thermal units, down 23% from a year earlier, according to the Energy Information Administration. In Pennsylvania, the comparable spot price was $1.56, 35% lower than it was in the state a year ago.

Pennsylvania Gov. Tom Wolf, a Democrat, is pushing for a severance tax on gas production to help fund the state's schools, but the gas industry says the measure is ill-timed.

"The governor's highest-in-the-nation energy tax would kick this industry while it's down," said Dave Spigelmyer, president of the Marcellus Shale Coalition, a trade group.

Shale-gas drilling has reshaped places like Greene County in southwestern Pennsylvania, historically one of the poorest counties in the state. In June, the county received $4.5 million from a fee that gas companies paid last year on wells that had been fracked. The county had 873 wells producing shale gas last year, the fifth-highest number in the state.

But the number of new wells has slowed significantly since then. Through Tuesday, 77 shale-gas wells had been drilled in Greene County this year, down 50% from the 154 drilled in the year-earlier period, according to state figures.

In Waynesburg, the county seat, flatbed trucks hauling equipment to drill sites and tanker trucks carrying wastewater from the hydraulic fracturing process chug along High Street, the main thoroughfare. But the traffic has fallen sharply over the past few months, according to residents.

Hot Rod's House of Bar-B-Que, a 156-seat restaurant in the center of town, used to have a wait at the door for lunch, said Rodney Phillips, the owner. But on a recent day half the tables were empty. "You can get a seat any day you want," Mr. Phillips said.

When gas workers flooded into town, Mr. Phillips and his wife gave up a location that seated only 30 people and took out a mortgage to buy their current location. More than 100 baseball caps with gas company logos from executives and rig hands are nailed to a wall.

Last year, Mr. Phillips had 23 employees. He is down to 17 after layoffs and isn't replacing others who left. Sales of steak dinners are down, along with tips. Last year, he sold advertising on tabletops to gas companies, but this year no one has wanted to pay the $650 rate.

"We're in survival mode," Chris Ramsey, northeast regional manager of KSW Oilfield Rental LLC, said between bites of a pulled pork sandwich. The company, which supplies pumps and vacuums to suck up mud and cuttings from drill sites, has reduced its staff to 14 from 20 last year. Like other companies it cut its prices, so profit margins have evaporated. He said monthly sales revenue is down 45% to 50%.

Mr. Ramsey, who is originally from West Monroe, La., home of the reality series "Duck Dynasty," hosted a crawfish boil in Waynesburg last year. He paid for a catering company to transport 2,000 pounds of crawfish 1,200 miles and for three cooks to work all day. He canceled the event this year. "In this market we're cutting out all promotional events," he said.

The downturn is hitting landowners too. Homer Harden, who owns a 100-acre farm 18 miles east of Waynesburg, said his monthly royalty checks from two wells on his land have fallen 80% in recent months compared with last year.

"Everything is in a downturn," said Jerry Simmons, executive director of the National Association of Royalty Owners, an education and advocacy group in Tulsa, Okla. "Companies aren't spending the money on new leases, so our folks aren't getting their bonus checks and production is cut way back and prices are down."

At a farmers market off High Street, Mr. Harden sells tomatoes, peaches and corn on Wednesdays. But sales have dropped even here.

"They're just buying less," said Mr. Harden. "They're not spending money like they used to."

EnergyEconomist.com

For a better long term perspective on North American drilling activity check out the long term graphs on the Rotary Rig Count page.

North American Workover Rig Count

International Rotary Rig Counts

International Rotary Rig Count Table

Oil & Gas Split

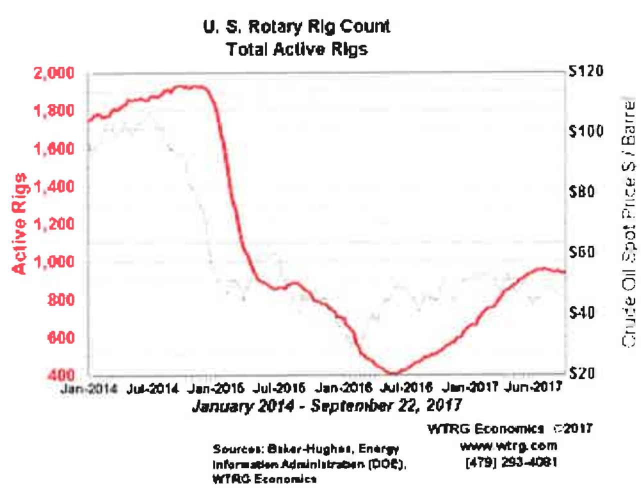
Graphic Overview

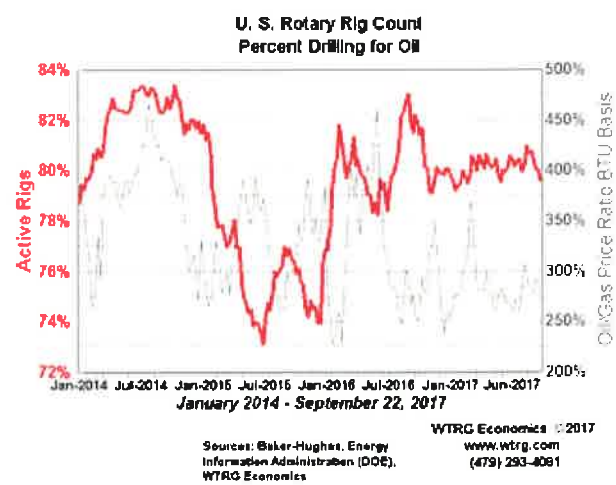
Short Term - Land/Offshore graphs & table
Long Term - Land/Offshore graphs & table

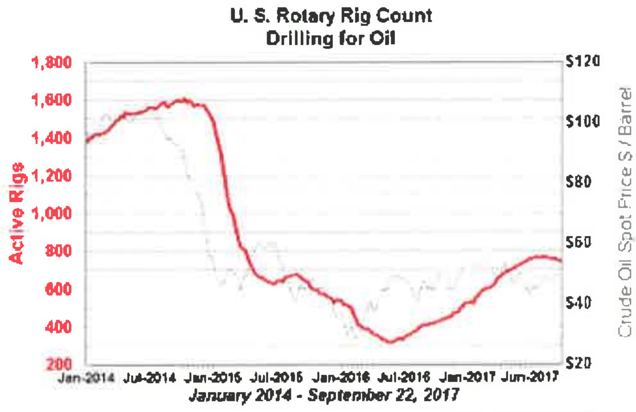
Weekly Rotary Rig Count

North American Rig Count				Change		Percent Change	
	09/22/2017	09/15/2017	09/23/2016	Weekly	Annual	Weekly	Annual
Total U.S.	935	936	511	(1)	424	-0.1%	83.0%
Offshore	19	17	20	2	(1)	11.8%	-5.0%
Land	916	919	491	(3)	425	-0.3%	86.6%
Inland Waters	3	4	3	(1)	0	-25.0%	0.0%
Oil	744	749	418	(5)	326	-0.7%	78.0%
Percent	79.6%	80.0%	81.8%	-0.4%	-2.2%		
Gas	190	186	92	4	98	2.2%	106.5%
Percent	20.3%	19.9%	18.0%	0.4%	2.3%		
Directional	77	74	49	3	28	4.1%	57.1%
Horizontal	790	795	402	-5	388	-0.6%	96.5%
Vertical	68	67	60	1	8	1.5%	13.3%
Gulf of Mexico	19	17	20	2	-1	11.8%	-5.0%
Gulf Oil	15	14	19	1	-4	7.1%	-21.1%
Percent	78.9%	82.4%	95.0%	-3.4%	-16.1%		
Gulf Gas	4	3	1	1	3	33.3%	300.0%
Percent	21.1%	17.6%	5.0%	3.4%	16.1%		
Canada	220	212	138	8	82	3.8%	59.4%
Oil	122	112	77	10	45	8.9%	58.4%
Percent	55.5%	52.8%	55.8%	2.6%	-0.3%		
Gas	98	100	61	(2)	37	-2.0%	60.7%
Percent	44.5%	47.2%	44.2%	-2.6%	0.3%		
North America	1,155	1,148	649	7	506	0.6%	78.0%
Prices							
Oil $/bbl.	$50.18	$49.07	$44.72	$1.11	$5.45	2.3%	12.2%
Oil $/mmbtu	$8.65	$8.46	$7.71	$0.19	$0.94	2.3%	12.2%
Gas $/mmbtu	$3.12	$2.95	$3.07	$0.17	$0.05	5.8%	1.6%

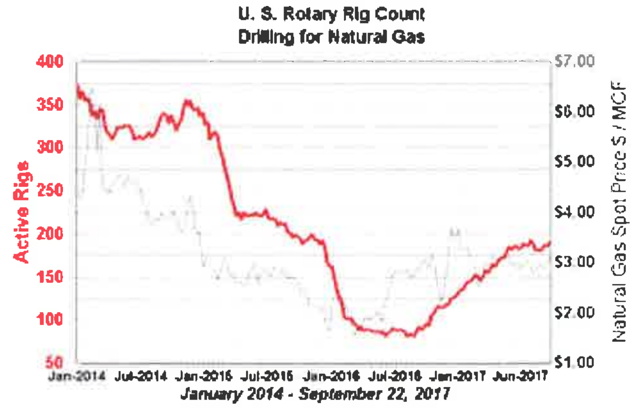
Click on graph for a larger image



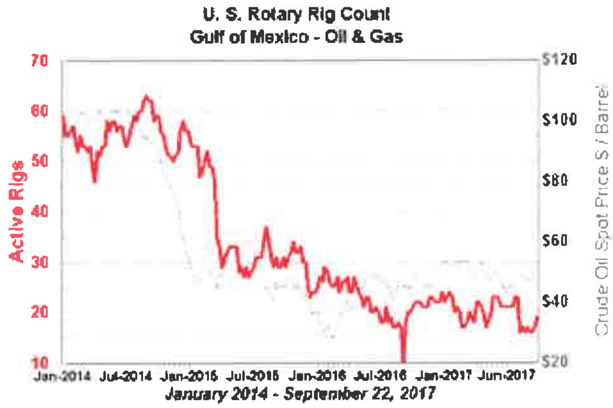




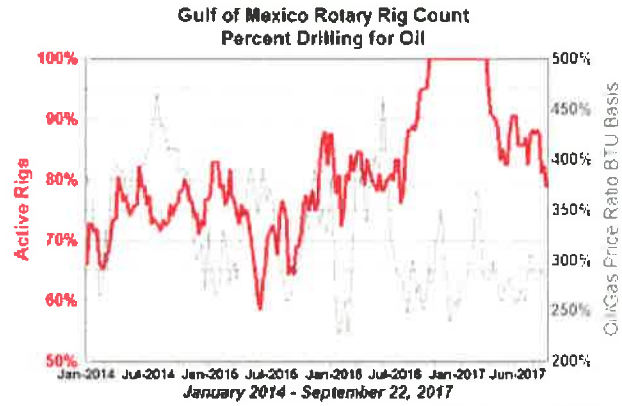
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics



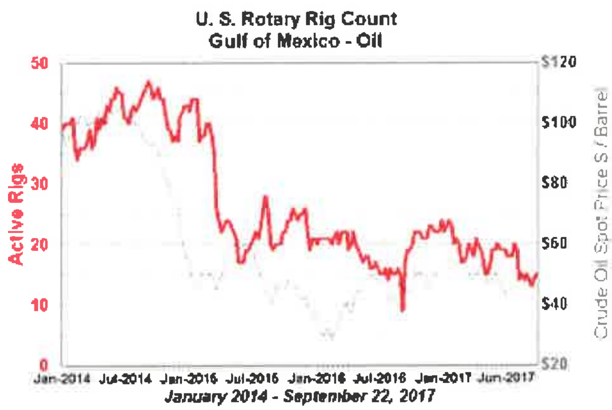
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics



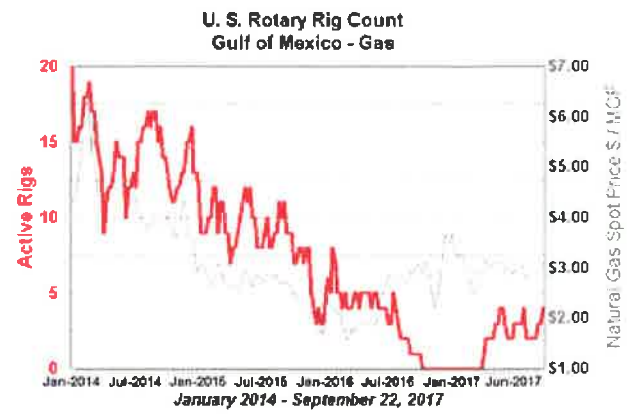
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics



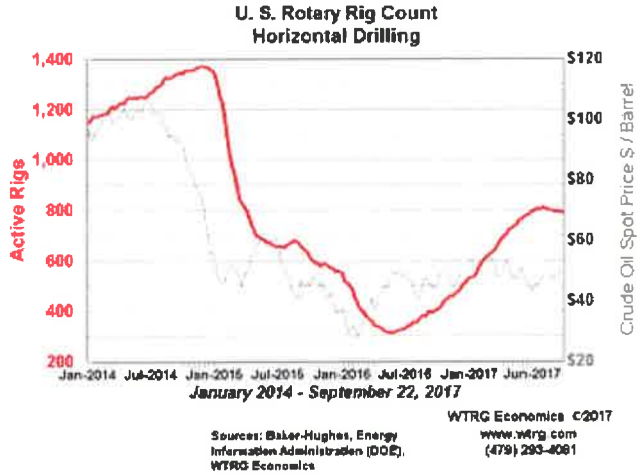
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics

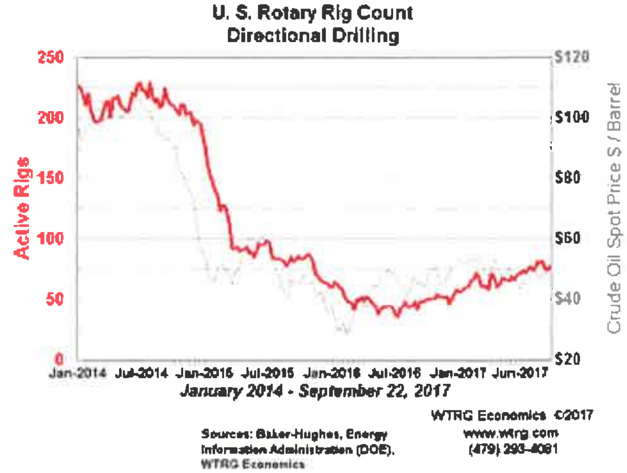


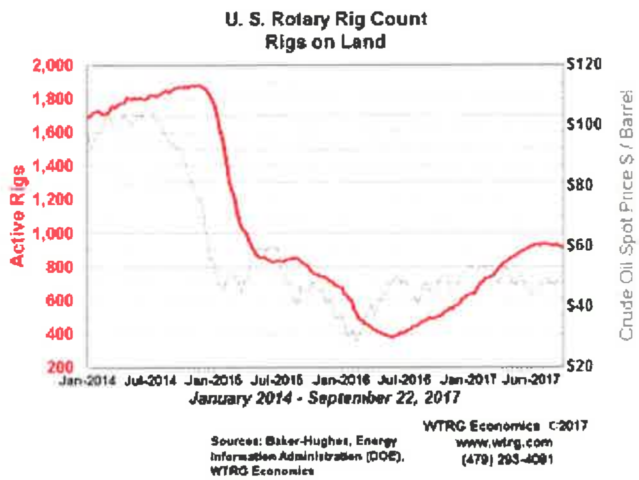
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics

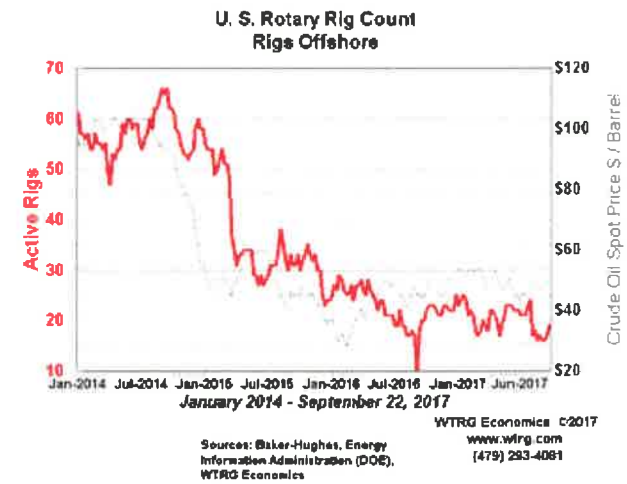


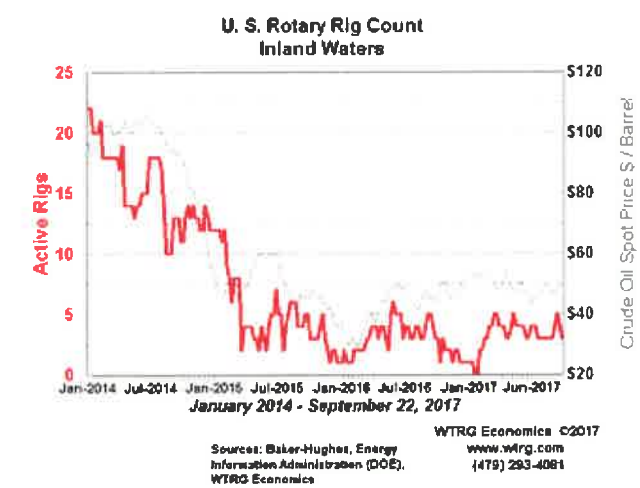
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics

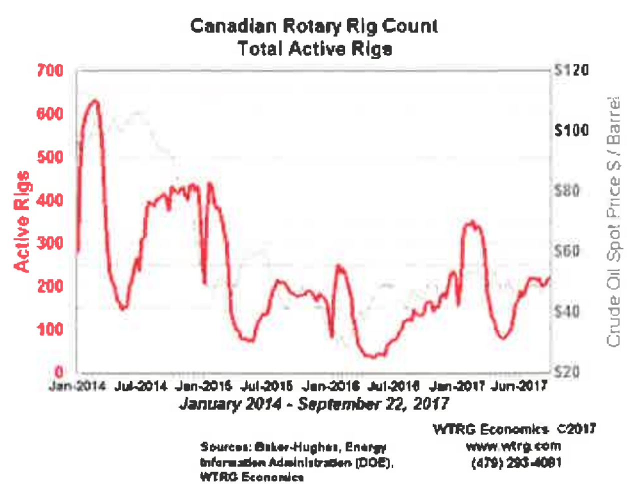

U. S. Rotary Rig Count
Horizontal Drilling
Active Rigs
Crude Oil Spot Price $ / Barrel
1,400
1,200
1,000
800
600
400
200
$120
$100
$80
$60
$40
$20
Jan-2014 Jul-2014 Jan-2015 Jul-2015 Jan-2016 Jul-2016 Jan-2017 Jun-2017
January 2014 - September 22, 2017
WTRG Economics ©2017
www.wtrg.com
(479) 293-4081
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics

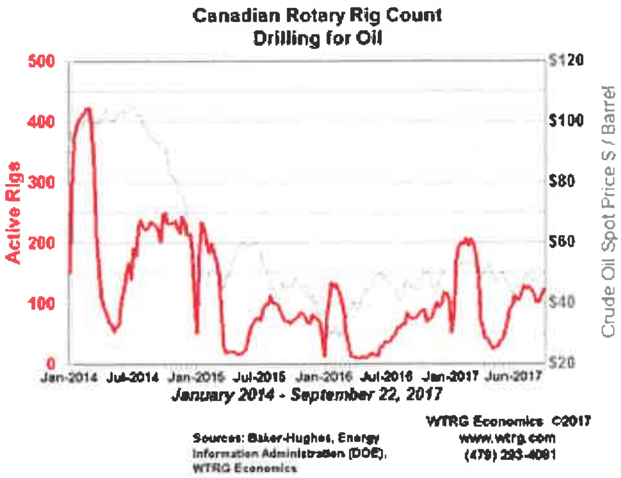

U. S. Rotary Rig Count
Directional Drilling
Active Rigs
Crude Oil Spot Price $ / Barrel
250
200
150
100
50
0
$120
$100
$80
$60
$40
$20
Jan-2014 Jul-2014 Jan-2015 Jul-2015 Jan-2016 Jul-2016 Jan-2017 Jun-2017
January 2014 - September 22, 2017
WTRG Economics ©2017
www.wtrg.com
(479) 293-4081
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics

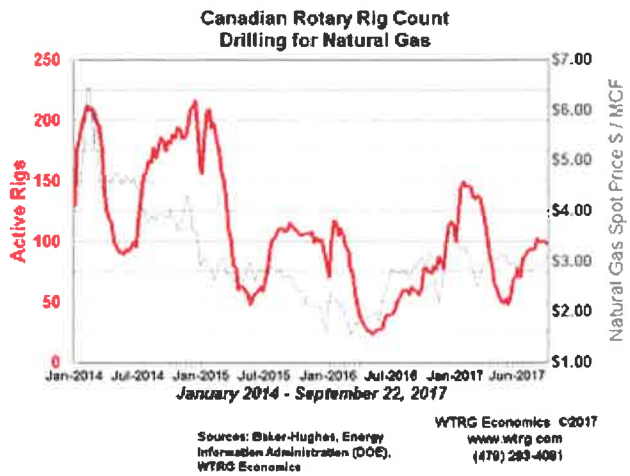

U. S. Rotary Rig Count
Rigs on Land
Active Rigs
Crude Oil Spot Price $ / Barrel
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
$120
$100
$80
$60
$40
$20
Jan-2014 Jul-2014 Jan-2015 Jul-2015 Jan-2016 Jul-2016 Jan-2017 Jun-2017
January 2014 - September 22, 2017
WTRG Economics ©2017
www.wtrg.com
(479) 293-4081
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics


U. S. Rotary Rig Count
Rigs Offshore
Active Rigs
Crude Oil Spot Price $ / Barrel
70
60
50
40
30
20
10
$120
$100
$80
$60
$40
$20
Jan-2014 Jul-2014 Jan-2015 Jul-2015 Jan-2016 Jul-2016 Jan-2017 Jun-2017
January 2014 - September 22, 2017
WTRG Economics ©2017
www.wtrg.com
(479) 293-4081
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics


U. S. Rotary Rig Count
Inland Waters
Active Rigs
Crude Oil Spot Price $ / Barrel
25
20
15
10
5
0
$120
$100
$80
$60
$40
$20
Jan-2014 Jul-2014 Jan-2015 Jul-2015 Jan-2016 Jul-2016 Jan-2017 Jun-2017
January 2014 - September 22, 2017
WTRG Economics ©2017
www.wtrg.com
(479) 293-4081
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics


Canadian Rotary Rig Count
Total Active Rigs
Active Rigs
Crude Oil Spot Price $ / Barrel
700
600
500
400
300
200
100
0
$120
$100
$80
$60
$40
$20
Jan-2014 Jul-2014 Jan-2015 Jul-2015 Jan-2016 Jul-2016 Jan-2017 Jun-2017
January 2014 - September 22, 2017
WTRG Economics ©2017
www.wtrg.com
(479) 293-4081
Sources: Baker-Hughes, Energy Information Administration (DOE), WTRG Economics





James L. Williams
WTRG Economics
P.O. Box 250
London, Arkansas 72847
Phone: (479) 293-4081
To contact us or if you have comments or suggestions, email WTRG at wtrg@wtrg.com

Bulletin No. 185

1912 to January 1, 2017

The Handy-Whitman Index® of Public Utility Construction Costs™

Trends of Construction Costs

COMPILED & PUBLISHED BY
Whitman, Requardt & Associates, LLP
Engineers, Architects and Planners
801 South Caroline Street
Baltimore, Maryland 21231
410-235-3450

G-3

COST TRENDS OF GAS UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS											
			2005		2006		2007		2008		2009		2010	
			Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1
1	Total Plant		542	539	570	580	558	562	573	654	636	611	618	639
2														
3	**Production Plant**													
4	L. P. G. Equipment		415	424	432	436	452	454	465	482	489	503	512	513
5	S. N. G. Equipment		422	429	442	451	470	473	487	503	507	498	512	510
6														
7														
8														
9														
10														
11														
12														
13	**Storage Plant**													
14	Gas Holders Excl. of Found	362	444	445	460	463	473	399	412	428	436	431	432	435
15														
16														
17														
18														
19														
20														
21														
22														
23														
24	**Transmission Plant**													
25	Total Transmission Plant		430	437	439	449	483	470	487	530	536	501	484	509
26	Structures & Improvements	366	409	410	421	426	439	453	468	481	474	462	474	480
27	Mains	367	428	431	434	444	483	464	482	530	536	495	472	501
28														
29	Compressor Station Equipment	368	467	503	491	499	514	525	537	569	577	572	578	589
30	Meas. & Reg. Sta. Equipment	369	513	515	534	547	552	548	563	622	616	590	594	590
31														
32														
33														
34														
35														
36														
37														
38														
39														
40														
41	**Distribution Plant**													
42	Structures & Improvements	375	409	410	421	426	439	453	468	481	474	462	474	480
43	Mains, Cast Iron	376	390	391	421	426	465	467	492	527	581	583	613	613
44	Mains, Steel	376	583	578	614	626	593	597	605	710	682	650	656	684
45	Mains, Plastic	376	400	409	423	430	449	453	464	470	493	495	482	482
46	Compressor Station Equipment	377	467	503	491	499	514	525	537	569	577	572	578	589
47	Meas. & Reg. Sta. Equipment	378	496	496	516	526	530	525	539	596	589	563	567	563
48	Meas. & Reg. Sta. Equipment-City Gt.	379	500	499	521	531	531	526	539	602	592	564	568	567
49	Services, Steel	380	475	476	498	505	501	504	518	558	557	546	555	565
50	Services, Plastic	380	411	415	433	436	455	457	472	475	492	493	501	501
51	Meters	381	185	184	188	197	205	231	241	250	261	252	257	252
52	Meter Installations	382	635	626	672	686	638	642	648	784	742	699	708	744
53	House Regulators	383	336	339	344	356	377	377	387	392	412	400	406	414
54	House Regulators Installations	384	615	607	651	664	622	626	633	757	719	680	692	724
55														
56														

G-3

COST TRENDS OF GAS UTILITY CONSTRUCTION

NORTH CENTRAL REGION (1973=100)

Line	CONSTRUCTION AND EQUIPMENT	FERC	COST INDEX NUMBERS													
			2011		2012		2013		2014		2015		2016		2017	
			Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1	Jan. 1	Jul. 1
1	Total Plant		675	688	759	755	757	749	754	759	758	745	723	731	759	
2																
3	**Production Plant**															
4	L. P. G. Equipment		535	566	597	601	609	608	615	621	625	627	635	638	657	
5	S. N. G. Equipment		524	538	545	548	572	554	557	570	576	589	591	593	604	
6																
7																
8																
9																
10																
11																
12																
13	**Storage Plant**															
14	Gas Holders Excl. of Found	362	445	445	454	457	465	466	468	477	482	479	484	485	492	
15																
16																
17																
18																
19																
20																
21																
22																
23																
24	**Transmission Plant**															
25	Total Transmission Plant		518	527	560	573	550	548	590	591	596	587	569	573	591	
26	Structures & Improvements	366	488	490	501	506	513	512	528	524	532	526	531	537	550	
27	Mains	367	510	518	556	571	542	539	587	588	593	581	559	563	583	
28																
29	Compressor Station Equipment	368	596	615	628	636	641	643	649	658	663	667	668	673	682	
30	Meas. & Reg. Sta. Equipment	369	639	656	702	704	701	696	717	720	723	713	697	718	738	
31																
32																
33																
34																
35																
36																
37																
38																
39																
40																
41	**Distribution Plant**															
42	Structures & Improvements	375	488	490	501	506	513	512	528	524	532	526	531	537	550	
43	Mains, Cast Iron	376	607	607	639	706	720	728	782	813	785	786	788	794	851	
44	Mains, Steel	376	727	743	833	826	825	815	815	820	816	797	765	776	806	
45	Mains, Plastic	376	490	497	513	521	521	524	522	527	530	532	535	538	542	
46	Compressor Station Equipment	377	596	615	628	636	641	643	649	658	663	667	668	673	682	
47	Meas. & Reg. Sta. Equipment	378	636	649	697	700	680	676	696	699	701	691	677	690	707	
48	Meas. & Reg. Sta. Equipment-City Gt.	379	637	651	703	704	686	681	699	702	704	692	677	690	708	
49	Services, Steel	380	588	596	637	637	643	641	649	652	653	647	641	646	664	
50	Services, Plastic	380	515	518	533	536	543	544	552	554	559	560	566	568	579	
51	Meters	381	252	256	261	271	271	272	341	342	372	372	388	388	442	
52	Meter Installations	382	799	818	933	923	918	904	899	905	899	873	827	840	877	
53	House Regulators	383	425	430	432	438	443	443	454	454	469	469	481	481	487	
54	House Regulators Installations	384	776	794	899	889	886	873	870	876	870	847	806	818	853	
55																
56																