I&E Statement No. 3
Witness: Ethan H. Cline

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Docket No. R-2018-2647577

Direct Testimony

of

Ethan H. Cline

Bureau of Investigation and Enforcement

Concerning:

Flex Rate Customers
Weather Normalization Adjustment
Revenue Normalization Adjustment
Test Year
Utility Plant in Service
Accumulated Depreciation
Annual Depreciation Expense
Rate Base
Future Test Year and Fully Projected Future Test Year Reports
Present Rate Revenue
Proposed Rate Revenue
Scale Back of Rates

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Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ethan H. Cline. My business address is P.O. Box 3265, Harrisburg, PA 17105-3265.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by the Pennsylvania Public Utility Commission in the Bureau of Investigation and Enforcement ("I&E") as a Fixed Utility Valuation Engineer.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. My education and professional background are set forth in Appendix A, which is attached.

Q. PLEASE DESCRIBE THE ROLE OF I&E IN RATE PROCEEDINGS.

A. I&E is responsible for protecting the public interest in proceedings before the Commission. The I&E analysis in the proceeding is based on its responsibility to represent the public interest. This responsibility requires the balancing of the interests of ratepayers, the regulated utility, and the regulated community as a whole.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My direct testimony relates to Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or "Company") requested a base rate revenue increase of $41,641,273, an increase in C&I Network revenue of $2,558,065, and an increase related to the Rider Universal Service Plan ("Rider USP") of $2,636,024. My testimony specifically addresses the following issues:

- Flex Rate Customers;
- Weather Normalization Adjustment;
- Revenue Normalization Adjustment;
- Fully Projected Future Test Year ("FPFTY");
- Use of the FPFTY as it applies to Rate Base;
- Application of the average rate base methodology;
- Present rate revenue;
- Revenue allocation;
- Rate Structure;
- Customer charge;
- Cost of Service allocation;
- Scale back of rates.

FLEX-RATE CUSTOMERS

Q. DOES THE COMPANY'S TARIFF ALLOW IT TO NEGOTIATE RATES FOR CUSTOMERS WITH AN ALTERNATIVE COMPETITIVE SUPPLY?

A. Yes. The Company's tariff currently allows it to grant discount or "flex-rates" to certain customers who can show that they have a competitive alternative to the Company's gas supply. The flex-rate provisions are described in Supplement No. 221 to Columbia Tariff Gas - PA P.U.C. No. 9, p. 68.

Q. DOES THE COMPANY CURRENTLY HAVE ANY CUSTOMERS RECEIVING FLEX-RATES?

A. Yes. The Company's present and proposed proof of revenue schedules show revenue from flex-rate customers for several rate schedules (Columbia Exhibits No. 3 and 103).

Q. DID THE COMPANY PROVIDE A SCHEDULE SHOWING A BREAKDOWN OF FLEX-RATE CUSTOMERS INCLUDING THE DATE THE CUSTOMER'S ALTERNATIVE SUPPLY WAS VERIFIED?

A. Yes. The Company's HIGHLY CONFIDENTIAL supplemental response to Office of Consumer Advocate interrogatory OCA-1-43, included as HIGHLY CONFIDENTIAL I&E Exhibit No. 3, Schedule 16, shows all flex-rate customers, a comparison of the customer's flex-rates to the otherwise applicable tariff rate, and the date the customers alternative supply was verified by the Company.

Q. ARE THERE ANY CUSTOMERS WHO HAVE NOT HAD THEIR ALTERNATIVE SUPPLY VERIFIED IN SEVERAL YEARS?

A. Yes. Six of the flex-rate customers have not had their alternative supply verified since 2008 and one customer has not had their alternative supply verified since 2010.

Q. WHAT DO YOU RECOMMEND CONCERNING THESE SEVEN FLEX-RATE CUSTOMERS?

A. I recommend that the Company provide a competitive alternative analysis for each of these seven customers in the next base rate case and justify the customers' flex-rates.

Q. WHY DID YOU MAKE THIS RECOMMENDATION?

A. To ensure that these customers continue to be eligible for flex-rates, each alternative supply claim should be periodically analyzed. It has been approximately ten years since an alternative supply analysis has been completed for the six customers, and approximately eight years since an alternative supply analysis was completed for the remaining customer. The Company's costs to supply service and operational conditions may have changed since the initial alternative supply studies were completed in the last eight to ten years. The customer's alternative source of supply and access to that alternative supply originally listed eight to ten years ago could also have changed.

Q. WHAT ARE SOME POTENTIAL CHANGES IN THE COMPANY'S ABILITY AND COST TO SUPPLY SERVICE?

A. Some potential changes are situations in which the Company can no longer supply the customer utilizing the current source of gas, utilize the existing capacity, or the cost to supply customers has increased or will increase. As an example, a situation could arise where a larger pipeline project is needed to serve both the flex-rate and tariff customers. In that case, termination of the flex-rate contract could result in the scale-back or cancellation of the larger pipeline project, and avoidance of capital and operating expense, which would result in savings for the Company and its customers.

Q. WHAT ARE SOME CHANGES IN THE CUSTOMER'S ALTERNATIVE SUPPLY THAT COULD AFFECT FLEX-RATE CUSTOMERS?

A. Some of the possible changes in the customer's alternative supply that could affect flex-rate customers are situations where the customers may no longer have a viable alternative supply, or the customer no longer has a viable alternative source of gas or gas capacity, or the cost of the alternate supply to customers has increased or will increase. There have been many changes in the natural gas industry in the last ten years. For example, a customer may have had access to an interstate pipeline that is now no longer available. Also, the cost and difficulty a customer would face to construct interconnections to pipelines has increased over the past ten years due to inflation, public concerns, restoration costs, and environmental impacts.

Q. WHY IS IT IMPORTANT TO PERIODICALLY ANALYZE COMPETITIVE ALTERNATIVES?

A. It is important to periodically analyze competitive alternatives to ensure that the rates of flex rate customers are not discounted lower than is necessary to avoid the customer choosing the alternative supply. Providing excessive discounts to customers would be harmful to both the Company and its customers since the other customers make up the lost revenue that results when flex-rate customers pay less than tariff rates.

WEATHER NORMALIZATION ADJUSTMENT

Q. WHAT IS THE WEATHER NORMALIZATION ADJUSTMENT?

A. The Weather Normalization Adjustment ("WNA") is a pilot program established by the Company after Commission approval in the 2012 Columbia base rate case. The WNA is set to expire after the final Order entered in the Company's first base rate case filed after May 31, 2016, which is the present proceeding. The purpose of the WNA is to adjust the temperature sensitive portion of a customer's bill in order to mitigate the impacts of warmer or colder than normal weather (Columbia St. No. 12, p. 4). In other words, customers are billed less than what a traditional bill calculation would require during colder than normal heating seasons and billed more during warmer than normal heating seasons (Columbia St. No. 12, p. 6).

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE WNA?

A. Yes. The Company is proposing to make the WNA a permanent tariff provision with modifications to discontinue weather adjustments in the month of October and to remove the 5% deadband (Columbia St. No. 12, p. 7).

Q. WHAT IS THE 5% DEADBAND?

A. The 5% deadband is a provision that the Company agreed to as a part of the 2012 base rate case settlement. As stated in Columbia Tariff Supplement 221 to Tariff Gas – Pa. P.U.C. No. 9 Eight Revised Page No. 162, paragraph (h) "The WNA for a billing cycle will apply only if the AHDD for the billing cycle are lower than 95% or higher than 105% of the NHDD for the billing cycle. A billing adjustment will only occur if the variation of AHDD is lower than 95% or higher than 105% of the NHDD for an individual billing cycle." In this definition, AHDD stands for the Actual Heating Degree Days and the NHDD stands for the Normal Heating Degree Days. The example provided by the Company is that, if a billing cycle is 4.5% warmer or colder than normal, then no adjustment would be made (Columbia St. No. 12, p. 8).

Q. DO ANY OTHER PENNSYLVANIA NATURAL GAS DISTRIBUTION COMPANIES HAVE A WNA WITH A DEADBAND PROVISION?

A. Yes. The Company has stated that Philadelphia Gas Works ("PGW") has a WNA with a 1% deadband rather than the 5% deadband that was agreed to in Columbia's 2012 settlement (Columbia St. No. 12, p. 9).

Q. IS IT REASONABLE TO COMPARE PGW'S WNA PROVISIONS TO THE COLUMBIA WNA?

A. No. PGW is a regulated municipal gas operation that has no shareholders, so any revenue risks are borne by the municipality and its ratepayers. The high percentage of low income customers served by PGW in conjunction with the lack of shareholders willing to bear investment risk makes a higher degree of revenue stability through a smaller deadband appropriate for PGW.

Q. WHAT DO YOU RECOMMEND REGARDING THE COMPANY'S WNA PROPOSALS?

A. I agree with the Company's proposal that the WNA be made a permanent tariff provision for the months November through May. However, I recommend that the proposal to remove the 5% deadband be denied.

Q. WHY DO YOU RECOMMEND THAT THE 5% DEADBAND BE RETAINED?

A. A WNA is a departure from traditional ratemaking in that it allows the Company to actually adjust a customer's base rate bill, which was calculated based on Commission approved rates, outside the scope of a base rate case. I believe such a departure from traditional ratemaking should only occur due to circumstances that are an extraordinary departure from normal operating conditions, such as abnormal weather. There is no need to reconcile the day-to-day temperature variations that can be considered a normal part of doing business. Therefore, a 5% deadband is a reasonable provision, because it allows for a range of what is considered "normal" weather in which the Company's Commission-approved rates would be applied without adjustment.

I believe that the WNA with the 5% deadband is a reasonable provision because it serves to protect both the Company and customers from the effects of abnormal weather, which cannot be predicted or controlled. However, as I stated above, there is no need to reconcile day-to-day weather changes, and I, therefore, recommend the 5% deadband that is currently in place also become permanent.

Q. IF THE COMMISSION ALLOWS A SMALLER DEADBAND OR NO DEADBAND, WHAT DO YOU RECOMMEND?

A. Should the Commission decide to not include a deadband provision or authorize a smaller deadband, I recommend that the WNA continue as a pilot program for an additional five (5) years so that the effects of the deadband change can be studied.

REVENUE NORMALIZATION ADJUSTMENT

Q. WHAT IS A REVENUE NORMALIZATION ADJUSTMENT?

A. A revenue normalization adjustment ("RNA") is a tariff provision that is "designed to 'break the link' between residential non-gas revenue received by the Company and gas consumed by non-CAP residential customers." (Columbia St. No. 12, p. 9). In other words, the Company is proposing to stabilize its revenue level received from customers by enacting a "benchmark distribution revenue level" and adjusting revenues to that point regardless of actual usage levels.

Q. IS THE COMPANY PROPOSING AN RNA IN THIS PROCEEDING?

A. Yes. The Company is proposing to apply an RNA to its non-CAP residential customers (Columbia St. No. 12, p. 9).

Q. HOW DOES THE COMPANY PROPOSE TO ENACT THE RNA?

A. The Company proposes to set the benchmark distribution revenue levels by month for the peak period, October through March, and off-peak period, April through September, separately, based on the revenue requirement approved in the present proceeding (Columbia St. No. 12, pp. 10-12).

Q. DO YOU AGREE WITH THE COMPANY'S RECOMMENDATION?

A. No. Through Act 11 and the FPFTY, the Company is permitted to build into its revenue requirement an adjustment for revenue lost due to a decline in usage that is projected to occur after rates go into effect.

Q. HAS THE COMPANY DEMONSTRATED A NEED FOR SUCH REVENUE STABILIZATION?

A. No. The purpose of revenue stabilization is to remove the inherent risk of not recovering the full amount of revenue requirement allowed by the Commission due to changes in usage. Between the frequent base rate cases filed by the Company, staying out no more than two years, the FPFTY, the DSIC, and the WNA, the Company has demonstrated no need for further revenue stabilization measures. Additionally, the Company has not indicated that the RNA will result in fewer base rate increases, thus removing any benefit from the residential customers.

Q. CAN THE PROPOSED RNA CAUSE HARM?

A. Yes. In order for customers to benefit from the RNA, they would need to use more gas to trigger the refund, contrary to conservation efforts. Customers who undertake conservation efforts will see their savings eroded and their investment payback time increase as the Company is permitted to increase rates in response to usage declines.

Further, customers who lack the financial means to undertake conservation efforts will be penalized by the RNA, which increases rates to address usage reductions. While the adjustment applies only to non-CAP residential customers, there are potentially many customers whose ability to pay may be compromised as their rates increase to address conservation efforts undertaken by more affluent customers. Therefore, for this reason and the reasons discussed above, I recommend the Company's proposed RNA be denied.

TEST YEAR

Q. WHAT IS A TEST YEAR AND HOW IS IT USED BY A COMPANY IN A RATE PROCEEDING?

A. A test year is the twelve-month period over which a utility's costs and revenues are measured as the basis for setting prospective base rates. Previously in rate case proceedings, in order to meet its burden of proof, a utility could only use a historic test year ("HTY") or a future test year ("FTY"). An HTY is a twelve-month period selected by a company that represents a recent full year of actual data. An FTY begins the day after the HTY ends and is used to allow for the time it takes to adjudicate a rate proceeding by permitting a company to select a future time period upon which to base its financial information. This is necessary so that the rates set by the Commission reflect current and synchronized financial information to prevent regulatory lag in the very first year that rates are in effect. By using an

FTY, a utility makes a projected annualized and normalized estimate of future revenues and expenses and a corresponding measure of value at the end of the period.

Q. HAVE THERE BEEN ANY STATUTORY AMENDMENTS THAT HAVE MODIFIED A UTILITY'S TEST YEAR OPTIONS?

A. Yes. Act 11, which was signed on February 14, 2012, permits utilities to use a fully projected future test year ("FPFTY") in order to meet their burden of proof in rate cases. The FPFTY is defined as the twelve-month period that begins with the first month that the new rates will be placed into effect, after the application of the full suspension period permitted under Section 1308(d). The FPFTY is a shift from the fundamental ratemaking principle that a public utility should only be permitted to include projects in rate base and earn a reasonable return on its investments after they become "used and useful" for the utility's public service. Prior to the passage of Act 11 by the Pennsylvania Legislature, utilities could use either an HTY or an FTY.

Q. WHAT TEST YEARS HAS THE COMPANY USED IN THIS PROCEEDING?

A. The Company used the twelve-month period ending November 30, 2017 as the HTY, the twelve-month period ending November 30, 2018 as the FTY, and the twelve-month period ending December 31, 2019 as the FPFTY.

UTILITY PLANT-IN-SERVICE

Q. WHAT IS UTILITY PLANT-IN-SERVICE?

A. Utility plant-in-service comprises all the utility's intangible assets (i.e., organization costs, franchise and consents costs, and land and land right costs) and tangible assets (i.e., facilities and equipment). Moreover, for a utility plant to be included in rates, the plant must be used and useful in the provision of utility service to the customers. Therefore, by definition, only plant currently providing or capable of providing utility service to customers is eligible to be reflected in rates.

Q. WHAT IS COLUMBIA'S UTILITY PLANT-IN-SERVICE CLAIM FOR ITS FTY AND FPFTY?

A. Columbia's plant-in-service claim for the FTY ending November 30, 2018 is $2,435,517,784 (Columbia Ex. No. 108, p. 3, col. 3, line 2). The Company's utility plant-in-service claim for the FPFTY ending December 31, 2019 is $2,741,791,737 (Columbia Ex. No. 108, p. 3, col. 5, line 2).

Q. DO YOU HAVE A RECOMMENDATION REGARDING UTILITY PLANT-IN-SERVICE IN THIS PROCEEDING?

A. Yes, I recommend that Columbia's FPFTY year-end utility plant-in-service be rejected and that a total gas plant-in-service amount of $2,588,654,760 be adopted instead (I&E Ex. No. 3, Sch. 1, col. H, line 1). I based my recommendation on the use of an average rate base methodology rather than the year-end rate base contained in the Company's filing. I computed I&E's recommended $2,588,654,760 of utility plant-in-service for the FPFTY by taking the average of the Company's total utility plant-in-service for the FTY ending November 30, 2018 and the Company's total utility plant-in-service for the FPFTY ending December 31, 2019 as shown on I&E Exhibit No. 3, Schedule 1, line 1 and below:

$$(\$2,741,791,737 + \$2,435,517,784) \div 2 = \$2,588,654,760.$$

Q. PLEASE DEFINE THE AVERAGE RATE BASE CONCEPT.

A. Under the FPFTY, the traditional interpretation of the "used and useful" requirement for rate base inclusion of investments is unclear because when a company employs the use of a FPFTY in a base rate case, the new rates go into effect before the end of the Company's FPFTY. The inclusion of rate base added in a FPFTY necessarily means that customers will be paying a return on and a return of a utility's plant investment that has not yet been placed in service. For example, customers will begin paying a return on and a return of plant when Columbia's new rates are effective January 1, 2019, or perhaps even earlier if the case is settled and new rates are approved before the January 2019 effective date, but that plant may not be used and useful until December 2019. By using an average of the rate base that is projected to be in service by the end of the FPFTY, rather than the full year-end amount, the impact of the necessary customer overpayment at the beginning of the year is mitigated. This results in rates that are more just and reasonable because ratepayers are not paying for approximately a year of plant that is not yet in service.

Q. WHY IS IT APPROPRIATE TO ADOPT AN AVERAGE RATE BASE IN THIS CASE?

A. As discussed above, Columbia is requiring ratepayers, in essence, to pre-pay a return on its projected investment in future facilities that are not only not in place and providing service at the time the new rates take effect, but also that are not subject to any guarantee of being completed and placed into service. As a result, ratepayers will begin paying for expenses and plant when new rates become effective on January 1, 2018, but those projected expenses and plant may not be incurred or placed into service until December 31, 2019 or even later.

Q. WHY DO YOU RECOMMEND THE USE OF THE AVERAGE RATE BASE METHODOLOGY FOR ESTABLISHING RATES?

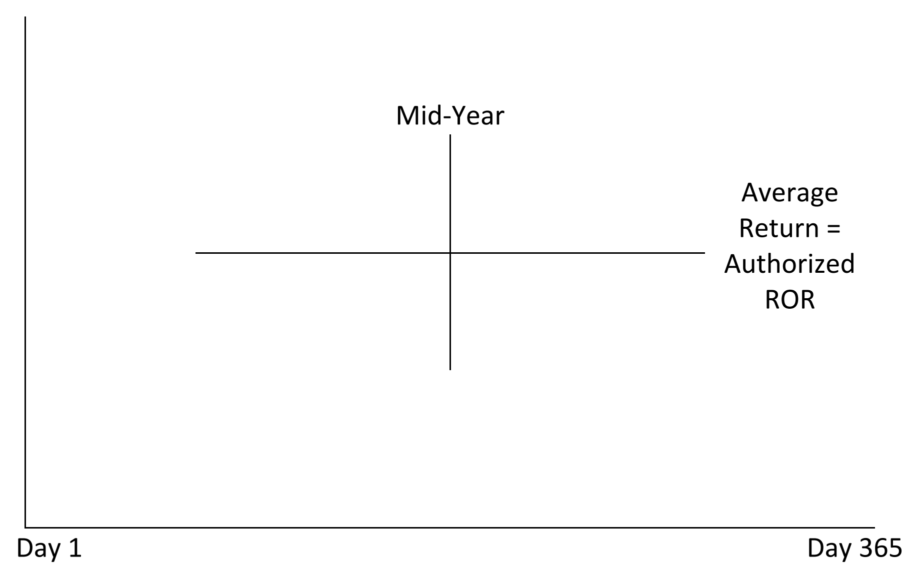
A. This case was filed on March 16, 2018. Columbia's new rates are expected to become effective on January 1, 2019, which is approximately twelve months before the end of the Company's FPFTY of December 31, 2019. Though the Company does not know of any projects that have a completion date beyond the end of the Company's FPFTY (I&E Ex. No. 3, Sch. 2), allowing the Company to use the December 31, 2019 year-end plant-in-service as proposed by Columbia in this proceeding could result in customers paying, for approximately twelve months, rates that include costs for projects and plant that are not in service and used or useful to those customers. In other words, Columbia would potentially be collecting a return of and a return on plant that is not used or useful in the provision of utility service to its customers for nearly a year before that plant actually goes into service.

Q. HOW DOES THE YEAR-END PLANT INCLUSION IN FPFTY CALCULATIONS IMPACT CUSTOMER RATES AND COMPANY RETURNS?

A. Using the year-end approach to determine rates, on day one the new rates go into effect on January 1, 2019, the Company is earning a return of and a return on plant investments that will not fully materialize before the final day of the FPFTY on December 31, 2019. Accordingly, customers would pay rates in January 2019 that are calculated to recover depreciation expense and a return on investment at the end of the FPFTY, which are in excess of the rates that are necessary to provide the revenue requirement that allows the Company the opportunity to earn its authorized rate of return ("ROR") on the plant and expenses that are used and useful when the new rates become effective. Requiring customers to pay a return of and on plant investments that will not occur for almost one year does not produce just and reasonable rates for ratepayers. Instead, ratepayers reach the projected "just and reasonable" rate point on the final day of the FPFTY or more specifically on the first day of the year after the FPFTY.

Q. HOW DOES THE USE OF AN AVERAGE RATE BASE RESULT IN RATES THAT ARE JUST AND REASONABLE?

A. An average rate base would yield an average annual return on rate base throughout the FPFTY equal to the authorized ROR. Simply illustrated, the picture is as follows:



Under the Company's proposed methodology, only the end-of-year point at Day 365 would coincide with the authorized ROR, which would shift the entire graph upwards with the entire ROR line shifted above the authorized rate of return for every point.

Q. DOES THE COMPANY MAKE OTHER FPFTY CLAIMS THAT FURTHER DEMONSTRATE HOW THE PROPOSED YEAR-END METHODOLOGY RESULTS IN UNJUST AND UNREASONABLE RATES?

A. Yes. As I mentioned previously, the return of investment, or depreciation expense, which is recovered on a dollar for dollar basis, will also be overstated to reflect an amount greater than the Company's actual recorded depreciation expense in the FPFTY. Because the plant is added at different dates throughout the year, the Company will not record a full-year of depreciation expense for plant that is added variably throughout the year, which results in a greater revenue requirement result than necessary when the full end-of-year depreciation expense is included in the Company's FPFTY claim.

Likewise, usage declines and customer count adjustments projected to the end of the FPFTY will not accurately reflect the actual FPFTY usage, nor will annualized expenses for which a full year's expense is not realized in the FPFTY accurately reflect the actual FPFTY expenses. Both will impact the revenue requirement through the ratemaking equation on a dollar for dollar basis and overinflate the Company's FPFTY revenue needs. These items will all serve to shift the return graph even further upward, which would result in an end of FPFTY ROR that is even higher than the authorized ROR.

The expense issues and authorized ROR will be addressed elsewhere in testimony by I&E witnesses Patel in I&E Statement No. 1 and Henkel in I&E Statement No. 2.

Q. IS YOUR DIRECT TESTIMONY MAKING A SPECIFIC ROR RECOMMENDATION?

A. No. I&E witness Henkel (I&E St. No. 2) discusses I&E's recommended adjustments to the Company's ROR claims. My testimony simply addresses the impact of the end-of-year versus average rate base, revenue, and expense claims have on the ROR and rates.

Q. IS THIS THE FIRST TIME I&E OR ANY OF THE STATUTORY ADVOCATES HAVE RAISED THIS AVERAGE RATE BASE ISSUE IN PROCEEDINGS BEFORE THE COMMISSION?

A. No. I&E and the Office of Consumer Advocate ("OCA") recently raised this issue in the Pennsylvania American Water Company base rate proceeding at Docket No. R-2017-2595853.[1] Prior to that, the OCA and the Office of Small Business Advocate ("OSBA") raised this issue in the UGI Penn Natural Gas, Inc. base rate proceeding at Docket No. R-2016-2580030. OCA also raised it in the FirstEnergy base rate proceedings at Docket Nos. R-2016-2537349, R-2016-2537352,

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[1] In that proceeding, I&E referred to the average rate base as the half-year convention.

R-2016-2537355, R-2016-2537359. Those cases were all resolved through settlement; therefore, this issue has not been presented to the Commission for resolution.

Q. DO ANY OTHER STATE UTILITY COMMISSIONS OR JURISDICTIONS APPLY AN AVERAGE RATE BASE TO THE FPFTY IN THE SAME MANNER AS YOU RECOMMEND IN THIS CASE?

A. Yes. The Illinois Commerce Commission ("Illinois Commission"), allows a utility to propose a "future" test year that is "[a]ny consecutive twelve month period of forecasted data beginning no earlier than the date new tariffs are filed and ending no later than 24 months after the date new tariffs are filed." (I&E Exhibit No. 3, Schedule 3.) This allowed projected time period includes the same time period that Pennsylvania allows as a FPFTY. While the Illinois Administrative Code does not specifically mandate that an average rate base should be used, paragraph (e) of Section 285.2005 mandates specific reporting and calculation requirements in the event that an average rate base is not used (I&E Exhibit No. 3, Schedule 4, p. 2). Additionally, the Illinois Commission has concluded that an average rate base is more appropriate than a year-end rate base, given a future test year, which, by definition, can match the FPFTY in Pennsylvania (*Re North Shore Gas Company*, 2013 WL 3762292 (Ill. C. C.), pp. 28-29 (Order entered June 18, 2013)).

Q. WILL THE REDUCTION IN THE REVENUE REQUIREMENT ASSOCIATED WITH THESE ADJUSTMENTS IMPACT RATE CASE FREQUENCY?

A. Possibly. However, companies should file rate cases on the frequency demanded by revenue needs and should not unnecessarily inflate customer rates beyond what is just and reasonable for the sole purpose of decreasing rate case frequency. Imposing rates on customers that are excessive and unreasonable to alleviate a single issue does not comport with a utility's obligation to provide service at just and reasonable rates.

Further, utilizing an average rate base could allow earlier implementation of a distribution system improvement charge ("DSIC") if the Company demonstrated that the plant-in-service used to establish rates had been added to rate base. Usage of the DSIC earlier would mitigate the impact of the rate increase that would result from assuming an end-of-year rate base in establishing rates and still provide the Company the opportunity to recover later DSIC-eligible plant investments, potentially within the FPFTY. Earlier implementation of the DSIC could also limit any increase in rate case frequency presumed to be associated with usage of the average rate base method.

Q. IS COLUMBIA CURRENTLY USING A DSIC TO MITIGATE THE COST OF PLANT INVESTMENTS BETWEEN RATE CASES?

A. No. In fact, Columbia's rate case filings have occurred with such frequency that the Company has not been eligible for a DSIC between rate cases.

Q. WHAT IS COLUMBIA'S RATE CASE FILING HISTORY?

A. Columbia's most recent base rate case at Docket No. R-2016-2529660 was filed on March 18, 2016. Columbia utilized a FPFTY ending December 31, 2017 in that filing. In recent years Columbia has increased its base rates frequently as shown below:

Docket No.	Proposed Increase ($Millions)	Settlement ($Millions)	Effective Date
R-2009-2149262	$32.3	$12.0	October 1, 2010
R-2010-2215623	$37.8	$17.0	October 18, 2011
R-2012-2321748	$77.3	$55.2	July 1, 2013
R-2014-2406274	$54.1	$32.5	December 20, 2014
R-2015-2468056	$46.2	$28.0	October 1, 2015
R-2016-2529660	$55.3	$35.0	December 19, 2016

In this filing, the Company is using an HTY ending November 30, 2017, which precedes its last FPFTY end. With this filing frequency and a year-end rate base assigned as determinative for reaching the threshold at which the Company would be eligible for a DSIC, the Company will never take full advantage of the DSIC to mitigate investment impacts and regulatory lag (Columbia's April 1, 2018 DSIC rate is 0.48%).

Q. HAS COLUMBIA PREVIOUSLY SUPPORTED THE USE OF A DSIC TO LIMIT BASE RATE CASE FREQUENCY?

A. Yes. In the Company's base rate cases in 2009 and 2010, Columbia witness Fox testified that "A gas DSIC would enable natural gas utilities to invest in infrastructure at an accelerated pace, while holding down the regulatory costs associated with full-scale base rate cases, which are ultimately borne by customers." (Docket No. R-2009-2149262, Columbia St. No. 1, p. 5; Docket No. R-2010-2215623, Columbia St. No. 1, p. 5). In fact, in the 2010 base rate case, Columbia witness Krajovic proposed a DSIC, and testified that "One of Columbia's primary concerns is the regulatory lag and the expense associated with litigating frequent base rate cases." (Docket No. R-2010-2215l623, Columbia St. No. 3, p. 3).

Q. WHAT COST AND RATE IMPACTS HAVE RESULTED FROM COLUMBIA'S FILING HISTORY?

A. First, the Company now proposes a rate case expense normalization period of 12 months and claims a rate case expense of $1,060,000 (Columbia St. No. 4, p. 41). This outcome is clearly not mitigating rate case expense that is borne by customers.

Second, the Company's history of rate cases has resulted in a 97.9% increase in base rates since the 2009 base rate case HTY present rate base rate revenue to the current case HTY present rate base rate revenue (($369,910,411 - $186,926,019) / $186,926,019) (R-2009-2149262, Columbia Ex. 102, Sch. 3, p. 3; R-2018-2647577, Columbia Ex. 2, Sch. 3, p. 3).

The Company's actual requested revenue increases and settled revenue increases are as follows:

Columbia Rate Case Increases					
Docket Number	HTY Base Rate Revenues at Present Rates	Requested Revenue Increase	Base Rate Revenue Percentage Increase Requested	Settlement Revenue Increase	Base Rate Revenue Percentage Increase Settled
R-2009-2149262	$ 186,926,019	$ 32,267,305	17.3%	$ 12,000,000	6.4%
R-2010-2215623	$ 195,453,577	$ 37,844,921	19.4%	$ 17,000,000	8.7%
R-2012-2321748	$ 212,908,870	$ 77,311,053	36.3%	$ 55,250,000	25.95%
R-2014-2406274	$ 275,697,027	$ 54,115,826	19.6%	$ 32,500,000	11.8%
R-2015-2468056	$ 316,025,587	$ 46,172,483	14.6%	$ 28,000,000	8.9%
R-2016-2529660	$ 337,065,977	$ 55,257,002	16.4%	$ 35,000,000	10.4%
Total Increases:			123.6%		72.1%

During this same time period, Pennsylvania's median family income grew by 26.6%:

	Median Income								
State	2016	2015	2014	2013	2012	2011	2010	2009	Income Growth 2009-2016
Pennsylvania	60,979	60,389	55,173	53,952	51,904	49,910	48,314	48,172	26.6%

Source: U.S. Census Bureau, Current Population Survey, Annual Social and Economic Supplements. Table H-8. Median Household Income by State: 1984 to 2016

Columbia's rate case filing history, and the corresponding revenue growth, clearly does not comport with I&E's historic position supporting gradualism and avoiding rate shock for customers. Columbia's rate increases have so far outstripped income growth that this rate case frequency, and the revenue increases requested and awarded, could be causing significant affordability issues for many of the Company's customers. Clearly the use of end-of-year plant additions only exacerbates this issue and this, therefore, further supports my recommendation for the average rate base methodology.

<u>ANNUAL DEPRECIATION EXPENSE</u>

Q. WHAT IS ANNUAL DEPRECIATION EXPENSE?

A. Depreciation is the loss of value of a utility's assets used and useful in the provision of utility service due to usage, passage of time, etc. The National Association of Regulatory Utility Commissioners defines annual depreciation expense as the annual cost associated with the diminution in the usefulness of an asset over time. Depreciation expense is the way the return of a utility's investment is captured in rates and is generally computed by dividing the original cost of an asset by its expected useful life or by multiplying the annual accrual rate by the original cost.

Q. WHAT IS COLUMBIA'S CLAIMED ANNUAL DEPRECIATION EXPENSE FOR THE FTY AND FPFTY?

A. Based on the data provided in Columbia's response to I&E-RB-30, Columbia's claimed annual depreciation expense for the FTY ending November 30, 2018 is $68,131,534 (I&E Ex. No. 3, Sch. 5) and for the FPFTY ending December 31, 2019 is $77,301,907 (Columbia Ex. No. 105, p. 6). The Company determined its annual depreciation expense claim for the FPFTY by taking the calculated annual depreciation expense plus the five-year amortization of net salvage.

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE COMPANY'S ANNUAL DEPRECIATION EXPENSE CLAIM?

A. Yes. Based on my use of average rate base methodology, I recommend an annual depreciation expense of $72,716,721, which represents a decrease of $4,585,187 to the Company's annual depreciation expense claim ($72,716,721 - $77,301,908) (I&E Ex. No. 3, Sch. 6).

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED ANNUAL DEPRECIATION EXPENSE?

A. My recommended $72,716,721 of annual depreciation expense for Columbia was calculated as follows:

First, I computed I&E's $68,249,763 recommended annual depreciation expense by taking the average of the Company's annual depreciation expense for the FTY ending November 30, 2018 and the Company's annual depreciation expense for the FPFTY ending December 31, 2019:

($63,942,330 + $72,557,195) ÷ 2 = $68,249,763.

Then, I computed the average the of the Company's five-year amortization of net salvage for the FTY ending November 30, 2018 and the Company's five-year amortization of net salvage for the FPFTY ending September 30, 2019:

($4,189,204 + $4,744,713) ÷ 2 = $4,466,958.

My $72,716,721 annual depreciation expense recommendation was determined by taking the average annual depreciation expense plus the average amortization of net salvage ($68,249,763 + $4,466,958) (I&E Ex. No. 3, Sch. 6, col. E).

DEPRECIATION RESERVE

Q. WHAT IS DEPRECIATION RESERVE?

A. A utility's depreciation reserve is the aggregate of all the annual depreciation expenses over the years that the asset was in service. The depreciation reserve is subtracted from the original cost of plant in service as part of the total rate base calculation.

Q. WHAT IS COLUMBIA'S DEPRECIATION RESERVE FOR THE FTY AND FPFTY?

A. The depreciation reserve for the FTY is $458,885,725 (Columbia Ex. No. 108, p. 3, col. 3, line 5) and for the FPFTY is $499,229,725 (Columbia Ex. No. 108, p. 3, col. 5, line 5).

Q. DO YOU HAVE A RECOMMENDATION REGARDING THE UTILITY'S DEPRECIATION RESERVE IN THIS PROCEEDING?

A. Yes. I recommend an accumulated depreciation amount of $479,057,725 for the FPFTY (I&E Ex. No. 3, Sch. 1, col. H, line 4).

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED DEPRECIATION RESERVE AMOUNT?

A. My recommended $479,057,725 of depreciation reserve was determined by taking the average of the Company's depreciation reserve for the FTY ending November 30, 2018 and the Company's depreciation reserve for the FPFTY ending December 31, 2019 as shown on I&E Exhibit No. 3, Schedule 1, line 5 and below:

($458,885,725 + $499,229,725) ÷ 2 = $479,057,725.

<u>RATE BASE</u>

Q. WHAT IS RATE BASE?

A. Rate base is the depreciated original cost of a utility's investment in plant a utility has in place to serve customers plus other additions and deductions that the Commission determines to be necessary in order to keep the utility operating and providing safe and reliable service to its customers.

Q. HOW IS RATE BASE USED WITHIN THE RATEMAKING FORMULA?

A. Rate base is one part of the financial equation used by the Commission to determine the appropriate revenue that a utility is granted in a rate proceeding. The revenue determination allows the utility to meet its expense obligations and gives it the opportunity to earn the rate of return established by the Commission in a rate proceeding. The equation used to determine the proper revenue requirement level is:

Revenue Requirement = (Rate Base x Rate of Return) + Operating Expenses + Depreciation Expenses + Taxes.

Q. HOW IS THE DEPRECIATED ORIGINAL COST OF PLANT-IN-SERVICE AT THE END OF THE TEST YEAR DETERMINED?

A. The depreciated original cost is equal to the original cost of the plant-in-service that is used and useful in the provision of utility service to the customers less the depreciation reserve as adjusted by other items such as salvage value and removal costs. Before the passage of Act 11, the end of the FTY was the focal point used to calculate the depreciated original cost. With the addition of the FPFTY in Act 11, the depreciated original cost of the plant in service is computed by taking a “snapshot” look at the depreciated original cost value of used and useful utility plant estimated to be in service at the end of the FPFTY. It is the “snapshot” look at the depreciated original cost value of used and useful utility plant estimated to be in service at the end of the FPFTY that is used to formulate my average rate base recommendation.

Q. WHAT OTHER ADDITIONS AND DEDUCTIONS TO THE DEPRECIATED ORIGINAL COST OF UTILITY PLANT ARE ALLOWED?

A. Some of the additions to the depreciated original cost of a company's investment in utility include materials and supplies, gas in storage, prepayments, and cash working capital. Some of the deductions include deferred income taxes and customer deposits. Some additions are applicable to a specific utility or utility type. The FPFTY depreciated original cost claimed by Columbia in this proceeding is $2,246,193,238 shown on Columbia Exhibit No. 108, page 3. The claimed additions to the Company's depreciated original cost are as follows:

1. Materials and Supplies;
2. Gas Storage Underground;
3. Prepayments;

The deductions to the depreciated original cost are:

1. Deferred Income Taxes;
2. Customer Deposits;
3. Customer Advances.

Q. DID THE COMPANY PROVIDE SUPPLEMENTAL TESTIMONY AS A RESULT OF THE TAX CUT AND JOBS ACT ("TCJA")?

A. Yes. Columbia witness Krajovic stated in supplemental testimony that the Company is proposing a credit to rate base as a result of the TCJA (Columbia St. No. 10-Supp, p. 7).

Q. WHAT IS THE COMPANY'S REVISED RATE BASE CLAIM AS A RESULT OF THE TCJA?

A. In Columbia Exhibit NJDK-S3 and the Company's response to I&E-RE-92, the Company reduced its rate base claim by $16,943,974 in both the FTY and FPFTY to account for changes made by the TCJA. The result is to reduce the Company's rate base claim in the FTY from $1,658,931,197 to and $1,641,987,223 and in the FPFTY from $1,915,996,457 to $1,899,052,483 (I&E Ex. No. 3, Sch. 1, lines 23-25, col. A and D).

Q. DO THE ADJUSTMENTS FOR THE TCJA IMPACT THE RECOMMENDATIONS YOU ARE MAKING FOR AVERAGE RATE BASE?

A. No. I&E witness Patel discusses the Company's proposal regarding the TCJA in I&E Statement No. 2.

Q. ON WHAT RATE BASE CLAIMS ARE YOU BASING YOUR RECOMMENDATIONS?

A. Based on I&E witness Patel's recommendation, I am basing my rate base recommendations on the Company's originally filed claims.

Q. IS I&E RECOMMENDING ANY ADJUSTMENTS TO THE ADDITIONS AND DEDUCTIONS LISTED ABOVE?

A. Yes. As discussed below, I am recommending adjustments to Materials and Supplies, prepayments, gas storage underground, total deferred income taxes, and customer deposits.

<u>MATERIALS AND SUPPLIES</u>

Q. HOW DID THE COMPANY DEVELOP ITS CLAIM FOR MATERIALS AND SUPPLIES?

A. As shown on Schedule No. 5 of Columbia Exhibit No. 108, the $851,388 claim for Materials and Supplies in the FPFTY was calculated based upon a 13-month average of historic monthly balances adjusted for inflation.

Q. DID THE COMPANY STATE THAT IT WOULD UPDATE ITS MATERIALS AND SUPPLIES CLAIM THROUGHOUT THIS PROCEEDING?

A. No. However, in response to I&E-RB-27, the Company provided a schedule with the most recent materials and supplies balances available, through April 2018 (I&E Exhibit No. 3, Schedule 7).

Q. WHAT DO YOU RECOMMEND CONCERNING THE COMPANY'S $851,388 CLAIM FOR MATERIALS AND SUPPLIES?

A. I recommend the Company's $851,388 claimed level of Materials and Supplies be increased by $12,926 to $864,314 (I&E Ex. No. 3, Sch. 1, line 9).

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED LEVEL OF MATERIALS AND SUPPLIES?

A. I updated the monthly level of materials and supplies in the FTY to account for the additional actual balances provided by the Company in its response to I&E-RB-27 (I&E Ex. No. 3, Sch. 7). This update results in an increase to the 13-month average materials supplies claim in the FTY of $23,991 from $828,714 to $852,705 (I&E Ex. No. 3, Sch. 1, col. A-C, line 9). Additionally, because the Company's monthly materials and supplies balances for the FPFTY are based on an adjustment for inflation of the FTY balances, the update to the FTY actual balances necessarily result in an adjustment to the FPFTY balances as shown on I&E Exhibit No. 3, Schedule 8. Therefore, the Company's 13-month average materials and supplies level in the FPFTY should be increased by $24,536 from $851,388 to $875,924 (I&E Ex. No. 3, Sch. 1, col. D-F, line 9).

Finally, based on the average rate base methodology that I discuss above, my recommended $847,885 materials and supplies level was determined by averaging the adjusted FTY and FPFTY materials and supplies levels that I determined above as shown on I&E Exhibit No. 3, Schedule 1, line 9, and below:

($852,705 + $875,924) ÷ 2 = $864,314.

Q. IF THE COMPANY PROVIDES FURTHER UPDATES THROUGH THE COURSE OF THIS PROCEEDING, SHOULD THE MATERIALS AND SUPPLIES CLAIM BE ADJUSTED?

A. Yes. It is appropriate to use the most recent 13-month average available to determine the Materials and Supplies balance.

PREPAYMENTS

Q. WHAT IS THE COMPANY'S CLAIM FOR PREPAYMENTS?

A. The Company's claim for prepayments in the FTY is $2,318,286 (Columbia Ex. No. 108, p. 3, col. 3, line 10), and the claim for prepayments in the FPFTY is $3,087,006 (Columbia Ex. No. 108, p. 3, col. 3, line 10).

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S PREPAYMENTS CLAIM?

A. Yes. I recommend that the Company's claim for prepayments be reduced by $385,389 from $3,087,006 to $2,701,617 (I&E Ex. No. 3, Sch. 1, line 10).

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S CLAIM FOR PREPAYMENTS?

A. I updated the monthly level of prepayments in the FTY to account for the additional actual balances provided by the Company in its response to I&E-RB-26 (I&E Ex. No. 3, Sch. 9). This update results in a decrease to the 13-month average prepayments claim in the FTY of $1,017 from $2,318,286 to $2,317,269 (I&E Ex. No. 3, Sch. 1, col. A-C, line 10). Additionally, because the Company's monthly prepayments balances for the FPFTY are based on an adjustment for inflation of the FTY balances, the update to the FTY actual balances necessarily result in an adjustment to the FPFTY balances as shown on I&E Exhibit No. 3, Schedule 9. Therefore, the Company's 13-month average prepayments level in the FPFTY should be decreased by $1,041 from $3,087,006 to $3,085,965 (I&E Ex. No. 3, Sch. 1, col. D-F, line 10)

Finally, based on the average rate base methodology, my recommended $2,701,617 level of prepayments was determined by taking the average of the adjusted prepayments claim for the FTY and the adjusted prepayments claim for the FPFTY as shown on I&E Exhibit No. 3, Schedule 1, line 10 and below:

($2,317,269 + $3,085,965) ÷ 2 = $2,701,617.

GAS STORAGE UNDERGROUND

Q. WHAT IS THE COMPANY'S CLAIM FOR GAS STORAGE UNDERGROUND?

A. The Company's claim for gas storage underground in the FTY is $50,708,579 (Columbia Ex. No. 108, p. 3, col. 3, line 11), and the claim for gas storage underground in the FPFTY is $50,432,424 (Columbia Ex. No. 108, p. 3, col. 5, line 11).

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S GAS STORAGE UNDERGROUND CLAIM?

A. Yes. I recommend that the Company's claim for gas storage underground be increased by $138,078, from $50,432,424 to $50,570,502 (I&E Ex. No. 3, Sch. 1, line 11).

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S CLAIM FOR GAS STORAGE UNDERGROUND?

A. Based on the average rate base methodology, my recommended $50,570,502 level of gas storage underground was determined by taking the average of the Company's gas storage underground claim for the FTY and the Company's gas storage underground claim for the FPFTY as shown on I&E Exhibit No. 3, Schedule 1, line 11 and below:

$$(\$50{,}708{,}579 + \$50{,}432{,}424) \div 2 = \$50{,}570{,}502.$$

CUSTOMER DEPOSITS

Q. WHAT IS THE COMPANY'S CLAIM FOR CUSTOMER DEPOSITS?

A. The Company's claim for customer deposits in the FTY is $2,832,220 (Columbia Ex. No. 108, p. 3, col. 3, line 20), and the claim for customer deposits in the FPFTY is $2,838,227 (Columbia Ex. No. 108, p. 3, col. 5, line 11).

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S CUSTOMER DEPOSITS CLAIM?

A. Yes. I recommend that the Company's claim for customer deposits be decreased by $12,379, from $2,838,227 to $2,850,606 (I&E Ex. No. 3, Sch. 1, line 20).

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED ADJUSTMENT TO THE COMPANY'S CLAIM FOR CUSTOMER DEPOSITS?

A. I updated the monthly level of customer deposits in the FTY to account for the additional actual balances provided by the Company in its response to I&E-RB-28, attached as I&E Exhibit No. 3, Schedule 10. This update results in a decrease to the 13-month average customer deposits claim in the FTY of $30,764 from $2,832,220 to $2,862,984 (I&E Ex. No. 3, Sch. 1, col. A-C, line 20). Additionally, because the Company's monthly customer deposit balances for the FPFTY are based on the HTY balances, the update to the FTY actual balances does not result in an adjustment to the FPFTY balances as shown on I&E Exhibit

No. 3, Schedule 10. Therefore, the Company's 13-month average customer deposits level in the FPFTY should remain at $2,838,227 (I&E Ex. No. 3, Sch. 1, col. D-F, line 20)

Based on the average rate base methodology, my recommended $2,850,606 level of customer deposits was determined by taking the average of the adjusted customer deposits claim for the FTY and the Company's customer deposits claim for the FPFTY as shown on I&E Exhibit No. 3, Schedule 1, line 20 and below:

($2,862,984 + $2,838,227) ÷ 2 = $2,850,606.

<u>CUSTOMER ADVANCES FOR CONSTRUCTION</u>

Q. WHAT IS THE COMPANY'S CLAIM FOR CUSTOMER ADVANCES FOR CONSTRUCTION?

A. The Company's claim for customer advances for construction in the FTY is $2,552 (Columbia Ex. No. 108, p. 3, col. 3, line 22), and the claim for customer advances for construction in the FPFTY is $2,552 (Columbia Ex. No. 108, p. 3, col. 5, line 22).

Q. ARE YOU RECOMMENDING AN ADJUSTMENT TO THE COMPANY'S CUSTOMER ADVANCES FOR CONSTRUCTION CLAIM?

A. No. The Company is claiming the same level of customer advances for construction in both the FTY and the FPFTY and, as such, an average of the two years would not result in an adjustment (I&E Ex. No. 3, Sch. 1, line 22).

Q. WHAT EFFECT DOES I&E'S RECOMMENDED ADJUSTMENTS HAVE ON COLUMBIA'S REVISED RATE BASE AND ANNUAL DEPRECIATION EXPENSE CLAIM?

A. My use of the average rate base methodology and the resulting recommended adjustments discussed above reduce the Company's revised claimed rate base as shown on I&E Exhibit No. 3, Schedule 1, line 25 and as follows:

Effects of I&E's Plant in Service, Accumulated Depreciation Expenses, Materials and Supplies, Gas Storage Underground, Prepayments, Deferred Income Taxes, and Customer Deposits on Columbia's Claimed Rate Base for the Fully Projected Future Test Year ending December 31, 2019

Line No.	Company Claimed	I&E Adjustment	I&E Recommended
(A)	(B)	(C)	(D)
1	$1,899,052,483	$(128,524,778)	$1,770,527,705

The same methodology reduces the annual depreciation expense claim as shown on I&E Exhibit No. 3, Schedule 6 and as follows:

I&E's Recommended
Annual Depreciation Expense for the
Fully Projected Future Test Year ending December 31, 2019

Line No.	Company Claimed	I&E Adjustment	I&E Recommended
(A)	**(B)**	**(C)**	**(D)**
1	$77,301,908	$(4,585,187)	$72,716,721

<u>**FTY AND FPFTY REPORTING**</u>

Q. WHAT AMOUNT OF ADDITIONAL RATE BASE WILL BE ASSOCIATED WITH THE INCLUSION OF THE FPFTY ENDING DECEMBER 31, 2019 FOR COLUMBIA?

A. As mentioned above, the Company's claimed rate base for the FPFTY ending December 31, 2019 is $1,915,996,457 (Columbia Ex. No. 108, p. 3). Columbia's rate base for the FTY ending November 30, 2018 is $1,658,931,197 (Columbia Ex. No. 108, p. 3). Therefore, $257,065,260 ($1,915,996,457 – $1,658,931,197) of rate base additions are associated with the thirteen months between the end of FTY and the end of the FPFTY.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING PLANT ADDITIONS THAT COLUMBIA PROJECTS TO BE IN SERVICE DURING THE FTY ENDING NOVEMBER 30, 2018 AND THE FPFTY ENDING DECEMBER 31, 2019?

A. Yes. I recommend that the Company provide the Commission's Bureaus of Technical Utility Services and Investigation and Enforcement with an update to Columbia Exhibit No. 108, Schedule 1 no later than April 1, 2019, under this docket number, which should include actual capital expenditures, plant additions, and retirements by month for the twelve months ending November 30, 2018. An additional update should be provided for actuals through December 31, 2019, no later than April 1, 2020.

Q. WHY DO YOU RECOMMEND THAT COLUMBIA PROVIDE THESE UPDATES?

A. Although I&E is recommending that Columbia's plant projections be modified by applying the average rate base methodology, I&E continues to believe that there is value in determining how closely Columbia's projected investments in future facility comport with the actual investments that are made by the end of the FTY and FPFTY. Determining the correlation between Columbia's projected and actual results will help inform the Commission and the parties in Columbia's future rate cases.

Whether based on the average rate base methodology or a FPFTY, the updates are important. As I previously explained, through use of the FPFTY, Columbia is essentially requiring ratepayers to pre-pay a return on its projected investment in future facilities that are not in place and providing service at the time the new rates take effect, but also are not subject to any guarantee of being completed and placed into service. While the FPFTY provides for such projections, there should be verification of the projections. Therefore, requiring the Company to provide updates demonstrating that actual investments comport with projections used in setting rates using the FPFTY provides the Commission with actual data to gauge the accuracy of Columbia's projected investments in future proceedings.

PRESENT RATE REVENUE

Q. WHAT IS THE COMPANY'S CLAIMED PRESENT RATE REVENUE LEVEL IN THE FPFTY?

A. The Company's claimed Total Operating Revenues under pro forma present rates in the FPFTY are $575,348,119 (Columbia Gas Ex. No. 103, Sch. No. 1, p. 15 of 15, line 45).

Q. HOW DOES THE COMPANY DETERMINE ITS CLAIMED PRESENT RATE REVENUE IN THE FPFTY?

A. The Company's present rate revenue is made up of revenue from number of bills, revenue from sales volumes, and revenue from Riders and gas costs. The Company calculates its number of bills based on which rate schedule the customer is on at the end of the HTY (Columbia St. No. 3, pp. 9-10). The number of bills is then adjusted for new construction customers and customer attrition as well as adjustments from Large Commercial or Industrial customers that will either discontinue or add to service in the FTY or FPFTY. The sales volumes are the sum of forecasted Dth, Large Commercial and Industrial adjustments, new construction consumption, attrition consumption, and rate schedule transfers (Columbia St. No. 3, pp. 10-11).

Q. WHAT DO YOU RECOMMEND REGARDING THE COMPANY'S PRESENT RATE REVENUE LEVEL IN THE FPFTY?

A. I recommend that the Company's Total Operating Revenue under pro forma present rate revenue be decreased by $2,533,278, from $573,757,395 to $571,224,117 (I&E Ex. No. 3, Sch. 11, p. 5, col. J, line 35).

Q. WHY DO YOU RECOMMEND THE COMPANY'S CLAIMED PRO FORMA PRESENT RATE REVENUE BE DECREASED TO $571,224,117?

A. When calculating a revenue requirement in a designated test year, it is vital that the expenses and revenues are assessed using the same time period. In this case, I&E is recommending the application of an average rate base to calculate the Company's rate base and depreciation expense claims, as described above. Therefore, for purposes of consistency, it is also necessary to calculate the Company's present rate revenue level in the FPFTY using a consistent average methodology.

The adjustments to present rate revenue claimed by the Company, which I listed above, occur in the approximately twelve months after rates go into effect for Columbia customers, or from January 1, 2019 through December 31, 2019. Therefore, the rates customers pay on January 1, 2019 will be improperly calculated based on a projected revenue requirement for the year ending December 31, 2019. A more reasonable approach would be to average the effect of changes that occur at varying rates over the course of the full year in order to match the average rate base that I described above.

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED PRESENT RATE REVENUE LEVEL IN THE FPFTY.

A. I averaged the Company's year-end FTY adjusted bills and sales projections and the Company's year-end FPFTY adjusted bills and sales projections. I then multiplied each by the appropriate rate (I&E Ex. No. 3, Sch. 11, pp. 1-5).

Q. PLEASE IDENTIFY YOUR RECOMMENDED ADJUSTMENT TO THE PRESENT RATE REVENUE LEVEL IN THE FPFTY BY RATE CLASS.

A. My recommended decrease is $2,533,278 to the present rate revenue level in the FPFTY from $573,757,395 to $571,224,117 (I&E Ex. No. 3, Sch. 11, p. 5, line 35). The amounts by rate class are shown on I&E Exhibit No. 3, Schedule 11, pages 2 and 5 and as follows:

Rate Class	Company Revenue	Adjustment	I&E Revenue
Total Residential Sales	$357,399,795	($926,537)	$356,473,258
Total Small General Sales	$79,352,495	($961,612)	$78,390,883
Total Negotiated Sales	$288,617	$0	$288,617
Total Large General Sales	$5,272,920	($52,123)	$5,220,797
Residential Distribution Service	$66,540,226	($184,380)	$66,355,846
Total Small Distribution Service	$45,820,685	($309,207)	$45,511,478
Total Large Distribution Service	$17,899,205	($74,347)	$17,824,858
Total Main Line Distribution Service	$1,183,452	($25,072)	$1,158,380
TOTAL GAS COST:	$573,757,395	($2.533,278)	$571,224,117

Q. DOES YOUR RECOMMENDED PRESENT RATE REVENUE ADJUSTMENT INCLUDE AN ADJUSTMENT FOR GAS COSTS?

A. Yes. The present rate revenue calculation for each rate class includes a line for the calculation of gas costs based on the sales. Therefore, my adjusted average sales would also necessarily be used to calculate a gas cost revenue adjustment based on the average sales as shown on I&E Exhibit No. 3, Schedule 11, p. 2, lines 42, 49, 53, 58 and I&E Exhibit No. 3, Schedule 11, p. 5, lines 21 and 26 and below.

Rate Class	Company Gas Cost	Adjustment	I&E Gas Cost
Total Residential Sales	$113,767,356	($246,567)	$113,520,789
Total Small General Sales	$36,670,038	($478,270)	$36,191,768
Total Negotiated Sales	$268,017	$0	$268,017
Total Large General Sales	$3,167,707	($33,429)	$3,134,278
Residential Distribution Service	$6,416,705	($14,826)	$6,401,879
Total Small Distribution Service	$3,217,113	($23,407)	$3,193,706
TOTAL GAS COST:	$163,506,936	($796,499)	$162,710,437

<u>COST OF SERVICE</u>

Q. WHAT IS AN ALLOCATED COST OF SERVICE ("ACOS") STUDY?

A. A utility provides service to a defined set of customer classes that are different in terms of demand and usage patterns. An ACOS allocates or assigns a utility's revenue requirement based on those service differences. In other words, an ACOS is a formalized analysis of costs that attempts to assign to each customer or rate class its proportionate share of the Company's total cost of service (i.e., the Company's total revenue requirement). The results of such a study can be utilized to determine the relative cost of service for each class and help determine the individual class revenue requirements and, to the extent a particular class is above or below the system average rate of return, show the additional revenues each class receives or conversely the additional revenues that each class contributes to the Company's overall revenues. In addition to the relative provision of revenues, a relative rate of return is also provided, which shows how the rate of return for each class compares to the system average rate of return.

Q. WHAT ARE RATE OF RETURN AND RELATIVE RATE OF RETURN?

A. The rate of return is the Commission authorized return on rate base that is determined in a base rate proceeding. A relative rate of return indicates how the rate of return of each customer class compares to the system average rate of return. In general, a relative rate of return that provides revenue equal to its cost to serve would have a relative rate of return equal to 1.0.

Q. DID THE COMPANY PROVIDE AN ACOS STUDY IN THIS PROCEEDING?

A. Yes. The Company performed and provided three ACOS studies in its filing sponsored by Columbia witness Mark P. Balmert as he described on page 4 of Columbia Statement No. 11. The first is a customer-demand ACOS study (Columbia Exhibit No. 111, Schedule 1), the second is a peak and average ACOS study (Columbia Exhibit No. 111, Schedule 2); and the third ACOS study is an average of the customer-demand studies and the peak and average studies (Columbia Exhibit No. 111, Schedule 3).

Q. WHAT IS THE LARGEST CAPITAL COST OF THE COMPANY?

A. According to Company's witness Mr. Balmert, 87 percent of Columbia's gross plant investment is devoted to mains and services and approximately twenty percent (20%) of its operation and maintenance costs are related to mains and services (Columbia Exhibit No. 11, page 15).

Q. WHAT IS THE MAIN DIFFERENCE BETWEEN THE CUSTOMER-DEMAND AND THE PEAK AND AVERAGE ACOS STUDIES?

A. The difference between the customer-demand ACOS and the peak and average ACOS studies presented by Mr. Balmert in Company Exhibit No. 111 is in the way that each study allocates the costs of mains. Consequently, the two ACOS studies yield different relative rates of return for each rate class. As witness describes on page 4 of Columbia Statement No. 11, the customer-demand study is generally more favorable to the industrial class and the peak and average study is generally more favorable to the residential class.

The customer-demand methodology classifies distribution mains as partially customer related and partially demand related. The customer portion of mains is then allocated to the various customer classes based on the total number of customers, while the demand portion of mains is allocated to classes based on peak day contributions or demand. This methodology has been rejected by the Commission in other natural gas base rate cases.

The peak and average ACOS, however, allocates distribution mains to classes based partially on contributions to peak day demand and partially on annual consumption (average demand). This methodology has been accepted by the Commission in previous cases.

Q. WHAT IS THE IMPACT ON THE RELATIVE RATE OF RETURN UNDER THE CUSTOMER-DEMAND METHODOLOGY AND THE PEAK AND AVERAGE METHODOLOGY?

A. With the customer-demand COSS, the relative rate of return under present rates for the RSS/RDS customer classes is 0.77 (Columbia Exhibit No. 111, Schedule 1, page 2, line 14, column D). Under this scenario, the Company does not recoup the full costs it incurs to provide service for the RSS/RDS customer classes. Conversely, under the peak and average methodology, the relative rate of return under present rates for the same customer classes (RSS/RDS) is 1.14 (Columbia Exhibit No. 111, Schedule 2, page 2, line 14, column D). With the peak and average COSS, the RSS/RDS customer classes pay more than the Company incurs to provide service for them under present rates.

This difference can be explained by the fact that the customer-demand study places more cost obligation on the customer component of the distribution system, which must be designed to reach all customers. This design aspect of the customer-demand study implies a greater impact on the largest class of customers in terms of number of customers. The demand component of the distribution system is the sizing of the system to meet peak demand, which would have a greater impact on largest class of customers in terms of volume.

Q. WHICH OF THE THREE ACOS STUDIES SPONSORED BY MR. BALMERT DID THE COMPANY UTILIZE TO ALLOCATE THE PROPOSED REVENUE INCREASES?

A. The Company utilized the third ACOS study sponsored by Mr. Balmert which is the average of the customer-demand study and the peak and average study, presented on Columbia Exhibit No. 111, Schedule No. 3 to allocate the proposed revenue increases (Columbia St. No. 3, pp. 4-5).

Q. WHICH ACOS STUDY DO YOU RECOMMEND THE COMMISSION USE TO ALLOCATE THE REVENUE INCREASES AMONG THE DIFFERENT CUSTOMER CLASSES IN THIS PROCEEDING?

A. I recommend the Commission use the peak and average ACOS study provided by the Company on Columbia Exhibit No. 111, Schedule 2 to allocate the final revenue increases among the different customer classes.

Q. HAS THE COMMISSION PREVIOUSLY APPROVED THE USE OF THE PEAK AND AVERAGE ACOS STUDY IN A RATE PROCEEDING?

A. Yes. The Commission has previously recognized that distribution mains are built on the basis of year-round demands as well as peak demands. In the National Fuel Gas Distribution Company ("NFGD") 1994 base rate proceeding, the Commission accepted the Peak & Average methodology, stating:

> "[t]he Peak and Average method that allocates mains equally is a sound and reasonable method of cost allocation and should remain intact." (*Pa. P.U.C. v. National Fuel Gas Distribution Co.,* 83 Pa. PUC 262 (1994).

Q. HAS THE COMMISSION PREVIOUSLY REJECTED INCLUDING THE COST OF DISTRIBUTION MAINS AS A CUSTOMER COST?

A. Yes. The Commission has previously rejected including the cost of distribution mains as a customer cost in the Philadelphia Gas Works 2007 base rate proceeding at Docket No. R-00061931. Specifically, the Commission stated at Docket No.

R-00061931, Order entered September 28, 2007 that “PGW’s proposal to allocate a percentage of the cost of the distribution mains as a customer cost not to be acceptable” and that “[r]eviewing the record, we find that the allocation of distribution mains investment costs should be done using both annual and peak demands.”

Q. ARE YOU AWARE OF ANY CASES IN WHICH THE COMMISSION HAS ACCEPTED THE USE OF THE CUSTOMER-DEMAND METHODOLOGY FOR DEVELOPING AN ACOS STUDY?

A. No. I am not aware of any case in which the Commission has accepted the use of the customer-demand methodology for developing a cost of service study.

Q. HOW DID THE COMPANY CLASSIFY AND ALLOCATE MAINS AND MAINS-RELATED ACCOUNTS IN THE PEAK AND AVERAGE COSS?

A. In the peak and average study, Columbia allocated low pressure mains and non-low pressure mains in the same manner. The Company equally weighted average throughput volumes based on the historic test year ended November 30, 2017 and design day volumes (Columbia St. No. 11, pp. 11-12).

Q. DO YOU AGREE WITH THIS MANNER OF CLASSIFYING AND ALLOCATING THE FIXED COST OF MAINS AND MAINS-RELATED ACCOUNTS?

A. Yes. The Commission previously determined in a 1994 Opinion and Order in the Pennsylvania American Water Company case at Docket No. R-00932670, Order entered July 26, 1994, at pages 111- 115, that direct customer costs include "the depreciation, return and income taxes associated with meter and service investment; the O&M costs for meters and services; and the expense associated with meter reading and billing." Mains are not included in any of these categories, and therefore should not be considered or classified as a customer cost. The basis for this determination is that the quantity and investment in mains does not change significantly if one customer joins or leaves the system. Mains are built to deliver gas, and the cost of mains cannot be assigned to one specific customer. Therefore, no portion of the fixed costs or depreciation expense associated with mains should be allocated to the customer cost function.

The Commission also reaffirmed that the cost of mains should be allocated on a combination of throughput and demand, and therefore not allocated to the customer function. In that case, Administrative Law Judge Jones noted that "the Commission has rejected minimum and zero-intercept system methods as inconsistent with causation." (PPL Gas Utilities, Docket No. R-00061398, Order entered February 8, 2007).

<u>CUSTOMER COST ANALYSIS</u>

Q. WHAT IS A CUSTOMER COST ANALYSIS AND HOW IS IT USED?

A. A customer cost analysis is a part of a COSS that is used to determine the appropriate fixed customer charges for the various classes and meter sizes. It includes customer costs only.

Q. WHY IS IT NECESSARY TO PERFORM A CUSTOMER COST ANALYSIS?

A. A fixed customer charge represents the revenue that the Company is guaranteed to receive each month, regardless of the level of usage. As acknowledged in the seventh edition of the American Water Works Association M1 Manual, there is a tradeoff between revenue stability from a high customer charge, and affordability and conservation from a low customer charge and higher usage rates.[2]

Q. WHAT IS A DIRECT CUSTOMER COST?

A. A direct customer cost is a cost that changes with the increase or decrease of a single customer.

Q. WHAT IS AN INDIRECT CUSTOMER COST?

A. An indirect customer cost is a customer related cost that does not change with the increase or decrease of a single customer. The Commission has allowed, in past instances, certain indirect customer costs to be included in a customer cost analysis and thus recovered in a customer charge. As an example, in previous cases, the Commission has allowed the indirect cost of Employee Pension and Benefits.

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[2] AWWA Manual of Water Supply Practices M1 Principles of Water Rates, Fees, Charges, Seventh Edition. pp. 154-155.

Q. DID COLUMBIA PREPARE A CUSTOMER COST ANALYSIS TO SUPPORT THE PROPOSED CUSTOMER CHARGE INCREASES IN THIS PROCEEDING?

A. Yes. The Company prepared two customer cost analyses presented in Columbia Exhibit No. 111, Schedule 1, pages 14-30. The first of the Company's customer cost analyses allocates a portion of the cost of mains to customers and is presented on pages 14-22. The second of the Company's customer cost analyses does not allocate any portion of the cost of mains to customers and is presented in Columbia Exhibit No. 111, Schedule 1, pages 23-31. The results of each customer cost analysis are presented in the following table:

Customer Class	Including Mains (Columbia Ex. No. 11, Sch. 1, p. 16, line 41)	Excluding Mains (Columbia Ex. No. 11, Sch. 1, p. 25, line 37)
RSS/RDS	$46.05	$19.66
SGSS1/SCD1/SGDS1	$51.18	$22.46
SGSS2/SCD2/SGDS2	$96.64	$41.78
SDS/LGSS	$517.57	$199.54
LDS/LGSS	$1,773.97	$910.57
MLDS	$584.57	$366.56

Q. HOW DID COLUMBIA DETERMINE THE FIXED MONTHLY COSTS BY CUSTOMER CLASS ABOVE?

A. According to Columbia witness Paula A. Strauss, the Company designed its rates to strike a balance between gradualism and movement towards the cost to serve residential customers (Columbia St. No. 3, p. 23).

Q. DO YOU BELIEVE THAT THE COMPANY'S CUSTOMER COST ANALYSIS THAT INCLUDES THE COST OF MAINS SHOULD BE CONSIDERED?

A. No. As I discussed above, the Commission has established in previous cases that mains are not properly included in a customer cost analysis. The Commission stated in the PGW base rate case at Docket No. R-00061931, Order entered September 28, 2007 that it found "PGW's proposal to allocate a percentage of the cost of the distribution mains as a customer cost not to be acceptable." Additionally, I am unaware of any cases in which the Commission has allowed the cost of mains to be included in a customer cost analysis. Therefore, I recommend the Company's customer cost analysis that includes the cost of mains should not be considered.

Q. DO YOU AGREE WITH ALL OF THE COSTS INCLUDED IN THE COMPANY'S CUSTOMER COST ANALYSIS?

A. No. I believe that the Company's customer cost analysis improperly includes indirect costs such as, but not limited to, uncollectibles, miscellaneous costs related to customer accounts, and miscellaneous costs related to customer service and information.

Q. ARE YOU SUBMITTING A CUSTOMER COST ANALYSIS IN THIS CASE TO SUPPORT A DIFFERENT RESIDENTIAL CUSTOMER CHARGE?

A. No. While I disagree with some of the items the Company included in its customer related revenue requirement analysis, my analysis does not produce results sufficiently different to warrant a revised customer cost analysis and related testimony in this case.

<u>CUSTOMER CHARGE</u>

Q. WHAT CUSTOMER CHARGES IS THE COMPANY PROPOSING FOR EACH RATE CLASS?

A. The customer charges proposed for each rate class is shown in the table below. The Company is only proposing an increase in the customer charge for the residential (RS, RDS, RCC) and Small General Service for customers using less than or equal to 6,440 Therms, annually (SGSS1, SCD1, SGDS1) (Columbia No. 103, Sch. No. 8, pp. 6-10).

Rate Schedule (Therms, annually)	Present Rate	Change	Proposed Rate	Percent Increase
RS, RDS, RCC				
All Usage	$16.75	$1.50	$18.25	8.96%
SGSS1, SCD1, SGDS1				
≤6,440	$21.25	$1.50	$22.75	7.06%
SGSS2, SCD2, SGDS2				
>6,440 to ≤64,440	$48.00	$0.00	$48.00	0.00%
SDS/LGSS				
>64,400 to ≤110,000	$229.75	$0.00	$229.75	0.00%
>110,000 to ≤540,000	$757.34	$0.00	$757.34	0.00%
NSS & MLDS-I and MDS Class II				
>274,000 to ≤540,000	$469.34	$0.00	$469.34	0.00%
>540,000 to ≤1,074,000	$1,149.00	$0.00	$1,149.00	0.00%
>1,074,000 to ≤3,400,000	$2,050.00	$0.00	$2,050.00	0.00%
>3,400,000 to ≤7,500,000	$4,096.00	$0.00	$4,096.00	0.00%
>7,500,000	$7,322.00	$0.00	$7,322.00	0.00%

Q. DO YOU AGREE WITH THE COMPANY'S RECOMMENDED INCREASE TO THE RESIDENTIAL AND SMALL GENERAL SERVICE RATE CUSTOMER CHARGES?

A. Yes. Despite the fact that I disagree with the items included in the Company's customer cost analysis, I believe the Company's requested increases to the residential and small general service rate customer charges are acceptable because the increases do not violate the concept of gradualism.

<u>**PROPOSED REVENUE**</u>

Q. HOW IS THE COMPANY PROPOSING TO DISTRIBUTE ITS REQUESTED ANNUAL REVENUE INCREASES AMONG THE DIFFERENT CUSTOMER CLASSES IN THIS PROCEEDING?

A. As described above, Columbia is recommending allocating its requested annual revenue increases among the different customer classes using an average of two ACOS studies as shown on Columbia Exhibit No. 111, Schedule 3, pages 1-2.

Q. WHAT ASPECTS OF RATE STRUCTURE SHOULD THE COMMISSION CONSIDER WHEN ESTABLISHING PROPOSED RATES?

A. Generally, the primary goal in establishing proposed rates is the resulting rate of return by customer class and their corresponding relative rate of return, which indicates how the rate of return of each customer class compares to the system average rate of return. Additionally, the principle of cost causation dictates that proposed rates be established so that the revenue received from a particular class is equal to the corresponding costs of providing service to that class. Generally, a relative rate of return above 1.00 for a class indicates that revenue received from that class is more than the cost of providing service to that class. Conversely, a relative rate of return below 1.00 for a class indicates that the revenue received from that class is less than the cost of providing service to that class. In the Company's peak and average ACOS study, the relative rate of return for each class is shown on Columbia Exhibit No. 111, Schedule No. 2, page 1, line 14.

Q. WHAT ACOS STUDY ARE YOU RECOMMENDING BE USED TO EVALUATE PROPOSED REVENUE IN THIS PROCEEDING?

A. For the reasons described above, I am recommending the proposed revenue in this proceeding be evaluated using the Company's provided Peak and Average ACOS study.

Q. IS A RELATIVE RATE OF RETURN FOR ALL CLASSES EQUAL TO 1.00 GOAL POSSIBLE IN THIS PROCEEDING?

A. No. The relative rate of return for RSS/RDS, SGSS1/SCD1/SDGS1, and SGSS2/SCD2/SGDS2 customers must be higher than 1.00 because the Company has flex rate and large usage customers who do not pay their full cost of service indicated in the ACOS study. Therefore, the relative rate of return goal must be above 1.00 for these other classes to accommodate the flex-rate customer who do not pay their full cost of service.

Q. WHICH CUSTOMERS CLASSES SHOULD BE EXCLUDED FROM THE MOVEMENT TOWARDS A TARGET RATE OF RETURN GOAL AND WHY?

A. Customers in the SDS/LGSS, LDS/LGSS, and MLDS classes should be excluded from the target rate of return goal because the income for flex rate customers is negotiated and the MLDS class exceeds the relative rate of return.

Q. WHAT WOULD BE THE RATE OF RETURN GOAL FOR ALL CLASSES EXCEPT SDS/LGSS, LDS/LGSS, AND MLDS CLASSES IN THIS PROCEEDING?

A. I determined that the relative rate of return goal for the RSS/RDS, SGSS1/SCD1/SDGS1, and SGSS2/SCD2/SGDS2 classes under a revenue neutral allocation should be approximately 9.13% (I&E Exhibit No. 3, Schedule No. 12, line 17).

Q. HOW DID YOU DETERMINE THE RELATIVE RATE OF RETURN GOAL OF 9.13% FOR THESE CLASSES IN THIS PROCEEDING?

A. I determined this target rate of return of 9.13% for these classes by excluding the SDS/LGSS, LDS/LGSS, and MLDS income and corresponding rate base from the total Company net income and rate base (I&E Exhibit No. 3, Schedule 12, lines 15-16). Dividing this resulting $144,617,663 of net income into the $1,583,991,755 rate base equals 9.13% (I&E Exhibit No. 3, Schedule 12, line 17). This 9.13% is the target rate of return that should be considered when allocating revenue between these remaining classes. The 9.13% rate of return equates to a relative rate of return of 1.13 (9.1% / 8.1%) (I&E Ex. No. 3, Sch. 12, line 18).

Q. HOW DOES THE COMPANY'S PROPOSED RATE DESIGN IMPACT THE RELATIVE RATE OF RETURN FOR EACH CUSTOMER CLASS?

A. The results of the peak and average ACOS study indicate the following movements of the relative rate of return at present and proposed rates:

Relative ROR	RSS/RDS	SGSS1/SCD1/SDGS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
Present Rates	1.14	1.08	1.20	0.70	0.08	14.37
Proposed Rates	1.16	0.97	1.04	0.73	0.15	11.62

Q. AS A RESULT OF THE COMPANY'S PROPOSED RATES PRODUCING RELATIVE RATES OF RETURN NOT EQUAL TO TARGET RELATIVE RATE OF RETURN OF 1.13, WHAT DO YOU RECOMMEND?

A. I recommend that $4,793,000 be subtracted from the proposed RSS/RDS class increase, that $3,113,000 be added to the proposed SGSS1/SCD1/SGDS1 class increase, that $1,680,000 be added to the proposed SGSS2/SCD2/SGDS2 class increase, to make the relative rate of return for these classes 1.13 (I&E Exhibit No. 3, Schedule No. 13, lines 1-3).

Q. WHY DO YOU RECOMMEND THAT THE PROPOSED REVENUE BE REALLOCATED?

A. As described above, one goal in ratemaking is that the rates established for each customer class produce revenue equal to the corresponding cost of providing service to that class. My recommendation satisfies this goal by making the relative rate of return for all classes except SDS/LGSS, LDS/LGSS, and MLDS the same 1.13 (I&E Exhibit No. 3, Schedule 13, line 20).

<u>SCALE BACK OF RATES</u>

Q. WHAT SCALE BACK METHODOLOGY DO YOU RECOMMEND IF THE COMMISSION GRANTS LESS THAN THE FULL INCREASE?

A. If the Commission grants less than the Company's requested increase, I recommend that the Commission follow the scale-back schedule that I prepared showing the reduction to the various classes and different scale-back levels. For example, if the Commission reduces the proposed increase by half, or $23,468,500 which would reduce I&E's revised Operating Revenue at proposed rates from $622,285,201 to $598,816,701 (I&E Ex. No. 3, Sch. 14), the scale-back would be as follows:

	RSS/RDS	SGSS1/SCD1/SDGS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
I&E Proposed Operating Revenue	$458,378,128	$61,830,258	$57,032,281	$23,458,935	$20,067,870	$1,517,729
50% scale back	($21,103,500)	$705,000	($733,000)	($1,252,000)	($1,064,000)	($21,000)

Operating Revenue at 50% scale back	$437,274,628	$62,535,258	$56,299,281	$22,206,935	$19,003,870	$1,496,729
Percent Increase	2.8%	10.8%	5.5%	6.0%	5.9%	1.5%

Any scale-back level between the amounts shown on I&E Exhibit No. 3, Schedule 14, should be interpolated.

Q. WHAT IS THE BASIS FOR YOUR RECOMMENDED SCALE BACK METHODOLOGY?

A. My scale back methodology is based first upon the results of Company's Peak and Average ACOS study which show the rate of return and relative rate of return under proposed rates. By changing various class increases through my targeted scale-back, the relative rate of return for the RSS/RDS, SGSS1/SCD1/SGDS1, and SGSS2/SCD2/SGDS2 classes will move towards 1.13 and the relative rate of return for the SDS/LGSS, LDS/LGSS, and MLDS classes will move towards 1.0, meaning that the cost to provide service to that class equals the revenue received from that class. For example, with the $23,468,500, the scale-back example above, the following relative rates of return are achieved: 1.13 for RSS/RDS, SGSS1/SCD1/SGDS1, and SGSS2/SCD2/SGDS2 classes combined, 0.72 for the SDS/LGSS class, 0.12 for the LDS/LGSS, and 12.83 for the MLDS class (I&E Ex. No. 3, Sch. 15, line 14).

Q. ARE YOU RECOMMENDING ANY RESTRICTIONS TO SPECIFIC RATE SCALE BACKS?

A. No. All customer charges and usage rates for each rate class that received a proposed increase should also be scaled back.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Appendix A

ETHAN H. CLINE

PROFESSIONAL EXPERIENCE AND EDUCATION

EXPERIENCE:

03/2009 - Present

Bureau of Investigation and Enforcement, Pennsylvania Public Utility Commission - Harrisburg, Pennsylvania

Fixed Utility Valuation Engineer – Assists in the performance of studies and analyses of the engineering-related areas including valuation, depreciation, cost of service, quality and reliability of service as they apply to fixed utilities. Assists in reviewing, comparing and performing analyses in specific areas of valuation engineering and rate structure including valuation concepts, original cost, rate base, fixed capital costs, inventory processing, excess capacity, cost of service, and rate design.

06/2008 – 09/2008

Akens Engineering, Inc. - Shiremanstown, Pennsylvania

Civil Engineer – Responsible, primarily, for assisting engineers and surveyors in the planning and design of residential development projects

10/2007 – 05/2008

J. Michael Brill and Associates - Mechanicsburg, Pennsylvania

Design Technician – Responsible, primarily, for assisting engineers in the permit application process for commercial development projects.

01/2006 – 10/2007

CABE Associates, Inc. - Dover, Delaware

Civil Engineer – Responsible, primarily, for assisting engineers in performing technical reviews of the sewer and sanitary sewer systems of Sussex County, Delaware residential development projects.

EDUCATION:

Pennsylvania State University, State College, Pennsylvania
Bachelor of Science; Major in Civil Engineering, 2005

- Attended NARUC Rate School, Clearwater, FL

TESTIMONY SUBMITTED:

I have testified and/or submitted testimony in the following proceedings:

1. Clean Treatment Sewage Company, Docket No. R-2009-2121928
2. Pennsylvania Utility Company – Water Division, Docket No. R-2009-2103937
3. Pennsylvania Utility Company – Sewer Division, Docket No. R-2009-2103980
4. UGI Central Penn Gas, Inc., 1307(f) proceeding, Docket No. R-2010-2172922
5. PAWC Clarion Wastewater Operations, Docket No. R-2010-2166208
6. PAWC Claysville Wastewater Operations, Docket No. R-2010-2166210
7. Citizens' Electric Company of Lewisburg, Pa, Docket No. R-2010-2172665
8. City of Lancaster – Bureau of Water, Docket No. R-2010-2179103
9. Peoples Natural Gas Company LLC, Docket No. R-2010-2201702
10. UGI Central Penn Gas, Inc., Docket No. R-2010-2214415
11. Pennsylvania-American Water Company, Docket No. R-2011-2232243
12. Pentex Pipeline Company, Docket No. A-2011-2230314
13. Peregrine Keystone Gas Pipeline, LLC, Docket No. A-2010-2200201
14. Philadelphia Gas Works 1307(f), Docket No. R-2012-2286447
15. Peoples Natural Gas Company LLC, Docket No. R-2012-2285985
16. Equitable Gas Company, Docket Nos. R-2012-2312577, G-2012-2312597
17. City of Lancaster – Sewer Fund, Docket No. R-2012-2310366
18. Peoples TWP, LLC 1307(f), Docket No. R-2013-2341604
19. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2013-2361763
20. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2013-2361764
21. Joint Application, Docket Nos. A-2013-2353647, A-2013-2353649, A-2013-2353651
22. City of Dubois – Bureau of Water, Docket No. R-2013-2350509
23. The Columbia Water Company, Docket No. R-2013-2360798
24. Pennsylvania American Water Company, Docket No. R-2013-2355276
25. Generic Investigation Regarding Gas-on-Gas Competition, Docket Nos. P-2011-227868, I-2012-2320323
26. Philadelphia Gas Works 1307(f), Docket No. R-2014-2404355
27. Pike County Light and Power Company (Gas), Docket No. R-2013-2397353
28. Pike County Light and Power Company (Electric), Docket No. R-2013-2397237
29. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2014-2403939
30. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2014-2420273
31. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2014-2420276
32. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2014-2420279
33. Emporium Water Company, Docket No. R-2014-2402324
34. Borough of Hanover – Hanover Municipal Water, Docket No. R-2014-2428304
35. Philadelphia Gas Works 1307(f), Docket No. R-2015-2465656
36. Peoples Natural Gas Company LLC 1307(f), Docket No. R-2015-2465172

37. Peoples Natural Gas Company – Equitable Division 1307(f), Docket No. R-2015-2465181
38. PPL Electric Utilities Corporation, Docket No. R-2015-2469275
39. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2015-2480934
40. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2015-2480937
41. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2015-2480950
42. UGI Utilities, Inc. – Gas Division, Docket No. R-2015-2518438
43. Joint Application of Pennsylvania American Water, et al., Docket No. A-2016-2537209
44. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2016-2543309
45. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2016-2543311
46. City of Dubois – Company, Docket No. R-2016-2554150
47. UGI Penn Natural Gas, Inc., Docket No. R-2016-2580030
48. UGI Central Penn Gas, Inc. 1307(f), Docket No. R-2017-2602627
49. UGI Penn Natural Gas, Inc. 1307(f), Docket No. R-2017-2602633
50. UGI Utilities, Inc. – Gas Division 1307(f), Docket No. R-2017-2602638
51. Application of Pennsylvania American Water Company Acquisition of the Municipal Authority of the City of McKeesport, Docket No. A-2017-2606103
52. Pennsylvania American Water Company, Docket No. R-2017-2595853
53. Pennsylvania American Water Company Lead Line Petition, Docket No. P-2017-2606100
54. UGI Utilities, Inc. – Electric Division, Docket No. R-2017-2640058
55. Peoples Natural Gas Company, LLC – Peoples and Equitable Division 1307(f), Docket Nos. R-2018-2645278 & R-2018-3000236
56. Peoples Gas Company, LLC 1307(f), Docket No. R-2018-2645296