COMMONWEALTH OF PENNSYLVANIA

October 14, 2020

E-FILED

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. 2020 Base Rate Filing / Docket No. R-2020-3018835

Dear Secretary Chiavetta:

The Pennsylvania Public Utility Commission's Implementation Order at *Electronic Access to Pre-Served Testimony*, Docket No. M-2012-2331973, requires that all testimony furnished to the court reporter during a proceeding must subsequently be provided to the Secretary's Bureau.

As such, this letter will confirm that the Office of Small Business Advocate ("OSBA") has e-filed the **Public Version** of Direct Testimony and Exhibits IEC-1 and IEC-2, of Robert D. Knecht, labeled OSBA Statement No.1 and the Rebuttal Testimony and Exhibit IEC-R1 of Robert D. Knecht labeled OSBA Statement No. 1-R and the **Public Version** of Surrebuttal Testimony and Exhibit IEc-S1, of Robert D. Knecht labeled OSBA Statement No. 1-SR on behalf of the OSBA, in the above-captioned proceeding.

All known parties were previously served with the aforementioned Testimony. If you have any questions, please contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: Robert D. Knecht
Parties of Record (Cover Letter and Certificate of Service Only)

COMMONWEALTH OF PENNSYLVANIA

July 28, 2020

The Honorable Katrina L. Dunderdale
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 5th Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. 2020 Base Rate Filing / Docket No. R-2020-3018835

Dear Judge Dunderdale:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht, **Public Version**, labeled OSBA Statement No. 1, with Exhibits IEc-1 through IEc-2, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Daniel G. Asmus

Daniel G. Asmus
Assistant Small Business Advocate
Attorney ID No. 83789

Enclosures
cc: **PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)**
Robert D. Knecht
Parties of Record

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018835**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Direct Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

********** PUBLIC VERSION **********

Topics:

Negotiated "Flex" Rates
Cost Allocation
Revenue Allocation
Rate Design

Date Served: July 28, 2020

Date Submitted for the Record: September 24, 2020

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. Witness Identification and Summary of Conclusions

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. I specialize in the economic analysis of basic industries. As a large part of my consulting practice, I have prepared analyses and expert testimony in the field of regulatory economics on a variety of topics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and a M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance. I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). My résumé and a listing of the expert testimony that I have filed in utility regulatory proceedings during the past five years are attached in Exhibit IEc-1.

I submitted testimony in the base rates proceedings involving Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") in 2008 (Docket No. R-2008-2011621), 2010 (Docket No. R-2009-2149262), 2011 (Docket No. R-2010-2215623), 2012/2013 (Docket No. R-2012-2321748), 2014 (Docket No. R-2014-2406274), 2015 (Docket No. R-2015-2488056), 2016 (Docket No. R-2016-2529660) and 2018 (Docket No. R-2018-2647577). I also submitted testimony in a variety of Section 1307(f) and other proceedings involving the Company over the past decade.

Because the Company's cost allocation and rate design proposals in this proceeding are, to a large extent, conceptually consistent with those posited in the Company's last four base rates proceedings, this testimony draws significantly on my testimony in those earlier proceedings. I confess to some significant self-plagiarizing in this testimony.

Q. Please describe your assignment in this matter.

A. The OSBA requested that I review the Company's filing in this proceeding to evaluate whether the rates proposed for small business customers are consistent with sound economics and regulatory principles. My analysis focuses primarily on issues of cost allocation, revenue allocation and rate design. My evaluation of Columbia's filing does not constitute an exhaustive review. If I have not addressed a particular issue, it cannot be inferred that I agree with Columbia's proposal for that topic.

Q. Please summarize the conclusions from your review.

A. My conclusions are as follows:

1. The Company's claim that the risk-adjusted cost of equity to which it is entitled is higher in 2020 than it claimed in 2018 despite a drop of more than 200 basis points in the yield on 10-year Treasury bonds is absurd. As a simple comparison, if the return on equity ("RoE") award for UGI Electric were adjusted for the change in risk-free rates and applied to Columbia's claim in this proceeding, the proposed $100.5 million increase would drop below $40 million, before any other adjustment. In the context of a pandemic, this proposal is impossible to comprehend.

2. The Company's flex rate customers obtain service at a large rate discount relative to full tariff rates. Depending on the cost allocation methodology chosen, the under-recovery of costs from those customers at Columbia's proposed rates can be as high as $31 million and is over $16 million using the Company's proposed methodology. While discounted flex rates can theoretically provide benefits to non-flex ratepayers, both the need for and the magnitude of such rate discounts must be carefully documented. At this writing, the Company has not presented sufficient justification for granting discounted rates to these customers. Unless or until the Company does so, the revenue shortfall from flex rates should be the responsibility of the shareholders and not other ratepayers.

3. The two allocated cost of service study methodologies ("ACOSSs") submitted by the Company produce results that vary enormously, but they still do not span the potential range for cost allocation results. Using an average of the Company's two methods is not necessarily unreasonable, but the specific averaging approach chosen is inherently arbitrary.

4. In this testimony, I develop two revenue allocation calculations based on a weighted average of the two Company cost allocation methods and value of service considerations, one based on the Company's 50/50 proposed costing method, and one based on a 75/25 weighting of the P&A and CD methods.

5. The Company's proposed changes to the tariff design for the small general service classes are reasonable and consistent with the ACOSS results, at the Company's full proposed revenue requirement. If the Commission reduces the overall proposed rate increase, the tariff charge increases should be scaled back.

Q. Please provide some background regarding the Company's filing, in comparison to its last three base rates proceedings.

A. Columbia submitted base rates filings in 2008, 2010, 2011, 2012, 2014, 2015, 2016, 2018 and now 2020. Prior to 2008, Columbia had not filed a base rates case since 1995. This steady flow of rate cases has generally been prompted by a significant mains and services replacement program, undertaken over the past decade. A summary of the base rates filing amounts and settlement rate increases is shown in Table IEc-1 below.

Table IEc-1
Recent Columbia Base Rate Increase Cases

Docket No.	Test Year Ending	Proposed Increase ($mm)	Settlement ($mm)	Settlement Percent
R-2008-2011621	Sep-2008	$58.9	$41.7	71%
R-2009-2149262	Sep-2010	$32.3	$12.0	37%
R-2010-2215623	Sep-2011	$37.8	$17.0	45%
R-2012-2321748	Jun-2014	$77.3	$55.3	72%
R-2014-2406274	Dec-2015	$54.1	$32.5	60%
R-2015-2468056	Dec-2016	$46.2	$28.0	61%
R-2016-2529660	Dec-2017	$55.3	$35.0	63%
R-2018-2647577	Dec-2019	$46.8	$26.0	56%
R-2020-3017206	Dec-2021	$100.5	--	--

Columbia's relatively large proposed increase in the R-2012-2321748 proceeding was due in part to the switch to using a fully forecasted future test year approach, thereby incorporating nearly three full years of (mostly forecast) capital expenditures in the mains replacement program since the prior base rates case.

Of course, this rate proceeding takes place in the extraordinary circumstances of a pandemic, which is having a devastating impact on residences and many small businesses in Pennsylvania. The Commission does not need me to elaborate on these impacts.

Unfortunately, the Company appears to have decided that the appropriate contribution for the Company's shareholders to this devastation is zero. While the Pennsylvania unemployment rate soars, thousands die from the virus, businesses downscale and close, the

Company demands a base rate increase of over twenty three percent.[1] The Company fails to even acknowledge that capital markets have shifted dramatically since its last base rates case, with interest rates far below those in effect a two years ago. Nevertheless, the Company demands the same proposed return on equity that it requested in its last base rates proceeding, implicitly requesting a huge increase in the risk premium on its equity. Moreover, this large increase in the equity risk premium takes place in the context of one of the Company affiliates disastrous failures in the Merrimack Valley in Massachusetts, where the Company's admitted management and operating failures resulted in an extraordinary public safety event.[2]

The Company's extraordinarily large increase in this proceeding is driven almost entirely by a nearly $500 million expansion of FPFTY rate base (including actual and forecast expenditures), primarily related to capital spending for mains, services and metering equipment. This type of capital spending binge is unsurprising to economists, because regulators (across the country) have allowed the risk premium in utility allowed rates of return to increase substantially over the past 30 years.[3] This increasing risk premium has occurred in the same period while regulators have been adopting various regulatory and rate design mechanisms that reduce utility risk.[4] As shown in Figure IEc-1 below, the risk premiums in allowed electric utility equity returns has increased by at least 300 basis points since the early 1990s.

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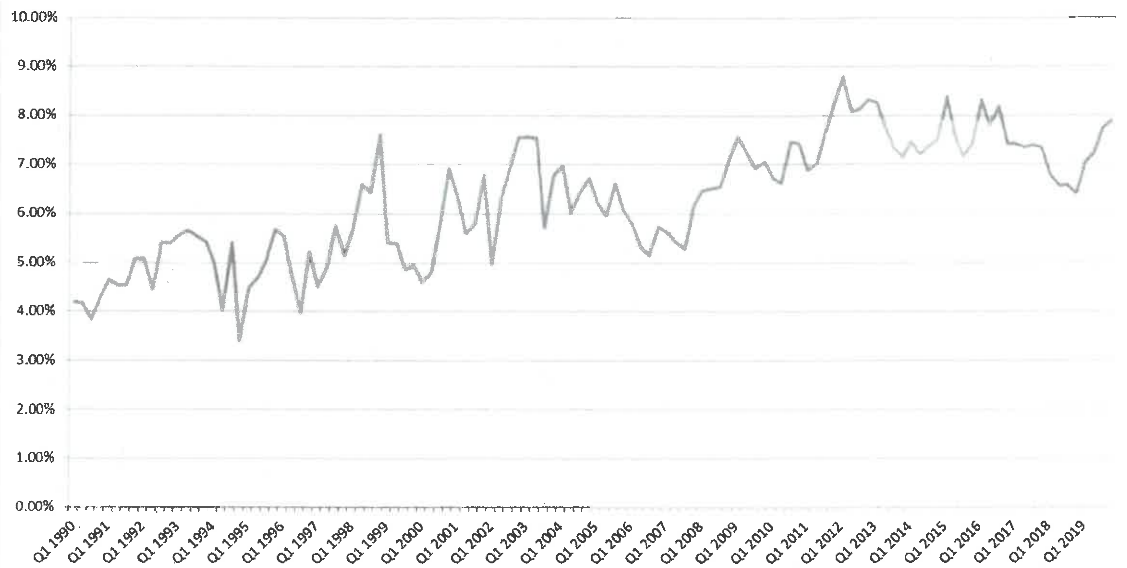
[1] See Pennsylvania unemployment rate at https://fred.stlouisfed.org/series/PAUR Pennsylvania unemployment in June 2020 was at 13.0 percent, compared to 4.4 percent in June 2018.

[2] Following a disastrous September 2018 over-pressurization event that resulted in a fatality, several injuries and an extended disruption of service, Columbia Gas of Massachusetts admitted full responsibility for the event, plead guilty to violating federal regulations, paid a $53 million criminal fine, and was required to sell its Massachusetts assets. See, for example, https://www.bostonglobe.com/2020/02/26/metro/columbia-gas-mass-pleading-guilty-federal-charge/.

[3] Economists often refer to the incentive to over-capitalize when allowed rates of return are set too high as the "Averch-Johnson" effect.

[4] In Pennsylvania, these measures include (but are probably not limited to) the use of a fully projected future test year with year-end annualization, the distribution system improvement charge ("DSIC") mechanism, weather normalization rates for some utilities (including Columbia), guaranteed cost recovery for electric and gas supply costs, guaranteed cost recovery for universal service programs, guaranteed recovery for smart meter programs for electric utilities, and guaranteed cost recovery for energy efficiency programs.

Figure IEc-1
EEI Electric Utility Allowed RoE:
Risk Premium over 10-Year T-Bond



Moreover, the Company has made no obvious effort to reflect changes in capital markets since its last base rates proceeding. In the last case, the Company requested a 10.95 percent return on equity, when 10-year T-Bond rates were generally in the 2.8 to 3.0 percent range. At present, the 10-year T-Bond rates have fallen by more than 200 basis points, and now hover in the 0.5 to 0.7 percent range. However, the Company continues to request a 10.95 percent return on equity, notwithstanding the huge decline in market interest rates.[5]

By way of comparison, the Commission awarded UGI Electric a 9.85 percent RoE in UGI Electric, at Docket No. R-2017-2640058. At the time, the yield on 10-year Treasury bonds was generally a little below 3.0 percent, implying that the Commission awarded UGI Electric a 6.9 percent (690 basis point) risk premium over the 10-year T-bond rate. At this writing, the yield on the 10-year T-bond is 0.57 percent. Thus, simply maintaining the risk premium allowed in the UGI Electric matter would imply an RoE award of about 7.5 percent. I estimate that simply applying the UGI Electric risk premium award to Columbia would reduce the $100.5 million increase by some $61 million. By way of contrast, the Company

[5] In addition to failing to reflect the decline in risk-free interest rates, the Company materially increased its proposed equity share of capital relative to that submitted two years ago. In effect, the Company is claiming that its risk-adjusted cost of equity is higher now than in 2018. See RDK WP6.

proposes that it be awarded an RoE of 10.95 percent, implying a risk premium of 10.4 percent over the T-bond rate, a premium that is more than 350 basis points higher than the award UGI Electric was granted in 2018.

Thus, even if the Company's claimed revenue requirement is adjusted to be consistent with the return on equity award granted by the Commission to UGI Electric in 2018, some 60 percent of the Company's claimed increase is not justified.

Q. How is the balance of your testimony organized?

A. This testimony is organized as follows:

- Section 2 provides a brief overview of Columbia's non-residential rate classes, to provide background to the cost allocation, revenue allocation and rate design issues.
- Section 3 reviews the Company's justification for the specific values for its flex rate discounts.
- Section 4 reviews my limited assessment of cost causation and Columbia's ACOSS methods and calculations.
- Section 5 addresses revenue allocation issues.
- Section 6 addresses rate design issues for small general service customers.

2. Review of Columbia's Non-Residential Rate Classes

Q. Before getting into the details of your analysis, please summarize the rate classes under which businesses take service from Columbia.

A. Columbia's tariff has a number of schedules under which non-residential customers take service. These tariff schedules are generally distinguished by size of customer (as measured by annual throughput) and type of service. Service types include the following:

- Sales service, in which customers procure both gas supplies and distribution service from Columbia;

- Retail transportation "Choice" service, in which smaller customers can purchase gas supply from NGSs and purchase both bundled load balancing services and distribution services from Columbia;

- Transportation service, in which larger non-residential customers purchase gas supplies from NGSs, purchase load balancing services as needed from Columbia and/or their NGSs, and purchase distribution service from Columbia.

For cost allocation purposes, Columbia aggregates these disparate rate classes into rate class groups.

In total, the non-residential rate classes represent about 58 percent of Columbia's total throughput, or about 49 million of Columbia's total 83 million Dth in the test year. Customer size varies widely, ranging from small businesses that consume less than 10 Dth per year to very large industrial customers with individual loads exceeding 2.5 million Dth per year.

The following are the non-residential rate class groups specified by Columbia for its cost allocation analysis. Because the Company's abbreviations for the rate class groups are somewhat contradictory, I include descriptive names for these groups.

SGSS/SCD/SGDS ("Small General" or "SGS"): This group consists of three tariff schedules: Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD"), and Small General Distribution Service ("SGDS"). Over the past several base rates proceedings, Columbia has adopted differentiated customer and commodity charges for customers in this class, split between customers with annual consumption above and below 644 Dth. Maximum annual throughput for this class is 6,440 Dth/year. Consistent with recent past practice, the Company separates these two groups for both cost allocation and rate design purposes. For simplicity, I refer to the customers with annual consumption below 644 Dth as "SGS1," and the larger customers as "SGS2."

Within these two rate class groups, SGSS is sales service, SCD is retail "Choice" transportation service and SGDS is regular transportation service.

In the SGS1 group, about 72 percent of the load is to sales customers, implying a shopping rate of 28 percent, which is a little higher than the residential shopping rate of 23 percent. The average SGS1 customer size is about 184 Dth per year, which is a little more than double the size of the average residential customer. Of the shopping customers in this group, about 85 percent of the load is in the Choice program. Overall, this class represents about 12 percent of the Company's non-residential throughput.

In the SGS2 group, about 46 percent of the load relate to sales customers. Of the shopping customers, retail Choice represent about 27 percent of the load. In effect, the majority of SGS2 shopping customers use traditional transportation service. The average SGS2 customer size is 1,622 Dth/year, which is about 9 times the size of the average SGS1 customer. Overall, this class represents 19 percent of the Company's non-residential throughput.

SDS/LGSS ("Medium General"): This rate class group includes both sales and transportation service customers, taking service under Rate Schedules LGSS (sales service) and Small Distribution Service ("SDS") (transportation service). Columbia's "Small" designation for the transportation customers in this tariff category is misleading, since the *minimum* throughput is 6,440 Dth per year, matching the *maximum* size requirement for the Small General customers. The maximum annual throughput for this class is 54,000 Dth per year, with an average annual customer throughput of about 15,600 Dth. This rate class group represents about 16 percent of non-residential throughput. Only about 2 percent of the load for this class is subject to discounted "flex" rates.

LDS/LGSS ("Large General"): This class includes the larger sales customers in the LGSS class along with the transportation service customers taking service under Rate Schedule Large Distribution Service ("LDS"). Minimum throughput is 54,000 Dth per year, matching the Medium General Service upper limit. Average throughput for these customers is about 245,000 Dth per year. This rate class group represents about 49 percent of non-residential throughput. Some 49 percent of the LDS load is subject to "flex" distribution rates, set on a negotiated basis below the maximum tariff rate. In this proceeding, the Company does not forecast any future test year sales (LGSS) customers in this category.

MDS ("Mainline"): Customers in this rate class group take service under Rate Schedule Main Line Distribution Service ("MDS").[6] To be eligible for this service, customers must have annual throughput over 27,400 Dth *and* be directly connected to an interstate pipeline (Class I), *or* have a minimum annual demand of 214,600 Dth *and* be located within two miles of an interstate pipeline interconnection (Class II). Because these customers require very little in the way of distribution facilities, and because Columbia reports that they are credible "bypass" threats, Columbia uses different cost allocation and rate design methods for this rate class group. The 7 Mainline customers identified by Columbia represent about 10 percent of non-residential throughput.

Consistent with recent practice, the Company does not treat large general sales service ("LGSS") customers as a separate rate class for cost allocation purposes, and it includes those customers with transportation customers of comparable size. As I testified in the last several proceedings, I agree with this approach. Sales customers taking service under Rate LGSS are free to switch to the comparable transportation service schedule, and, generally, vice versa. Thus, it is reasonable that the distribution rates for all customers of a similar size be the same, so as to avoid distorting the decision to shop. Since the distribution rates are the same, there is no need to separately allocate costs. Moreover, the total load associated with Rate LGSS is relatively small.

3. <u>Flex Rate Customers</u>

Q. Please summarize the economic and regulatory issues surrounding Columbia's "flex rate" customers.

A. In general, regular specific tariff rates are set based on allocated cost of service and other rate design criteria, and these tariff charges apply to all customers within the rate class.[7] However, under certain conditions, it can be beneficial to all parties to allow the utility to negotiate rate discounts from the regular tariff rate in order to retain customers who either

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[6] Columbia's tariff includes a Main Line Sales Service schedule, but no customers currently take service under that schedule.

[7] See, for example, <u>Principles of Public Utility Rates</u>, Second Edition, Bonbright, James C., Albert L. Danielsen; David R. Kamerschen; Public Utility Reports, Inc., 1988, pages xx.

have lower-cost options or are in imminent danger of business closure/relocation. Lower cost options include alternative fuel, pipeline bypass, and in the bizarre case of western Pennsylvania, "gas-on-gas competition" from other natural gas distribution companies ("NGDCs").[8] The specific criteria where negotiated discounts are in the interests of all ratepayers are:

- Negotiated rates exceed the incremental cost of providing service to the customer. Thus, for example, if Columbia needs to upgrade its distribution system to continue to provide service to a flex rate customer, the tariff rates must be sufficient to justify that expenditure.

- In the case of alternative fuel competition, negotiated tariff rates plus the cost of gas should be set at the full delivered cost of the alternative fuel plus the customer's costs of conversion.

- In the case of pipeline bypass, negotiated tariff rates are justified only if there is a credible engineering plan for how the customer could physically bypass the NGDC. If that criterion is met, the negotiated tariff rate plus the cost of gas should be set at the customer's full cost for bypassing the NGDC and taking service directly from the pipeline. This cost necessarily includes obtaining the necessary permits to allow for such bypass.

- In the case of NGDC "competition," the Commission has determined that where customers are served in overlapping NGDC service territories, the minimum flex rate that can be charged is the lowest regular tariff rate of the NGDCs serving the customer's location.[9]

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[8] Of course, NGDCs do not "compete" for customers in overlapping service territories on the basis of cost or service. They have historically "competed" on the basis of which NGDC can offer the largest rate discount to those customers with options and pass those discounts on to captive customers who do not have those options.

[9] *Opinion and Order,* Pennsylvania Public Utility Commission, Docket Nos. P-2011-2277868 and I-2012-2320323, Order Entered May 4, 2017, page 52. To my knowledge, there has not been a firm resolution as to how the lowest applicable tariff rate should be defined, See *Opinion and Order,* Pennsylvania Public Utility Commission, Docket Nos. P-2011-2277868 and I-2012-2320323, Order Entered June 13, 2019.

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Q. Has the Company offered sufficient evidence to justify the flex rate discounting?

A. Not at this writing. For those customers who are bypass risks, the Company has not demonstrated that there is a credible option for physical bypass, nor has it provided any estimate of the customers' costs for such a bypass. For the NGDC competition, the Company has not identified the specific NGDC and regular tariff charges upon which the discounted flex rate is based.[11]

Thus, for the purpose of my revenue allocation analysis in this proceeding, I assume that the flex rate customer group is providing full current tariff rate revenues, and that these customers can absorb a rate increase subject to the same considerations as the other rate classes. If the Company can demonstrate that the bypass and NGDC competitive threats are credible, and that the negotiated rates reasonably reflect those threats, I will update my recommendations accordingly.

4. Cost Allocation

Q. What is the purpose of a utility's ACOSS?

A. The most important criterion for setting regulated utility rates is the cost incurred by the utility for providing the service.[12] To assign costs to specific customers, utilities aggregate customers into rate classes, within which the customers have similar load sizes, seasonal consumption, peak demand patterns, and other characteristics. An ACOSS is an analytical tool with which the utility's total cost (or "revenue requirement") is allocated among each of the rate classes. These allocated costs are then used as a key input in determining the total revenues that the utility plans to recover from each rate class through tariff rates.

In using the results from an ACOSS to develop class revenue requirements, utilities and regulatory authorities usually have a longer-term goal of moving the revenue recovered from each class as close as possible to the costs allocated to that class. That is, in each proceeding,

[11] **** HIGHLY CONFIDENTIAL *****

[12] The Commonwealth Court affirmed this basic principle, referring to cost of service as the "polestar" criterion. Lloyd v. Pennsylvania Public Utility Commission, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

regulators try to move class revenues more into line with cost-based rates. Thus, rate classes whose revenues substantially exceed allocated costs are assigned either relatively low rate increases or rate decreases. Rate classes whose revenues are well below allocated costs are assigned relatively larger rate increases than those classes whose revenues are only slightly below allocated costs.

In addition to class revenue requirement issues, an ACOSS can provide useful cost information regarding the specific nature of utility tariff charges. In particular, an ACOSS provides a cost basis for the relative magnitude of the various individual tariff charges, including the customer charge, demand charges and commodity charges.

Q. How does an ACOSS assign costs to the various rate classes?

A. The underlying principle of an ACOSS is that costs are assigned to the rate classes that *cause* the utility to incur those costs. This principle of cost causation is both equitable and economically efficient. It is equitable because costs are borne by those customers who cause them. It is economically efficient because the price signal for consumption from a particular rate class is reasonably consistent with the cost incurred by the utility to provide the service. In that way, the consumer receives the correct price signal for determining whether he should purchase more or less utility service. In effect, the consumer balances the value that he receives from the purchase of that service against the utility's cost of providing the service.

Q. What is the Company's approach to cost allocation in this proceeding?

A. With its filing, the Company presented three detailed cost allocation studies, in Exhibit 111 Schedules 1, 2 and 3.

Q. Why does the Company present three different cost allocation studies?

A. For gas distribution utilities, the issue of the classification and allocation of mains costs is often contested in regulatory proceedings.[13] This debate has a significant impact on rate

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[13] In a traditional cost allocation study, the "classification" step involves segregating costs into basic cost causation categories, generally energy/commodity-related, peak demand-related, excess demand-related, or customers. "Allocation" is the step which spreads the classified costs among customers or customer classes, based on some reasonable measure of the classification factor. For example, gas utility distribution costs classified as peak demand-related are typically allocated using some measure of customer class peak demand, such as design day demand or contract demand.

design for several reasons. First, mains costs are "joint use" costs, meaning that they cannot be directly assigned to a particular customer or customer class, and must be allocated using some reasonable methodology. Second, mains represent a large percentage of a gas utility's overall rate base, thereby determining each class' share of income tax and return on capital costs. Moreover, given the nature of ACOSSs, the allocation of mains costs also drives the allocation of a large percentage of the O&M costs, as well as indirectly affecting the allocation of A&G costs. Third, the analytical models used by cost allocation experts can vary considerably in their impact on the percentage of mains costs assigned to each class. And fourth, the cost allocation methodology for mains can have a significant impact on the ultimate rate design for the recovery of costs within each rate class, notably with respect to the magnitude of the customer charge.

Rather than take a firm position on this debate, the Company essentially picks two methods which it asserts lie at opposite ends of the philosophical spectrum and presents the results of both. These studies are denoted the CD ACOSS (Exhibit 111 Schedule 1) and the P&A ACOSS (Exhibit 111 Schedule 2). The third ACOSS (Exhibit 111, Schedule 3) is a simple average of the two. The differences between these three ACOSSs are related only to the issue of mains cost allocation – all other allocations are methodologically the same in the three studies.

Q. Can you comment briefly on the issue of mains cost classification and allocation?

A. Gas distribution mains are installed to meet two basic objectives: (a) to connect the customer with the interstate pipeline system (or other gas supply resources) and (b) to be able to transport sufficient gas to meet the demand of customers downstream under peak conditions.

Having stated that, however, it is not easy to develop an analytical model capable of reflecting these cost causation factors reasonably. Ideally, the cost of each segment of main would be allocated only to those specific customers who are served downstream from that segment.[14] In practice, however, undertaking such an analysis could be detailed, costly and time consuming. Few utilities attempt such an undertaking. While Columbia is no exception to this rule, Columbia's current ACOSS methodology has taken a step in that direction, by sub-dividing its mains costs by size/operating pressure and allocating each group of mains only to customers who take service from those mains. Also, in an earlier base rates proceeding, Columbia indicated that its information systems have much of the information for allocating mains costs on a pipe segment by segment basis, only to downstream customers. I again encourage Columbia to investigate whether it can develop such an approach in the future, and in that way avoid the wildly disparate results that come from the traditional allocation methods.[15]

Given the expansion of GIS software and modeling technology, it is somewhat surprising that utilities and regulators do not know which mains service which customers and are therefore forced to rely on arbitrary top-down costing methods which produce wildly different results.

Q. If a detailed systems assessment is not undertaken, what are the "traditional" methods that apply to mains cost classification and allocation?

A. Absent a detailed assessment, various analytical models are used. These methods generally focus on the following questions:

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[14] Even allocating the costs for a single main segment when the customers served by the segment are known is not an obvious matter. Economics theory indicates only that a subsidy-free allocation method is one in which each customer, or any group of customers, will be allocated costs that fall below the stand-alone cost of service, and which exceed the incremental cost of service. With the significant scale economies in mains construction costs, these restrictions still leave a fairly wide range of subsidy-free allocation methods. However, it can be demonstrated that both methods used by the Company in this proceeding (minimum system and P&A) can produce results that lie outside that range. By way of contrast, the 100 percent demand and zero-intercept methods will generally produce results that do not violate these criteria.

[15] I note that a few utilities pursue such a detailed approach. For example, at Docket No. Docket R-00953297, UGI Utilities, Inc. (Gas Division) put forward a Network Analysis cost allocation approach, in which costs for each main segment were allocated to downstream customers in proportion to customer design day demands. (Sadly, that utility chose to abandon this approach for smaller customers in its more recent base rates proceedings. Also, Alberta electric utility Aquila Networks Canada put forward a distribution cost allocation proposal in which allocated costs were derived at a detailed level for a sample of electric distribution feeders, in which distribution costs were allocated only to the specific customers downstream of each asset in proportion to on-peak load. (See Alberta Energy and Utilities Board (now Alberta Utilities Commission) Decision 2003-019.)

- Are mains costs causally related to the number of customers? And, if so, how should the "customer component" of mains costs be derived?

- How should mains costs that are not causally related to number of customers be allocated among the various rate classes?

Regarding the first question, the common-sense argument (to which I generally subscribe) is that more footage of mains must be installed to interconnect many small customers than to connect one large customer.[16] This common-sense argument is supported by some aggregate industry statistical analysis.[17] As such, mains footage is causally related to the number of customers, and therefore mains costs are partially customer-related. However, some experts disagree, and conclude that no component of mains costs is causally related to customer count. Moreover, even if there is a statistical correlation between mains footage and number of customers, none of the traditional mains cost classification methods reasonably reflects that quantitative relationship.[18]

The cost allocation treatment for gas distribution mains is only infrequently litigated in Pennsylvania. The most recent Commission precedent indicates that the Commission has

[16] Note that this causal relationship does not mean that mains length is directly proportional to customer count regardless of customer, as some analysts assert. It implies that mains length is partly related to customer count, partly related to customer size, and partly related to a variety of geographic factors.

[17] See, for example, a report prepared by Black & Veatch for Gaz Métropolitain, at http://publicsde.regie-energie.qc.ca/projets/235/DocPrj/R-3867-2013-B-0005-Demande-Piece-2013_11_15.pdf, pages 12-16.

[18] See pre-filed evidence of Robert D. Knecht, Dossier R-3867-2013, 26 February 2015, Exhibit IEc-3, http://publicsde.regie-energie.qc.ca/projets/235/DocPrj/R-3867-2013-C-ACIG-0028-Preuve-RappExp-2015_02_26.pdf .

rejected the use of a customer component for gas distribution utilities.[19] However, more recent Commission precedent for electric distribution utilities, where the conceptual arguments regarding cost causation are similar, supports the recognition of a customer component for joint-use distribution plant allocation.[20]

In this proceeding, the Company's filed CD ACOSS includes a customer component for mains costs, while the P&A ACOSS does not.

If a customer component is included, the basic approaches involve deriving a customer component of costs based on the cost associated with a theoretical system with little or no load-carrying capability. The demand-related component of cost is then calculated as the cost to expand that "minimum system" to the actual existing system.

One basic approach for deriving the minimum system is to base the customer component of mains cost as if entire system if it were built using only the minimum diameter main in current use (e.g., a 2-inch diameter main). This is, in fact, the method the Company uses in its CD ACOSS. However, this method is often criticized for including an implied demand-related component in the minimum system, because the minimum system of 2-inch pipe has some load carrying capability.

[19] In a case involving PPL Gas at Docket No. R-00061398, the Commission approved an allocation of all mains costs using a variant on the A&E allocation method advanced by the utility expert witness. In that proceeding, the approved weighting was 40 percent to average demand and 60 percent to excess demand. This weighting was not based on system load factor. PA PUC et al. v. PPL Gas Utilities Corporation, R-00061398, Order Entered February 8, 2007, page 112 – 114. Also, in a case involving the Philadelphia Gas Works ("PGW") at Docket No. R-00061931, PGW proposed to classify some mains costs as customer-related and the balance as demand-related, and proposed to allocate demand-related costs using a peak demand allocator. However, the Commission concluded that no mains costs should be classified as customer-related, and that mains costs should be allocated using a variant of the A&E allocation method advanced by the Office of Trial Staff expert. In the PGW proceeding, the approved weighting was 50 percent to average demand and 50 percent to excess demand. This weighting was also not based on system load factor. See PA PUC v. Philadelphia Gas Works, R-00061931, Recommended Decision, July 24, 2007, page 63, and PA PUC v. Philadelphia Gas Works, R-00061931, Order Entered September 28, 2007, page 80.

[20] For example, PPL Electric has used a minimum system methodology for many years for secondary system plant, and subsequently expanded the minimum system method to primary system plant in its 2010 and 2012 base rates cases. This methodology was fully litigated and explicitly approved by the Commission. *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2010-2161694, at 46 (Order entered December 21, 2010), and *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2012-2200597, at 113 (Order entered December 28, 2011.)

In the alternative, some experts generally prefer to use a method in which the customer component is based on a minimum system with a zero-diameter pipe. This approach is denoted a zero-intercept ("ZI") classification method. In this method, the cost of a zero-diameter pipe is estimated statistically using the utilities' actual costs for various pipe sizes. The ZI approach avoids the problem of the load carrying capability of the minimum system, since a zero-diameter pipe has no load carrying capability. This approach, however, is often subject to statistical issues and data problems that do not arise with a traditional minimum system.

In addition, some experts attempt to address the load carrying capability of the minimum system by adjusting the allocation of demand-related costs.[21] However, any such adjustment necessarily requires arbitrary adjustments to demand allocators, since it is very difficult to evaluate just what the load carrying capability of a system consisting solely of 2-inch mains actually is for each customer on the system.

In this proceeding, in its CD ACOSS, the Company uses a minimum system approach, based on 2-inch mains, with no adjustment to the demand allocators.[22] The Company applies the minimum system approach to both its low-pressure and medium-pressure systems. Transmission mains are allocated on a 100 percent peak demand basis.

Finally, there is a debated issue as to how the non-customer component or "demand component" of mains costs should be allocated. Conceptually, some experts (myself included) argue that, because mains diameters must be sized to meet peak demand, the demand component of mains costs should be allocated only on peak demand. Other experts advocate for a weighting of average demand (arithmetically equivalent to throughput) and *excess* demand (peak demand minus average demand), which is known as an average-and-

[21] Unfortunately, I know of no theoretically reasonable method for deriving the load carrying capability of the minimum system.

[22] The Company's minimum system method uses simple average gross book cost for calculating the cost of minimum system and total system pipe. The use of inflation-adjusted costs for deriving the customer percentage would be modestly better practice, as it reduces distortive effects of vintaging.

excess ("A&E") allocator, while others support a weighting of average demand and peak demand, which is known as a peak-and-average ("P&A") allocation factor.

Relatively recent Commission precedent for gas utilities in Pennsylvania generally supports the use of an A&E allocation method (albeit a non-traditional version of the A&E method), while for electric utilities Commission precedent supports the use of a peak demand allocator.

In this proceeding, the Company uses a peak demand allocator in the CD ACOSS, and a P&A allocator in the P&A ACOSS. In effect, neither Company method is consistent with the most recent Commission precedent on this issue.

Q. Do the Company's methods encompass the full range of potential cost allocation results that may be offered by cost allocation professionals?

A. Probably not. As evidenced in the Company's last base rates case, the Company's two cost allocation studies do not span the full range of possible options. The Company's P&A method segregates mains between larger diameter, higher pressure mains and mains that are either small diameter or operated at low pressure. Some experts disagree that it is appropriate to segregate mains in this fashion, and they argue that all joint use mains should be allocated as an integrated system.[23] I refer to this approach as the "Traditional P&A" method in this testimony. If the only objective is to present the range of possible cost allocation methods, the Traditional P&A is a more extreme approach than the Company's P&A method.

Q. Why do the CD ACOSS and the Traditional P&A ACOSS present the extremes of mains cost allocation philosophy?

A. The CD ACOSS is most favorable to larger customers. It includes a customer component of costs, which recognizes system economies of scale associated with serving large customers. Customer-related costs are almost entirely assigned to smaller customers, resulting in relatively higher costs for those classes. Moreover, the CD method uses a

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[23] See, for example, OCA Statement No. 3 at Docket R-2016-2529660, pages 7-8. In general, Commission precedent supports this view.

minimum system method for classifying costs as customer related, which produces a larger customer component than does the zero-intercept approach, thereby assigning more costs to small customers. Finally, the CD ACOSS uses a peak demand allocator. As larger customers are less "peaky" than smaller customers, with loads that are less temperature-sensitive, a peak demand allocator reduces the allocation of costs to larger, higher "load factor" customers.

In contrast, the Traditional P&A ACOSS is generally most favorable to the smallest customers for three reasons. First, the P&A method has no customer component at all, which is favorable to the smallest customers, as economies of scale are not reflected in mains cost allocation. Second, because smaller and low-pressure mains are allocated to all customers, the Traditional P&A approach is generally more favorable to smaller customers than the Company's approach, which does not allocate any of these mains costs to larger customers. Third, the Traditional P&A method allocates costs substantially based on average demand. Because small customers tend to be more weather sensitive than larger customers and therefore have relatively less average demand per unit of peak demand (i.e., a lower "load factor"), the P&A method assigns less costs to smaller customers than other methods which rely more heavily on peak demand.

Q. Have you prepared a full independent version of a cost allocation study in this proceeding?

A. No. However, over the years, I have developed a working version of the Company's model, and I use that for my analysis. For this proceeding, I relied on my near-replication of the Company's results for the CD and P&A ACOSS models, as shown in RDK WP1 and RDK WP2.[24] The only modification that I made was to reflect regular tariff rate revenue for the flex rate customer class, as explained above. This has the effect of increasing the overall system rate of return at both present and proposed rates. I also developed a "Traditional P&A" ACOSS, shown in RDK WP1A.

[24] In replicating the Company's analysis, I was able to adopt much but not all of the rounding approach used in the Company's study, leading to small differences. It is unclear why the Company retains this rounding technique.

Q. What are the implications of the various ACOSS methodologies that you reviewed in this testimony?

A. Table IEc-2 below shows the implications of the various ACOSS methodologies discussed in this testimony. These values are based on my simulations of the ACOSS models, adjusted as discussed above. Also, because it is a significant issue for revenue allocation, I split the Large General class into regular rate and flex rate customers.[25]

Table IEc-2
Summary of ACOSS Implications
($000)

	Total	Residential	SGS1	SGS2	Medium General	Large General	MDS	Flex
Current Non-Gas Revenues	433,835	318,013	34,082	39,058	21,885	15,356	552	4,887
CD ACOSS								
Increase to CBR	100,527	109,299	7,588	(9,913)	(7,431)	(5,166)	(458)	6,608
Percent	23.2%	34.4%	22.3%	-25.4%	-34.0%	-33.6%	-83.0%	135.2%
P&A ACOSS								
Increase to CBR	100,527	35,785	8,161	7,221	6,897	16,702	(458)	26,218
Percent	23.2%	11.3%	23.9%	18.5%	31.5%	108.8%	-83.0%	536.4%
Traditional P&A ACOSS								
Increase to CBR	100,527	2,038	3,784	11,781	16,730	28,805	(458)	37,848
Percent	23.2%	0.6%	11.1%	30.2%	76.4%	187.6%	-83.0%	774.4%

Source: RDK WP1, WP2, WP1A

As shown in Table IEc-2, while the three cost allocation philosophies may span the possible range of allocated cost outcomes, they provide little in the way of consistent guidance for cost allocation and rate design. Only the results for the MDS class show a consistent pattern,

[25] While other rate classes have some flex rate customers, these customers have a material impact on revenue allocation only for Rate LDS.

and then only because mains are directly assigned to that class in all three methods and therefore there is no cost difference. The results for the SGS1 class are not wildly different, but cost-based rate increases still vary from 12.5 percent to 25.5 percent.

After that, the results are all over the map. Rate increases for the residential class needed to bring revenues into line with allocated cost range from $2.0 million (0.6%) to $109 million (34.4%), a range that is wider than the entire increase proposed by the Company. Even more variable, the rate changes needed to move revenues for the Large General class into line with allocated cost range from a *reduction* of over 30 percent to an increase of nearly 200 percent.

Thus, absent some arbitrary averaging method, using the full range of possible cost allocation results provides little guidance for revenue allocation in this proceeding.

6. <u>Revenue Allocation</u>

Q. What is revenue allocation?

A. Revenue allocation is the assignment of the dollar net increase or decrease to each of the Company's rate classes in a base rates proceeding. In contrast, *rate design* determines how the allocated revenue is recovered from individual ratepayers within each class. From a cost recovery standpoint, revenue allocation addresses *inter-class* cross-subsidization issues, while rate design addresses *intra-class* cross-subsidization issues.

Q. What are the primary economic and regulatory criteria for revenue allocation?

A. In general, allocated cost is the primary criterion used by regulators in the revenue allocation process. Most utilities and regulators adopt a policy in a base rates proceeding of attempting to move revenues more into line with allocated costs by varying the magnitude of the rate increases for the individual classes. However, regulators also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue allocation process are:

- the *gradualism* principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customers are avoided; and

- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand.[26]

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. With this proposal, the ACOSS can be simulated at both present and proposed rates to evaluate the magnitude of "progress" has been made toward the policy of achieving cost-based rates.

Q. In evaluating the Company's revenue allocation, which aspects of the Company's revenue have you considered in this proceeding?

A. Although this is a base rates proceeding, the Company's ACOSSs and its proof of revenue analyses (Exhibit 103) include all of the Company's revenue. However, the costs and revenues for purchased gas for sale customers are not the subject of this proceeding, and simply balance out. The rest of the costs incurred by Columbia are the subject matter of this proceeding, and are effectively part of the revenue requirement, the cost allocation and the rate design. Thus, I include all of the costs and revenues except purchased gas costs in my analysis, including costs and revenues related to base distribution rates, Rider USP (universal service), Rider CC, the GPC (gas procurement charge for administrative costs related to utility gas supply), and the MFC (merchant function charge, related to recovery of uncollectibles costs for utility gas sales service). In measuring percentage changes, I also include all non-purchased gas cost revenues.

Q. Please summarize Columbia's proposed revenue allocation in this proceeding.

A. The Company indicates that it subscribes to the principle that rates should be moved into line with allocated costs, subject to rate gradualism considerations. For its cost basis, the Company claims that it generally relies on its Average ACOSS methodology. The Company also proposes not to assign a rate decrease to the MDS class (and in fact includes

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[26] See, for example, Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. The criteria in this text apply to the overall development of a utility rate structure. The criteria that I discuss in this testimony are those that apply to the revenue allocation portion of the process, which is only one aspect of the overall development of utility rates.

an increase for the C&I Network), although a decrease would be justified based on allocated costs. In addition, the Company appears to have considered the fact that it cannot impose rate increases on flex rate customers, the vast majority of which take service in the Large General Service class. The Company's revenue allocation proposal is summarized in Table IEc-3 below.

Table IEc-3
Summary of Columbia Revenue Allocation Proposal
($000)

	Total	Residential	SGS1	SGS2	Medium General	Large General	MDS	Flex
Current Non-Gas Revenues	433,835	318,013	34,082	39,058	21,885	15,356	552	4,887
Proposed Increase	100,527	72,614	8,397	9,664	5,672	4,178	0	2
Increase%	23.2%	22.8%	24.6%	24.7%	25.9%	27.2%	0.0%	0.0%
Cost-based Increase	100,527	72,542	7,875	(1,346)	(267)	5,768	(458)	16,413
Percent	23.2%	22.8%	23.1%	-3.4%	-1.2%	37.6%	-83.0%	335.8%

Notes:

1. Revenues include all tariff revenues except gas supply costs.
2. Cost-based increase is rate increase to bring revenues fully into line with allocated cost, based on 50/50 weighting of CD and P&A mains allocator.

Source: RDK WP3

As shown, the Company's revenue allocation proposal is not consistent with its own cost allocation analysis, even recognizing the Company's belief in a need to accommodate flex rate customer shortfalls. In that respect, the revenues from the Flex rate customers fall far short of allocated costs, by $16.4 million. This shortfall is only slightly offset by the over-recovery from the MDS class of about $0.5 million, for which the Company does not propose a rate decrease. Nevertheless, these impacts imply that the Company should impose higher than cost-based increases for the other rate classes to meet its proposed revenue requirement. However, for the Large General Service class, the Company proposes rate increases that are well below those necessary to move rates into line with allocated costs, meaning that these classes are not covering their own costs, and of course not contributing to the Flex rate shortfall. For Residential and Rate SGS1, the Company proposes an increase that is approximately equal to the cost-based increase requirement, which means this class will not make any contribution to the Flex rate shortfall.

This leaves the remaining classes, namely SGS2 and Medium General, to bear significant rate increases, despite the cost evidence that negative or minimal rate increases would be justified under the Company's stated cost basis. The case of the SGS2 class is particularly problematic, in that the Company assigns a material increase to that class despite the fact that the class substantially over-recovers costs at current rates.

Thus, it is not entirely clear how the Company developed the revenue allocation proposal for this proceeding. The Company indicates only that its revenue allocation serves to move class revenues closer to allocated costs, but it does not explain how its proposed revenue allocation is consistent with its cost allocation method, nor whether the *progress* toward cost-based rates is consistent across rate classes.[27]

Q. How does the Company's proposal compare to the revenue allocation over the past several base rates proceedings, all of which were resolved by settlement?

A. Table IEc-4 below provides the comparison. Note that I've included the revenue sharing percentages that would result from moving all rates into line with allocated costs under the two ACOSS methods.

[27] The Company evaluates whether progress toward cost-based rates is achieved using the indexed rate of return metric. While I recognize that this metric has long been used by utilities in Pennsylvania, it is a biased measure that can imply that rates are moving into line with allocated costs when basic common sense would indicate otherwise.

Table IEc-4
Revenue Allocation Shares in Recent Columbia Base Rate Cases
Measured as a Percentage of the Approved Revenue Increase

Docket No.	Residential	SGS1	SGS2	Medium General	Large General	MDS	Flex
Settlements							
R-2008-2011621	79%	13%		4%	4%	0%	--
R-2009-2149262	73%	18%		5%	4%	0%	--
R-2010-2215623	75%	19%		5%	1%	0%	--
R-2012-2321748	74%	19%		6%	1%	0%	--
R-2014-2406274	75%	16%		4%	5%	0%	--
R-2015-2468056	73%	16%		7%	4%	0%	--
R-2016-2529660	74%	8%	9%	5%	0%	0%	--
R-2018-2647577	72%	10%	6%	8%	0%	0%	--
Columbia Proposed at R-2020-3018835							
Proposed	72%	8%	10%	6%	4%	0%	0%
Avg. ACOSS*	85%	9%	0%	0%	6%	0%	--

* Increase needed to bring rates in line with allocated costs using 50/50 average, with reallocated Flex shortfall.
Sources: RDK Workpapers, Settlement documents, RDK Testimony from R-2018-2647577

Table IEc-4 generally shows that the Company's proposed allocation of the revenue requirement would produce a sharing that is not substantially different from the settlements of the past seven base rates proceedings. The Company proposes to assign a lower share of the increase to the Large General (LDS/LGSS) rate class than it has in the past, and considerably lower than is justified by its own cost allocation study. The Residential class is generally consistent with the past, but is at the low end of the range, and well below a cost-based share. The Company's proposal for Small General Service (SGS1 and SGS2) and Medium General rate class increases is at the high end of the historical range, and well above the amount justified by the Company's cost allocation analysis. Thus, as is not uncommon in base rates proceedings, the Company proposes to impose a relatively high increase on Small General Service customers relative to both the historical pattern and its own cost analysis, while assigning lower increases to Residential, Large General

Q. Do you agree with Columbia's proposed revenue allocation methodology in this proceeding?

A. No. First, I do not agree with the use of a 50/50 weighting of ACOSS methods for the reasons discussed below. Second, for the reasons discussed above, if the Commission adopts the Company's proposed 50/50 weighting of the CD and P&A ACOSS methods, a very different revenue allocation would be appropriate. If that were the case, first, a material increase should be assigned to the Flex rate customers, because the Company has not justified a rate discount for those customers. Second, no rate increase should be assigned to the SGS2 or Medium General class, because those classes already produce revenues well in excess of allocated cost. In addition, under a 50/50 weighting of cost allocation methods, a modestly larger increase should be assigned to both the Residential and Large General classes, reflecting their below average class rates of return. Finally, the SGS1 increase proposed by the Company is about right. I have included a proposed revenue allocation proposal below, in the event that the Commission approves the Company's 50/50 weighting of its ACOSS methodologies.

Q. Have you developed an alternative revenue allocation proposal for this proceeding?

A. I have. In developing my proposal for this proceeding, I considered three factors:

First, as the cost basis, I used a weighted average of the revenue requirements from the two Company ACOSSs. In this average, I weighted the results of the P&A ACOSS at 75 percent and the CD ACOSS at 25 percent, implicitly weighting the P&A ACOSS as three times more important than the CD ACOSS. I chose these weighting factors for the following reasons. In the Company's 2012 base rates proceeding, the results of my independent ACOSS (based on Commission precedent) were generally closer to those of the Company's P&A ACOSS than the CD ACOSS. For the SGS/SGDS class, an implied weighting of 75/25 of the Company's ACOSS results approximated my independent results. In addition, the P&A

ACOSS is conceptually more similar to the A&E methodology that the Commission has approved for gas distribution utilities. Thus, for reasons of precedence, I weight it more heavily. My revenue allocation calculation therefore begins with an assessment of the increase needed to bring each class into line with allocated cost, based on this weighted average of ACOSS results.

Second, I include the $6.5 million in Flex rate revenues the Company's currently foregoes in its negotiated rates as current-rates revenue, because the Company has not justified those discounts. I also allow rate increases to be applied to that class like any other rate class.

Third, to reflect the principle of rate gradualism, I limited the increase to any rate class to be no more than 2.0 times the system average. While there are no "hard-and-fast" rules for gradualism, limiting the maximum increase to 1.5 to 2.0 times the system average increase is not uncommon. In my analysis, this limit is applied to the Flex Rate class under 50/50 weighting, and both the Large General and Flex rate classes in the 75/25 weighting. In addition, I adjusted the revenue requirement for the SGS2 class to avoid a rate decrease.

Fourth, I set eliminate the rate reductions implied for SGS2 and Medium General and set the increases to zero, in the 50/50 weighting calculation.

Fifth, the net revenue shortfall that reflects from the adjustments in Steps 2, 3 and 4 above is reallocated to the remaining classes on the basis of overall allocated cost.

Supporting calculations are provided in my electronic workpapers, RDK WP2.

Q. Why do you not rely on the Traditional P&A ACOSS method in developing your revenue allocation proposal?

A. As I indicated earlier, none of the traditional cost allocation approaches for gas distribution mains costs provide a theoretically sound approach for recognizing the specific usage of individual components of the distribution system. As such, these methods simply cannot reflect such system differences as:

- Whether large mains have been extended to serve large commercial or industrial customers or whether the extension serves distributed residential customer networks;

- Whether gas distribution mains must be extended for longer distances to serve small and medium commercial customers than for residential customers, or whether such commercial customers are more likely to be more geographically concentrated in commercial areas, thereby requiring less main extension;

- Whether the very significant economies of scale associated with the use of larger and higher-pressure mains are proportionally related to all customer class loads, or whether the economic benefits disproportionately result from serving particular customers or classes.

These problems cannot be solved without a detailed assessment of system configuration and mains usage. While Columbia has not undertaken such an analysis in this proceeding, the segregation of mains into categories is a step in the right direction. By segregating mains by size/pressure, the Company's method provides some recognition of the scale economies of serving fewer larger customers than serving many small customers.

Moreover, Columbia has made reasonable efforts to try to ensure that this segregation of mains costs is as accurate as possible, by (a) assigning no costs for small mains costs to any customer served from the larger, higher-pressure mains, and (b) assigning costs for larger, higher-pressure mains that serve only larger customers only to those customer classes.

Finally, it must be recognized that the Traditional P&A method produces allocated cost results for the Large General Service class that are significantly at variance with current rates, and which will very likely result in a further shift to negotiated flex rates for that class. As it is, the average distribution rates for non-flex Large General Service customers are more than 3.5 times higher than those for flex rate customers (on a per-Dth basis), and my algorithm already maxes out the rate increase for those customers. The Traditional P&A approach would imply a substantially larger revenue shortfall from that class, which simply cannot be recovered given the settlement pattern of the last decade of base rate increases.

Thus, while a Traditional P&A method could, as an arithmetic exercise, be adopted for cost allocation purposes, it is unlikely that it would have any useful implications for rate setting for the Large General Service class, and would increase the magnitude of the revenue shortfall that must be reallocated to the other rate classes. A cost allocation result that is that far at variance with market conditions at least suggests that there is a technical problem with the methodology.

Q. What are the implications of your revenue allocation proposal?

A. Table IEc-5 below shows the results of my proposed revenue allocation under the 50/50 and 75/25 weighting scenarios, compared to the Company's proposal.

Table IEc-5
RDK Proposed Revenue Allocation, Compared to Columbia Proposal

	Columbia Proposal		RDK 50/50 Weighting		RDK 75/25 Weighting	
	$000	**%**	**$000**	**%**	**$000**	**%**
Residential	72,614	22.8%	75,021	23.6%	64,966	20.4%
SGS1	8,397	24.6%	8,141	23.9%	9,240	27.1%
SGS2	9,664	24.7%	0	0.0%	4,157	10.6%
Medium General	5,672	25.9%	0	0.0%	4,047	18.5%
Large General	4,178	27.2%	5,903	38.4%	6,655	43.3%
MDS	0	0.0%	0	0.0%	0	0.0%
Flex Current Rate Adj.	--	--	6,519	--	6,519	--
Flex Increase	2	0.0%	4,943	43.3%	4,943	43.3%
Total	**100,527**	**23.2%**	**100,527**	**21.7%**	**100,527**	**21.7%**

Note: The adjustment to current flex rates to reflect the lack of evidentiary support for the discounts is included to true the totals to the Company's proposed increase. The system and flex rate percentage increases are calculated based on the adjusted base rates values.

Source: RDK WP2

6. <u>Rate Design Issues</u>

Q. Please describe the tariff structure for the SGSS, SCD and SGDS rate classes.

A. Base rate tariff charges for these three classes currently consist of a bifurcated monthly customer charge and a bifurcated commodity charge, both split between customers with annual consumption above and below 644 Dth. Within each size category, SGSS and SCD customers pay the same commodity charge, while SGDS customers pay a slightly lower commodity charge reflecting the fact that the Company does not incur gas storage working capital costs for regular transportation customers. The basic distribution rate tariff structure is shown in Table IEc-6 below.

In addition, the SGSS sales customers are subject to PGC, GPC, MFC and Rider CC charges. Rate SCD Choice and Rate SGDS transportation customers are subject to certain PGC charges (related to load balancing), and the Rider CC charge.

Q. How does Columbia propose to implement its rate increase for these classes?

A. Columbia's proposed increases for the base rates components of Small General Service classes are shown in Table IEc-6 below.[28]

Table IEc-6
Columbia Proposed Small General Service Base Rate Design

	Current Rate	Proposed Rate	Percent Increase
Rates SGSS and SCD			
Customer Charge < 644Dth/year	$22.75	$30.00	31.9%
>644 Dth/year	$48.00	$60.00	25.0%
Commodity Charge <644 Dth/year	$4.4145	$5.4513	23.5%
>644 Dth/year	$3.7912	$4.7478	25.2%
Rate SGDS			
Customer Charge < 644Dth/year	$22.75	$30.00	31.9%
>644 Dth/year	$48.00	$60.00	25.0%
Commodity Charge <644 Dth/year	$4.2925	$5.3428	24.5%
>644 Dth/year	$3.6691	$4.6396	26.5%

Q. What approach do you recommend for setting rates for these classes?

[28] Table Iec-6 shows the Company's proposed rate design as detailed in Exhibit 103 Schedule 7, which appears to be consistent with the proposed revenues reported in the Company's ACOSSs. These values do not appear to be consistent with the testimony of Columbia witness Melissa J. Bell (Statement No. 3) at pages 36-37.

A. In general, for small and medium general service classes, I advocate setting the customer charge at or near the customer-related costs for the smaller customers within each class, subject to rate gradualism constraints. The commodity charge is then adjusted to produce the appropriate revenue requirement.

Q. How do you determine the cost basis for the customer charge?

A. I begin with a 75/25 weighted average of the two ACOSS methods and determine the per-customer costs that are allocated using customer-based allocation factors. In developing the cost basis for the customer charge, I take a relatively simple approach to the problem, in that I include all costs that are allocated on a customer basis. I recognize that some experts, and at least some Commission precedent, support the exclusion of certain "indirect" customer-related costs from this calculation. Nevertheless, I follow the basic principle that the rates should follow the costs. If customer charges are set below the allocated customer cost, then larger customers will subsidize smaller customers, as measured by the logic of the ACOSS. While subsidizing smaller customers may have a public policy rationale for the residential class, I see no particular advantage to such an intra-class cross-subsidy for the non-residential classes.

However, in making the calculations, I *excluded* all uncollectibles costs from customer-related costs. Uncollectibles costs are essentially a fee on customers who pay their bills to compensate the utility for those customers who do not. As these costs are essentially a tax, I deem it reasonable to recover these costs with volumetric charges within the small business classes. This approach is conceptually similar to the Company's treatment of universal service costs within the Residential class.

Q. What are the implications of your analysis for the SGS/SGDS customer class customer charges?

A. My analysis indicates that the fully loaded customer cost based on my 75/25 weighted average ACOSS approach is $40 for the Residential class, $45 for the Small General Service class (under 644 Dth/year) and $66 for the Small General Service class (over 644 Dth/year). Based on this analysis, I believe that the Company's proposals to increase the SGS1 customer charge to $30 and increase the SGS2 customer charge at $48 are cost-justified at the full revenue requirement. If the Company's overall increase is scaled back, the increase in the customer charge for SGS1 should similarly be scaled back. Thus, for example, if the approved rate increase is reduced from $100.5 million to $40.0 million, the $7.25 increase in the SGS1 should be scaled back to $40/100.5 * $7.25 = $2.89, resulting in a $25.64 customer charge. A similar adjustment should apply to the SGS2 customer charge.

Q. How does the Company's proposed customer charge for the SGS1 customers compare to the practices of other Pennsylvania NGDCs?

A. Table IEc-7 below presents the customer charges. As shown, PGW's customer charge is currently mid-range, and its proposal would nearly move it to the top, exceeded only by the relatively small Peoples Gas (formerly TWP) utility.

Table IEc-7
Non-Residential Customer Charges: Pennsylvania NGDCs

	$/month
National Fuel Gas Dist'n C&PA (< 250 mcf)	$19.89
Peoples Natural Gas SGS (< 500 mcf)	$20.00
Columbia Gas SGSS/SCD/SGDS (Current)	**$22.75**
PGW GS-C (Current)	$23.40
UGI Gas N/NT	$23.50
PECO Gas GC	$28.55
Columbia Gas SGSS/SCD/SGDS (Current)	**$30.00**
PGW GS-C (Proposed in Current Case)	$32.75
Peoples Gas (TWP) SGS (<500 mcf)	$35.00
Sources: Company websites	

Since it is likely that the Company's proposed increase will be scaled back, I conclude that scaling back the $30.00 proposed charge would keep the Columbia Gas practice reasonably in the range of the other Pennsylvania NGDCs.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

Overview

Mr. Knecht has more than 35 years of practical economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 25 years, Mr. Knecht's practice has primarily involved providing analysis, consulting support and expert testimony in regulatory matters, primarily involving electric and natural gas utilities. Mr. Knecht's work includes many aspects of utility regulation, including industry restructuring, cost unbundling, cost allocation, rate design, rate of return, customer contributions, energy efficiency programs, smart metering programs, treatment of stranded costs and utility revenue requirement issues. He has worked for state advocacy agencies, industrial customer groups, law firms, regulatory agencies, government agencies and utilities, in both the United States and Canada. He has provided expert testimony in more than one hundred separate utility proceedings.

In addition to his work with regulated utilities, Mr. Knecht has consulted on international industry restructuring studies, prepared economic policy analyses, participated in a variety of litigation matters involving economic damages, and developed energy industry forecasting models.

Education

Master of Science, Management (Applied Economics and Finance), Sloan School of Management, M.I.T.

Bachelor of Science, Economics, Massachusetts Institute of Technology

Select Project Experience

For more than twenty years, Mr. Knecht has provided consulting services, analysis and expert testimony before the Pennsylvania Public Utility Commission on all manner of regulatory proceedings to the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**. In addition to expert testimony, Mr. Knecht has assisted OSBA with the development of public policy positions, litigation strategy, and longer term strategy.

For the **INDUSTRIAL GAS USERS ASSOCIATION**, Mr. Knecht provided consulting and expert witness services in a generic cost allocation proceeding involving Gaz Métro before the Régie de l'énergie in Québec.

For the **NEW BRUNSWICK PUBLIC INTERVENER,** Mr. Knecht provides consulting and expert witness services in a variety of regulatory proceeding before the New Brunswick Energy and Utilities Board involving New Brunswick Power, Enbridge Gas New Brunswick, and petroleum products. Mr. Knecht has addressed issues of load forecasting, costs forecasting, cost of capital, allocation of corporate overhead costs, utility cost allocation, revenue allocation, market-based rate design, cost-based rate design, and rate decoupling.

For **L'ASSOCIATION QUÉBÉCOISE DES CONSOMMATEURS INDUSTRIELS D'ÉLECTRICITÉ (AQCIE) AND LE CONSEIL DE L'INDUSTRIE FORESTIÈRE DU QUÉBEC (CIFQ)**, Mr. Knecht provided analysis, consulting advice and expert testimony before the Régie de l'énergie in regulatory matters involving Hydro Québec Distribution and TransÉnergie. This work includes revenue requirement, power purchasing, cost allocation, treatment of cross-subsidies, and rate design.

For the **INDEPENDENT POWER PRODUCERS SOCIETY OF ALBERTA**, Mr. Knecht provided consulting advice, analysis and expert testimony before the Alberta Energy and Utilities Board in a series of proceedings involving the restructuring of the electric utility industry, the unbundling of rates, and the development of transmission rates.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2016-2580030	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	April 2017	Pennsylvania Office of Small Business Advocate	Test year, load forecast, O&M expenses, rate base, rate of return, cost allocation, rate design, EE&C program, capacity assignment
Matter 336	New Brunswick Energy & Utilities Board	New Brunswick Power	January 2017	New Brunswick Public Intervener	Financial forecast, equity requirement, depreciation life, variance mechanisms, cost allocation, rate design
Matter 338	New Brunswick Energy & Utilities Board	Generic	December 2016	New Brunswick Public Intervener	Retail petroleum margins
Matter 330	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2016	New Brunswick Public Intervener	Revenue requirement, investment test, customer retention initiatives, cost allocation, rate design
R-2016-2537359	Pennsylvania Public Utility Commission	West Penn Power Company	July 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-2016-2537355	Pennsylvania Public Utility Commission	Pennsylvania Power Company	July 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
P-2016-2537609, 2537594	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas	July 2016	Pennsylvania Office of Small Business Advocate	Waiver of DSIC cap.
P-2016-2543523	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Electric Division	July 2016	Pennsylvania Office of Small Business Advocate	Default service procurement.
R-2016-2529660	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	June 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-2015-2469275	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	May 2016	Pennsylvania Office of Small Business Advocate	Default service procurement plan.
R-2015-2518438	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Gas Division	April 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, energy efficiency and conservation program.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-2016-2521993	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	April 2016	Pennsylvania Office of Small Business Advocate	Waiver of DSIC cap.
M-2015-2477174	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Electric Division	February 2016	Pennsylvania Office of Small Business Advocate	Energy efficiency and conservation plan review and development.
Matter No. 306	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	February 2016	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2015-2511333, 2511351, 2511355, 2511356	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2016	Pennsylvania Office of Small Business Advocate	Default service procurement plans, purchase of receivables.
P-2015-2501500	Pennsylvania Public Utility Commission	Philadelphia Gas Works	October 2015	Pennsylvania Office of Small Business Advocate	DSIC rate design under cash flow regulation, capital structure
P-2014-2459362	Pennsylvania Public Utility Commission	Philadelphia Gas Works	June 2015	Pennsylvania Office of Small Business Advocate	Demand side management programs, rate decoupling mechanism, incentive mechanism, cost-benefit analysis.
R-2015-2469275	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2015	Pennsylvania Office of Small Business Advocate	Misc. revenue requirement issues, cost allocation, rate design
R-2015-2468056	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2015	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, customer contribution policy
R-2015-2461373	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	April 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-2014-2456648	Pennsylvania Public Utility Commission	Peoples TWP LLP	March 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-3867-2013	Régie de l'énergie, Québec	Société en commandite Gaz Métro	February 2015	l'Association des Consommateurs de Gaz	Distribution cost allocation

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-3888-2014	Régie de l'énergie, Québec	Hydro Québec TransÉnergie	December 2014	AQCIE/CIFQ	Transmission customer contribution policy
R-2014-2428744 R-2014-2428742	Pennsylvania Public Utility Commission	Pennsylvania Power Company, West Penn Power Company	November 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
M-2014-2430781	Pennsylvania Public Utility Commission	PPL Electric Utilities	October 2014	Pennsylvania Office of Small Business Advocate	Smart meter procurement, rate design
Matter No. 253	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2014-2417907	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, class eligibility, reconciliation
R-2014-2406274	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2407345	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Customer contribution policy, alternative financing mechanism
R-2014-2408268	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2014	Pennsylvania Office of Small Business Advocate	Gas procurement sharing mechanism, cost allocation
R-2014-2397237	Pennsylvania Public Utility Commission	Pike County Light & Power (Electric)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2397353	Pennsylvania Public Utility Commission	Pike County Light & Power (Gas)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation
R-2014-2399598	Pennsylvania Public Utility Commission	Peoples TW Phillips	March 2014	Pennsylvania Office of Small Business Advocate	Gas procurement, design day demand, cost allocation rate design, retainage
P-2013-2389572 (Remand)	Pennsylvania Public Utility Commission	PPL Electric Utilities	February 2014	Pennsylvania Office of Small Business Advocate	Time of use rates, net metering rates

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter 225	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	January 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2013-2391368, P-2013-2391372, P-2013-2391375, P-2013-2391378	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, cost allocation, rate design
Matter No. 214	New Brunswick Energy & Utilities Board	Generic	November 2013	New Brunswick Public Intervenor	Maximum retail margins for motor fuel and residential heating oil.
Matter No. 171	New Brunswick Energy & Utilities Board	New Brunswick Power	September 2013	New Brunswick Public Intervenor	Amortization method for deferral costs associated with refurbishing Point Lepreau Generating Station
C-2013-2367475	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2013	Pennsylvania Office of Small Business Advocate	Forecasting and reconciliation of default service electric costs and revenues.
P-2011-2277868, I-2012-2320323	Pennsylvania Public Utility Commission	Generic	August 2013	Pennsylvania Office of Small Business Advocate	Ratemaking treatment for customers in overlapping NGDC service territories ("gas-on-gas").
P-2013-2356232	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Program design, cost recovery and rate design for alternative system expansion financing pilot program ("GET Gas")
R-2013-2355886	Pennsylvania Public Utility Commission	Peoples TWP LLC	July 2013	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2013-2361764, R-2013-2361763, R-2013-2361771	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter No. 178	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	July 2012	NB Public Intervenor	System expansion economic test, test year revenue requirement, cost allocation, rate design, treatment of stranded costs.
R-2012-2290597	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2012	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2012-2293303	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2012	Pennsylvania Office of Small Business Advocate	Treatment of pipeline credits
AUC ID #1633	Alberta Utilities Commission	Alberta Electric System Operator	April 2012	Powerex, Northpoint Energy Solutions, Cargill	Economic efficiency issues for allocation of constrained transmission capacity.
R-2012-2286447	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, reconciliation
R-2012-2281465	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, gas price procurement and hedging
R-2011-2273539	Pennsylvania Public Utility Commission	Peoples TWP	March 2012	Pennsylvania Office of Small Business Advocate	Design day demand methodology
P-2011-2273650 P-2011-2273668 P-2011-2273669 P-2011-2273670	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	February 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, retail market enhancement, rate design.
R-2011-2264771	Pennsylvania Public Utility Commission	PPL Electric Utilities	January 2012	Pennsylvania Office of Small Business Advocate	TOU Rates

Note: Dates shown reflect submission date for direct testimony.

May 2017

EXHIBIT IEc-2

RDK ELECTRONIC WORKPAPERS

RDK WP1: Replication of P&A ACOSS

RDK WP1A: Traditional P&A ACOSS

RDK WP2: Replication of CD ACOSS

RDK WP3: Replication of 50/50 Weighted ACOSS

RDK WP4: Flex Rate Customer Information HIGHLY CONFIDENTIAL

RDK WP5: Columbia Proposed Proof of Revenues

RDK WP6: Return on Equity Calculations

*** Non-Confidential Workpapers will be transmitted via separate e-mail attachment in excel spreadsheet format simultaneous to e-mail service of this document***

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018835**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits IEc-1 through IEc-2 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 28, 2020

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable Katrina L. Dunderdale
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DATE: July 28, 2020

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

August 26, 2020

The Honorable Katrina L. Dunderdale
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 5th Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. 2020 Base Rate Filing / Docket No. R-2020-3018835

Dear Judge Dunderdale:

Enclosed please find the Rebuttal Testimony and Exhibit of Robert D. Knecht, labeled OSBA Statement No. 1-R, with Exhibit IEc-R1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Daniel G. Asmus

Daniel G. Asmus
Assistant Small Business Advocate
Attorney ID No. 83789

Enclosures

cc: **PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)**
Robert D. Knecht
Parties of Record

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018835**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Rebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Universal Service Cost Allocation
Cost and Revenue Allocation
Return on Equity

Date Served: August 26, 2020

Date Submitted for the Record: September 24, 2020

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. Introduction

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony and associated exhibits earlier in this proceeding, and my qualifications were presented therein.

Because some of the issues raised in intervenor testimony are, to a large extent, conceptually consistent with those posited in other proceedings, this testimony draws significantly on my testimony in those earlier proceedings. I therefore acknowledge some self-plagiarizing in this testimony.

Q. Please describe your assignment in this matter.

A. This rebuttal testimony addresses three aspects of intervenor testimony:

- Proposals by Mr. Roger D. Colton representing the Pennsylvania Office of Consumer Advocate ("OCA") and Mr. Mitchell Miller representing the Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") to allocate and charge universal service costs to non-residential customers;

- Mains cost allocation proposals of Mr. Ethan H. Cline representing the Pennsylvania Public Utility Commission's ("Commission") Bureau of Investigation and Enforcement ("I&E") and OCA witness Mr. Jerome B. Mierzwa, as well as Mr. Mierzwa's revenue allocation proposals;

- The biases relating to estimating the cost of equity capital in the testimony of OCA witness Mr. Kevin W. O'Donnell, CFA.

These issues are addressed in Sections 2 through 4 below.

Q. Please summarize the conclusions from your review.

A. My conclusions are as follows:

1. Conceptually, the recovery of universal service costs can be based on an "insurance" model in which customers pay for the benefit they receive, or a "tax-

and-spend" model, in which a social benefit program is financed through utility rate taxation. Heretofore, the Commission has generally followed the insurance model, and I recommend that it continue to do so.

2. Neither Mr. Colton nor Mr. Mitchell has prepared a customer impact evaluation of their proposals on business customers.

3. If the Commission adopts the "tax-and-spend" philosophy for recovery of universal service costs, honesty and regulatory transparency require that these charges be separately identified on non-residential customer bills.

4. The peak-and-average cost allocation philosophy for mains cost allocation advocated by Mr. Mierzwa and Mr. Cline does not reasonably reflect the economies of scale of serving larger non-residential customers, particularly the more geographically concentrated small and medium businesses.

5. Using my evaluation of the testimony of Mr. O'Donnell in this proceeding, I demonstrate why I believe regulators have allowed the risk premium in utility RoE awards to rise substantially over the past thirty years, to the enormous detriment of utility ratepayers. While I recognize that utility regulators are unlikely to make substantial changes in return on equity awards in a single proceeding, I believe it is important for the Commission to recognize that Mr. O'Donnell's calculations for the cost of equity capital contain material biases in favor of utility shareholders.

2. <u>Universal Service Costs</u>

Q. Please describe the positions of the parties with respect to the allocation and recovery of universal service costs in this proceeding.

A. Utility-sponsored universal service programs in Pennsylvania provide benefits to some low-income residential ratepayers. It is the long-standing policy of the Pennsylvania Public Utility Commission that the costs for these programs be allocated only to residential rate classes and recovered in reconcilable variable charges.[1] The only exception to that policy has been the programs at the Philadelphia Gas Works ("PGW"), where universal service costs are recovered on a volumetric basis from all firm service rate classes, with the larger industrial customers exempted. Heretofore, the Commission has allowed PGW to be an

[1] By "variable," I refer to charges that vary with ratepayers' consumption, namely energy charges for electric distribution utilities and commodity/volumetric charges for gas distribution utilities.

exception to the general rule, at least in part because its policy was adopted prior to the start of Commission regulation of PGW.[2]

However, the Commission recently undertook a review of both the nature and the financing of low-income assistance programs, and it issued a final Policy Statement.[3] While there are numerous detailed aspects to the Policy Statement, the key changes are (a) universal service benefits to low-income customers, and thus the associated costs, will increase substantially, and (b) the Commission would consider changing the current cost recovery policy. Regarding the latter, the Commission ordered that "[u]tilities should be prepared to address recovery of CAP costs (and other universal service costs) from any ratepayer classes in their individual rate case filing *[sic]*."[4] The Commission's primary motivation for considering a change in the cost recovery method was not based on any identifiable change in regulatory philosophy or cost causation principles.[5] The rationale for considering a change to the policy appears to be that the low-income assistance programs have become unaffordable to those residential customers who are ineligible or who otherwise do not participate in the programs.[6]

In this proceeding, Columbia proposes to continue the existing practice of assigning and recovering its universal service program costs from residential ratepayers using a volumetric "Rider USP" charge. For the FPFTY, the Company' forecasts that it will incur $26.73 million in universal service costs, or about $5.56 per month for a typical residential customer.

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[2] Pennsylvania Public Utility Commission, Opinion and Order, Docket No. R-2017-2586783, Order entered November 8, 2017, pages 73-74.

[3] "Final Policy Statement and Order," Pennsylvania Public Utility Commission, Docket No. M-2019-3012599, Order Entered November 5, 2019.

[4] *Id.*, page 104.

[5] The Commission does conclude that it has the legal right to make such a change, and that opposing parties did not demonstrate that such a change would have a negative impact on businesses. *Id.*, at 96. While I am not an attorney, the Commission appears to have shifted the burden of proof regarding a negative customer impact from this major change in regulatory policy from the advocates for the change to the advocates for the status quo.

[6] *Id.*, at 93.

It is not clear how much, if any, of that $26.73 million recognizes the Commission's changes that will expand the cost of benefits.[7]

Mr. Colton recommends that all customers be required to contribute to the costs of the universal service plans, to reflect the public benefits of universal service. He proposes that the costs be allocated among the rate classes based on the Company's proposed distribution rate revenues, exclusive of the current universal service charge ("USP").[8] Mr. Colton does not propose a specific recovery rate design method.

CAUSE-PA witness Mr. Miller similarly opines that non-residential classes should contribute to the recovery of universal service costs, but he proposes neither a specific cost allocation method nor a rate design method for those costs.

Q. Is there an advantage to recovering the cost of programs that assist low-income customers through utility rates?

A. There are strong political advantages. Political sponsors of legally mandated utility income redistribution programs can rightfully say that they have worked to help low-income residents, and they can do so without having to explicitly raise taxes. Moreover, because these costs are often not itemized on customers' bills, many ratepayers are unaware of the magnitude or even the existence of the charges on their bills for these subsidies.

Q. Are there disadvantages?

A. Several. First, using ratepayer bills to finance low-income customer programs comes with a fairness downside. Taxes on utility bills are generally what economists call "regressive," in that utility bills represent a larger percentage of the income of low- and medium-income customers than they do for more well-to-do customers. Thus, while the lowest-income

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[7] These calculations are shown in electronic workpaper RDK WP5R, circulated with this rebuttal testimony.

[8] Mr. Colton's views on how best to allocate universal service costs among rate classes are somewhat fluid. For PGW, Mr. Colton has supported a volumetric allocation, but (possibly unknowingly) allowing larger customers to avoid cost responsibility. OCA Statement No. 4R, Docket No. R-2017-2586783. For UGI Gas, Mr. Colton advocated allocating universal service costs based on bill count, such that a barber shop and Procter & Gamble would make the same monthly contribution. OCA Statement No. 5, Docket No. R-2019-3015162. Each of these methods produce substantially different cost responsibilities and customer impacts.

residents get a benefit, the tax tends to come disproportionately from middle-income working people rather than from upper-income members of society.

Second, for reasons that are subject to some debate, customer participation in these ratepayer-financed programs appears to be well below the number of customers who qualify for the benefits.[9] Thus, the programs are not equitably distributing the benefits among the needy. Programs that are more effective in getting benefits to all customers in need would be superior for achieving societal aims.

Third, ratepayer-financed programs can only benefit electric and gas heating customers. Low-income customers using fuel oil, propane and biomass are implicitly excluded from these benefits. As such, a broad-based program for all low-income customers would result in more equitable assistance.

Fourth, funding for these programs comes only from electric and gas customers. The societal benefits referenced by Mr. Colton inure to all residents and businesses of Pennsylvania, whether or not they are natural gas customers, and whether or not they use substantial amounts of electricity or gas in their operations.

Fifth, in Pennsylvania, the ratepayer programs are implemented utility-by-utility, rather than through a statewide program. Thus, utilities that serve relatively low-income geographical areas have a dual inequity. First, the overall cost of the program relative to the size of the utility is higher, resulting in a higher rate impact. Second, because the service territory is less affluent, the tax burden is placed on a lower-income populace, exacerbating the regressive nature of the tax.

Q. What are the key conceptual differences in cost recovery policies for universal services?

A. There are two general philosophies: the insurance model, and the public policy tax model.

[9] Mr. Colton acknowledges this problem at page 60 of his testimony in this proceeding, where he concludes that less than 23 percent of the low-income population in Columbia's service territory participate in the Company's customer assistance program ("CAP").

The philosophy of recovering all costs from the residential class is based on the argument that only residential customers are eligible for the benefits. A universal service program is therefore a form of insurance, in which residential gas customers are paying premiums to the utility, so that they will be eligible for cash benefits in the event they have an unfortunate turn in their economic circumstances. In this model, it is fair and reasonable that only gas customers should get the insurance benefits from the program, because it is only gas customers who pay for the program. It is also reasonable that these programs can be deemed to be an integral part of utility service, because the insurance relates only to utility service. Thus, in this model, there is arguably less of a need to separately report the charges on the utility bill.

The alternative model is the government policy tax model. This model, as described in some detail by both Mr. Colton and Mr. Miller, is based on the argument that there are societal benefits associated with assisting low-income residents. Under this paradigm, all customers should pay because all customers obtain the social benefits.[10] In effect, this form of low-income programs looks like many other government programs which provide both individual and societal benefits, and the costs of which are borne by the taxpayers.

Q. **Of the two models for recovery of utility low-income assistance programs, which do you advocate?**

A. My recommendation is that the Commission retain the insurance model, for reasons of cost causation and equity. In this model, customers pay for the benefits for which they are eligible. Residential customers benefit from the insurance, and residential customers pay for that insurance. Non-residential customers are not eligible for that insurance, and they therefore should not pay for the insurance.

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[10] I respectfully disagree with Mr. Colton that these benefits are a "public good," at least as that term is used by economists. See Reply Comments of the Office of Small Business Advocate, Docket No. M-2017-2587711, May 23, 2019, pages 6-8. Whether financed by ratepayers or taxpayers, utility universal service programs are income redistribution programs, designed to ensure that low-income residents receive basic utility services at an affordable price. Nevertheless, I agree that there are societal benefits associated with public assistance to low-income residents, although there may also be societal costs depending on the nature of the programs.

While I acknowledge that there are ancillary societal benefits from policies that assist low income residents, I observe that using broad societal benefits for allocating utility costs may lead to more confusion and complexity in regulatory matters. If all societal benefits get factored into utility rate cost causation, there will be no end of claimants seeking special treatment. For example, the OSBA could argue that small businesses provide benefits to the economy in the form of job creation, economic dynamism, innovation, *et cetera, et cetera,* and are therefore deserving of special rate treatment.

As to the societal benefits of aid to low-income customers, utility programs do not represent a particularly effective means for providing that assistance. In my view, achieving the societal benefits is better accomplished through programs that (a) provide benefits to *all* low-income customers regardless of their heating fuel, (b) provide benefits to *all* low-income customers, regardless of whether they enroll in a utility program, (c) are carefully integrated into all other legislated benefits for low-income customers, and (d) are financed in a more progressive manner through tax policy.

Q. **The Commission indicated that its concern with the existing model is the affordability. Has any party prepared an evaluation as to whether Columbia's universal service costs are affordable?**

A. No. However, my rough calculations show the following. The current rates USP charge for residential customers is approximately 68 cents per Dth, or about $4.84 per non-CAP customer per month. Under the Company's proposed increase, that would rise to 83 cents per Dth, or $5.89 per customer per month.

Under Mr. Colton's proposal, I estimate that the test year universal service charge for residential customers would average $4.22 per month ($4.14 with Mr. Mierzwa's revenue allocation), a savings of about 60 to 70 cents per month relative to the current rates.

Whether 60 to 70 cents per month resolves the Commission's concern about the affordability of universal service costs is a matter I leave to the advocates and the Commission.

Q. Has any party tried to evaluate the combined rate impact on non-residential customers related to a combination of the overall rate increase and the proposed change in the allocation of universal services costs?

A. No. Mr. Colton does not offer an alternative cost allocation study, and OCA witness Mr. Mierzwa did not incorporate Mr. Colton's recommendation into his analysis. Similarly, Mr. Mierzwa did not address the impact of Mr. Colton's recommendations in either his cost allocation analysis or his evaluation of rate gradualism.

Based on my review, Mr. Colton's proposal would result in an additional increase in current base rates of about 6.5 to 7.2 percent for most of the non-residential classes, with an increase of about 5.3 percent for the MLDS and Flex rate classes.[11] Thus, if the Commission accepts both Mr. Mierzwa's proposal for revenue allocation and Mr. Colton's proposal for universal service cost allocation, small to medium businesses would face increases of nearly 37 percent (the SGS classes), while large businesses would face increases of over 43 percent (SDS and LDS classes).

Q. If the Commission decides that non-residential customers should contribute to the cost for low-income customer programs, can you comment on who would implicitly bear those costs?

A. From a political perspective, the beauty of taxing businesses is that no one knows who bears the burden. As the saying goes, "Businesses don't pay taxes. People pay taxes." A tax on business is eventually borne by people, whether they are business shareholders, customers, employees, or even other taxpayers. While it may be popular to believe that a tax on a business will necessarily be borne by its (theoretically higher-income) owners, it is also possible that the tax will simply be passed on to customers in higher prices, it will be passed back to workers in the form of lower wages, or it will result in business closures.

[11] Mr. Colton's proposed allocation of universal service costs is based on Columbia's proposed revenue allocation. If Mr, Mierzwa's proposed revenue allocation is used, the percentage increases for non-residential customers are larger. I note also that Mr. Colton would assign a significant rate increase to the Flex rate customer class, whereas Mr. Mierzwa assigns only a *de minimis* base rate increase to that class, presumably based on the Company's position that the negotiated flex rates are capped by competitive alternatives.

The reason that the answer to this question is unknown is because the impact of a business tax depends on the competitive circumstances faced by the business. The key factors affecting how a tax on non-residential utility customers will be borne are the following:

- Is the entity highly competitive?
- Are the competitors (both businesses and other products) affected comparably by the tax?
- Does the entity have some significant cost advantage over its competitors?
- Does the tax represent a significant cost to the entity?

For those entities where the answer to the last question is negative, it is unlikely that the tax will have shutdown implications. Nevertheless, even a small tax will still be borne by someone.

For businesses that serve highly competitive markets, the tax will only be passed on to customers if its competitors are also affected by the tax. If the tax applies equally to all the competitive options, it will be passed through to customers.

For businesses who face competition from entities who are not affected by the tax, the burden cannot be passed on to customers, and will either fall on the owners, workers, other stakeholders, or will result in closure.

For businesses or entities who enjoy a strong market position and whose prices are set by customers' willingness to pay, the tax will generally be borne by the owners.

Thus, the answer to the question of "who bears the burden of this tax on business" is "it depends."

Q. If the Commission does opt for the government tax policy model, how might the Commission impose the taxes on non-residential customers?

A. There is a wide range of possibilities. However, as I indicated earlier, the PGW model allocates and recovers universal service costs on a volumetric basis, with the largest customers being exempted entirely. In the UGI Gas proceeding, Mr. Colton indicated that the other jurisdictions he reviewed use an energy-based allocation.

In contrast, Mr. Colton proposes to allocate the costs among rate classes in proportion to distribution rate revenues. While he does not offer a specific cost recovery scheme, the obvious choice would be to follow the allocation and use a percentage markup, in the manner of a sales tax or the DSIC charge.

Q. Can you offer any guidance as to the relative advantages and disadvantages?

A. As I indicated earlier, it would be better if the tax were more progressive or less regressive, but that is simply impossible to determine as we have no idea who would bear the burden of such a tax.

However, since the objective of Mr. Colton's philosophy is to reflect the socioeconomic benefits of low-income assistance in rates, it would be useful to try to scale the costs to the magnitude of those benefits. As many of the benefits cited by Mr. Colton relate to labor cost and social stability, it is reasonable to conclude that a larger business with more employees benefits to a larger extent than does a sole proprietorship.

In addition, it would be useful for such a tax policy to try to limit competitive distortions within Pennsylvania and within the utility's service territory to the extent practicable. While this is also impossible, it does imply that, for those circumstances where smaller businesses compete with larger ones, it would be unreasonable to put a much larger burden on smaller businesses.

Q. How does Mr. Colton's proposal to allocate low-income assistance costs on a per-bill basis stack up on these criteria?

A. Mr. Colton's proposal is far more logical than the one he offered a couple of months ago in the UGI Gas base rates case, which was based on bill count. Nevertheless, his proposal has problematic policy considerations:

- First, it assigns minimal costs to the Company's largest customers, whereas the largest businesses likely benefit the most from the societal benefits to which Mr. Colton refers. I estimate that Mr. Colton's proposal would imply that small business customers in Rate SGS1 would pay about 39 cents per Dth, while the very largest customers in Rate MDS would pay less than 3 cents per Dth.

- Second, Mr. Colton's proposal would disadvantage small businesses that compete with larger ones. Does Walmart really need another cost advantage over local retail shops?

Q. Do you have any other comments on the assignment of low-income assistance costs to non-residential customers?

A. Yes. If the Commission does confirm its policy of both increasing the magnitude of the costs and changing its philosophy with respect to cost recovery, it should be open and transparent about the policy change. A new tax is a new tax; non-residential ratepayers should be clearly and openly informed of their increased social responsibilities as determined by the Commission. The universal service charge for non-residential customers should therefore appear as a separate bill item beginning at the time that these charges are first imposed on non-residential customers. In my view, burying these taxes in distribution rates would be dishonest and inconsistent with a responsibility to represent the public interest.

3. <u>Cost and Revenue Allocation</u>

Q. Please summarize the positions of the parties regarding the allocation of mains costs.

A. In its filing, the Company proposes to sub-functionalize its mains costs into four categories: low-pressure, regulated pressure serving non-low-pressure customers, other regulated pressure mains, and transmission. It then allocates each of the non-transmission categories using two different methods, a customer-demand ("CD") method and a peak-and-average ("P&A") method.[12] Columbia reports that it uses a simple average of those two methods for revenue allocation in this proceeding.

In my direct testimony, I supported the Company's sub-functionalization method as a first step toward a causation-based direct assignment cost allocation methodology. Until such a method is developed, I used an average of the two allocation methods presented by the Company, although I used a weighted average based on 75 percent P&A and 25 percent CD.

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[12] See Columbia Statement No. 11, page 8.

Using that weighted average, I presented an alternative revenue allocation proposal. I also offered an alternative revenue allocation in the event the Commission adopts the Company's 50/50 approach.

Mr. Cline appears to support the Company's sub-functionalization approach, but he advocates reliance on the Company's P&A methodology, based largely on Commission precedent. However, it does not appear that Mr. Cline proposes any changes to the Company's revenue allocation as a result of using the P&A methodology.

Mr. Mierzwa rejects the sub-functionalization approach and advocates a "Traditional" P&A approach. He presents an alternative revenue allocation based on that methodology.[13]

Q. Please address I&E witness Mr. Cline's statement that the Commission has never "accepted the use of the customer-demand methodology for developing a cost of service study."

A. I agree with Mr. Cline to the extent his statement is limited to natural gas distribution utilities. However, the Commission has affirmatively approved customer-demand cost allocation methods for electric utilities.[14] The conceptual argument for customer/demand classification for electric distribution and gas distribution is identical. I also observe (a) the Commission's most recent precedent regarding mains cost allocation supports the use of an average-and-excess ("A&E") allocation factor rather than the P&A method supported by Mr. Cline, and (b) the Commission has approved the use of direct assignment methodologies for some customers and customer classes. As such, Commission precedent is not entirely clear.

Q. Please address Mr. Mierzwa's rationale for rejecting the Company's sub-functionalization of mains.

[13] Mr. Mierzwa also makes other changes to the Company's proposed cost allocation study that I do not address.

[14] See, for example, Commission orders involving PPL Electric at Docket No. R-2010-2161694, Order entered December 21, 2010, pages 46-47; confirmed at Docket No. R-2012-2290597, Order entered December 28, 2012, page 113.

A. Mr. Mierzwa appears to rely on the argument that, in sub-functionalizing mains costs, the Company failed to recognize that low pressure mains are likely to be older and more fully depreciated than higher-pressure mains of the same size. This argument is a red herring, for a couple of reasons.

First, none of the cost allocation methods being considered in this proceeding would address the issue raised by Mr. Mierzwa. For example, the Traditional P&A method advocated by Mr. Mierzwa produces the identical result if smaller customers are served by lower-cost 2-inch mains or if the small customers are served by higher-cost 2-inch mains.

Second, attempting to "vintage" the mains as Mr. Mierzwa proposes would exacerbate cost swings over time. For example, Columbia is currently engaged in a wholesale replacement of its aging infrastructure, replacing old cast iron and unprotected steel mains with plastic. Unsurprisingly, Mr. Mierzwa's analysis indicates that Columbia has replaced more of its higher-pressure pipe first, since that would likely be better for addressing safety issues and leaks. Thus, higher-pressure pipe is currently newer and more expensive on a book cost basis. However, as Columbia replaces more of its lower-pressure system, those pipes will become more expensive. When that occurs, it seems unlikely that a consumer advocate would support the vintaging of mains, resulting in proportionately higher costs for small customers. In contrast, Columbia's method of using the same cost per foot by size of pipe is a reasonable and neutral method that serves to reduce cost shifts over time as different parts of the system are replaced. It is therefore more reflective of longer-term mains costs, with less distortion from the timing of recent pipe replacements.

Q. Please address the example presented by Mr. Mierzwa on page 11 that indicates that mains are sized only based on load served and not based on number of customers.

A. Mr. Mierzwa has concocted an example in which the length of main needed to serve one larger customer is exactly the same as the length of main needed to serve five smaller customers, each of one-fifth the load of the larger customer. Thus, as long as the ratio of main length per customer is identical to ratio of peak load per customer, Mr. Mierzwa can sensibly conclude mains costs are not causally related to customer count.

The problem, of course, is that Mr. Mierzwa's example is hypothetical, and there is no evidence that it is representative of an actual gas distribution system. Similar hypothetical examples could be constructed based on the idea that the incremental length for a main to serve a large customer is less than proportionate to its relative load. Under those conditions, a strictly load-based allocator will over-assign costs to the larger customer.

In the real world, I agree with Mr. Mierzwa that, on average, it is likely that larger customers require more footage than smaller customers. However, that additional footage is likely to be less than proportional to the load, thereby resulting in scale economies for those customers. Also, business customers, particularly small and medium businesses, are more likely to be concentrated in commercial areas, and therefore require less additional footage per unit of additional load than dispersed residential neighborhoods. Thus, it is likely that there are some economies of scale in mains footage requirements that are not reflected in a P&A allocation method.

The rub, of course, is the exact magnitude of those economies cannot be determined without detailed system modelling.

Q. Can you respond to Mr. Mierzwa's arguments about economies of scale and scope?

A. Mr. Mierzwa offers a couple of arguments regarding scale and scope economies for mains construction. At page 21, he explains that there are a variety of fixed costs that do not vary with the size of the mains being installed. At pages 23-24 he demonstrates that the cost for any particular main segment increases less than proportionally with peak demand.

I agree that the cost for each main segment exhibits significant economies of scale. A 4-inch main can generally carry at least four times as much gas as a 2-inch main, but generally costs much less than four times as much to purchase and install. When fixed planning costs are factored in, the economies of scale increase. In addition, there is no doubt that it is more cost effective for a single company to serve a particular geographic area than for several competitors to do so. The issue is not *whether* these economies of scale and scope exist; the issue is what, if anything, those economies imply for cost allocation.

Cost allocation analysts endlessly debate how these scale economies should be assigned. Unsurprisingly, analysts representing smaller, low-load-factor customers argue that their classes should be assigned a large share of these benefits by using average demand allocation, while analysts representing larger, higher-load-factor customers feel their clients should get a larger share by supporting customer-based allocation. Both groups cite to these same economies of scale in support of their argument.

From a common-sense perspective, however, neither argument is valid. Any particular main must be sized to meet the design demands of the downstream customers. And every unit of design demand on that main contributes equally to the necessary size, whether that peak demand comes from 1,000 low-load factor residential customers or one large industrial customer or both. Thus, for any particular main, the equitable solution is to allocate its costs in proportion to downstream peak demands.[15] To the extent scale economies should be reflected in cost allocation, they should be based on the relative footage of mains required to serve the different types of customers.

Q. How do the parties' revenue allocation proposals compare in this proceeding?

A. In responding to this question, I will correct an error in my direct testimony. In that testimony, I presented a comparison of the settled revenue allocations from Columbia's last eight rate proceedings. Table IEc-4 incorrectly reported the LDS customer share for the two most recent proceedings, corrected in Table IEc-R1 on the next page. To that table, I have added the parties' proposed revenue allocations for this case.

[15] Theoretical economics is not terribly helpful in this regard. Economic theory dictates that the cost assigned to any particular customer, or any particular class of customers, must be (a) no more than the standalone cost to serve that customer, and (b) no less than the *incremental* cost to serve that customer. With the strong economies of scale in mains size, incremental costs are relatively low, and any of the various mains cost allocation methods would pass the theoretical economics requirements. For that reason, I use an equity argument, rather than economic theory.

Table IEc-R1 Revenue Allocation Shares in Recent Columbia Base Rate Cases Measured as a Percentage of the Approved Revenue Increase							
Docket No.	**Residential**	**SGS1**	**SGS2**	**Medium General (SDS)**	**Large General (LDS)**	**MDS**	**Flex**
Settlements							
R-2008-2011621	79%	13%		4%	4%	0%	--
R-2009-2149262	73%	18%		5%	4%	0%	--
R-2010-2215623	75%	19%		5%	1%	0%	--
R-2012-2321748	74%	19%		6%	1%	0%	--
R-2014-2406274	75%	16%		4%	5%	0%	--
R-2015-2468056	73%	16%		7%	4%	0%	--
R-2016-2529660	74%	8%	9%	5%	3%	0%	--
R-2018-2647577	72%	10%	6%	8%	4%	0%	--
Columbia Proposed at R-2020-3018835							
$000	$74,474	$8,380	$9,644	$5,665	$4,172	$0	$0
Share	72%	8%	10%	6%	4%	0%	0%
OSBA Proposed 75/25 Weighting							
$000	$64,966	$9,240	$4,157	$4.047	$6,655	$0	$4,943
Share	69%	10%	4%	4%	7%	0%	5%
OCA Proposed							
$000	$62,614	$10,090	$11,580	$7,835	$5,514	$0	$0
Share	64%	10%	12%	8%	6%	0%	0%
Corrected values from Table IEc-4 in red. Sources: RDK Workpapers, Settlement documents, RDK Testimony from R-2018-2647577							

1 The differences in the three revenue allocation proposals substantially result from the
2 following factors:

- As I explained in my direct testimony, the Company essentially ignored its own cost allocation study in developing its revenue allocation proposal, and it opted for a nearly across-the-board approach for all classes except MDS and Flex. Thus, for example, the Company's proposed increase for the SGS2 class far exceeds any increase that could be justified from its cost analysis.

- I assigned a significant increase to the Flex rate customers, based on my conclusion that the Company did not adequately demonstrate that flex rates were justified based on fuel competition or bypass.

- Both Mr. Mierzwa and I relied on cost allocation results that justified large rate increases for the LDS class. Mr. Mierzwa assigns a modestly lower value to that class based on judgment regarding rate gradualism.

- Mr. Mierzwa's larger proposed rate increases for the SGS2 and SDS classes (medium businesses) reflect his reliance on the Traditional P&A cost allocation method for mains costs, as compared to the averaging approach used by the Company and me.

Q. What do you conclude from your review of th0e revenue allocation proposals?

A. Mr. Mierzwa's revenue allocation proposals are directionally consistent with this cost analysis. However, if the Commission adopts Mr. Mierzwa's cost allocation philosophy, I would conclude that the rate increases for the LDS classes should be materially higher than those advocated by Mr. Mierzwa. Mr. Mierzwa's costing approach is very different from that implied by the settlements of the last eight rate proceedings, since it indicates that revenues from the LDS class (excluding the flex rate customers) as established in those proceedings result in a class rate of return only slightly above zero. As such, if Mr. Mierzwa's cost allocation approach is adopted, I would recommend that the increase for the LDS class be set at least at twice the system average increase, to reflect the enormous cost under-collection.

4. **Cost of Equity Capital**

Q. Please summarize Mr. O'Donnell's recommendation regarding a return on equity award for Columbia in this proceeding.

A. Mr. O'Donnell concludes that the return on equity ("RoE") award should be in the 8.00 to 9.00 percent range, with a recommended value of 8.50 percent. He also recommends that the equity share of capital be limited to 50.0 percent. Mr. O'Donnell bases his recommendation primarily on the results of his discounted-cash-flow ("DCF") analysis of the cost of equity capital, as supplemented by consideration of the capital asset pricing model ("CAPM") and comparable earnings ("CE") approaches. A summary of the three components of Mr. O'Donnell's analysis is shown in Table IEc-R2 below:

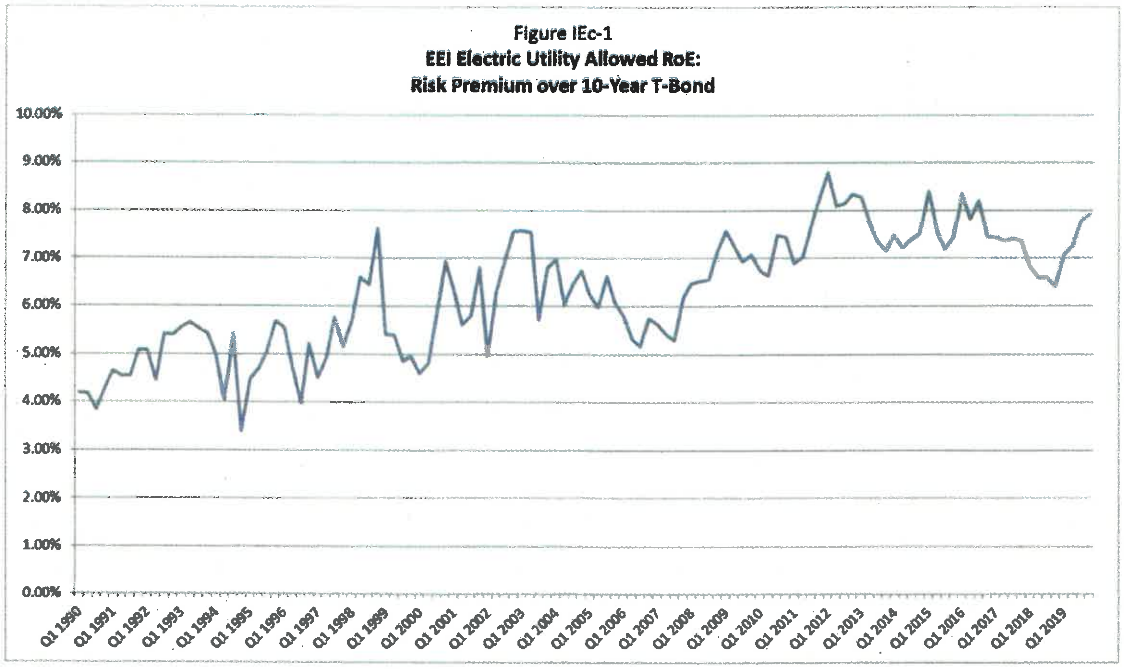
Table IEc-R2 OCA RoE Analysis Summary	
	Range
Discounted Cash Flow	7.5% - 9.5%
Comparable Earnings	9.25% - 10.25%
Capital Asset Pricing Model	5.5% - 7.5%
Overall	**8.0% - 9.0%**
Sources: OCA Statement No. 3	

Q. In your direct testimony, you included a graph of the history of equity risk premium awards for electric utilities as compiled by the industry itself. How does Mr. O'Donnell's recommendation fit into that pattern?

A. Mr. O'Donnell's recommendation shows no deviation from the trend. My Figure IEc-1 is copied below, showing that the risk premium in regulatory RoE awards relative to 10-Year Treasury Bond yields has been allowed to rise from the 400 to 500 basis point range 25 years ago to 700-800 basis points in the past few years.[16] At this writing the yield on the 10-Year

[16] I recognize that Mr. O'Donnell relies on the 30-year T-Bond rate as a measure of the risk-free rate in this proceeding. I respectfully disagree. There is nothing about this proceeding that will lock Columbia into an equity return that is based on 2020 30-year T-Bond rates. As detailed in my direct testimony, this Company is filing a base rates case more than once every two years. Since RoE is re-assessed in each case, the relevant risk-free rate should more reasonably be based on a period of about two years. I use a 10-year approach because it is reasonably common, it results in greater cost stability, and its use is supported by a reputable academic analyst. See http://people.stern.nyu.edu/adamodar/pdfiles/papers/riskfreerate.pdf

T-Bond is 0.65 percent, implying that Mr. O'Donnell recommends a risk premium of 785 basis points, in line with recent regulatory awards and far in excess of historical values.[17]



Thus, Mr. O'Donnell's recommendation is not remotely aggressive when viewed in the context of recent awards, and far exceeds those of the more distant past.

Q. How does Mr. O'Donnell's recommendation compare to the most recent Commission RoE award for Pennsylvania electric and gas utilities?

A. As I indicated in my direct testimony, the Commission awarded UGI Electric a 9.85 percent RoE in mid-2018 when yields on 10-Year T-Bonds were a little below 3.0 percent, implying a risk premium award of 690 basis points. Commendably, that award lies at the lower end

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[17] Mr. O'Donnell is presumably aware of this trend for natural gas distribution utilities, as he includes a figure showing allowed RoE's from 2005 to 2019. While this is a shorter period than that in Figure IEc-1, it shows allowed RoEs dropping from 10.4 percent in 2005 to 9.7 percent in 2019. When adjusted for average 10-Year T-Bond rates of 4.3 percent and 2.1 percent respectively, Mr. O'Donnell's figure confirms that allowed risk premiums in the natural gas distribution industry have risen from 6.1 to 7.5 percent over the past 15 years. For the first three months of 2020, Mr. O'Donnell's reported allowed return of 9.35 percent implies that regulators have awarded a risk premium of approximately 7.9 percent over the 1.42 percent average 10-Year T-Bond rate.

of the more recent awards shown in Figure IEc-1. Unfortunately, Mr. O'Donnell is now proposing a substantial increase in the risk premium award.

Q. Why would an analyst representing a consumer advocate propose a higher risk premium award than that recently awarded by the regulator?

A. While there are likely to be many answers to that question, my conclusion is that this anomaly results from Mr. O'Donnell's substantial reliance on the DCF model rather than a model based on a risk premium over current capital market interest rates.

Q. What are your concerns about the use of the DCF method for cost of equity capital determination, as applied to natural gas distribution companies?

A. In responding, I first acknowledge that the DCF model is a well-established technique for deriving the equity cost of capital that is widely used in utility regulation. I also acknowledge (and agree with Mr. O'Donnell) that no method is perfect, and all rely on certain heroic assumptions. Nevertheless, relying to a large extent on the DCF model has two significant disadvantages.

The first is circularity. As Mr. O'Donnell explains, the DCF model requires as inputs (a) the dividend yield and (b) the expected perpetual growth rate for the per-share dividend for a sample of "pure play" natural gas distribution utilities. The dividend yield, of course, is a directly observable market phenomenon, and can be defined with reasonable accuracy (although the selection of the sample is often a matter of dispute). I agree with Mr. O'Donnell that the DCF model has the advantage that the dividend yield input directly reflects one aspect of the market's view of the cost of capital. If, for example, the market determined that the cost of equity capital for a particular utility had declined, the utility's share price would rise and, *all other factors being equal*, the DCF cost of equity would fall.

In the DCF model, however, all other things are not equal, since there is a second input to the model that is not directly observable. And worse, that other parameter is directly dependent on market expectations for regulatory RoE awards.

Specifically, market expectations for per-share dividend growth must necessarily be based on the market's expectation for regulatory RoE awards. Thus, if the market observes that regulators have been following a pattern in which the implied risk premiums for RoE awards have been rising for decades, the market will likely expect those RoE award risk premiums to remain high and perhaps continue to rise until proven otherwise. This, expectation, of course, then keeps the implied equity costs from the DCF model high and provides an excuse for regulators to fail to adjust RoE awards to reflect capital market realities.

If historical trends are used to estimate growth, the expected growth rate is dependent on past regulatory awards. If regulatory awards are excessive, as Figure IEc-1 suggests, or if capital market conditions have changed, future RoE awards from the DCF method are going to be distorted.

Since regulators, as a matter of human nature, all watch each other and make adjustments to RoE awards only gradually, excessive reliance on the DCF model understates real changes in capital markets, most notably those related to the yields on risk-free (or relatively low-risk) investments.

My second concern about the DCF model is the perpetual nature of the growth assumptions in the model. Practitioners of DCF evaluations must demonstrate that the growth rate used in deriving the cost of equity capital is not the expected growth for the next three or five or even fifty years, but in perpetuity. This is particularly an issue for natural gas distribution. It is unlikely that natural gas will continue to be a major and growing fuel source forever. Even in Pennsylvania, where natural gas is an abundant and economical resource, statewide policies are being adopted that will require reductions in natural gas consumption over the longer term.[18] Natural gas is often seen as a "transition fuel," providing near-term reductions in carbon dioxide emissions relative to other fossil fuels, but gradually giving way to alternative resources.[19]

In the DCF context, however, the difference between a thirty-year or even a fifty-year growth period and a perpetuity is substantial. For example, consider a DCF analysis which

[18] See, e.g., https://www.governor.pa.gov/newsroom/governor-wolf-takes-executive-action-to-combat-climate-change-carbon-emissions/

[19] See, e.g., https://www.iea.org/reports/the-role-of-gas-in-todays-energy-transitions

concludes that the dividend yield is 3.5 percent and the expected growth rate is 5.0 percent, roughly the numbers used in Mr. O'Donnell's analysis. In a perpetual DCF, those assumptions imply a an equity cost of capital of 8.5 percent. However, if the regulated entity is expected to last fifty years rather than forever, and even if the 5.0 percent growth is retained throughout those fifty years, the implied DCF cost of equity capital falls to 7.3 percent. Or, suppose (heroically) that per-share dividend growth will continue forever, but drops from 5.0 percent to 4.2 percent after the first 10 years (matching DOE/EIA's long-term forecast for economic growth), reflecting not a decline but a steady state for natural gas. Even this small change reduces the DCF cost of capital to 7.9 percent.[20] Thus, even using favorable assumptions for 10 years and neutral assumptions thereafter moves the DCF cost of equity capital down below the bottom of Mr. O'Donnell's overall recommended range. And, of course, assuming continued growth with the overall economy is optimistic, since energy economists recognize that energy use as a share of the overall economy has been declining for decades and is likely to continue to do so.[21]

Believing Mr. O'Donnell's DCF model results would mean that the Commission must believe that natural gas distribution, a mature business that delivers a finite natural resource whose consumption has a detrimental effect on the planet, will grow forever at a rate that exceeds that of the overall economy.[22] A much more reasonable interpretation is that the market expects a lower average growth rate over a shorter time period than that assumed in

[20] Support for these calculations is provided in electronic workpaper RDK WP-6R, circulated with this testimony.

[21] Mr. O'Donnell's view of the economic outlook for natural gas distribution companies ("NGDCs") appears to be substantially colored by the growth of natural gas use for electricity generation in the past decade, as he refers twice to this phenomenon (at pages 51 and 59). In fact, NGDC's such as Columbia earn very little margin from serving large electric generators, as these facilities are usually located in close proximity to interstate pipelines and can either bypass the NGDC or negotiate extremely low competitive bypass rates. The vast majority of NGDC distribution rate revenues come from residential and small/medium business customers, where gas is facing increasing competition from electric heat pumps and minisplits, as well as facing increasing concerns about safety.

[22] The US DOE/EIA Annual Energy Outlook uses a long-term annual real growth rate of 1.9 percent through 2050, with a range from 1.4 to 2.4 percent, and an inflation forecast of 2.3 percent. The nominal economic growth is forecast at 3.7 to 4.7 percent, materially below Mr. O'Donnell growth forecast for a mature and carbon-intense industry. https://www.eia.gov/outlooks/aeo/pdf/AEO2020%20Critical%20Drivers%20and%20Model%20Updates.pdf ; https://www.eia.gov/outlooks/aeo/data/browser/#/?id=18-AEO2020&cases=ref2020&sourcekey=0

the "perpetual" traditional DCF, and thus the market likely deems that the cost of equity capital is considerably lower than that estimated by Mr. O'Donnell's DCF calculations.

Q. Please comment on Mr. O'Donnell's CE analysis.

A. The conceptual underpinning of the CE approach for deriving the cost of equity capital is to assume that the actual longer-term returns for firms of comparable risk represent a reasonable estimate for the cost of equity capital for the regulated firm. Mr. O'Donnell correctly recognizes one significant problem associated with the CE approach, namely that it is difficult to identify firms of comparable risk. I agree that unregulated firms are indeed a poor proxy for regulated utilities. Mr. O'Donnell attempts to address that problem by focusing only on natural gas distribution company earnings. He considers (a) the actual 2018 to 2025 actual/forecast book equity returns for his proxy group of NGDCs, and (b) regulatory Commission awards for equity returns to NGDCs.

While Mr. O'Donnell's reliance on natural gas utility returns is well-intentioned, it further explains why regulatory commissions have permitted equity risk premiums to depart so far from historical norms. Both of Mr. O'Donnell's CE estimates rely on the assumption that past regulatory awards represent a reasonable proxy for future regulatory awards. Historical and near-term book returns for NGDCs are obviously based on the returns awarded to those utilities in regulatory proceedings. And, of course, relying on allowed actual regulatory awards, unadjusted for any changes in the capital markets, serves to perpetuate existing awards.

In short, Mr. O'Donnell's CE method incorrectly relies on the premise that past regulatory RoE awards are reasonable, and thus simply provides regulators with an additional rationale for not modifying RoE awards to reflect capital market realities.

Moreover, methodologically, the CE method is devoid of actual market information. It reflects neither the actual market dividend yields used in the DCF method, nor the current capital market and interest rate environment reflected in the CAPM.

For those reasons, I conclude Mr. O'Donnell's CE analyses provide no useful information for this proceeding.

Q. Please comment on Mr. O'Donnell's CAPM analysis.

A. As shown earlier, Mr. O'Donnell's CAPM results imply that the cost of equity capital for NGDCs is far lower than his overall recommendation, ranging from 5.5 to 7.5 percent. This is not surprising as the CAPM is a risk premium model, and thus it directly reflects the current low interest rates in the capital markets.

Nevertheless, even in this analysis, Mr. O'Donnell makes at least one assumption that is modestly biased in favor of utilities. In the CAPM, the relative riskiness of a particular investment is measured by the parameter "beta," which reflects the relative riskiness of the investment compared to the market as a whole. A beta of 1.0 implies riskiness equal to that of the overall market. Mr. O'Donnell relies on beta estimates for both Columbia's parent Nisource as well as estimates for each of the NGDCs in his proxy group. The end result is that Mr. O'Donnell uses a beta of 0.85, implying that natural gas distribution utilities are nearly as risky as the overall market. This also is hardly credible for Columbia, since NGDCs serve monopoly service territories, prices are set by regulation rather than market forces, and both regulators and legislators have steadily been adopting policies that reduce utility risk.[23]

One contributor to bias comes from Mr. O'Donnell's source for beta estimates, namely the *Value Line*. That publication first derives a "raw" beta, based on a regression analysis of weekly stock price changes over a five-year period. However, *Value Line* then adjusts the beta using a "Blume" mechanism, which serves to arbitrarily move the raw beta closer to unity (1.0).[24] This adjustment is based on the hypothesis that market betas tend to move closer to unity over time, based on a market evaluation from 1971. Many analysts do not rely on the Blume adjustment, given its relatively weak empirical basis. These analysts

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[23] In Pennsylvania, these risk reduction policies include the DSIC, the use of a fully forecast future test year (with the adjustment that rate base and costs are based on year-end rather than full year values), near guaranteed recovery of universal service costs, energy efficiency costs, gas commodity costs, pipeline and storage costs, and (in Columbia's case) weather normalization clauses.

[24] See https://www.valueline.com/Tools/Educational_Articles/Stocks/Using_Beta.aspx#.X0UUOshKiUl

either rely on raw beta estimates, or rely on a "Vasicek" adjustment, which is based on the idea that the beta for an individual company will tend to move toward the industry average.[25]

As Mr. O'Donnell concedes that he has no evidence supporting the use of a Blume adjustment for NGDCs, the effect of the Blume adjustment should properly be factored out of his beta estimates. The common Blume adjustment formula is the following:

$$\text{Adjusted Beta} = 2/3 * \text{Raw Beta} + 1/3 * 1.0$$

Thus, to unwind the *Value Line* adjustment producing a 0.85 beta:

$$\text{Raw Beta} = (\text{Adjusted Beta} - 1/3 * 1.0) * 3/2$$

$$\text{Raw Beta} = (0.85 - .3333)*3/2 = 0.78$$

When applied to Mr. O'Donnell's market premium estimates, this adjustment would serve to reduce his CAPM estimates of the cost of equity capital by 0.3 to 0.45 percent, thereby lowering his CAPM range to 5.2 to 7.1 percent.

Q. **Please comment on Mr. O'Donnell's lack of an adjustment for management performance.**

A. Mr. O'Donnell sensibly concludes that the Company should not be awarded any upward adjustment for exemplary management performance in this proceeding. Surprisingly, however, Mr. O'Donnell takes no notice of the massive management failure and criminal negligence of fellow Nisource subsidiary Columbia Gas of Massachusetts in September 2018.[26] This admitted criminal behavior led to one fatality, a massive disruption to the lives of the residents and businesses of several towns in the Merrimack Valley in Massachusetts, and the required divestiture of that local distribution company by Nisource. The Company admits that it also led to the diversion of resources away from planned investments at

[25] This is the approach historically used by Ibbotson Associates in its evaluations of industry costs of capital. See https://vasdc8grscoc.blob.core.windows.net/resources/FAQ-Data-Funct-Final.pdf .

[26] See, for example, https://www.nytimes.com/2020/02/26/us/columbia-gas-massachusetts.html , https://www.bostonglobe.com/2020/07/02/business/columbia-gas-agrees-pay-56-million-resolve-state-investigations-into-merrimack-valley-incident/

Columbia Gas of Pennsylvania. Moreover, while it would be impossible to quantify, this enormous management failure likely had a negative impact on the cost of debt capital for all Nisource subsidiaries.

In my view, Mr. O'Donnell should reasonably have recommended a negative adjustment to the technical estimates of the cost of equity capital related to reflect this failure of Company management less than two years ago.

Q. Realistically, Mr. Knecht, do you expect the Commission to adopt a cost of equity capital for Columbia that is consistent with your analysis in this rebuttal testimony?

A. No. As I indicated, all regulators watch each other constantly, and the Pennsylvania Public Utility Commission is not going to move far from the behavior of other regulators or its own past practice simply because the facts indicate that it should.

Nevertheless, when the Commission evaluates the return on equity issue in this proceeding, I hope that it will recognize that Mr. O'Donnell, rather than advocating a position that is extremely favorable to ratepayers, has in fact advanced a recommendation that is materially biased in favor of utility shareholders.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-R1

ELECTRONIC WORKPAPERS

RDK WP5R: Supporting Proof of Revenue Calculations

RDK WP6R: Supporting Return on Equity Calculations

Workpapers will be transmitted via separate e-mail attachment simultaneous to e-mail service of this document

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018835**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Rebuttal Testimony labelled OSBA Statement No. 1-R and associated Exhibit IEc-R1 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 26, 2020

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

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DATE: August 26, 2020

/s/ Steven C. Gray

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COMMONWEALTH OF PENNSYLVANIA

September 16, 2020

The Honorable Katrina L. Dunderdale
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place
301 5th Avenue, Suite 220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. 2020 Base Rate Filing / Docket No. R-2020-3018835

Dear Judge Dunderdale:

Enclosed please find the Surrebuttal Testimony and Exhibit of Robert D. Knecht, **Public Version**, labeled OSBA Statement No. 1, with Exhibit IEc-S1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: **PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)**
Robert D. Knecht
Parties of Record

Office of Small Business Advocate
Forum Place | 555 Walnut Street, 1st Floor | Harrisburg, PA 17101 | 717.783.2525 | Fax 717.783.2831 | www.osba.pa.gov

OSBA Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018835**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Surrebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

***************** PUBLIC VERSION ****************

Topics:

Flex Rates

Date Served: September 16, 2020

Date Submitted for the Record: September 24, 2020

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony, rebuttal testimony, and associated exhibits earlier in this proceeding, and my qualifications were presented therein.

Q. Please describe the purpose of this surrebuttal testimony.

A. This surrebuttal testimony addresses the issue of test year revenues related to "flex rate" customers. Specifically, this testimony addresses the rebuttal testimony of Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") witness Andrew S. Tubbs, as well as additional information provided to me through formal and informal discovery.

Q. Please review the issue regarding flex rate customers.

A. As explained in my direct testimony, it can be in ratepayer interests to allow a utility to "flex" its regular tariff rates, to offer discounted rates to customers it might otherwise lose to bypass or alternative fuel competition. However, because flex rate discounts may be unduly discriminatory (as they apply to some customers and not others), and because they must implicitly be funded by other ratepayers, they require regulatory scrutiny. These discounts should only be allowed under certain economic conditions, most notably that they should be set at the maximum level possible while still retaining the customer. Based on the information available to me at the time my direct testimony was filed, I concluded that Columbia had not demonstrated that its flex rate discounts met those requirements.

Q. Did any other party contest the Company's flex rate discounts?

A. No. Mr. Ethan Cline representing the Commission's Bureau of Investigation and Enforcement ("I&E") indicated that he had reviewed the limited information provided by the Company, and he took no exception to the flex rate discounts. He recommended that the Company update its evaluation of competitive alternatives for "any customer that has not had their alternative fuel source verified for a period of 10 years or more."[1]

---

[1] I&E Statement No. 1 at 5-7.

To my knowledge, no other party addressed the magnitude of Columbia's flex rate discounts.[2]

Q. What is Columbia's position in its rebuttal testimony regarding the concerns you raised in your direct testimony?

A. In rebuttal, Columbia offered no additional evidence in support of the specific flex rate discounts. Mr. Tubbs indicates only that the confidential material that I requested had, in fact, been provided to me before the due date for direct testimony.[3]

Q. What is your response to the Company's rebuttal?

A. While I respectfully disagree with the Company's rebuttal testimony, there is little point to debating the matter. I have now received the confidential response to my discovery. Moreover, Columbia allowed me to have an informal discovery call with a large accounts manager to address my questions regarding how flex rate discounts are set, and the Company provided additional information regarding the distance to the interstate pipeline for the potential bypass customers.

Q. What are your conclusions from your review of this additional information?

******************* BEGIN HIGHLY CONFIDENTIAL ***********************

[redacted]

[redacted]

---

[2] Mr. Frank Plank representing Columbia Industrial Intervenors ("CII") indicates that Columbia no longer offers a flex rate discount to his firm because it is not necessary to discount firm rates to be competitive with fuel oil in today's market conditions. Mr. Plank's testimony is thus evidence that Columbia does make an effort to ensure that flex rate discounts are not excessive, at least for Knouse Foods Cooperative, Inc.

[3] Columbia Statement No. 1-R, at 61.

[redacted]

[redacted]

[redacted]

[redacted]

[4] See OSBA Statement No. 1, footnote 9.

[redacted]

[redacted]

[redacted]

******************** END HIGHLY CONFIDENTIAL ***********************

Q. Based on this analysis, what are your conclusions regarding Columbia's claim for a $6.7 million flex rate discount.

[5] Columbia's replacement cost for mains exceeded $2.3 million per mile in 2019, per OSBA-I-1. $74,000 per mile per year would not cover even the cost of capital for such an investment.

A. I conclude that Columbia has not demonstrated that its gas-on-gas flex rate discounts of $0.9 million are consistent with Commission policy. Based on informal discovery and back-of-the-envelope calculations (which is the only information I have), approximately $2.1 million of the bypass flex discounts are credible, and $3.6 million are suspect without more detailed information from the Company regarding those customers.

Q. How does that affect the revenue allocation calculations in your direct testimony?

A. In my direct testimony, I recommended that $6.5 million in flex rate discounts be included in the revenue allocated to the flex rate customer class. Based on the information I now have, that value should be $4.4 million, to exclude the $2.1 million in credible rate discounts to MDS and certain other bypass customers. I also recommended that $4.9 million of the $100 million rate increase be assigned to the flex rate classes as the regular rate increase for those customers not subject to flex rates. That value should be lowered to $3.3 million. In total, these changes increase the total revenue required from the other rate classes by $3.2 million. I recommend that this $3.2 million be reassigned to the other classes in the proportions set forth in my proposed revenue allocation for those classes, in Table IEc-5.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-S1

ELECTRONIC WORKPAPERS

RDK WPS4 Flex Rate HIGHLY CONFIDENTIAL.xlsx

Confidential Workpapers will be transmitted via separate e-mail attachment to the confidential service list in excel spreadsheet format simultaneous to e-mail service of this document

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2020-3018835**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Surrebuttal Testimony labelled OSBA Statement No. 1-S and associated Exhibit IEc-S1 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: September 16, 2020

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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v.	:	**Docket No. R-2020-3018835**
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DATE: September 16, 2020

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