Columbia Gas of Kentucky, Inc.
Case No. 2021-00183
Standard Filing Requirements
5/28/2021
Volume 3 of 9

Tab	Filing Requirement	Description	Responsible Witness(es)
22	807 KAR 5:001 Section 16-(7)(a)	Testimony	Judith L. Siegler
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24	807 KAR 5:001 Section 16-(7)(a)	Testimony	Vincent V. Rea
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Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Judith L. Siegler attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Judith L. Siegler

Columbia Exhibit No. 22

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

PREPARED DIRECT TESTIMONY OF
JUDITH L. SIEGLER
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF JUDITH SIEGLER

STATE OF INDIANA	)
	)
COUNTY OF LAKE	)

Judith Siegler, Lead Regulatory Analyst for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of her Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Judith Siegler
Judith Siegler

The foregoing Verification was signed, acknowledged and sworn to before me this 19th day of May, 2021, by Judith Siegler.

Heather Snoddy

HEATHER SNODDY
Notary Public - Seal
Lake County - State of Indiana
Commission Number NP0722513
My Commission Expires Sep 18, 2027

Notary Commission No. NP0722513

Commission expiration: Sept. 18, 2027

PREPARED DIRECT TESTIMONY OF JUDITH L. SIEGLER

Q: Please state your name and business address.

A: My name is Judith L. Siegler. My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410.

Q: What is your current position and what are your responsibilities?

A: I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Lead Regulatory Studies Analyst at NCSC.

Q: What is your educational background and professional experience?

A: I received a Bachelor of Science degree in Accounting from Purdue University in 2002 and a Masters of Business Administration from Indiana Wesleyan University in 2017.

I began my employment with Northern Indiana Public Service Company, Inc. in 2009 in the Rates and Regulatory Department as a Senior Regulatory Analyst. My responsibilities included providing regulatory support for NiSource's three Indiana companies' (Northern Indiana Public Service Company, Inc., Northern Indiana Fuel & Light Company, Inc., and

Kokomo Gas and Fuel) Gas Cost Adjustment ("GCA") filings. In 2010, I was involved in the preparation of a petition to the Indiana Utility Regulatory Commission, seeking approval to merge the three companies into Northern Indiana Public Service Company, LLC ("NIPSCO"). In 2012, I accepted a position under the group that prepares the revenue proof, rate design, tariffs and rules and regulations in NIPSCO's gas and electric rate cases. Since 2015, I have held the position Lead Regulatory Analyst in the Rates and Regulatory Department of NCSC. Prior to NCSC and NIPSCO, I worked as an analyst and then as an accountant in the casino industry, and as a public accountant.

Q. Have you previously testified before any regulatory commissions?

A. Yes, I submitted direct testimony before the Maryland Public Service Commission on behalf of Columbia Gas of Maryland in Case No. 9609 and in its most recent base rate proceeding, Case No. 9644.

Q. What is the purpose of your testimony?

A. I am supporting the development of revenues for both the Base Period and Forecasted Test Period as presented in Filing Requirement 16-(8)(m), Schedule M. I am also sponsoring the typical bill comparisons at current and proposed rates shown in Filing Requirement 16-(8)(n), Schedule N. I also co-sponsor Filing Requirements 16-(6)(a), 16-(6)(b), 16-(7)(c), and 16-(8)(d).

Q: What are the test periods that you will be addressing in this testimony?

A: I will be addressing the twelve month period ending August 31, 2021, as the Base Period, as well as the twelve months ending December 31, 2022, as the Forecasted Test Period.

Q: What process is undertaken to produce the number of bills used to calculate revenue in this case?

A: The detail supporting the number of bills used for the Forecasted Test Period is found in Workpaper WPM-B (the workpapers have been filed as part of the Application). Forecasted active customer counts are first determined on a total company basis by customer class, by type of service, (sales/CHOICE/transportation) by month in Columbia's forecast supported by Columbia Witness Melissa Bartos. Large customers individually forecasted by the Large Customer Relations ("LCR") group are identified separately from the total forecast. The remaining non-LCR commercial and industrial customer counts in the forecast are then spread for each month of the test period by type of service, by customer class, by rate schedule based on the latest twelve months of historical experience ending February 28, 2021. Bill counts for the LCR customers are adjusted to reflect customers who are expected to either discontinue or add service during the forecasted period as shown in Workpaper WPM-D. The bills are accumulated based upon which rate schedule the customer was on as of February 28, 2021. Additionally, an adjustment is made to the number of forecasted bills to reflect final billed customers because the forecast is based on projected active customers. In the months that a final bill is issued, the customers are coded inactive and are not counted for the month even though they are billed a customer charge for their final month of service. Because Columbia does not forecast final bills, Columbia considers the historical final bill counts to be representative of what can be expected during the Forecasted Test Period. As a result, final bills are added to the active bills used in the forecast to price customer charge revenue in this case. Forecasted Test Period bills are then taken from WPM-B and used to price customer charge revenue at current rates in Schedule M-2.2 and proposed rates in Schedule M-2.3.

The total customer counts for the Base Period are determined using six months of actual customer bills from September 2020 through February 2021, and six months of forecasted bills through August 2021.

Q: What process is used to develop the throughput in Mcf used to calculate revenue in this case?

A: Workpaper WPM-C details the throughput in Mcf used to calculate revenue in this case. Similar to the methodology used to produce the number of bills, forecasted Mcf are first determined on a total company basis by customer class, by type of service, by month in Columbia's forecast supported by Columbia Witness Bartos. Forecasted throughput associated with LCR customers is identified separately from the total forecast based upon the individual large customer forecast performed by the LCR group. The remaining non-LCR throughput is then spread for each month of the Forecasted Test Period by type of service, by customer class, by rate schedule based on the latest twelve months of historical experience ending February 28, 2021. Throughput is accumulated based upon which rate schedule the customers were on at February 28, 2021.

Adjustments resulting from LCR customers either discontinuing or adding service during the Forecasted Test Period are shown in Workpaper WPM-D. Additionally, Workpaper WPM-D reflects any anticipated significant usage changes for LCR customers during the Forecasted Test Period. Adjustment volumes in Workpaper WPM-D are then recorded in Workpaper WPM-C to arrive at the total adjusted volume forecast used to price revenue for the forecasted period.

The throughput for the Base Period is determined using six months of actual volumes from September 2020 through February 2021 and six months of forecasted volumes through August 2021.

Q: How were the non-LCR commercial and industrial forecasted volumes in WPM-C split by rate block?

A: The spread of non LCR commercial and industrial throughput is performed at the individual customer level by month based on historical experience for the twelve months ended February 28, 2021. Each customer's forecasted monthly throughput is then split among the rate blocks pertaining to that customer's rate schedule and then accumulated by rate block and shown in Workpaper WPM-C.

Q: How was the gas cost revenue calculated for the Forecasted Test Period?

A: Columbia's Commission-approved gas cost recovery rate, effective March 1, 2021, was applied to volumes (Mcf) for each month of the Forecasted Test Period based on rate class. Calculations are shown on Workpaper WPM-A.

Q: Please describe Schedule M.

A: Schedule M summarizes total forecasted revenue by customer class, by month at both current and proposed rates. Revenue at current rates is summarized from Schedule M-2.2 and revenue at proposed rates is summarized from Schedule M-2.3.

Q: Please describe Schedule M-2.1.

A: Schedule M-2.1 shows the comparison of revenue at current rates and revenue at proposed rates by rate classification. Columns B (Forecasted Bills), C (Forecasted Mcf), and D (Revenue at Current Rates) are recorded from Schedule M-2.2. Column G (Revenue at Proposed Rates) is recorded from Schedule M-2.3. Column E (D-2.4 Rate Making Adjustment) is utilized to reflect any ratemaking adjustments that comes through the cost of service. The difference between revenue at proposed rates and revenue at current rates is shown in column H with the corresponding percentage change shown in column I.

Q: Please explain how the gas cost uncollectible rate is calculated.

A: The calculation of gas cost uncollectible charge utilized in Schedule M 2.3 is in Attachment JLS-1. The uncollectible charge is calculated by multiplying the total cost of gas effective March 1, 2021 and the net charge off rate which is provided by Company Witness Jeff Gore Attachment JTG-2. The resulting rate is used to price out the gas cost uncollectible revenue at proposed rates.

Q: How was the Forecasted Test Period revenue at current rates developed in Schedule M-2.2?

A: Forecasted Test Period bills from Workpaper WPM-B and Forecasted Test Period volumes from Workpaper WPM-C are recorded in Schedule M-2.2 by month by rate class. Forecasted Test Period bills and volumes for each month for each rate class are then multiplied by the applicable current rates in column C to develop the Forecasted Test Period revenue at current rates.

Q: How was the Forecasted Test Period revenue at proposed rates developed in Schedule M-2.3?

A: Forecasted Test Period bills and volumes in Schedule M-2.3 are identical to Schedule M-2.2. Forecasted Test Period bills and volumes for each month for each rate class are then multiplied by the applicable proposed rates in column C. An adjustment is applied to Account 487 to reflect an expected increase in forfeited discounts attributable to the proposed rates. The result is the Forecasted Test Period revenue at proposed rates.

Q: How was Schedule N (Typical Bill Comparison) developed?

A: Monthly usage levels were selected in order to give a representative effect of the change in a typical monthly bill based on proposed rates as compared to current rates. Tariff sales rate schedules were compared with and without gas cost. Customer and commodity charges were compared for transportation rate schedules.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary.

ATTACHMENT JLS-1
GAS COST UNCOLLECTIBLE CALCULATION

Columbia Gas of Kentucky, Inc.
Calculation of Gas Cost Uncollectible Charge Utilized in Schedule M 2.3
Calculated Using Gas Costs as of March 1, 2021

Attachment JLS-1
Page 1 of 1

Line No.	Description	Reference		Rate $	
1	Commodity Rate	Sch. 1 , L. 19, Col. 3 (March 2021 GCA)		2.7919	
2	Total Commodity Cost of Gas			**2.7919**	per Mcf
3	Net-Charge off Rate	Attachment JTG-2	0.42800%		
4	Uncolectible Gas Cost Rate	(Line 2 x Line 3)		0.0119	per Mcf

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Melissa Bartos attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Melissa Bartos

Columbia Exhibit No. 23

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

PREPARED DIRECT TESTIMONY OF
MELISSA BARTOS
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF MELISSA BARTOS

COMMONWEALTH OF MASSACHUSETTS	)
	)
COUNTY OF MIDDLESEX	)

Melissa Bartos, Vice President of Concentric Energy Associates, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of her Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Melissa Bartos

Melissa Bartos

The foregoing Verification was signed, acknowledged and sworn to before me this 19th day of May, 2021, by Melissa Bartos.

Kristina D. Bruce

Notary Commission No. __________

Commission expiration: November 4, 2027

KRISTINA D. BRUCE
Notary Public
Commonwealth of Massachusetts
My Commission Expires
November 4, 2027

PREPARED DIRECT TESTIMONY OF MELISSA BARTOS

Q: Please state your name and business address.

A: My name is Melissa Bartos. My business address is 293 Boston Post Road West, Suite 500, Marlborough MA 01752

Q: What is your current position and what are your responsibilities?

A: I am employed by Concentric Energy Advisors ("Concentric"). My current title is Vice President. In my current position as a Vice President at Concentric, I am responsible for the execution of numerous projects related to the energy industry. I specialize in demand forecasting, rates and regulatory issues, and market analysis.

Q: What is your educational background?

A: I received a Bachelor of Arts in Mathematics and Psychology with a concentration in Computer Science in 1998 from the College of the Holy Cross in Worcester, Massachusetts. I received a Master of Science degree in Mathematics with a concentration in Statistics in 2003 from the University of Massachusetts at Lowell.

Q: What is your employment history?

A: My entire career, which spans over twenty years, has been in energy consulting. I began my career with Reed Consulting Group, which was later purchased and merged into Navigant Consulting, Inc. I joined what is now

Concentric Energy Advisors in 2002. Both firms specialize in consulting for the energy industry. Attachment MB-1 describes my professional experience.

Q: Have you previously testified before the Kentucky Public Service Commission?

A: I have not previously testified before the Kentucky Public Service Commission, but I have testified before several other state, federal, and Canadian provincial regulatory agencies on dozens of occasions. Attachment MB-2 lists my expert testimony submissions.

Q: What is the purpose of your testimony in this proceeding?

A: I will explain the forecast methodology used to develop the forecasted number of customers and usage for the second half of the Base Period ("BP"), which is the twelve months ended August 2021, as well as for the Forecasted Test Period ("FTP"), which is calendar year 2022.

Q: Do you sponsor any Filing Requirements in this case?

A: Yes. I sponsor 807 KAR 5:001 Sections 16-(7)(c), 16-(7)(h), 16-(7)(h)14, and 16-(7)(h)15.

Q. For the Filing Requirements that you are sponsoring, were the resulting schedules prepared either by you or by someone working under your supervision?

A. Yes.

A. <u>Demand Forecast Methodology Overview</u>

Q. Please explain the methodology employed for developing the forecasted number of customers and volume for the BP and FTP.

A. Total residential and total commercial customers and volume are forecasted using econometric models. Total industrial volume is forecasted based on knowledge gained through relationships with large industrial customers. Total residential, total commercial, and total industrial forecasts are subsequently split into sales, choice, and gas transportation service ("GTS") customers and volumes, as appropriate, using historical data.

Q. What data sources do you use to develop the econometric models for the residential and commercial classes?

A. I use Columbia Gas of Kentucky's ("Company") billing records through February 2021 to obtain historical monthly customer counts and billed usage for the residential and commercial customer classes. Historical billed usage is divided by historical customer counts to produce monthly historical use per customer data for residential and commercial customers. The historical customer counts and use per customer are used as the dependent variables in the residential customer, residential use per customer, commercial customer, and commercial use per customer econometric models.

Several sources are used to obtain data for the independent variables included in the econometric models. Historical and forecast gas price data is sourced from the U.S. Energy Information Administration ("EIA"). Historical and forecast values for economic and demographic variables (e.g., population and gross state product) and deflator data are from IHS Global Insight, Inc., a data consultant. Historical weather data (HDD) is provided by DTN, a weather consulting service. Both IHS Global Insight, Inc. and DTN are large, independent data providers relied upon by the Company in previous rate cases, as well as relied upon by many other companies worldwide. A 20-year average HDD ending December 31, 2020 is used as the weather during forecast period.

Q. How are the economic effects associated with COVID-19 incorporated into the forecast?

A. Data indicates that COVID-19 had three identifiable impacts on customer counts and usage that can generally be categorized as short-term, medium-term, and long-term impacts. First, on a very short-term basis, the shutdowns and other immediate changes to normal behavior associated with COVID-19 appear to have affected use per customer for some classes in

2020 and early 2021. These short-term impacts are addressed when necessary by including an indicator variable[1] in the econometric model to account for specific months in which the use per customer significantly differed from what would have been expected absent the shut-downs. These impacts on use per customer are not expected to persist into the second half of the BP or the FTP as the most significant shut-downs are largely over. Therefore, it is not necessary to make adjustments to the forecast associated with impacts on use per customer associated with the temporary COVID-19 shut-downs.

Second, on a medium-term basis, the Kentucky Public Service Commission's prohibition on termination of customers[2] due to the economic effects of COVID-19 ("COVID-19 Moratoriums") affected customer counts starting in the spring of 2020 and continues to affect residential customer counts. As will be described in more detail below, March 2021 through October 2021 residential customer counts produced from the econometric model are adjusted upward to capture the impacts of the ongoing COVID-19 Moratorium that are not captured by the econometric models, but FTP

[1] In this case, an indicator variable (or dummy variable) is an independent variable that represents a time-related event. The indicator variable equals 1 when the specific time-related event occurs and equals 0 outside of that specific time. The coefficient on the indicator variable is determined through the econometric modeling process. Statistical results associated with the econometric model identifies whether the indicator variable is significant.

[2] *See In the Matter of Electronic Emergency Docket Related to the Novel Coronavirus COVID*-19, Case No. 2020-00085, Order (Ky. P.S.C. March 16, 2020).

customer counts were not adjusted as it is anticipated that customer counts will return to expected levels before the start of the FTP. The impact of the COVID-19 Moratoriums on Commercial and Industrial customer counts appears to be minimal and any impact ended by the end of 2020, therefore no COVID-19 Moratorium adjustment is necessary for Commercial or Industrial forecasted customer counts.

Third, shut-downs and changes in consumer activity associated with COVID-19 affected the local and national economy with impacts being sustained into the long-term, which in turn affects natural gas customers and usage. For example, unemployment spiked in the spring of 2020, and while unemployment has declined from the peak, it is currently expected to take time for employment levels to return to pre-COVID levels. These longer-term economic impacts associated with COVID-19 are incorporated into the forecast through the use of economic independent variable data. Historical and forecasted economic data series used in the econometric models reflect the economic outlook of IHS Global Insight as of February 2021. Therefore, COVID-19 economic impacts on customer counts and usage are incorporated in the forecasts produced by the econometric models so the forecasts do not require further adjustment to account for longer-term economic conditions related to COVID-19.

B. Residential Forecast

Q. Please describe the residential customer forecast methodology.

A. The residential customer forecast is developed using a monthly econometric model that incorporates population and several monthly variables for shaping. As described above, residential customer counts in 2020 were affected by the moratorium on customer shut-offs due to the COVID-19 declared state of emergency. As shown by the orange line in Figure 1 below, residential customer counts typically are highest in the winter and decrease in the summer as customer accounts are shut-off, (i.e., removed or terminated) for non-payment or other reasons. The prohibition on terminations that was ordered by the Public Service Commission in March 2020[3] resulted in residential customer counts that remained at higher-than-normal levels throughout the remainder of 2020 and into 2021. The Public Service Commission has lifted the COVID-19 Moratorium and the Company initiated termination procedures in late February 2021.[4] From a modeling perspective, indicator variables are added to the residential customer count model for each month of April 2020 through February 2021 (the end of the historical data set) to account for the

[3] *See In the Matter of Electronic Emergency Docket Related to the Novel Coronavirus COVID-19*, Case No. 2020-00085, Order (Ky. P.S.C. March 16, 2020).
[4] *See* Case No. 2020-00085, Order (Ky. P.S.C. Sept. 21, 2020).

fact that the customer count data for this period does not reflect normal business conditions. These indicator variables essentially eliminate the impact of the COVID-19 Moratorium on the econometric model and result in a raw model forecast that does not include the effects of the COVID-19 Moratorium, illustrated by the green "Raw Model Output" line on the graph in Figure 1. However, in reality, there are additional customers on the system related to the COVID-19 Moratorium that are not accounted for in the raw forecast produced by the econometric model. Therefore, the model results are adjusted to account for the COVID-19 Moratorium, as described below.

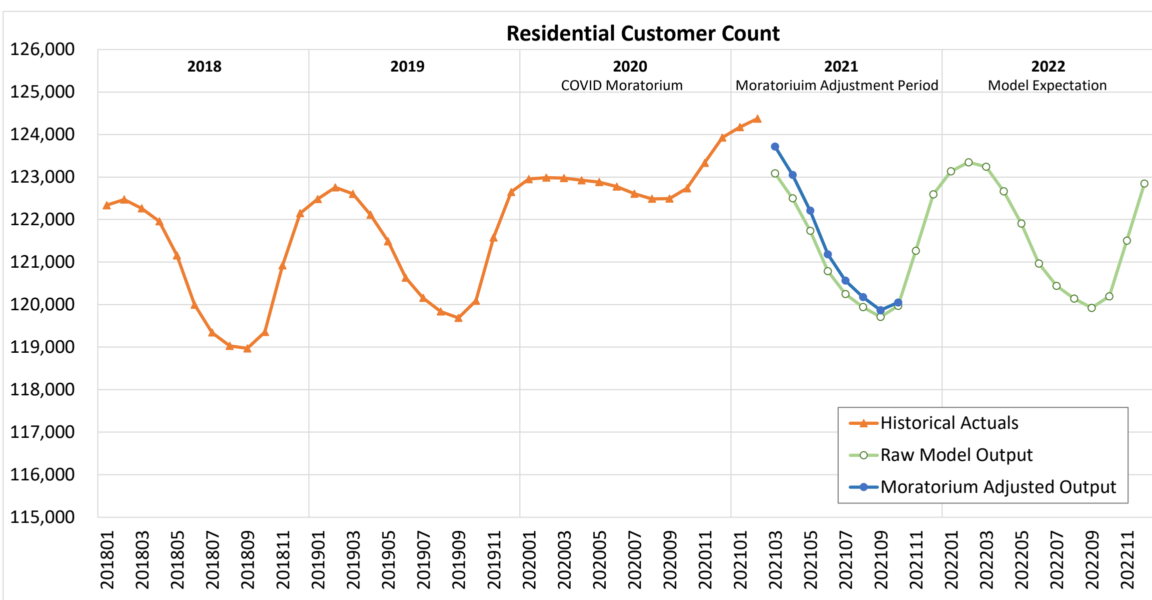
Q. How is the COVID-19 Moratorium accounted for in the residential customer forecast?

A. The residential customer count forecast produced by the econometric model for March 2021 is increased by 630 customers (approximately 0.5%) to account for the additional residential customers that are estimated to be on the system as a result of the COVID-19 Moratorium, as shown by the blue line in the graph in Figure 1. This is not based upon a specification of individual customers that would have been terminated, but represents an estimation of the additional residential customers who currently are being served by Columbia above the customer count that would have been anticipated but for the COVID-19 Moratorium. The level of the residential moratorium adjustment is based on 2020/2021 monthly customer counts compared to previous years, the values of the April 2020-February 2021 indicator variables in the econometric model, the number of customers who have already been terminated, and data regarding the current number of accounts that are eligible for termination as well as the overall increase in termination orders from pre-COVID to now.

Q. Please explain how the adjustment for the moratorium on shut-offs associated with COVID-19 is phased out of the forecast.

A. Although terminations resumed in late February 2021, the Company did not automatically terminate delinquent customers. In accordance with Commission guidance, the Company continues to work with customers who are behind on their bills to develop payment arrangements and identify newly-available assistance funding. It is expected that, over time, the differential of 630 additional residential customers will phase out as termination procedures are reinstated and the normal cycle of customer counts returns. Given the information available at this time, it is estimated that customer counts will return to normal business conditions (i.e., the 630 additional residential customers that were assumed to be associated with the COVID-19 Moratorium will be addressed) by November 2021. Therefore, adjustments are necessary for several months in 2021 to account for the gradual reduction of the additional residential customers resulting from the COVID-19 Moratorium. For the purposes of the customer count forecast, it is assumed starting in March 2021 the 630 residential customer increase is reduced by an equal proportion, such that by November 2021 no adjustment is made, and the forecast returns to the levels produced by the econometric model as shown in the blue line in Figure 1. The adjustments associated with the COVID-19 Moratorium only affect the months of March 2021 through October 2021, so only the second half of the BP is impacted. The FTP customer count forecast is the unadjusted forecast resulting from the econometric model.

Figure 1



Q. Please describe the residential use per customer forecast methodology.

A. The residential use per customer forecast is developed using a monthly econometric model that incorporates weather in the form of HDD, real natural gas prices, and several monthly variables for additional shaping. As described above, residential use per customer was temporarily and periodically affected by the shut-downs associated with COVID-19. From a modeling perspective, an indicator variable was added to the residential use per customer count model for the months of April 2020, May 2020, October 2020, December 2020, January 2021, and February 2021 because data indicates that residential use per customer was significantly affected in those months. These indicator variables essentially eliminate the impact of the short-term COVID-19 shut-downs on the econometric model and results in a forecast that does not include these short-term effects. Because these effects from the short-term COVID-19 shut-downs are expected to be over, no adjustment to the forecasted use per customer is necessary.

Q. How is the forecast of monthly residential volume determined?

A. Monthly residential customer counts are multiplied by monthly residential use per customer to produce monthly residential volume.

Q. How is the total residential customers and usage split into residential sales and residential CHOICE?

A. Residential CHOICE customer counts are based on extrapolating the recent declining trend in residential CHOICE customers. Residential sales customer counts is determined by subtracting residential CHOICE customer count from the total residential customer count.

Use per customer for residential CHOICE customers has been higher than use per customer for residential sales customers in recent years. Forecasted use per customer for residential CHOICE customers is determined by applying the historical monthly ratio of residential CHOICE use per customer to total residential use per customer. Forecasted residential CHOICE usage is determined by multiplying residential CHOICE customers by residential CHOICE use per customer. Residential sales usage is determined by subtracting residential CHOICE usage from the total residential usage.

C. <u>Commercial Forecast</u>

Q. Please describe the commercial customer forecast methodology.

A. The commercial customer forecast is developed using a monthly econometric model that incorporates real gross state product and several monthly variables for shaping. As described above, commercial customer counts in 2020 were also affected by the COVID-19 Moratorium; however, those effects appear to have ended before the end of 2020, so there are no further adjustments.

From a modeling perspective, indicator variables are added to the commercial customer count model for each month of May 2020 through October 2020 to account for the fact that the customer count data for this period does not reflect normal business conditions. The data demonstrates that the commercial customer counts appear to have returned to normal levels by November 2020 because no indicator variables were required for November 2020 through February 2021, therefore no further adjustments were made related to the COVID-19 Moratorium.

Q. Please describe the commercial use per customer forecast methodology.

A. The commercial use per customer forecast is developed using a monthly econometric model that incorporates weather in the form of HDD, real natural gas prices, and several monthly variables for additional shaping. As described above, commercial use per customer was temporarily affected by the shutdowns associated with COVID-19. From a modeling perspective, an indicator variable is added to the commercial use per customer count model for each of the months of March 2020 through June 2020 and October 2020 through January 2021. This indicator variable essentially eliminates the impact of the short-term COVID-19 shut-downs on the econometric model and results in a forecast that does not include these short-term effects.

Q. How is the forecast of monthly commercial volume determined?

A. Monthly commercial customer counts are multiplied by monthly commercial use per customer to produce monthly commercial volume.

Q. How are the total commercial customers and volumes split into commercial sales, commercial CHOICE, and commercial GTS?

A. Commercial GTS customers are forecasted to remain at recent historical customer levels while commercial CHOICE customers are forecasted to continue to decrease at recently observed rates. Commercial sales customers are the customers remaining when commercial GTS and commercial CHOICE customers are subtracted from the total commercial customer forecast. Total commercial usage is allocated to sales, GTS and CHOICE based proportions experienced in the most recent 12-months.

D. <u>Industrial Forecast</u>

Q. Please describe industrial forecast methodology.

A. The industrial forecast is provided by the NiSource Large Customer Relations group by incorporating information generated through individual customer interviews. Since the Large Customer Relations group covers over 95% of the total industrial volumes, it is assumed that the remaining industrial customer volume grows at the same rate as that forecasted by the Large Customer Relations group.

Q. How is the total industrial usage split into industrial sales, industrial CHOICE, and industrial GTS?

A. The majority of the industrial usage is directly assigned to sales or GTS based on the forecast provided by the Large Customer Relations group. The remaining industrial usage is allocated to sales, CHOICE, and GTS based historical monthly proportions.

E. <u>Forecast Results</u>

Q. Please provide a summary of the customer count and demand forecast results.

A. Tables 1 and 2 below contain forecasted annual customer counts and volumes. This data can also be found in Filing Requirements 16-(7)(h)14 and 16-(7)(h)15. For historical data and monthly forecasts, please see the testimony of Witness Judith Siegler.

Table 1 – Forecasted Customer Counts (Year End)

	2021	2022	2023	2024
SALES CUSTOMERS BY CLASS				
RESIDENTIAL	108,166	109,520	110,979	112,499
COMMERCIAL	11,463	11,710	11,958	12,207
INDUSTRIAL	53	53	53	53
WHOLESALE	2	2	2	2
ELECTRIC GENERATION	1	1	1	1
TOTAL SALES CUSTOMERS	119,685	121,286	122,993	124,762
TRANSPORTATION CUSTOMERS BY CLASS				
RESIDENTIAL	14,425	13,325	12,225	11,125
COMMERCIAL	2,593	2,363	2,133	1,903
INDUSTRIAL	66	66	66	66
TOTAL TRANSPORTATION CUSTOMERS	17,084	15,754	14,424	13,094
TOTAL CUSTOMERS	**136,769**	**137,040**	**137,417**	**137,856**

Table 2 – Forecasted Annual Volume (CCF)

	2021*	2022	2023	2024
SALES VOLUMES BY CLASS				
RESIDENTIAL	72,885,916	72,601,345	76,040,497	77,114,463
COMMERCIAL	38,349,597	37,640,630	37,558,405	37,689,848
INDUSTRIAL	2,376,853	2,419,552	2,437,532	2,459,725
WHOLESALE	113,894	112,511	112,293	112,697
ELECTRIC GENERATION	5,150	5,150	5,150	5,150
TOTAL SALES VOLUMES	113,731,410	112,779,189	116,153,877	117,381,882
TRANSPORTATION VOLUMES BY CLASS				
RESIDENTIAL	11,150,437	10,226,096	9,731,729	8,898,386
COMMERCIAL	47,770,967	47,085,735	46,998,340	47,174,367
INDUSTRIAL	131,525,618	132,656,441	133,765,359	135,166,622
TOTAL TRANSPORT VOLUMES	190,447,022	189,968,273	190,495,428	191,239,374
TOTAL THROUGHPUT	**304,178,432**	**302,747,462**	**306,649,305**	**308,621,257**

** 2021 includes actuals for January and February*

Q. Does this conclude your direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony.

ATTACHMENT MB-1

RESUME

CONCENTRIC ENERGY ADVISORS

MELISSA F. BARTOS

Vice President

Ms. Bartos is a financial and economic consultant with more than twenty years of experience in the energy industry. In the last several years, she has focused on natural gas markets issues, including conducting comprehensive market assessments for various clients considering infrastructure investments and developing detailed demand forecasts for a number of gas distribution companies. Ms. Bartos has also designed, built, and enhanced numerous financial and statistical models to support clients in asset-based transactions, energy contract negotiations, reliability studies, asset and business valuations, rate and regulatory matters, cost-of-service analysis, and risk management. Her modeling experience includes building Monte-Carlo simulation models, designing an allocated cost-of-service model, statistical modeling using SPSS, and programming using Visual Basic for Applications (VBA). Ms. Bartos has also provided expert testimony on multiple occasions regarding natural gas demand forecasting and supply planning issues, natural gas markets and marginal cost studies.

REPRESENTATIVE PROJECT EXPERIENCE

Natural Gas Market Assessments

- Reviewed and evaluated long-term natural gas supply and demand, existing natural gas pricing dynamics, and future implications associated with new natural gas infrastructure in New England, New York, and New Jersey.
- Provided an analysis of the existing Gulf Coast natural gas market, the client's natural gas pipeline competitors, changing flows, and how those factors may affect transportation values to the client going forward.
- Prepared a comprehensive study examining the costs associated with improving natural gas pipeline access from western Canada and the eastern U.S. to Atlantic Canada.
- Produced a report on the benefits associated with incremental natural gas supplies delivered to New York City.
- Prepared an independent natural gas supply and pipeline transportation route assessment associated with natural gas for the client's proposed LNG export terminal.
- Conducted a study that examined potential commercial and industrial conversions from oil-based fuels to natural gas in various east coast U.S. markets.
- Produced a report that identified growth potential in off-system stationary and mobile markets in the mid-west that could be served by compressed natural gas or liquefied natural gas.
- Performed an external audit and filed expert testimony associated with two natural gas utilities' hurdle rate/contribution in aid of construction calculations for new off main customers.

- Produced a report that identified and reviewed innovative cost model approaches that utilities and regulators are using across the U.S. that allow expansion of gas distributions systems to new communities.
- Assisted in developing a strategy to identify residential natural gas growth opportunities within the client's franchise area.
- Presented at two Northeast Gas Association conferences regarding "Regulatory Policy and Residential Main Extensions".
- Conducted a study to determine the cost of significantly reducing peak day natural gas demand for a northeast gas utility through energy efficiency, conservation and demand management measures. Project involved researching natural gas energy efficiency plans in multiple U.S. states and Canadian provinces, reviewing energy efficiency potential studies, and exploring geothermal, peak pricing and direct load control options.

Demand Forecasting

- Filed expert testimony regarding the development of demand forecast models and the evaluation of natural gas resource plans for several gas utilities.
- Provided litigation support regarding demand forecasting techniques with respect to certain natural gas pipeline and storage decisions for a mid-west gas utility.
- Evaluated demand forecasts and produced alternative demand forecasts in the context of due diligence support for several asset transactions.
- Reviewed demand forecasting practices and procedures and recommended certain changes to improve the methodology and accuracy of the forecast for a multi-state utility.
- For a mid-west gas utility, developed a natural gas demand forecast that was utilized for supply and capacity decisions.

Ratemaking and Utility Regulation

- Participated in the rate case of a large North American gas distribution company, which determined the client's five-year incentive regulation plan, including performing benchmarking and productivity analyses that were filed with the regulator.
- Developed and testified in support of several marginal cost studies filed in rate cases for several New England utilities.
- Provided comprehensive analysis, drafted testimony and provided litigation support regarding the appropriate return on equity for a New England water utility, and for proposed wind and coal electric generation facility additions for a mid-west combination utility.
- Performed a detailed analysis of the components included in the client's lost and unaccounted for gas calculation.
- Conducted multiple natural gas portfolio asset optimization analyses to evaluate performance of the client's asset manager for regulatory purposes.

- On behalf of multiple New England gas companies, participated in the 2009 Avoided Energy Supply Cost Study Group (for New England), which worked with third-party consultants to develop the marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Vice President
Assistant Vice President
Project Manager
Senior Consultant

Navigant Consulting, Inc. (1996 – 2002)
Senior Consultant

EDUCATION

University of Massachusetts at Lowell
M.S., Mathematics (Statistics), 2003

College of the Holy Cross
B.A., Mathematics and Psychology, *magna cum laude*, 1998

PROFESSIONAL ASSOCIATIONS

Member of the American Statistical Association

Member of the Northeast Energy and Commerce Association

Member of the Northeast Gas Association

ATTACHMENT MB-2
TESTIMONY HISTORY

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	2014	Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	Docket No. 13-06-02	CIAC Hurdle Rate Calculation
Federal Energy Regulatory Commission				
PennEast Pipeline Company, LLC	2015	PennEast Pipeline Company, LLC	Docket No. CP15-558	Market Conditions/Need
PennEast Pipeline Company, LLC	2016	PennEast Pipeline Company, LLC	Docket No. CP15-558	Market Conditions/Need
Millennium Pipeline Company, LLC	2017	Millennium Pipeline Company, LLC	Docket No. CP16-486	Market Conditions/Need
Laclede Gas Company	2017	Spire STL Pipeline, LLC	Docket No. CP17-40	Market Conditions/Need
Maine Public Utilities Commission				
Northern Utilities, Inc.	2011	Northern Utilities	Docket No. 2011-526	Integrated Resource Plan; Demand Forecast
Massachusetts Department of Public Utilities				
New England Gas Company	2008	New England Gas Company	D.P.U. 08-11	Integrated Resource Plan; Demand Forecast; Supply Planning
New England Gas Company	2010	New England Gas Company	D.P.U. 10-61	Integrated Resource Plan; Demand Forecast; Supply Planning
Berkshire Gas Company	2010	Berkshire Gas Company	D.P.U. 10-100	Integrated Resource Plan; Demand Forecast
New England Gas Company	2012	New England Gas Company	D.P.U. 12-41	Integrated Resource Plan; Demand Forecast; Supply Planning
Berkshire Gas Company	2012	Berkshire Gas Company	D.P.U. 12-62	Integrated Resource Plan; Demand Forecast
NSTAR Gas Company	2014	NSTAR Gas Company	D.P.U. 14-63	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2014	Berkshire Gas Company	D.P.U. 14-98	Integrated Resource Plan; Demand Forecast

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Liberty Utilities (New England Gas Company)	2015	Liberty Utilities (New England Gas Company)	D.P.U. 15-75	Marginal Cost of Service Study
Berkshire Gas Company	2016	Berkshire Gas Company	D.P.U. 16-103	Integrated Resource Plan; Demand Forecast
Eversource Energy	2017	Eversource Energy (NSTAR Electric and WMECO)	D.P.U. 17-05	Marginal Cost of Service Study
National Grid (Boston Gas Company and Colonial Gas Company)	2017	National Grid (Boston Gas Company and Colonial Gas Company)	D.P.U. 17-170	Marginal Cost of Service Study
Bay State Gas Company d/b/a/ Columbia Gas of Massachusetts	2018	Bay State Gas Company d/b/a/ Columbia Gas of Massachusetts	D.P.U. 18-45	Marginal Cost of Service Study
Berkshire Gas Company	2018	Berkshire Gas Company	D.P.U. 18-40	Marginal Cost of Service Study
Berkshire Gas Company	2018	Berkshire Gas Company	D.P.U. 18-107	Integrated Resource Plan; Demand Forecast
NSTAR Gas Company	2019	NSTAR Gas Company	D.P.U. 19-120	Marginal Cost of Service Study
Bay State Gas Company d/b/a Columbia Gas of Massachusetts	2019	Bay State Gas Company d/b/a Columbia Gas of Massachusetts	D.P.U. 19-135	Integrated Resource Plan; Demand Forecast
Berkshire Gas Company	2020	Berkshire Gas Company	D.P.U. 20-139	Integrated Resource Plan; Demand Forecast
Boston Gas d/b/a National Grid	2020	Boston Gas d/b/a National Grid	D.P.U. 20-120	Marginal Cost Study
New Hampshire Public Utilities Commission				
Northern Utilities, Inc.	2011	Northern Utilities	DG 2011-290	Integrated Resource Plan; Demand Forecast
Liberty Utilities (EnergyNorth Natural Gas)	2017	Liberty Utilities (EnergyNorth Natural Gas)	DG 17-048	Marginal Cost of Service Study
Liberty Utilities (Granite State Electric)	2019	Liberty Utilities (Granite State Electric)	De 19-064	Marginal Cost of Service Study
New Jersey Board of Public Utilities				
South Jersey Gas Company	2015	South Jersey Gas Company	GR15010090	Energy Efficiency Cost Benefit Analysis

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Ontario Energy Board				
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study
Enbridge Gas Distribution	2013	Enbridge Gas Distribution	EB-2012-0459	Incentive Rate Making
Pennsylvania Public Utility Commission				
Columbia Gas of Pennsylvania, Inc.	2021	Columbia Gas of Pennsylvania, Inc.	R-2021-3024296	Weather Normalization; Demand Forecast
Régie de l'énergie du Québec				
TransCanada Pipelines Ltd.	2014	TransCanada Pipelines Ltd.	R-3900-2014	Natural Gas Market Assessment
Washington Utilities and Transportation Commission				
Puget Sound Energy, Inc.	2015	Puget Sound Energy, Inc.	UG-151663	Distributed LNG Market Assessment

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Vincent V. Rea attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Vincent V. Rea

Columbia Exhibit No. 24

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

	)	
In the matter of:	)	
	)	Case No. 2021-00183
ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC.	)	
FOR AN ADJUSTMENT OF RATES;	)	
APPROVAL OF DEPRECIATION STUDY;	)	
APPROVAL OF TARIFF REVISIONS;	)	
ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND	)	
NECESSITY; AND OTHER RELIEF	)	

PREPARED DIRECT TESTIMONY OF
VINCENT V. REA
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF VINCENT REA

STATE OF NORTH CAROLINA	)
	)
COUNTY OF MOORE	)

Vincent Rea, Managing Director of Regulatory Finance Associates, LLC, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of his Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Vinct V. Rea

Vincent Rea

The foregoing Verification was signed, acknowledged and sworn to before me this 17 day of May, 2021, by Vincent Rea.

Stephen W Sikes

STEPHEN W SIKES
Notary Public, North Carolina
Moore County
My Commission Expires
October 21, 2023

Notary Commission No. ______

Commission expiration: 10-21-23

TABLE OF CONTENTS

ACRONYMS AND DEFINED TERMS

ACRONYM	DEFINED TERM
β	Beta
b	Expected earnings retention ratio
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CKY	Columbia Gas of Kentucky, Inc.
DCF	Discounted Cash Flow Model
EBITDA	Earnings before interest, taxes, depreciation and amortization
FFO	Funds from Operations
FOMC	Federal Open Markets Committee
g	Growth Rate (perpetual)
GDP	Gross Domestic Product
M&M	Modigliani and Miller
PUHCA	Public Utility Holding Company Act of 2005
QE	Quantitative Easing

ACRONYMS AND DEFINED TERMS

ACRONYM	DEFINED TERM
r	Expected rate of return on common equity
Rf	Risk-Free Rate of Return
Rm	Expected return for the overall stock market
RGR	Retention Growth Rate
ROE	Return on Equity
RPM	Risk Premium Method
s	Represents new common shares expected to be issued by a firm
s x v	Represents external growth
SMRP	Safety Modernization and Replacement Program
S&P	Standard & Poor's
SURFA	Society of Utility and Regulatory Financial Analysts
v	Value that accrues to existing shareholders from selling stock at a price different from book value
WACC	Weighted average cost of capital

I. INTRODUCTION

Q. Please state your name, occupation and business address.

A. My name is Vincent V. Rea. I currently serve as Managing Director of Regulatory Finance Associates, LLC, an independent financial and regulatory consulting firm. My business address is 80 Blake Boulevard, #4572, Pinehurst, NC 28374.

Q. Please describe your professional experience.

A. Prior to moving into my current position, I served as Director, Regulatory Finance and Economics for NiSource Corporate Services Company. In this position, I provided expert testimony and other regulatory support on behalf of NiSource's utility subsidiaries with regard to the cost of equity, overall fair rate of return, and ratemaking capital structures. Prior to serving as Director, Regulatory Finance and Economics, I served as Assistant Treasurer for both Columbia Gas of Kentucky, Inc. ("Columbia" or "the Company") and its ultimate parent company, NiSource. In the capacity of Assistant Treasurer, I was responsible for the external capital raising activities and banking activities for NiSource, for inter-company financing activities among all NiSource subsidiaries (including Columbia), and also provided regulatory support and testimony for utility rate proceedings and financing petitions. My educational background, professional experience and other qualifications are presented in greater detail in Attachment VVR-1, which follows my direct testimony.

Q. Please describe your educational background.

A. I hold an M.B.A. in Finance from Indiana University, Bloomington, Indiana, and a B.A. with honors distinction in Business Administration from Lake Forest College, Lake Forest, Illinois.

Q. Do you hold any professional designations?

A. Yes. I have been awarded the designation of Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"), and I am also a registered Certified Public Accountant ("CPA") in the State of Illinois.

Q. Are you a member of any industry or professional organizations?

A. Yes. I serve on the Board of Directors of the Society of Utility and Regulatory Financial Analysts, and am also a member of the American Institute of Certified Public Accountants.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony presents supporting evidence, analysis and a recommendation concerning the appropriate rate of return on common equity and overall rate of return that the Public Service Commission of Kentucky (the "Commission") should establish for Columbia in relation to its revenue requirement calculation. My recommendations are supported by the detailed financial information and comprehensive analyses presented within my testimony.

Q. Are you sponsoring any attachments through your direct testimony?

A. Yes. The table below lists the attachments that I am sponsoring through my testimony, and includes a brief description of each attachment:

Attachment	Description
Attachment VVR-1	Professional Qualifications of Vincent V. Rea
Attachment VVR-2	W.A.C.C. and Fair Rate of Return
Attachment VVR-3	Comparative Risk Assessment
Attachment VVR-4	Analysis of Regulatory Mechanisms
Attachment VVR-5	Capitalization and Capital Structure Ratios
Attachment VVR-6	Embedded Cost of Long-Term Debt
Attachment VVR-7	DCF Method - Gas LDC Group
Attachment VVR-8	DCF Method - Combination Utility Group
Attachment VVR-9	DCF Method - Non-Regulated Group
Attachment VVR-10	Book vs. Market Value Capital Structures
Attachment VVR-11	Capital Asset Pricing Model
Attachment VVR-12	Risk Premium Method

I am also sponsoring Filing Requirements KAR 5:001 Sections 16-(7)(c), 16-7(h), 16-(7)(h)11, and 16-(8)(j).

Q. Were these attachments and Filing Requirements prepared either by you or someone working under your supervision?

A. Yes.

II. SUMMARY OF RECOMMENDATIONS

Q. Based upon your comprehensive analyses and supporting evidence, what have you concluded with respect to the appropriate rate of return for Columbia in

this proceeding?

A. Based upon my comprehensive evaluation, I have concluded that Columbia's cost of common equity is presently in the range of 10.30 - 10.80 percent. In view of this range estimate, it is my opinion that a reasonable point estimate of Columbia's cost of equity in the current market environment is 10.55 percent. However, as further discussed in the direct testimony of Columbia witness Cole, the Company has elected to request a 10.30 percent cost of equity in this proceeding[1], which is at the low-end of the range of reasonableness indicated by my comprehensive evaluation.

Based upon this finding, and as reflected in Attachment VVR-2, I have also determined that the Company's weighted average cost of capital is 7.48 percent, which is based upon Columbia's thirteen-month average capital structure and cost of debt for the fully forecasted test period ending December 31, 2022, as reflected within Attachment VVR-5 and Attachment VVR-6, respectively. This resulting overall cost of capital, if adopted by the Commission, will allow Columbia to earn the prevailing opportunity cost of capital, maintain its financial integrity, and attract capital at reasonable terms.

[1] Direct Testimony of Kimra H. Cole (Case No. 2021-00183), at 22.

Q. What general approach have you taken in determining the cost of common equity in this proceeding?

A. To properly estimate Columbia's cost of equity, I have analyzed market-derived data and other financial information for each of the companies comprising three separate proxy groups. Considering that investors utilize this very same information in assessing risk and making investment decisions, it provides a reliable basis for estimating the cost of equity for Columbia. In total, I evaluated the market and financial data of 28 companies, including seven companies comprising the Gas LDC Group, nine companies comprising the Combination Utility Group, and twelve companies comprising the Non-Regulated Group. I will discuss the selection criteria I utilized in developing each of these proxy groups later in my testimony.

During the course of my evaluation, I applied three well-recognized analytical models to the market and/or financial data of the selected proxy group companies. These models include the Discounted Cash Flow ("DCF") model, Capital Asset Pricing Model ("CAPM"), and the Risk Premium Model ("RPM"). I have also evaluated two other model variants of the CAPM, specifically, the CAPM with size adjustment, and the Empirical CAPM ("ECAPM"), both of which have been validated by empirical research. Using the multi-faceted analytical approach described above, my evaluation resulted in 15 individual estimates of the cost of equity for Columbia, thereby ensuring a thorough and comprehensive analysis.

Q. Specifically, how did you complete your cost of equity analyses using the market-derived data and other financial information for the three respective proxy groups?

A. With respect to the DCF analyses, I evaluated the proxy group companies on an individual basis, which resulted in a separate cost of equity estimate for each company. By taking this approach, I was able to identify anomalous or "outlier" results at the individual company level which did not pass fundamental tests of economic logic. I then eliminated these outlier results from further consideration based upon both "high-end" and "low-end" outlier thresholds as established by regulatory precedent. The fundamental advantage of employing this approach is that it *removes* the effects of anomalous results from the cost of equity evaluation process. In my judgment, this approach is clearly preferable to the "total group approach," which simply averages the data of all proxy group companies, irrespective of whether outlier results are included or not. As such, the total group approach effectively "blends in" the effects of anomalous results into the cost of equity evaluation process.

Notwithstanding the foregoing, with respect to the CAPM and RPM analyses, the respective proxy groups were evaluated on a group average basis rather than on an individual company basis. This is necessary because virtually all of the input variables into these two analytical models are non-company specific variables (i.e. risk-free rate of return, corporate bond yields for a certain credit rating, market rate of return, etc.), with the sole exception of beta, meaning that under these two approaches, company-specific input anomalies will have less of an impact on the cost of equity estimate as compared to the other analytical methods.

Q. What are the results of your cost of equity evaluation for the proxy sources, and how did you derive the cost of equity for Columbia using these proxy group results?

A. I developed my cost of equity recommendation after carefully evaluating 15 individual cost-of-equity estimates, which were derived from applying the various analytical models to the market and financial data of the proxy group companies. Using a variety of analytical models in conjunction with multiple comparable-risk proxy groups ensures that a diversity of investor perspectives is incorporated into my evaluation, and provides a solid foundation upon which the analyst can apply his/her informed judgment in making a cost of equity recommendation. Initially, cost of equity estimates were derived for the respective proxy groups by applying a total of five different analytical models/methods to the market and/or financial data of the proxy group companies (my evaluation included two additional variants of the traditional CAPM model). This resulted in a total of 15 individual estimates of the cost of equity among the three proxy groups, which I have summarized in Table VVR-1 below. Further support for the 15 individual estimates of the cost of equity reflected in Table VVR-1 below can be found in Table VVR-6, Table VVR-7, Table VVR-8, Table VVR-11 and Table VVR-12, which appear later in my testimony.

Table VVR-1
Indicated Cost of Equity for the Proxy Groups

Method/Model	Gas LDC Group	Combination Utility Group	Non-Reg. Group
DCF	10.54%	9.84%	11.54%
Traditional CAPM	10.55%	10.29%	10.38%
CAPM (w/size adj.)	11.30%	10.78%	10.16%
ECAPM	10.61%	10.42%	10.49%
Risk Premium	10.33%	10.28%	10.72%

As reflected in Table VVR-2 below, an analysis of the above results yielded the following measures of central tendency for each of the analytical methods employed.

Table VVR-2 Cost of Equity Estimates for CKY Measures of Central Tendency	
Median DCF Result	10.54%
Average DCF Result	10.64%
Median CAPM Result	10.49%
Average CAPM Result	10.55%
Median RPM Result	10.33%
Average RPM Result	10.44%

Based upon these measures of central tendency, I have concluded that Columbia's cost of common equity is presently in the range of 10.30 - 10.80 percent. In view of this range estimate, it is my opinion that a reasonable point estimate of Columbia's cost of equity in the current market environment is 10.55 percent. However, as noted earlier, and as further discussed in the direct testimony of Columbia witness Cole, the Company has elected to request a 10.30 percent cost of equity in this proceeding, which is at the low-end of the range of reasonableness indicated by my comprehensive evaluation.

III. FUNDAMENTAL ANALYSIS

A. Background

Q. What background information have you considered in evaluating Columbia's cost of common equity and overall required rate of return?

A. Columbia provides natural gas services to over 135,000 residential, commercial, and transportation customers across 30 counties in central and eastern Kentucky. During 2020, the Company's total gas throughput was divided among the following customer classes: 22.2 percent residential; 12.6 percent commercial, industrial and other; and 65.2 percent transportation customers. Columbia sources its natural gas supplies from various producers and marketers and has delivery arrangements with various interstate pipeline companies, and supplements its flowing gas supplies with gas withdrawn from underground storage.

The Company is a wholly-owned subsidiary of NiSource Gas Distribution Group, Inc., which, in turn, is a subsidiary of NiSource, a holding company under the Public Utility Holding Company Act of 2005. NiSource's headquarters are located in Merrillville, Indiana, and its core operating companies engage in natural gas distribution, as well as electric generation, transmission and distribution. NiSource operating companies deliver energy to nearly 4.0 million gas and electric customers in six states.

B. Natural Gas Utility Risk Factors

Q. What business risks are natural gas utilities like Columbia subjected to in the current market environment?

A. Although the United States continues to make steady progress in putting the COVID-19 pandemic in the rearview mirror, largely as the result of the now accelerating roll-out of the COVID-19 vaccines, natural gas utilities continue to face pandemic related challenges which have had the effect of raising the investment risk profile of gas utility holding companies. These challenges have included reduced gas usage and throughput for commercial and industrial customers, higher levels of uncollectible accounts and bad debt expense (which is partially attributable to recent industry moratoriums on gas shut-offs), and additional costs associated with biohazard safety precautions and disinfection protocols to ensure the safe delivery of energy services to utility customers, as well as the safety of utility employees. Most recently, as a result of Winter Storm Uri, which wreaked havoc throughout the southern and central parts of the U.S. during February 2021, a number of gas utilities have faced dramatically higher natural gas procurement costs as a result of gas supply disruptions which occurred as a direct result of Winter Storm Uri. These significantly higher gas procurement costs have strained the liquidity of a number of gas utility holding companies, and due to the sheer magnitude of the increase in gas procurement costs, there remains some uncertainty as to whether gas utilities will be able to recover these higher costs through the traditional gas cost adjustment mechanisms. Yet another important risk factor facing gas utilities today relates to the ongoing trend toward decarbonization, which negatively impacted gas utility stock valuations during the second half of 2020. Collectively, these recent events have further increased the investment risk profile of gas utility companies. This has clearly been demonstrated by significantly higher beta coefficients reported by Value Line for gas utilities over the past year, which indicates that the level of systematic risk associated with gas utility investments has risen in the past year, and which, in turn, is consistent with a higher cost of equity.

Other substantive business risks that are more commonly encountered by gas utilities include: (i) safety and reliability issues relating to aging pipeline infrastructure and the sizable capital investments required to replace such infrastructure; (ii) regulatory risks in the form of lower authorized ROEs and regulatory lag, both of which can negatively impact a utility's credit ratings; (iii) competition from alternative heating sources such as fuel oil, electric heat, and propane; (iv) competition from other transportation service providers (i.e., natural gas pipelines); (v) the impact of cyclical downturns on economically-sensitive commercial, industrial and transportation customers; and (vi) rising compliance costs relative to increasingly stringent environmental mandates from the U.S.

Environmental Protection Agency and state agencies.

With regard to utility risk factors that are unique to Columbia, it is noteworthy that approximately 78 percent of the Company's gas throughput relates to serving commercial, industrial and transportation customers, and as a result, a very high proportion of Columbia's total gas throughput is susceptible to downturns in the U.S. economic cycle. Moreover, approximately 70 percent of Columbia's gas throughput to transportation customers is concentrated among just five industrial customers, which exposes Columbia to a significantly higher level of business risk, as compared to the typical gas distribution company. In addition, Columbia's significantly higher allocation of gas throughput to industrial and transportation customers, as well as the Company's high customer concentration level, also causes the Company to be more vulnerable to the threat of bypass.

C. Overview of Current Economic and Capital Markets Conditions

Q. Please provide a brief overview of recent trends in the U.S. economy and the U.S. capital markets.

A. As the U.S. continues to make steady progress towards putting the COVID-19 pandemic in the rearview mirror, there is mounting evidence that the U.S.

economy is rebounding from the pandemic even faster than previously anticipated. As of early May 2021, U.S. economic growth is being fueled by a number of factors, including: (1) the reemergence of pent-up consumer demand, which has been suppressed for the past fourteen months as a result of governmental restrictions, as well as a general apprehension among Americans of contracting or spreading the COVID-19 virus. Both of these impediments to robust consumer demand and general economic activity are increasingly being addressed through the successful roll-out of the COVID-19 vaccines in the U.S.; (2) actual or proposed fiscal stimulus measures that have been championed by the Biden Administration, which thus far has included the $1.9 trillion American Rescue Plan, and could ultimately result in as much as $7.6 trillion in new fiscal stimulus spending by the federal government in the coming years; and (3) the ongoing extraordinary monetary policy interventions of the Federal Reserve Board (the "FED"). The FED's interventions include targeting of short-term interest rates at essentially zero (i.e. the Federal Funds rate), as well as the FED's recent reinitiating of its quantitative easing or bond-buying programs, both of which are intentionally designed to stimulate U.S. economic growth. Despite the rapidly improving U.S. economic outlook, FED Chairman Jerome Powell recently indicated that there is a low likelihood that the FED would increase the Federal Funds rate prior to 2023, and also that the FED's bond-buying programs would continue at the current pace until the FED sees substantial further progress in the U.S. economic picture[2]. This strongly suggests that FED monetary policy will continue to bolster U.S. economic growth for the foreseeable future.

As a result of the aforementioned factors driving the U.S. economic recovery, a number of economists have recently raised their forecasts of expected U.S. GDP growth over the next several quarters. For example, during April 2021, the Blue Chip Financial Forecasts[3] panel of economists once again raised its real GDP forecast for Q2, 2021 to 8.1 percent, from the panel's previous month forecast of 6.8 percent. At the same time, the Blue Chip Financial Forecasts consensus estimates reflect an average real GDP growth rate of 6.03 percent for the four quarters of calendar year 2021, which is a very robust growth rate by recent historical standards. Consistent with the Blue Chip forecasts, the Congressional Budget Office also recently reported that it expects the U.S. economy will regain its pre-COVID-19 pandemic size by the second half of 2021.

Q. What effects are the rebounding U.S. economy having on the U.S. labor market?

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[2] https://www.marketwatch.com/story/fed-sees-no-rate-hikes-through-2023-despite-some-inflation-overshoot-11616004261

[3] *Blue Chip Financial Forecasts*, (CCH Incorporated, Wolters Kluwer), Volume 40, No. 4, April 1, 2021, at 2.

A. Despite the fact that total U.S. employment remains *down* 8.4 million jobs as compared to pre-pandemic levels[4], this particular statistic does not necessarily reflect the true conditions in the U.S. labor market, which, as based on other key measures, are actually much more encouraging. In fact, the U.S. labor market is presently best characterized as experiencing a critical supply and demand imbalance. On the demand side of the curve, as U.S. businesses emerge from the COVID-19 crisis and reopen their doors, the labor market has seen markedly increased demand for workers over the past several months. However, on the supply side of the curve, the reality remains that millions of prospective labor market participants remain on the sidelines and are not actively seeking employment opportunities. This has been attributed to a number of factors, including either illness or fear of illness from the COVID-19 virus, or extended unemployment benefits, which, in either case, may help explain why many prospective labor market participants have remained on the sidelines.

Regardless of the underlying reasons contributing to the reluctance of a substantial number of U.S. workers to reenter the work force, the current supply and demand imbalance in the labor market is probably best illustrated by the number of jobs that remain currently unfilled in the U.S. In fact, the U.S. Bureau

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[4] *Labor Market Tighter Than It Looks*, The Wall Street Journal, April 22, 2021, at A2.

of Labor Statistics recently reported that approximately 15.0 million U.S. jobs currently remain unfilled[5]. Many of these positions are not just entry level jobs, but also include highly-skilled positions, such as in nursing and information technology. It is therefore understandable why the U.S Labor Department's employment cost index recently reported that employee wage earnings increased 2.80 percent during Q4, 2020[6], as the supply and demand imbalance in the U.S. labor market has clearly resulted in upward pressure on U.S. wages. This, almost invariably, results in higher inflationary expectations, which, in turn, has the effect of putting upward pressure on intermediate and long-term interest rates. This has clearly been the case since the beginning of calendar year 2021. It remains to be seen how the supply side of the U.S. labor market curve will improve over the near-to-intermediate term, but recent data reflects a somewhat more sanguine outlook. The U.S. Labor Department recently reported that the 4-week moving average of initial unemployment claims as of mid-April 2021 declined to 651,000[7], which reflects a post-pandemic low.

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[5] https://www.nbcnews.com/now/video/millions-of-job-openings-go-unfilled-as-millions-collect-some-form-of-unemployment-110278213770

[6] *Labor Market Tighter Than It Looks*, The Wall Street Journal, April 22, 2021, at A2.

[7] *Jobless Claims Fall to New Pandemic Low*, The Wall Street Journal, April 23, 2021, at A2

Q. What effects are the rebounding U.S. economy, strengthening labor market, and the fiscal stimulus measures proposed by the Biden Administration expected to have on long-term U.S. interest rates?

A. The rapidly improving U.S. economy, strengthening labor market and fiscal stimulus measures noted above are all widely-expected to contribute to higher long-term interest rates over the next several years, which is attributable to both the "real" and inflationary growth components embedded in nominal interest rates. In fact, this has already been demonstrated by the recent run-up in 30-year U.S. Treasury bond yields that has occurred since late 2020 - early 2021. The recent run-up in U.S. Treasury yields demonstrates that U.S. bond market participants believe that stronger post-pandemic economic growth, and inflationary pressures resulting from the large fiscal stimulus measures proposed by the Biden Administration, will result in both higher inflation expectations and higher interest rates over the intermediate-to-longer term horizon. In point of fact, as of early May 2021, the 30-year U.S. Treasury bond yield has been trading in the range of [2.30 - 2.35] percent, which is approximately [0.75 - 0.80] points higher than the 1.56 percent average yield recorded during calendar year 2020. This recent uptick in long-term interest rates clearly has *upwardly-biased* implications for all long-term capital costs, including the cost of common equity.

Q. Recognizing that intermediate and long-term interest rates have already begun to trend higher in recent months, how do current U.S. Treasury and corporate bond yields compare to the corresponding yields forecasted over the next several years?

A. Both prominent economists and capital market participants widely expect that intermediate and longer-term interest rates will continue to trend higher over the next several years, as the U.S. economy continues to expand in the post-COVID-19 environment. As reflected in Table VVR-3 below, the consensus estimates of prominent economists, as reflected in the Blue Chip Financial Forecasts,[8] are currently projecting material increases in long-term interest rates over the next several years.

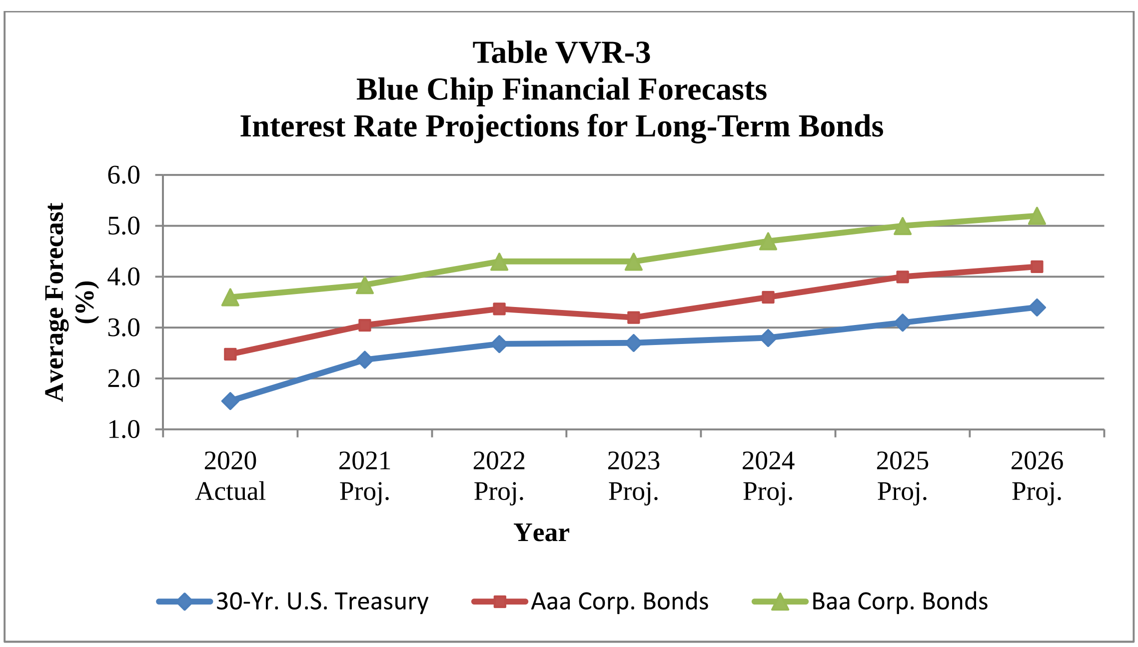

Table VVR-3
Blue Chip Financial Forecasts
Interest Rate Projections for Long-Term Bonds

[8] *Blue Chip Financial Forecasts*, Volume 40, No. 4 (April 1, 2021), and *Blue Chip Financial Forecasts,* Volume 39, No. 12 (December 1, 2020).

As demonstrated in Table VVR-3 above, the consensus view of prominent economists is that over the next several years, in the post-COVID-19 environment, long-term interest rates will trend materially higher. For this reason, it is appropriate to incorporate reputable interest rate forecasts, such as those published by the Blue Chip Financial Forecasts, into the cost of equity estimation process. Considering that long-term debt capital is considered to be a form of permanent capital, it is only logical to conclude that the cost of equity capital will also continue to rise during this same period.

D. <u>Comparative Risk Assessment of Proxy Groups</u>

Q. Why is it necessary to analyze groups of proxy companies to estimate the cost of equity for Columbia?

A. The cost of equity is an opportunity cost concept, which is determined in the financial markets based upon the relative risk assessments of investors. Simply stated, in order to attract sufficient capital to support their public service obligations, regulated utilities must offer investors a rate of return that is commensurate with returns available on alternative investments bearing similar risks. Thus, the use of proxy groups is useful in estimating a utility's cost of equity, since each company comprising the proxy group represents an alternative investment opportunity of comparable risk vis-à-vis the subject utility. Regardless of whether the subject utility is publicly-traded or not, proxy group analyses ensure that fair rate of return principles, including comparable earnings, corresponding risks, and the opportunity cost of capital are all considered when estimating a utility's cost of equity.[9] Nonetheless, it should be noted that when the various cost of equity models are applied to the market and financial data of proxy group companies, various model inputs and/or assumptions are required, which contributes to the risk of observation error. For this reason, when possible, the use of larger proxy groups or even multiple proxy groups is recommended to mitigate these effects and to ensure a higher level of confidence in the reliability of the analytical results.

Q. What criteria did you apply in selecting the companies included in your gas utility proxy group?

A. In selecting a gas utility proxy group, my objective was to identify a group of publicly-traded natural gas distribution companies with risk characteristics similar to Columbia, which is not a publicly-traded company. Accordingly, I applied the following selection criteria in making this determination: (i) Value

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[9] These fair rate of return principles were articulated by the U.S. Supreme Court in various landmark case decisions, including *Willcox et. al., Constituting the Public Service Commission of New York v. Consolidated Gas Co*., 212 U.S. 19 (1909); *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*); and *Federal Power Commission et al. v. Hope Natural Gas Company*, 320 U.S. 591 (1944) (*Hope*). Although the *Hope* and *Bluefield* cases are widely-referenced with regard to fair rate of return standards, the *Consolidated Gas* case was actually the first case where the Supreme Court addressed principles surrounding a fair rate of return for public utility companies.

Line Investment Survey Industry Classification as a Natural Gas Utility; (ii) Value Line Safety Rank of "1," "2" or "3"; (iii) S&P corporate credit rating no lower than BBB-, or Moody's long-term issuer rating of no lower than Baa3 ; (iv) operating income from the company's regulated gas distribution operations equals or exceeds 60 percent of the company's consolidated operating income; (v) company must currently pay dividends and must not have discontinued or reduced its dividend during the previous five years (2016-2020); (vi) company must have significant revenue stabilization mechanisms in place; and (vii) company is not, and has not recently been, an acquisition target. Applying the above selection criteria yielded a core proxy group that is comprised of the following seven publicly-traded natural gas distribution companies:

Atmos Energy Corp.
New Jersey Resources Corp.
Northwest Natural Gas Co.
ONE Gas, Inc.
South Jersey Industries Inc.
Southwest Gas Corp.
Spire, Inc.

Throughout the remainder of my testimony, I will refer to this proxy group as the "Gas LDC Group."

Q. Why is it necessary to complete a comparative risk assessment between Columbia and the Gas LDC Group?

A. Considering that market-derived information for the Gas LDC Group companies will be used to estimate Columbia's cost of equity, it is critical that the Gas LDC Group is risk-comparable to the Company. If material differences in risk are identified, the analyst must apply his/her informed judgment in determining whether further adjustments are required to the cost of equity estimates indicated by application of the various analytical models. Because Columbia itself is not publicly-traded, market-based financial information is not available for the Company. Therefore, in conducting my comparative risk assessment, I have instead analyzed various widely-recognized business and financial risk metrics, none of which are dependent upon stock prices or other market-based information.

Q. Do a utility's credit ratings provide insight into its risk profile, cost of debt and cost of equity?

A. Yes. Credit ratings reflect the risk of default with respect to a company's debt obligations, and are therefore strongly correlated with a company's borrowing costs. For example, companies with a lower risk of default are assigned higher credit ratings and therefore benefit from lower borrowing costs. Conversely, companies with a high risk of default are assigned lower credit ratings and consequently incur higher borrowing costs. A firm with higher borrowing costs will also have a higher cost of equity, since investors invariably demand an equity risk premium above and beyond the firm's cost of debt as compensation for bearing the additional risks inherent in common stocks. Although the credit rating agencies do not currently issue ratings for Columbia itself, the Company's ultimate parent company, NiSource, is currently rated BBB+ by Standard and Poor's and Baa2 by Moody's.

Presently, S&P has assigned an average corporate credit rating of "A-" for the companies comprising the Gas LDC Group, while Moody's has assigned an average long-term issuer rating of "A3" for the Gas LDC Group companies. Both the S&P and Moody's ratings reflect the overall credit worthiness of the issuing company, rather than the risk of default for a specific debt issue. Additional information on the Gas LDC Group's average credit ratings can be found on page 8 of Attachment VVR-7.

Q. When evaluating Columbia versus the Gas LDC Group, how do their business and financial risk metrics compare?

A. The results of my comparative risk assessment for Columbia and the Gas LDC Group are presented on pages 1 and 2 of Attachment VVR-3, respectively. Pages 3 and 4 of Attachment VVR-3 provide additional information on the capitalization ratios for each of the seven companies comprising the Gas LDC Group. Within this attachment, I have evaluated the five-year historical period of 2016-2020, along with the five-year historical averages. My findings are summarized by individual risk metric as presented below:

1. Relative Size

Based on a total book capitalization of $340.6 million, Columbia is approximately 1/16th the size of the average company within the Gas LDC Group ($5.5 billion). It is well-documented in the finance literature that small capitalization companies have a higher risk profile as compared to large capitalization companies, and therefore earn higher relative returns. This is known as the "size effect" and is often attributed to the greater relative impact that significant (negative) events can have on smaller firms, vis-à-vis larger firms. Morin summarizes the size effect in *New Regulatory Finance,* a widely-referenced authoritative guide on utility cost of capital matters, as follows:

> Investment risk increases as company size diminishes, all else remaining constant. Small companies have very different returns than large ones, and on average they have been higher. . . . . In short, [small] size is a significant factor that increases both business risk and financial risk and, therefore, the cost of capital.[10]

Furthermore, in multiple academic papers, distinguished researchers Fama and French identified company size as a significant factor in explaining equity returns. As a result of their research, Fama and French developed an enhanced CAPM,

[10] Roger A. Morin, *New Regulatory Finance* (Public Utilities Reports, Inc., 2006), at 181, 187.

known as the "Three Factor Model," which recognized that the "size premium" is an essential component in estimating the cost of equity for small capitalization firms[11].

2. Volatility of Return on Book Equity

In the absence of observable market data, both the standard deviation and coefficient of variation of a time series of annual book ROEs can serve as suitable risk measurement substitutes for beta. Although standard deviation is a measure of total risk, while beta is a measure of non-diversifiable systematic risk, these two risk measures have been shown to be highly correlated. The coefficient of variation is calculated as the ratio of the standard deviation of ROE to the mean ROE, which facilitates a comparison of the degree of variation from one data series to another (i.e., Columbia vs. Gas LDC Group), even if the respective mean ROEs differ significantly. Higher calculated values for the standard deviation and coefficient of variation indicate greater volatility in achieved ROEs, which corresponds to a higher overall level of investment risk. For the period 2016-2020, the standard deviation of achieved ROEs was 1.97 percent for Columbia, and 0.64 percent for the Gas LDC Group. For the same period, the coefficient of variation

[11] See Eugene F. Fama and Kenneth R. French, "Industry Costs of Equity," *Journal of Financial Economics,* 43 (1997): 153-193; and Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *The Journal of Economic Perspectives*, 18 (Summer 2004), at 25-46.

was 0.210 for Columbia and 0.071 for the Gas LDC Group, reflecting a markedly higher relative volatility in achieved ROEs for Columbia.

3. <u>Equity Capitalization Ratio</u>

All else being equal, a company with a higher equity capitalization weighting has a lower level of financial risk, while a company with a lower equity capitalization weighting has a higher level of financial risk. This is because companies which rely more heavily on debt capital to finance their operations are subject to a higher level of contractual obligations in the form of periodic principal and interest payments. Increasing levels of fixed-payment obligations constrain a company's financial flexibility, especially during economic downturns, and therefore increase a company's financial risk profile. For this reason, the debt-to-capitalization ratio, which is the complement of the equity capitalization ratio, serves as an important financial metric that is routinely used by the rating agencies to assess a company's credit quality and overall financial risk profile. The 5-year average equity capitalization ratio for Columbia was 53.7 percent based upon permanent capitalization, and 50.3 percent based upon total capitalization. The 5-year average equity capitalization ratio for the Gas LDC Group was 53.6 percent based upon permanent capitalization, and 48.0 percent based upon total capitalization. As outlined in Attachment VVR-5, the Company is proposing a 52.64 percent common equity ratio for rate-setting purposes in the instant proceeding (based upon total capitalization), which, consistent with Commission precedent, includes short-term debt.

4. EBITDA-to-Interest Coverage

The EBITDA-to-Interest Coverage ratio is a key analytical metric routinely used by the rating agencies to evaluate whether a company's earnings and cash flow are sufficient enough to adequately cover its debt service obligations. Higher coverage ratios generally imply lower levels of financial risk and higher credit quality. The 5-year average EBITDA-to-Interest Coverage ratio for the years 2016-2020 was 5.37x for Columbia and 6.87x for the Gas LDC Group.

5. FFO-to-Adjusted Total Debt

The FFO-to-Adjusted Debt ratio is another important analytical metric used by the rating agencies and expresses a company's annual operating cash flows as a percentage of its total adjusted debt. The reciprocal of the FFO-to-Adjusted Debt ratio provides an approximate estimate of the total number of years of annual cash flows that would be required to retire a company's adjusted debt obligations. The 5-year average FFO-to-Adjusted Total Debt ratios for the years 2016-2020 was 23.7 percent for Columbia and 17.2 percent for the Gas LDC Group.

Q. What conclusions have you drawn from your comparative risk assessment between Columbia and the Gas LDC Group?

A. Columbia's investment risk metrics indicate that the Company has a slightly higher risk profile as compared to the Gas LDC Group. In particular, the business risk metrics I evaluated suggest that the Company has a higher risk profile vs. the Gas LDC Group, as demonstrated by the Company's: (1) significantly smaller size compared to the average company in the Gas LDC Group; and (2) markedly higher variability of book returns on equity, as measured by both the standard deviation and the coefficient of variation. In addition, as noted earlier, Columbia's higher relative allocation of gas throughput to industrial and transportation customers, as well as its high customer concentration level among the Company's top five transportation customers, also has the effect of increasing CKY's business risk profile. At the same time, however, the financial risk metrics[12] I evaluated suggest that on an overall basis, Columbia and the Gas LDC Group have similar financial risk profiles.

Therefore, on an overall basis, the results of my comparative risk assessment suggests that Columbia's overall investment risk profile is slightly higher than that of the Gas LDC Group. However, at the same time, it is my opinion that this risk differential is not significant enough to justify a further

[12] These financial risk metrics include the Equity Capitalization ratio, EBITDA-to-Interest Coverage ratio, and the FFO-to-Adjusted Total Debt ratio, as presented in Attachment VVR-3.

upward adjustment to the Gas LDC Group's indicated cost of equity. For this reason, I have relied entirely upon the cost of equity estimates yielded by applying the analytical models to the market and financial data of the proxy group companies I analyzed, without any further need to make an additional risk adjustment to these estimates.

Q. Have you considered any other proxy groups in estimating the cost of equity for Columbia?

A. Yes, I have. As previously stated, the use of multiple comparable-risk proxy groups ensures a higher level of confidence in the statistical reliability of the analytical results when estimating a utility's cost of equity. The importance of evaluating complementary proxy groups has become particularly evident in recent years, as recent merger and acquisition activity in the regulated utility space has reduced the number of gas utility holding companies to select from in deriving a gas utility proxy group. Therefore, to ensure a robust sample size that will obviate potential distortions caused by observation errors in the various financial model inputs, I have also evaluated a proxy group of nine combination gas and electric utility companies, and a proxy group of 12 non-regulated companies (i.e., the Combination Utility Group and the Non-Regulated Group, respectively). Both of these proxy groups have risk profiles which are similar to the Gas LDC Group. Considering that Columbia is not publicly-traded, the analysis of comparative risk metrics discussed earlier was necessary to establish the relative risk relationship between the Company and the Gas LDC Group. In order to facilitate a comparison of the risk profiles of the Combination Utility Group and the Non-Regulated Group to Columbia, this was accomplished indirectly through a comparative risk assessment of the three proxy groups, as based upon published risk indicators. I will discuss the relative risk relationships between the three proxy groups and Columbia later in my testimony.

Q. Why is it appropriate to evaluate a proxy group of combination gas and electric utility companies?

A. Considering the relatively small size of the Gas LDC Group, evaluating a proxy group of comparable-risk combination gas and electric utility companies ensures a higher level of confidence in the statistical reliability of the analytical results when estimating the cost of equity for a gas distribution company. This approach is also consistent with the comparable earnings standard established in *Hope* and *Bluefield*, since gas utilities are entitled to earn a rate of return commensurate with returns offered by other companies having "corresponding risks," including combination gas and electric utility companies. Morin provides additional support for this approach in *New Regulatory Finance*, where he argues that a proxy group of *electric* utility companies is a suitable complement to a proxy group of gas utilities. In this regard, Morin observes:

> This procedure is reasonable given that the natural gas distribution business possesses an investment risk profile that is similar in risk to investment-grade electricity distribution utilities. The latter possess economic characteristics similar to those of natural gas distribution utilities as they are both involved in the distribution of energy services products at regulated rates in a cyclical and weather-sensitive market. They both employ a capital intensive network with similar physical characteristics. They are both subject to rate of return regulation[13].

Therefore, considering that the companies included in my proxy group of combination utilities are all engaged in significant gas distribution operations, as contrasted with the "all-electric" utility approach suggested by Morin, my Combination Utility Group represents an entirely reasonable complement to the Gas LDC Group.

Q. Can you provide any additional evidence that your proxy group of combination gas and electric utility companies possesses a risk profile which is comparable to a proxy group of gas-only utilities, and therefore represents a suitable complement to your Gas LDC Group in estimating Columbia's cost of equity?

A. Yes. Substantial evidence suggests that to the extent combination gas and electric utilities are riskier than pure-play gas utilities, the risk differential is not significant. This is demonstrated by the average difference in authorized ROEs granted to gas versus electric utilities by state regulatory commissions over the

[13] Roger A. Morin, *New Regulatory Finance* (Public Utilities Reports, Inc., 2006) at 402.

past 40 years (1981-2020), which have only been about 13 basis points[14] higher for electric utilities. More recently, during the past 10-year period (2011-2020), the difference in authorized ROEs has been about 15 basis points[15] higher for electric utilities. However, in recent years the authorized ROEs reported by Regulatory Research Associates for electric utilities include special surcharge and rider cases relating to electric generation in the Commonwealth of Virginia, which allow ROE premiums of up to 200 basis points. This suggests that the actual difference between gas and electric utility ROEs, when stated on a comparable basis, is actually less than 15 basis points. If state regulatory commissions nationwide believed that the risk differential between gas and electric utilities was more significant, this would have been demonstrated by a greater disparity in the historically authorized ROEs between gas and electric utilities. Furthermore, considering that my Combination Utility Group derives an average of 30% of its consolidated revenues from regulated gas distribution operations, this further suggests that the Group's overall risk profile is actually lower than that of the typical electric utility.

Q. What criteria did you use to select the companies included in your Combination

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[14] *The Cost of Capital – A Practitioner's Guide*, D. Parcell, Society of Utility and Regulatory Financial Analysts, (2010), quoting Regulatory Research Associates, at 91; and *RRA Regulatory Focus, Major Rate Case Decisions – January-December 2020,* Regulatory Research Associates, February 2, 2021, at 1.

[15] *RRA Regulatory Focus, Major Rate Case Decisions - January-December 2020,* Regulatory Research Associates, February 2, 2021, at 1.

Utility Group?

A. In developing the Combination Utility Group, my objective was to identify a group of publicly-traded combination gas and electric utility companies with risk characteristics similar to the Gas LDC Group, and by extension, Columbia. Accordingly, I applied the following screening criteria in selecting companies for inclusion in the Combination Utility Group: (i) Value Line Investment Survey Industry Classification as an Electric Utility; (ii) Value Line Safety Rank of "1", "2" or "3"; (iii) S&P corporate credit rating no lower than BBB-, or Moody's long-term issuer rating of no lower than Baa3; (iv) company must have been engaged in both the natural gas distribution and electric distribution businesses for at least the past five years; (v) company must *not* currently operate nuclear power generation facilities, be a significant independent power producer, or have major gas transmission and storage operations; (vi) company must currently pay dividends and must not have discontinued or reduced their dividend payments during the previous five years (2016-2020); and (vii) company must not have recently been an acquisition target. Applying the above selection criteria yielded a proxy group consisting of the following nine publicly-traded combination gas and electric utility companies:

Alliant Energy Corp.
Black Hills Corp.
CMS Energy Corp.
Consolidated Edison, Inc.
Eversource Energy
MGE Energy Inc.
Northwestern Corp.
Sempra Energy
WEC Energy Group

I will refer to this group throughout my testimony as the Combination Utility Group.

Q. Why is it also appropriate to evaluate a proxy group of non-rate-regulated U.S. companies when estimating Columbia's cost of equity?

A. Under the fair rate of return standards established in *Hope* and *Bluefield*, the U.S. Supreme Court determined that regulated utilities are entitled to earn a rate of return commensurate with other companies having comparable risks, irrespective of their business activities or the extent to which they are regulated. For example, in *Bluefield,* the Supreme Court concluded:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by

corresponding risks and uncertainties[16].

It is important to note that within its *Bluefield* opinion, the Supreme Court specifically stated that public utilities should be permitted to earn a return that is equal to the returns on *"investments in other business undertakings,"* provided they have corresponding risks. By virtue of its reference to *"other business undertakings,"* the Supreme Court implicitly endorsed the use of non-utility proxy groups in the determination of a fair rate of return for utilities. Furthermore, in the *Hope* decision, the Supreme Court concluded:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.[17]

It is clear then, based upon the decisions of the Supreme Court in these landmark cases, that the use of non-rate-regulated proxy companies in the determination of a utility's cost of equity is a sound practice, and is consistent with the comparable earnings standard established in these cases. After all, utilities do not only compete with other utility companies for investor capital. They must also compete with an entire universe of risk-comparable companies, irrespective of industry classification and level of regulatory oversight. Therefore, in order to attract sufficient capital to support its public service obligations, and consistent with the

[16] *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 692 (1923).

[17] *Federal Power Commission et.al. v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944).

concept of opportunity cost, Columbia must provide a return to its investors that is similar to the returns offered by non-rate-regulated companies of comparable risk. Otherwise, over the long run, investor capital will simply flow to its most productive use elsewhere.

It is also important to note that cost-of-service ratemaking is intended to be a substitute for competition. That is, the objective of rate regulation is to produce the same results that would be achieved under the forces of market competition. In particular, it is the phenomenon of "competitive equilibrium" that rate regulation is intended to replicate, where, in the long run, market forces limit companies to earning returns that are no greater than, but also no less than, investors' minimum required rate of return. Expressed in microeconomic terms, long-run equilibrium is achieved where firms only earn minimally-required levels of "normal profits," while excessive profits, often referred to as "economic profits," are by definition equal to zero. Accordingly, the returns of regulated utilities should be no lower than the returns of comparable risk companies which operate under the constraints of market competition. The 12 companies included in the Non-Regulated Group are lower-risk companies in the consumer staple, food and beverage, chemicals processing, transportation, and telecommunication service industries, each of which operate under the competitive pressures of the free marketplace. Considering that this proxy group is demonstrably comparable on a total risk basis to the Gas LDC Group, its use is consistent with the fair rate of return standards established in *Hope* and *Bluefield.*

Q. What criteria did you use to select the companies included in the Non-Regulated Group?

A. In selecting the Non-Regulated Group, my objective was to identify a large group of publicly-traded domestic companies with a risk profile either equivalent to, or preferably lower than, the Gas LDC Group. This approach is designed to ensure a conservative analysis when applying the various cost of equity models to the market and financial data of the Non-Regulated Group companies. To achieve this objective, I applied the following screening criteria in selecting companies for inclusion in the Non-Regulated Group: (i) Value Line Investment Survey Classification as a Conservative Stock, which is defined as stocks having a Value Line Safety Rank of no lower than "1" (Highest Rank for Relative Safety); (ii) Value Line beta ranging between 0.75 and 0.95; (iii) Value Line Financial Strength Rating of "A+" or higher; (iv) S&P corporate credit rating that is no lower than BBB-, or Moody's long-term issuer rating of no lower than Baa3; (v) company shall not be in the gas and/or electric distribution business, and shall not be an investment, financial services, pharmaceutical, life sciences, medical technology, hardware/software, or defense contract company; (vi) the company must currently pay dividends and must not have discontinued or reduced their dividend payments during the previous five years (2016-2020); and (vii) the company must have at least one consensus earnings estimate published by an information service provider such as Thomson Reuters or Zacks. Applying these highly-selective criteria yielded the Non-Regulated Group, which is comprised of 12 lower-risk companies which operate in the consumer staple, food and beverage, chemicals processing, transportation, and telecommunications sectors of the economy. The 12 companies comprising the Non-Regulated Group are as follows:

AT&T, Inc.
Air Products and Chemicals, Inc.
Coca-Cola Co.
Comcast Corp.
Hershey Company
International Flavors & Fragrances, Inc.
J.B. Hunt Transport Services
McCormick & Co.
McDonald's Corp.
PepsiCo, Inc.
Sherwin-Williams Co.
United Parcel Service

Q. How does the Combination Utility Group compare on a total risk basis to the Gas LDC Group?

A. To facilitate a comparative risk assessment between the respective proxy groups, I have compared the three groups on the basis of six well-recognized measures of investment risk. The first of these measures is the Value Line "beta," which measures a stock's non-diversifiable or systematic risk. The second measure is the Value Line "Safety Rank," which is Value Line's proprietary measure of the total risk of a stock and is determined based upon an equal weighting between Value Line's Financial Strength rating and Stock Price Stability rating. I have also considered the Value Line Financial Strength and Stock Price Stability ratings on an individual basis, which are presented as risk measures three and four. The fifth and sixth measures of investment risk I have evaluated are the long-term credit ratings assigned by S&P and Moody's, respectively. Considering that credit ratings are the product of a comprehensive, multi-dimensional analysis which considers a utility's business risk (including regulatory risk) and financial risk, they provide a useful perspective into the overall investment risk profile of the respective proxy groups.

The summarized results of my comparative risk assessment are presented in Table VVR-4 below. Based upon my evaluation of the aforementioned risk measures, I have concluded, that taken on an overall basis, the Combination Utility Group has a very similar investment risk profile as compared to the Gas LDC Group. This conclusion is based upon the fact that the Combination Utility Group and the Gas LDC Group have equivalent risk ratings with respect to the Value Line Safety Rank ("2"), Value Line Financial Strength rating ("A") and their respective long-term credit ratings from S&P ("A-"). Although the Combination Utility Group's average Value Line beta (0.86) indicates a slightly lower level of investment risk when compared to the Gas LDC Group's average beta of 0.89, this risk differential is offset by the higher investment risk implied by the Combination Utility Group's average Stock Price Stability rating of "89", versus an average Stock Price Stability rating of "86" for the Gas LDC Group, and the Combination Utility Group's lower average credit rating at Moody's ("Baa1") as compared to the Gas LDC Group's average rating of "A3". Based upon these findings, I have concluded that the Combination Utility Group and the Gas LDC Group are of comparable risk.

Q. How does the Non-Regulated Group compare on a total risk basis to the Gas LDC Group?

A. Based upon my evaluation of the aforementioned risk measures, and as summarized in Table VVR-4 below, I have concluded that the Non-Regulated Group also has a very similar overall investment risk profile as compared to the Gas LDC Group.

Table VVR-4 Comparative Risk Assessment of Proxy Groups			
Risk Measure	**Gas LDC Group**	**Comb. Utility Group**	**Non-Reg. Group**
Value Line Beta	0.89	0.86	0.87
Value Line Safety Rank	2	2	1
Value Line Fin. Strength Rating	A	A	A+
Value Line Stock Price Stability Rating	86	89	94
S&P Long-Term Debt Rating	A-	A-	A-
Moody's Long-Term Debt Rating	A3	Baa1	A3

E. Analysis of Regulatory Mechanisms

Q. In view of the fact that Columbia utilizes a Weather Normalization Adjustment ("WNA") mechanism [and employs a flat monthly customer charge for its residential customers], would it be appropriate to apply a downward adjustment to Columbia's cost of equity under the premise that CKY's WNA mechanism [and flat monthly customer charge] have risk-reducing effects on the Company's overall investment risk profile?

A. No, because an adjustment of this type would be clearly redundant and therefore inappropriate. Considering that a majority of the utility proxy group companies I reference in my quantitative evaluations already utilize similar revenue stabilization mechanisms, any theoretical risk reduction and/or theoretical reduction in the cost of equity resulting from these mechanisms would already be reflected within the market prices of the proxy group companies. In other words, since investors are already aware of the stabilization mechanisms employed by the proxy group companies, they have already incorporated these mechanisms into their risk perceptions and rate of return expectations. Therefore, a downward adjustment to Columbia's cost of equity is not necessary or appropriate, since on an overall basis, the extent to which the proxy group companies already employ revenue stabilization mechanisms is generally equal to, or more comprehensive than, Columbia's WNA mechanism [and flat monthly customer charge]. Accordingly, any theoretical reduction in ROE would already be reflected in the indicated cost of equity for each of the proxy group companies.

Q. Have you completed a comparative evaluation to determine the extent to which the companies comprising your proxy groups also employ revenue stabilization mechanisms?

A. Yes, I have. My evaluation of the revenue stabilization mechanisms employed by each of the companies comprising the Gas LDC Group and the Combination Utility Group is presented within Attachment VVR-4. Using information available from Securities and Exchange Commission filings and investor conference presentations, my evaluation identified, for each state jurisdiction in which the proxy group companies have utility operations, the specific types of revenue stabilization mechanisms employed in each of those jurisdictions. During the course of my evaluation, I determined that a wide range of revenue stabilization mechanisms are employed by the majority of companies comprising the two utility proxy groups, including full decoupling, revenue normalization, weather normalization, rate stabilization, straight fixed-variable rate design, modified fixed-variable rate design, and lost revenue/lost margin recovery mechanisms.

Q. Based upon your evaluation of the revenue stabilization mechanisms employed by the proxy group companies, what conclusions have you drawn?

A. Again, I have determined that the clear majority of companies comprising the two utility proxy groups utilize rate designs that are either fully or partially non-volumetric in nature. More specifically, and as reflected in Attachment VVR-4, my evaluation determined that all seven of the companies comprising the Gas LDC Group, and that eight of the nine companies comprising the Combination Utility Group, employ various forms of revenue stabilization mechanisms. Pages 1-8 of Attachment VVR-4 demonstrates that, on balance, the revenue stabilization mechanisms employed by the proxy group companies share many of the same characteristics, and are therefore generally comparable, to Columbia's WNA program. As a result, my cost of equity evaluation, which relies upon the market and financial data of the proxy group companies, already incorporates the effects of these revenue stabilization programs on the risk perceptions and rate of return expectations of investors. Accordingly, an adjustment to Columbia's cost of equity to compensate for any such theoretical reduction of risk is clearly not warranted, since to the extent such risk reduction was to actually occur, its effect on Columbia's cost of equity will have already been captured within the market data of the proxy group companies.

Q. Based upon your evaluation of the infrastructure cost recovery mechanisms employed by the utility proxy group companies, what conclusions have you drawn?

A. As noted earlier, in determining the extent to which the proxy group companies utilize infrastructure cost recovery mechanisms, I employed the same approach that investors typically employ in conducting their relative risk assessments among various investment alternatives. That is, I reviewed each company's SEC public filings (i.e. 10-Ks and 10-Qs) and investor conference presentations. This is an important observation since investors will generally form their risk perceptions with respect to the impacts of infrastructure cost recovery mechanisms largely on the basis of the information contained within a company's public filings and/or other publicly-disseminated information.

As presented in Attachment VVR-4, I have determined that three-quarters of the utility proxy group companies (12 out of 16) employ infrastructure cost recovery mechanisms that are generally comparable to Columbia's SMRP program. More specifically, within the Gas LDC Group, six of the seven proxy group companies employ such infrastructure mechanisms, while within the Combination Utility Group, six of the nine companies utilize these mechanisms. Therefore, in the aggregate, the market-based data of the utility proxy group companies would already capture a significant portion of any theoretical risk reduction resulting from the reduced regulatory lag associated with such cost recovery mechanisms. For the above stated reasons, it would be inappropriate to apply a downward adjustment to Columbia's proposed ROE due to the presence of the Company's SMRP program, since such an adjustment would be redundant to the effects that would already be incorporated within the market data of the proxy group companies.

F. <u>Rate-Setting Capital Structure</u>

Q. What capital structure are you recommending for rate-setting purposes in this proceeding?

A. Attachment VVR-5 presents Columbia's capitalization as of February 28, 2021, which corresponds to the actual data in the base period for the Company. The August 31, 2021 capital structure is estimated at the end of the base period, and consists of six-months of actual data and six-months of projected data.

Considering that the rate-setting process is prospective in nature, the Company's authorized rate of return should incorporate known and foreseeable changes expected to occur during the fully forecasted test period, including those changes impacting the Company's capital structure.

As further outlined in Attachment VVR-6, after the base period, and through the end of the fully forecasted test period, the CKY plans to issue a total of $46.0 million in new long-term debt to NiSource. The Company also has a long-term debt maturity in the amount of $16.0 million that will occur during November 2021. Therefore, CKY's fully forecasted test period capital structure is estimated as of December 31, 2022, and incorporates the Company's planned financing activities as outlined above.

As further reflected in Attachment VVR-5, the Company is recommending that Columbia's thirteen-month average capital structure through the fully forecasted test period, ending December 31, 2022, be referenced for rate-setting purposes in the instant proceeding. As reflected in both Attachment VVR-2 and Attachment VVR-5, Columbia's capital structure ratios of 44.25 percent long-term debt, 3.11 percent short-term debt, and 52.64 percent common equity, are recommended. Each of these ratios are based upon the thirteen-month average balance for the 2022 fully-forecasted test year.

To confirm the reasonableness of the Company's estimated test year capital structure, I have evaluated the actual and projected equity capitalization levels published by Value Line for the Gas LDC Group companies, which are calculated on the basis of permanent capitalization, and therefore exclude short-term debt. On an *equivalent measurement basis* (based on permanent capitalization) the Company's thirteen-month average equity capitalization level as of December 31, 2022, is estimated to be 54.3 percent ($234,535,137 / $431,679,368), which excludes the impact of short-term debt. As reflected in Table VVR-5 below, this capitalization level is clearly in line with the range of equity capitalization ratios anticipated for the utilities comprising the Gas LDC Group, as based upon near-term forecasts from Value Line.

Table VVR-5
Forecasted Equity Capitalization Ratios
Gas LDC Group

Company	2020	Forecast 2021	Forecast 2022	Forecast 2024-2026
Atmos Energy Corp.	60.0%	60.0%	60.0%	60.0%
New Jersey Resources Corp.	44.9%	45.5%	45.0%	45.5%
Northwest Natural Gas Co.	51.5%	51.0%	53.5%	57.0%
ONE Gas, Inc.	58.0%	60.0%	60.0%	60.0%
South Jersey Industries, Inc.	39.0%	38.5%	38.0%	42.0%
Southwest Gas Corp.	49.5%	49.5%	50.0%	52.0%
Spire, Inc.	51.0%	51.0%	51.0%	55.0%
Gas LDC Group Average	50.6%	50.8%	51.1%	53.1%
Source: Value Line Investment Survey, February 26, 2021.				

This data indicates that Columbia's proposed capital structure ratios fall well within the typical and customary range for gas utilities. While the Company's estimated test year-end common equity ratio *measured on an equivalent basis* is 54.3 percent, the common equity ratios forecasted for the Gas LDC Group companies range from 38.0 percent to 60.0 percent over the five-year forecast horizon. Therefore, the Company's proposed test year-end capital structure ratios fall well within this range, and are therefore typical and customary for a regulated gas utility.

G. Embedded Cost of Debt

Q. What debt cost rate did you apply to the long-term debt and short-term debt components of Columbia's capital structure?

A. Attachment VVR-6 presents Columbia's embedded cost of long-term debt at February 28, 2021, and estimated cost of long-term debt at August 31, 2021 and December 31, 2022. Attachment VVR-6 also presents Columbia's estimated average cost of long-term debt for the thirteen month period ending December 31, 2022, which reflects an average debt cost rate of 4.56 percent. With respect to the Company's future planned issuances of long-term debt, I have referenced an estimated debt cost rate of 3.90 percent for the issuances expected to occur during the remainder of 2021, and a debt cost rate of 4.00 percent for those issuances expected to occur during 2022. The Company anticipates that these future debt issuances will be made on an intercompany basis to NiSource.

With regard to the short-term debt component of CKY's capital structure, I have used a cost rate of 1.40 percent, which represents the Company's estimate for the fully forecasted test period. The Company obtains its short-term debt financing through the NiSource money pool, which is supported by a revolving credit facility that NiSource has in place with a syndicate of banks. The interest rate estimate was determined based on the 1-month LIBOR rate, plus an applicable margin, as reflected within the pricing grid in NiSource's revolving credit facility agreement. Accordingly, for rate-setting purposes I will adopt 4.56 percent as Columbia's cost of long-term debt, and 1.40 percent as Columbia's cost of short-term debt.

IV. COST OF EQUITY ESTIMATES

A. Cost of Equity - General Approach

Q. Please describe the general approach you have taken in estimating the cost of equity for Columbia.

A. In order to facilitate a thorough analysis of Columbia's cost of equity, I first conducted a comparative risk assessment to establish the risk relationships between Columbia and the three respective proxy groups. I then determined the indicated cost of equity for each of the respective proxy groups by applying three widely-recognized cost of equity models to the market and/or financial data of the proxy group companies. To estimate Columbia's cost of equity, I started with the indicated cost of equity for the respective proxy groups for each of the analytical methods employed, and made the required return adjustments based upon the results of my comparative risk assessment.

It should be noted that although the cost of equity cannot be directly observed, it can be estimated using a variety of analytical models, each of which attempt to explain and/or predict investor behavior. However, since investor expectations often differ and investors rely on a variety of information sources and financial models to make their investment decisions, no single analytical model can possibly capture the broader universe of investor expectations. Moreover, each financial model has its own practical shortcomings, either in the form of rigid underlying assumptions or required model inputs which are dependent upon the subjective judgment of the analyst. For these reasons, in *The Cost of Capital - A Practitioner's Guide*, Parcell presents a compelling argument for the use of a variety of analytical methods in estimating a utility's cost of equity, and cautions against overreliance on any one particular model. In *The Cost of Capital*, Parcell maintains:

> …..no single model is so inherently precise that it can be relied upon solely to the exclusion of other theoretically sound models….Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality…Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors. Therefore, it is essential that estimates of investors' required rate of return produced by one method be compared with those produced by other methods, and that all cost of equity estimates be required to pass fundamental tests of reasonableness and economic logic[18].

Consistent with the foregoing arguments articulated by Parcell, to ensure a thorough evaluation of Columbia's cost of equity, I have applied a variety of analytical models to the market and/or financial data of a large number of proxy

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[18] David C. Parcell, *The Cost of Capital - A Practitioner's Guide* (Society of Utility and Regulatory Financial Analysts, 2010), at 84.

group companies.

B. Discounted Cash Flow ("DCF") Analysis

Q. Please provide an overview of the DCF approach used to estimate the cost of equity.

A. The DCF approach is a commonly-used valuation model, which is based on the fundamental premise that investors value financial assets on the basis of their expected future cash flows, discounted by an appropriate risk-adjusted rate of return. The model maintains that the market-determined price of a share of common stock or other financial asset will continually adjust until investors are sufficiently compensated for the level of investment risk they bear. It is only at the point that investors have realized their required rate of return that valuation equilibrium will have been achieved. The objective of the DCF approach is to reproduce this iterative market valuation process in the form of a financial model. Considering that the price of a given share of common stock can be directly observed in the equity market, and that the stock's future dividends and capital gains can be estimated, the DCF model can be successfully rearranged to solve for the cost of common equity. It is this "rearranged" version of the DCF model that is commonly used in utility rate proceedings, as I will discuss later in my testimony.

Q. What is the underlying theoretical basis for employing the DCF approach to

value financial assets, and how has the DCF approach evolved over the years?

A. The theoretical underpinnings of the DCF approach are consistent with classical valuation theory, which states that the intrinsic value of any security is a function of its future earnings power. Specifically, intrinsic value can be quantified as the present value of the security's future cash flows discounted at the appropriate risk-adjusted rate of return. This concept was first formally advanced by Fisher in *The Rate of Interest*[19], and was further elaborated upon in his subsequent work, *The Theory of Interest*, wherein Fisher maintained:

> Capital, in the sense of capital value, is simply future income discounted or, in other words, capitalized. The value of any property, or rights to wealth, is its value as a source of income and is found by discounting that expected income[20].

Fisher's seminal valuation concept, which was first articulated over a century ago, laid the foundation for modern versions of the DCF approach, which both investors and academics continue to rely upon today.

Almost a decade after *The Theory of Interest* was published, Williams expanded upon Fisher's earlier work in valuation theory in his classic publication, *The Theory of Investment Value* (1938). It was here that Williams first expressed in modern economic terms a fully developed DCF equation, which was intended to serve as a valuation model for common stocks. Although Williams emphasized

[19] Irving Fisher, *The Rate of Interest*, (The Macmillan Company 1907).

[20] Irving Fisher, *The Theory of Interest*, (The Macmillan Company 1930), Part I, Chapter I, Section 7.

that his DCF equation was a *dividend* discounting model rather than an earnings-based model, he also acknowledged that over the long run, the two approaches would produce equivalent valuation results. Indeed, upon introducing his DCF equation in *The Theory of Investment Value*, Williams explains:

> Let us define the investment value of a stock as the present worth of all the dividends to be paid upon it….
>
> …
>
> Most people will object at once to the foregoing formula for stocks by saying that it should be the present worth of future *earnings*, not future *dividends*. But should not earnings and dividends both give the same answer under the implicit assumptions of our critics? If earnings not paid out in dividends are all successfully reinvested at compound interest for the benefit of the stockholder, as the critics imply, then these earnings should produce dividends later; if not, then they are money lost….
>
> …
>
> On analysis, therefore, it will be seen that no contradiction really exists between our formula using dividends and the common precept regarding earnings. How to estimate the future dividends for use in our formula is, of course, the difficulty[21].

The DCF approach introduced by Williams included a general "long-form" equation, which reflected an ongoing series of dividend payments extending into the indefinite future, and a simplified constant growth version of the equation,

[21] John Burr Williams, *The Theory of Investment Value*, (Cambridge, MA, Harvard University Press, 1938) 55, 57-58.

which was later refined by Gordon and Shapiro[22].

In subsequent years, Williams' long-form DCF equation was adjusted to accommodate various forms of future cash flows, rather than only dividends, and evolved into a general purpose valuation model. This so-called "general DCF model" continues to be used today in a variety of applications extending beyond security valuation, including corporate finance decision support, real estate development, and other financial applications. However, when the general DCF model is employed to value common stocks, the following equation is utilized:

$$P_0 = D_1/(1+K) + D_2/(1+K)^2 + D_3/(1+K)^3 + ...+ D_n/(1+K)^n \quad \text{(Equation 1.1)}$$

Where: P_0 = current market price of the stock,
D_1 = expected dividend at end of year 1, year 2, year 3, etc.,
n = infinity,
K = investors' expected return on common equity (the discount rate).

[22] Myron J. Gordon and Eli Shapiro, "Capital Equipment Analysis: The Required Rate of Profit," *Management Science*, 3 (October 1956) 102-110.

Q. What form of the DCF model is used to estimate the cost of common equity in utility regulatory proceedings?

A. In practice, the general DCF model can be challenging to apply to common stock valuation, since the model requires that discrete dividend payments be estimated well into the distant future. However, if investors assume that future dividend payments will increase at a constant growth rate each year into perpetuity, the valuation process can be greatly simplified. Drawing upon the constant growth model developed by Williams, and later refined by Gordon and Shapiro, the following constant growth equation can be utilized in valuing common stocks:

$$P_0 = D_1/(K-g) \qquad \text{(Equation 1.2)}$$

Where: P_0 = current market price of the stock,
D_1 = expected dividends over the next year,
K = investors' expected return on common equity (the discount rate),
g = expected dividend growth rate into perpetuity.

This simplified equation states that a company's stock price is determined by the present value of dividend payments occurring over the next year, plus all subsequent dividend payments growing at a constant annual rate, as discounted by the expected return on common equity. Although the constant growth model is conceptually viable and simplifies the process of estimating future dividend payments, the model is also premised upon strict underlying assumptions,[23] which are not always observed in reality.

The constant growth equation reflected above can be rearranged to solve for "K," which yields the standard DCF formulation for estimating the cost of common equity, which is expressed as follows:

$$K = D_1/P_0 + g \qquad \text{(Equation 1.3)}$$

Where: Variables are as previously defined.

It is this standard form of the DCF model that is commonly used in utility rate proceedings. The model is intuitive in that it states that common stock investors have a total return requirement ("K") which is comprised of a forward looking dividend yield component (D_1/P_0), plus the expected growth rate of dividends (and/or stock price appreciation) into perpetuity ("g"). Considering that both components of the dividend yield (D_1 and P_0) can be readily observed through a variety of publicly-available sources, and that the investor expected growth rate

23 The strict assumptions underlying the constant growth DCF model include: (i) dividends and earnings grow at the same constant growth rate (or constant average growth trend); (ii) book value per share and the stock price also grow at the same constant growth rate; (iii) investors expect the same rate of return ("K") in all future periods, implying no changes in risk and a flat yield curve; (iv) the discount rate, "K," must exceed the expected constant growth rate, "g"; (v) a fixed dividend payout ratio will be maintained; (vi) a fixed price-earnings ("P/E") multiple will be maintained; (vii) dividends are only paid at the end of each year; and (viii) no external financing occurs, as growth is financed strictly through the retention of earnings (or alternatively, any new sales of stock only occur at book value). Despite the fact that these assumptions are not always reflective of reality, the constant growth model maintains its usefulness due in its ability to adequately explain investor behavior and the stock market valuation process.

can be estimated using a variety of approaches, the analyst can infer "K," the required return on common equity.

Q. What steps are involved in implementing the constant-growth DCF model for estimating the cost of common equity?

A. Implementing the DCF model involves three essential steps. The first step is to determine the expected dividend yield component (D_1/P_0), which is defined as dividends expected to be paid over the next twelve months (D_1) divided by the current stock price (P_0). From an investor's perspective, the dividend yield represents *current income*. The second step is to estimate the long-term growth expectations of investors, or "g," relative to the security's future dividends and/or price appreciation. From the investor's perspective, whether realized in the form of higher future dividend payments, or in the form of stock price appreciation, the growth component represents *future income.* Considering that a strict interpretation of constant-growth theory requires that a *perpetual* growth rate be estimated, while the available sources of forward-looking growth estimates are limited in their forecast horizons, determining an appropriate growth estimate is the most challenging and controversial aspect of the DCF approach. The third and final step is simply to sum together the expected dividend yield component with the expected long-term growth component, to determine "K," the investor required cost of common equity.

A detailed discussion of the steps I took in implementing the DCF constant growth model can be found in Appendix A to my testimony. Additionally, Appendix B discusses the treatment of "outlier" DCF results which do not meet threshold tests of reasonableness and economic logic. Appendix C discusses the importance of applying a financial risk adjustment to DCF estimates whenever the market-value equity capitalization level of the proxy group companies is materially different than the corresponding book-value capitalization levels. Finally, Appendix D discusses the importance of applying a flotation cost adjustment to the "baseline" cost of equity results under the DCF model.

Q. What cost of equity estimates are indicated for the Gas LDC Group using the DCF approach?

A. A detailed presentation of DCF results for each member of the Gas LDC Group is presented on pages 1 and 2 of Attachment VVR-7, and is also summarized in Table VVR-6 below. After eliminating both high-end and low-end outlier results, the average unadjusted DCF estimate for the Gas LDC Group ranged from 7.20 percent to 11.60 percent. The three unadjusted DCF estimates based upon earnings growth forecasts demonstrate a central tendency of approximately 9.90 - 10.00 percent. The DCF estimate based upon the 5-year and 10-year historical average earnings growth rate indicates an unadjusted cost of equity of 9.60 percent. On an overall basis, an unadjusted DCF estimate of 9.70 percent is indicated for the Gas LDC Group. In deriving this estimate, I placed the greatest emphasis on the EPS consensus growth estimates of equity analysts, which have been demonstrated to be a primary driver of stock prices. After making the required leverage and flotation cost adjustments to the unadjusted DCF estimate referenced above, the results of my analysis indicate a cost of equity of 10.54 percent for the Gas LDC Group.

Table VVR-6
Average DCF Estimates - Gas LDC Group

Calculation Method	Cost of Equity
Earnings Forecast	
Yahoo Finance	8.70%
Zacks	9.40%
Value Line	11.60%
Retention Growth Rate Forecast	7.20%
Historical Earnings Growth Rate	9.60%
Unadjusted DCF Estimate	9.70%
Flotation Cost Adjustment (3 basis points)	x 1.00315%
Subtotal	9.73%
Plus: Market Value-Book Value Financial Risk Adjustment*	0.81%
Indicated DCF Estimate	= 10.54%

This financial risk adjustment recognizes that the cost of equity estimates reflected above are based on the market-value based capital structure of the proxy group companies, while these estimates will actually be applied to a book-value based rate-setting capital structure, which reflects a materially higher level of financial risk.

Q. What cost of equity estimates were indicated for the Combination Utility Group using the DCF approach?

A. DCF estimates for each member of the Combination Utility Group are presented on pages 1 and 2 of Attachment VVR-8, and are summarized in Table VVR-7 below. After eliminating both high-end and low-end outlier results, the unadjusted DCF estimates for the Combination Utility Group ranged from 7.20 percent to 9.20 percent. The three unadjusted DCF estimates based upon earnings growth forecasts demonstrate a central tendency of approximately 9.10 percent. The DCF estimate based upon the 5-year and 10-year historical average earnings growth rate indicates an unadjusted cost of equity of 9.00 percent. On an overall basis, an unadjusted DCF estimate of 9.00 percent is indicated for the Combination Utility Group. After making the required leverage and flotation cost adjustments to the unadjusted DCF estimate, the results of my analysis indicate a cost of equity of 9.84 percent for the Combination Utility Group.

Table VVR-7 Average DCF Estimates – Combination Utility Group	
Calculation Method	**Cost of Equity**
Earnings Forecast	
Yahoo Finance	9.20%
Zacks	9.00%
Value Line	9.00%
Retention Growth Rate Forecast	7.20%
Historical Earnings Growth Rate	9.00%
Unadjusted DCF Estimate	9.00%
Flotation Cost Adjustment (3 basis points)	x 1.00315%
Subtotal	9.03%
Plus: Market Value-Book Value Financial Risk Adjustment*	0.81%
Indicated DCF Estimate	= 9.84%

* This financial risk adjustment recognizes that the cost of equity estimates reflected above are based on the market-value based capital structure of the proxy group companies, while these estimates will actually be applied to a book-value based rate-setting capital structure, which reflects a materially higher level of financial risk.

Q. What cost of equity estimates were indicated for the Non-Regulated Group using the DCF approach?

A. DCF estimates for each member of the Non-Regulated Group are presented on pages 1 and 2 of Attachment VVR-9, and are summarized in Table VVR-8 below. After eliminating both low-end and high-end outlier results, the unadjusted DCF estimates for the Non-Regulated Group ranged from 10.00 percent to 12.60 percent. The three unadjusted DCF estimates based upon earnings growth forecasts demonstrate a central tendency of approximately 10.80 percent to 10.90 percent. The DCF estimate based upon the 5-year and 10-year historical average earnings growth rate indicates an unadjusted cost of equity of 10.60 percent. On an overall basis, an unadjusted DCF estimate of 10.70 percent is indicated for the Non-Regulated Group. After making the required leverage and flotation cost adjustments to this estimate, the results of my DCF analysis indicate a cost of equity of 11.54 percent for the Non-Regulated Group.

Table VVR-8 Average DCF Estimates – Non-Regulated Group	
Calculation Method	**Cost of Equity**
Earnings Forecast	
Yahoo Finance	11.20%
Zacks	11.20%
Value Line	10.00%
Retention Growth Rate Forecast	12.60%
Historical Earnings Growth Rate	10.60%
Unadjusted DCF Estimate	10.70%
Flotation Cost Adjustment (3 basis points)	x 1.00315%
Subtotal	10.73%
Plus: Market Value-Book Value Financial Risk Adjustment*	0.81%
Indicated DCF Estimate	= 11.54%

* This financial risk adjustment recognizes that the cost of equity estimates reflected above are based on the market-value based capital structure of the proxy group companies, while these estimates will actually be applied to a book-value based rate-setting capital structure, which reflects a materially higher level of financial risk.

Consistent with established regulatory principles, authorized returns for regulated utilities should be similar to returns offered by comparable risk firms operating in the competitive marketplace. Along these lines, it is noteworthy that despite the fact that my comparative risk assessment has clearly established that the Non-Regulated Group has a similar risk profile to the two utility proxy groups, the DCF estimates for the Non-Regulated Group are nevertheless higher than the DCF estimates for the two utility proxy groups.

C. Capital Asset Pricing Model ("CAPM") Analysis

Q. Please provide an overview of the CAPM and the theoretical basis for using it to estimate a utility's cost of equity.

A. The CAPM is a market-based risk and return investment model which derives its theoretical underpinnings from both Capital Market Theory and Modern Portfolio Theory ("MPT").[24] Originally developed by Sharpe in the early 1960s for investment analysis purposes, the CAPM is considered an ex-ante, forward-looking model which recognizes that investors are generally risk-averse and will demand higher returns in exchange for assuming higher levels of investment risk. The traditional CAPM equation is expressed as follows:

$$K = R_F + \beta(R_M - R_F) \qquad \text{(Equation 1.4)}$$

Where: K = Required rate of return for a stock;
R_F = Expected risk-free rate of return;
β = Beta, or systematic risk of a stock; and
R_M = Expected return for the overall stock market.

[24] MPT, which was developed by Harry Markowitz in the early 1950's, heavily influenced William Sharpe's development of the CAPM. MPT advanced the concept of an "efficient frontier" of dominating investment portfolios, which provided the highest rate of return possible for a given level of investment risk, as measured by the portfolio's covariance of returns. Essential concepts from MPT which influenced the development of the CAPM included the risk and return tradeoff relationship, and the value of diversification for eliminating firm-specific investment risk. Markowitz and Sharpe both earned the Nobel Prize in Economics in 1990 for their body of work relative to these classic financial theories.

The investor required rate of return (K) indicated by the CAPM is equal to the expected risk-free rate of return (R_F) plus a risk premium which is proportional to the level of systematic risk implicit in the security being evaluated. Systematic risk, also referred to as market risk, is the sole risk element found within the CAPM, and refers to the variability of overall stock market returns, which are largely influenced by socioeconomic and political trends. It is only this systematic risk which commands a return premium within the CAPM, as a critical assumption underlying the model is that investors have already eliminated firm-specific investment risk in their investment portfolios via diversification.

Within the CAPM framework, an individual stock's contribution to the systematic risk of a given portfolio is indicated by the stock's beta (β) coefficient. In essence, the beta coefficient measures the co-variability of the price movements of an individual stock versus the price movements of the total market portfolio. The beta of the market portfolio is equal to 1.0, which reflects a level of variability consistent with the overall stock market. Stocks with beta values *lower* than 1.0 have a lower expected variability and therefore less systematic risk than the overall market, while stocks with betas *higher* than 1.0 have a higher expected variability and thus greater systematic risk than the overall market. To determine the investor-required risk premium for an individual stock, the difference between the expected market return (R_M) and the expected risk-free rate of return (R_F), which is defined as the market risk premium (R_M - R_F), is proportionately adjusted based upon the stock's beta. Lastly, the investor required rate of return (K) is determined by adding the expected risk-free rate of return to the stock-specific risk premium.

Much like other analytical models including the DCF model, the CAPM is premised upon strict underlying assumptions, which are not always observed in reality.[25] Nonetheless, the model still possesses useful explanatory and predictive abilities, as it has been consistently demonstrated that beta is both positively and linearly correlated to security returns. At the same time, as I will discuss later in my testimony, empirical studies have also demonstrated that the risk-return relationship indicated by the CAPM, as graphically depicted by the Security Market Line ("SML"), is in reality not as steeply sloped as the model implies. In fact, the empirical evidence has shown that the implied y-axis intercept of the SML is actually higher, while the slope of the SML is actually flatter than what is predicted by the traditional CAPM. The implication of these findings is that cost of equity estimates derived from the traditional CAPM will tend to underestimate the investor-required rate of return for lower beta stocks, including gas utility

[25] The strict assumptions underlying the CAPM include: (i) security markets are highly efficient and consistently reflect the true value of a given security; (ii) investors will always pursue their own best economic self-interest, including the maximization of profit and end-of-period wealth; (iii) all investors have the same rate of return expectations; (iv) all investors hold diversified investment portfolios; and (v) investors are not subject to taxes, transaction costs, short-selling restrictions or borrowing restrictions.

stocks, absent an adjustment to the traditional model.

Q. Is the CAPM commonly used to estimate the cost of equity, and does it influence the return expectations of investors?

A. Yes, the CAPM is a widely-referenced method for estimating the cost of equity among investment professionals, academics, and corporate finance departments and, therefore, influences the return expectations of investors. According to the *Ibbotson® SBBI® Valuation Yearbook*:

> The capital asset pricing model (CAPM) is a simple and elegant model that describes the expected (future) rate of return on any security or portfolio of securities. It is among the most widely used techniques to estimate the cost of equity[26].

Further evidence of the CAPM's popularity as a cost of equity analytical model is found in *Corporate Finance: A Focused Approach,* where Ehrhardt and Brigham state:

> Recent surveys found that the CAPM approach is by far the most widely used method. Although most firms use more than one method, almost 74% of respondents in one survey, and 85% in the other, used the CAPM[27].

Considering the widespread acceptance of the CAPM in both investment management and academic settings, there can be no doubt that the CAPM exerts significant influence over the return expectations of investors.

Q. In structuring your CAPM analysis, what approach did you take in estimating

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[26] *Ibbotson® SBBI® 2013 Valuation Yearbook* (Morningstar, Inc.) at 43.

[27] Michael Ehrhardt and Eugene Brigham, *Corporate Finance: A Focused Approach*, (South-Western Cengage Learning, 2008) at 303.

the market risk premium expectations of investors?

A. To ensure a thorough and comprehensive evaluation of the risk premium expectations of investors, I have completed market risk premium analyses on both a prospective basis and on a historical basis. With regard to my prospective analysis, I have evaluated forward-looking indicators of the market return expectations of investors, along with time-horizon matched forecasts of the risk-free rate of return. As for my historical analysis, I have relied upon the widely-referenced historical returns data published within the *2021 SBBI Yearbook* for the 95-year period between 1926 and 2020.

Q. What approach did you take in estimating the prospective market return expectations of investors?

A. To estimate the prospective market return expectations of investors, or "R_M," I have completed forward-looking DCF analyses for both the S&P 500 Index and the Value Line 1,700 stock universe. The results of these DCF analyses, which have been consistently applied to the Gas LDC Group, Combination Utility Group and Non-Regulated Group, are presented on page 1 of Attachment VVR-11. These results are also summarized as follows:

<u>DCF Estimate of Market Return for the S&P 500 Index</u>

1.61% (D/P) + 12.32% (g) = 13.93% (K) or (R_M)

Where: D/P = expected dividend yield over the next 12 months;
g = long-term earnings growth rate estimate;
R_M = expected return of the market portfolio.

The DCF results for the Value Line 1,700 stock universe are summarized as follows:

DCF Estimate of Market Return for the Value Line 1,700 Stock Universe

1.93% (D/P) + 6.70% (g) = 8.63% (K) or (R_M)

Based upon the results of the above DCF analyses for the S&P 500 Index and the Value Line 1,700 stock universe, an 11.28 percent ((13.93%+8.63%)/2=11.28%) prospective market rate of return is indicated, which I have applied to each of the respective proxy groups.

Q. What approach did you take in estimating the prospective risk-free rate of return expectations of investors?

A. When discussing appropriate proxies for the risk-free rate of return in *New Regulatory Finance*, Morin observes:

> At the conceptual level, given that ratemaking is a forward-looking process, interest rate forecasts are preferable. Moreover, the conceptual models used in the determination of the cost of equity, such as the CAPM, are prospective in nature, and require expectational inputs[28].

[28] Roger A. Morin, *New Regulatory Finance* (Public Utility Reports, Inc., 2006) at 172.

Indeed, ever since the time of the 2008-09 financial crisis, the interest rate environment in the U.S. has been heavily influenced by the Fed's unprecedented monetary policy interventions, which were intentionally designed to put downward pressure on long-term interest rates. For this reason, the importance of expectational inputs (i.e., interest rate forecasts) is more evident now than ever.

Moreover, the use of interest rate forecasts appropriately synchronizes the time horizon of the expected risk-free rate of return with the prospective market return I have employed within my analysis. Therefore, as a proxy for the risk-free rate of return, I have evaluated short-to-intermediate term forecasts of the 30-year U.S. Treasury Bond yield from the Blue Chip Financial Forecasts, a highly reputable source of interest rate forecasts. In selecting the appropriate "risk-free" security to evaluate, it should be noted that, despite S&P's 2011 downgrade of the long-term sovereign debt rating of the United States, U.S. Treasury securities remain the closest thing to a risk-free financial asset, largely due to the U.S. government's taxing authority and ability to create new currency. From a duration or tenor standpoint, 30-year Treasury Bonds most closely parallel the investment characteristics of common stock, since both are considered long-term, if not permanent, capital. Furthermore, in the absence of market anomalies, 30-year Treasury yields, like common stocks, reflect the long-term inflation expectations of investors, and are subject to less volatility than shorter-dated

Treasury securities. Based upon an evaluation of interest rate forecasts available from the Blue Chip Financial Forecasts, my analyses reference a rate of return of 2.94 percent as a reasonable proxy for the prospective risk-free rate of return.

Q. What prospective market risk premium is indicated by your analysis?

A. Based upon a prospectively determined market rate of return of 11.28 percent and a risk-free rate of return of 2.94 percent, a prospective market risk premium of 8.34 percent is indicated (11.28%-2.94%=8.34%).

Q. Have you relied upon the current 30-year U.S. Treasury bond yield as the proxy for the risk-free rate of return?

A. No. As discussed earlier, due to recent anomalous capital market conditions, and particularly the Fed's most recent monetary policy interventions as a result of the COVID-19 pandemic, today's 30-year U.S. Treasury bond yield does not reflect the forward looking risk-free return expectations of investors, and for this reason, its use would contradict the basic tenets of the CAPM. In view of these circumstances, it is appropriate to utilize reputable forecasts of long-term Treasury yields as a proxy for the expected risk-free rate of return.

Q. What average historical market risk premium is indicated by your analysis?

A. Based upon historical returns data published in the *2021 SBBI Yearbook* for the period 1926-2020, a 7.30 percent historical market risk premium is indicated. This figure is derived from the 12.20 percent arithmetic average of total returns for large company stocks (S&P 500) for the period 1926-2020, and the 4.90 percent arithmetic average income return on long-term government bonds for the same period (12.20%-4.90%=7.30%).

Q. Based upon your informed judgment, what level of market risk premium have you applied to your CAPM analysis?

A. As previously stated, to ensure a thorough and comprehensive evaluation of the risk premium expectations of investors, I have conducted market risk premium analyses on both a prospective basis and a historical basis. Although the historical average market risk premium provides a useful point of reference for the analyst, it should not be assumed that market risk premiums have been constant over time. In point of fact, multiple empirical studies have demonstrated that not only do market risk premiums fluctuate over time, but that they actually bear an inverse relationship with long-term interest rates. For example, studies by Harris,[29] Harris and Marston[30], and Maddox, Pippert and Sullivan[31] have shown that historically, for every one percentage point (1.0 percent) increase in long-term Treasury bond yields, the equity risk premium has declined by 0.37% - 0.79% (with an average

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[29] Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return", *Financial Management* (Spring 1986), at 58-67.

[30] Robert S. Harris and F. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management,* 21 (Summer 1992), at 63-70.

[31] Farris M. Maddox, Donna T. Pippert and Rodney N. Sullivan, "An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry," Financial Management, 24 (Autumn 1995), at 89-95.

decline of 0.61 percent). Morin reported similar results in his 2005 rate of return testimony for Hydro-Quebec,[32] and further elaborated on this topic in *New Regulatory Finance,* as follows:

> The gist of the empirical research on this subject is that the cost of equity has changed only half as much as interest rates have changed in the past. The knowledge that risk premiums vary inversely to the level of interest rates can be used to adjust historical risk premiums to better reflect current market conditions. Thus, when interest rates are unusually high (low), the appropriate current risk premium is somewhat below (above) that long-run average[33].

These empirical findings argue for the use of caution when applying the historical average risk premium to the current risk-free rate of return, to the extent the latter differs significantly from the historical average risk-free rate of return. As the above studies imply, when long-term Treasury yields decline significantly below their historical averages, I would fully expect that the equity risk premium expectations of investors will increase by some fractional amount thereof. Considering that the prospective risk-free rate of return applied to my analysis (2.94 percent) is actually lower than the historical average risk-free rate reported by the *2021 SBBI Yearbook* (4.90 percent), I would fully expect that, based upon my risk-free rate assumption, investors would require a market risk premium in

[32] Roger A. Morin, *New Regulatory Finance* (Public Utility Reports, Inc., 2006) at 129, 132 (citing Roger A. Morin, *Prepared Testimony on Fair Rate of Return on Equity for Hydro-Quebec* (Utility Research International, 2005).

[33] Roger A. Morin, *New Regulatory Finance* (Public Utility Reports, Inc., 2006), at 129.

excess of the historical average risk premium. For this reason, I have also evaluated the prospective risk premium expectations of investors using the prospective risk-free rate assumption referenced above (2.94 percent). Therefore, by using the historical average risk premium as reported by the SBBI Yearbook in combination with the prospectively determined risk premium discussed above, I have taken a balanced approach in estimating the risk premium expectations of investors. Accordingly, the expected market risk premium indicated by my analysis is 7.82 percent ((8.34% + 7.30%)/2 = 7.82%). I further corroborated this value by also evaluating the currently-implied market risk premium, as based upon the aforementioned empirical studies that have demonstrated an inverse relationship between government interest rates (U.S. Treasury security yields) and the market risk premium. This supporting analysis, which can be found at the bottom of page 1 of Attachment VVR-11, suggests that the currently-implied market risk premium is in the range of 8.50 - 8.60 percent. Therefore, the 7.82 percent expected market risk premium that I have incorporated into my CAPM analyses represents a conservative assumption.

Q. How did you derive the beta values employed within your CAPM analysis?

A. In determining the appropriate betas to use for each of the respective proxy groups, I initially evaluated published betas from the Value Line Investment Survey, a widely-referenced source of beta values in utility regulatory proceedings. As illustrated in Table VVR-9 below, the average Value Line betas for the Gas LDC Group, Combination Utility Group and Non-Regulated Group are 0.89, 0.86 and 0.87, respectively. However, published betas from sources such as Value Line should not be directly applied to the CAPM, unless the resulting cost of equity estimate will be applied to a market value based capital structure. This is because published betas are derived from the market value price movements of individual stocks and total market indices, and thus reflect the level of financial risk associated with a market value based capitalization. In the utility regulatory setting, published betas must be adjusted to reflect the higher relative financial risk associated with a book value capital structure, which is typically utilized for rate-setting purposes. In order to derive betas and a CAPM-based cost of equity that is relevant to the book value capital structure of the Gas LDC Group, I have utilized a beta-adjustment technique known as the Hamada method.[34]

Using the Hamada equation, I first "unlevered" the average Value Line beta for the Gas LDC Group using the group's average market value capital structure, which yielded an unlevered beta possessing only a business risk component. Next, I "re-levered" the unlevered beta based upon the average book value capital structure of the Gas LDC Group, thereby reintroducing an appropriate level of

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[34] _See,_ Robert S. Hamada, The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stocks," *The Journal of Finance,* 27 (May 1972) at 435-452.

financial risk into the beta, which is consistent with a book value based rate-setting capital structure. The Hamada equation and results of my beta adjustment analysis are as follows:

$$\beta_L = \beta_U [1 + D/E\ (1 - t) + P/E] \qquad \text{(Equation 1.5)}$$

Where: β_L = levered beta;
β_U = unlevered beta;
D = debt/capital ratio;
E = common equity/capital ratio;
P = preferred stock/capital ratio;
t = income tax rate.

<u>Gas LDC Group</u>

Value Line Beta 0.89 = .5587 [1 + (44.1%/55.3%)(1-0.27) + (0.6%/55.3%)]

Re-Levered Beta 0.969 = .5587 [1 + (49.3%/50.0%)(1-0.27) + (0.7%/50.0%)]

<u>Combination Utility Group</u>

Value Line Beta 0.86 = .5399 [1 + (44.1%/55.3%)(1-0.27) + (0.6%/55.3%)]

Re-Levered Beta 0.936 = .5399 [1 + (49.3%/50.0%)(1-0.27) + (0.7%/50.0%)]

<u>Non-Regulated Group</u>

Value Line Beta 0.871 = .5468 [1 + (44.1%/55.3%)(1-0.27) + (0.6%/55.3%)]

Re-Levered Beta 0.948 = .5468 [1 + (49.3%/50.0%)(1-0.27) + (0.7%/50.0%)]

Table VVR-9 Summary of Results – Hamada Method			
	Gas LDC Group	**Comb. Utility Group**	**Non-Reg. Group**
Value Line Beta	0.890	0.860	0.871
Unlevered Beta	0.559	0.540	0.547
Re-Levered Beta	0.969	0.936[35]	0.948[36]

In order to derive cost of equity estimates which are relevant to the average book value capital structure of the Gas LDC Group, I have applied the above re-levered betas to my CAPM analyses, as these betas reflect the higher level of financial risk associated with the book value based capital structure that is used for rate-setting purposes. Specifically, I have applied re-levered betas of 0.969, 0.936, and 0.948 for the Gas LDC Group, Combination Utility Group and Non-Regulated Group, respectively.

Q. When applying the CAPM, what other adjustments are required to fully reflect

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[35] The magnitude of the difference between the average market value capital structure and the average book value capital structure for both the Combination Utility Group and the Non-Regulated Group was significantly greater than the difference between the average market value and book value capital structures of the Gas LDC Group. As such, under the Hamada equation, the required upward beta adjustment for the Combination Utility Group and the Non-Regulated Group would be significantly greater than that of the Gas LDC Group. To recognize this disparity and make the Hamada method adjustment relevant to a typical gas utility company capital structure, I have applied the Hamada equation to both the Combination Utility Group and the Non-Regulated Group's average Value Line beta using the average capital structure ratios of the Gas LDC Group, which yielded a re-levered beta of 0.936 and 0.948, respectively. Utilizing this approach ensures a more conservative analysis.

[36] See footnote #32 above.

the return expectations of investors?

A. Multiple academic studies have advocated the use of a size-premium adjustment to the traditional CAPM.[37] These studies have revealed that small capitalization stocks have historically earned returns that are materially higher than the returns predicted by the CAPM. Indeed, the empirical research strongly suggests that beta, or systematic risk alone, does not fully explain the higher relative returns earned by small capitalization stocks. The *2021 SBBI Yearbook* explains the size phenomenon as follows:

> One of the most remarkable discoveries of modern finance is the finding of a relationship between company size and return, generally referred to as the "size effect". The size effect is based on the empirical observation that companies of smaller size tend to have higher returns than do larger companies.
>
> ….
>
> The company size phenomenon is remarkable in several ways. First, the greater risk of small-cap stocks does not, in the context of the capital asset pricing model, fully account for their higher returns over the long term period. In the capital asset pricing model (CAPM) only systematic, or beta risk, is rewarded; small-cap stock returns have exceeded those implied by their betas.
>
> ….
>
> The increased risk faced by investors in small stocks is quite real[38].

[37] See, Michael Annin, "Equity and the Small-Stock Effect," *Public Utilities Fortnightly*, October 15, 1995, 42-43; and, Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Stock Returns," *The Journal of Finance*, 48 (June 1992), at 427-465.

[38] *2021 SBBI Yearbook*, (Duff & Phelps, A Kroll Business), at 7-1, 7-3 and 7-5.

Therefore, in order to correct for the inherent deficiencies of the CAPM relative to smaller capitalization stocks, another Duff & Phelps product offering, the *Cost of Capital Navigator*, reports size premiums, which can be used in conjunction with the CAPM to more accurately estimate the return expectations of investors relative to small and mid-capitalization stocks. According to the *Cost of Capital Navigator,* based upon an average market capitalization of $4.5 billion, the Gas LDC Group would be classified as a Decile 4 portfolio and assigned a size premium of 0.75 percent. Based on an average market capitalization of $17.2 billion, the Combination Utility Group would be classified as a Decile 2 portfolio, and assigned an average size premium of 0.49 percent. Finally, with an average market capitalization of $112.7 billion, the Non-Regulated Group would be classified as a large-cap, Decile 1 Portfolio, and assigned a size premium of *negative* -0.22 percent. In the absence of these size premium adjustments, the results indicated by the traditional CAPM for the Gas LDC Group and the Combination Utility Group will *understate* the return expectations of investors, while with respect to the Non-Regulated Group, the traditional CAPM would have the tendency to *overstate* the return expectations of investors.

Q. Have you considered any other variants of the CAPM?

A. Yes. I have also considered the ECAPM within my evaluation. The ECAPM model is based upon extensive empirical evidence that the risk-return relationship between beta and stock returns, as graphically depicted by the Security Market Line reflected in Table VVR-10 below, is actually flatter than what is predicted by the traditional CAPM.

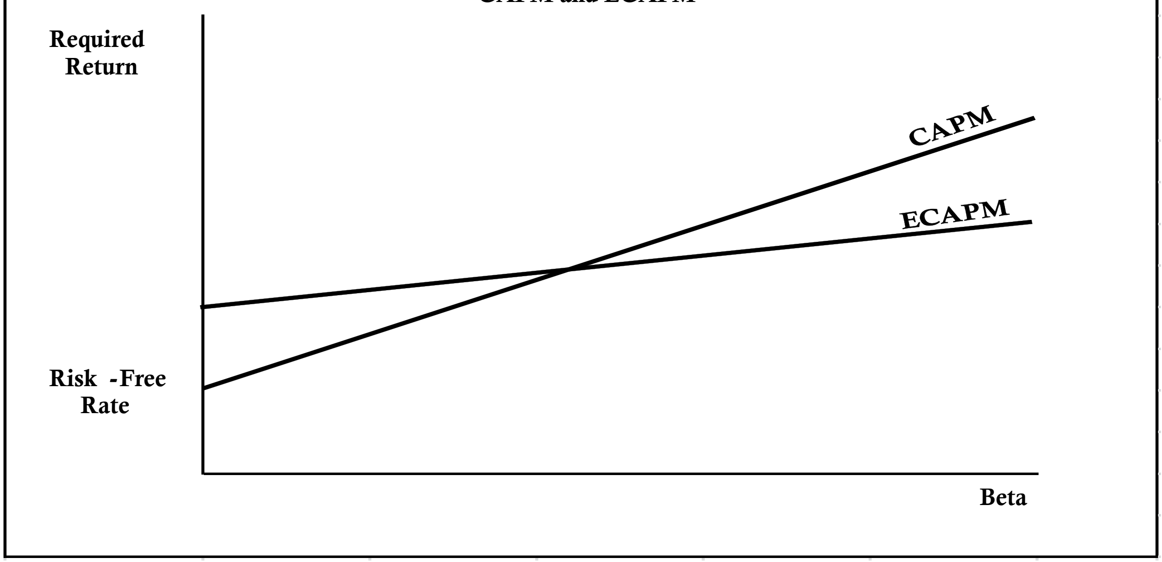

Table VVR-10
Security Market Line
CAPM and ECAPM

In a 1989 empirical study conducted by Morin, a simplified version of the ECAPM was derived and is expressed as follows:[39]

$$K = R_F + 0.25\,(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$

In essence, the ECAPM places a 25 percent weighting on the overall market risk premium and a 75 percent weighting on the company specific, beta-adjusted risk

[39] Roger A. Morin, *New Regulatory Finance* (Public Utilities Reports, Inc., 2006), at 190.

premium. The use of similar forms of the ECAPM has been recognized by state public service commissions, including the New York Public Service Commission and the Regulatory Commission of Alaska. The results of my ECAPM analysis for the Gas LDC Group, Combination Utility Group and Non-Regulated Group are presented within pages 2, 4 and 5 of Attachment VVR-11, respectively, and are also summarized in Table VVR-11 below.

Q. What were the results of your application of the CAPM, including the variants of the model you evaluated?

A. A detailed presentation of the results of my CAPM analysis for the Gas LDC Group, Combination Utility Group and Non-Regulated Group is presented on pages 2, 4 and 5 of Attachment VVR-11, respectively, and is also summarized in Table VVR-11 below. Although substantial empirical evidence supports the use of both the CAPM with size adjustments and the ECAPM, I have incorporated all three model variants into my evaluation, including the traditional CAPM, in determining the CAPM-indicated cost of equity for each of the respective proxy groups.

Table VVR-11 CAPM Results by Model Variant			
Model Variant	**Gas LDC Group**	**Comb. Utility Group**	**Non-Reg. Group**
Traditional CAPM	10.52%	10.26%	10.35%
+ Flotation adjustment	0.03%	0.03%	0.03%
Traditional CAPM	10.55%	10.29%	10.38%
CAPM (with size adj.)	11.27%	10.75%	10.13%
+ Flotation adjustment	0.03%	0.03%	0.03%
CAPM (with size adj.)	11.30%	10.78%	10.16%
Empirical CAPM	10.58%	10.39%	10.46%
+ Flotation adjustment	0.03%	0.03%	0.03%
Empirical CAPM	10.61%	10.42%	10.49%

These results, which incorporate the appropriate flotation cost adjustment, indicate a CAPM-derived cost of equity having a central tendency of around 10.80 percent for the Gas LDC Group, 10.50 percent for the Combination Utility Group, and 10.35 percent for the Non-Regulated Group.

D. Risk Premium Method ("RPM") Analysis

Q. Please provide an overview of the RPM and the theoretical basis for using it to estimate a utility's cost of equity.

A. The RPM is based upon the fundamental premise that a company's cost of common equity is greater than its prospective cost of debt, due to the additional risks associated with investing in common stocks. The most important of these risks is residual claim risk, which arises due to the subordinated position of common stockholders relative to bondholders and preferred stockholders. In essence, common shareholders stand "last in line" with respect to the distribution of a company's earnings, since common stock dividends are paid only after contractually required debt service payments and discretionary preferred dividend payments have been made. The same priority of claims also applies to asset-sale proceeds in the event of a bankruptcy liquidation scenario, where common shareholders typically only recover a small fraction, if any, of their original investment. As compensation for bearing these additional risks, common stock investors demand an equity risk premium over and above a company's cost of debt. Considering that the equity risk premium is a forward-looking concept, it must be estimated on the basis of investor expectations, and cannot be directly observed. Once the expected risk premium has been estimated, it can be added to the company's prospective cost of debt to estimate the cost of common equity, as follows:

$$K = C_D + P_R$$

Where: K = expected cost of common equity;

C_D = company's prospective cost of debt;

P_R = expected equity risk premium.

Q. Is the RPM commonly used to estimate the cost of equity and does it influence the return expectations of investors?

A. Yes, the RPM is a widely-referenced cost of equity model among investors, analysts and academics, and therefore influences investor return expectations. This is evidenced by the commercial success of the *Duff and Phelps Cost of Capital Navigator*[40], which publishes historical risk premia data for the benefit of investors and valuation professionals. Further evidence of the popularity of the RPM is found in *Corporate Finance: A Focused Approach*, where Ehrhardt and Brigham state that "three methods typically are used" in estimating the cost of common equity, one of which is the RPM[41].

Q. How did you approach your RPM analysis?

A. In applying the RPM to the three respective proxy groups, I employed a virtually identical approach, as only a few minor adjustments were required for the Non-Regulated Group. In essence, my approach involved estimating the prospective long-term bond yields (C_D) for each of the proxy groups based upon their average credit ratings, and then estimating the appropriate equity risk premium (P_R) for each of the three groups. Once these two components were derived for each of the

[40] Prior to 2018, Duff & Phelps previously published this risk premia data in the *Duff and Phelps Valuation Handbook (U.S. Guide to Cost of Capital).*

[41] M. Ehrhardt and E. Brigham, *Corporate Finance: A Focused Approach* (South-Western Cengage Learning, 2008), at 294.

proxy groups, they were simply added together to arrive at the RPM-indicated cost of equity. My comprehensive RPM analysis is presented within Attachment VVR-12, which is comprised of 10 pages. Summary results for the Gas LDC Group, Combination Utility Group and the Non-Regulated Group are presented on pages 1, 7 and 9 of Attachment VVR-12, respectively. A detailed discussion of the RPM results for the Gas LDC Group is presented herein. Quantitative results for the Combination Utility Group and Non-Regulated Group are presented within pages 7-10 of Attachment VVR-12.

Q. How did you derive the 4.35 percent prospective bond yield for the Gas LDC Group?

A. The bond yields referenced in the RPM must appropriately reflect the forward-looking return expectations of investors. For this reason, in determining the "C_D" component of the RPM equation, I have employed a forward-looking long-term bond yield for the Gas LDC Group based upon the Group's average long-term credit ratings of "A-" from S&P, and "A3" from Moody's. As reflected on page 1 of Attachment VVR-12, this was accomplished by first evaluating forecasted bond yields for Aaa rated corporate bonds, and then making the necessary credit spread adjustments to reflect the higher level of default risk associated with "A-/A3" rated utility bonds.

As reflected on pages 1 and 2 of Attachment VVR-12, the Blue Chip

Financial Forecasts consensus forecast for Aaa corporate bond yields is 3.67 percent for the 2022-2026 period. An upward adjustment of 0.55 percent was required to reflect the credit spread differential between Aaa rated corporate bonds and A rated utility bonds, both of which reflect Moody's generic ratings categories. A further upward adjustment of 0.12 percent was also required to reflect the credit spread differential between the generic rating category of "A" and the more precise "A-" rating from S&P and "A3" rating from Moody's. Additional information supporting both of these credit spread adjustments can be found within pages 1 and 3 of Attachment VVR-12. The prospective bond yield for the Gas LDC Group was derived by adding both of the aforementioned credit spread adjustments to the prospective Aaa corporate bond yield, which resulted in a 4.35 percent[42] prospective bond yield.

Q. What general approach have you taken in estimating the expected equity risk premium for the Gas LDC Group?

A. Consistent with established practices, I have conducted equity risk premium analyses using both the total market approach and the public utility index approach. The total market approach is considered an "indirect" approach, since an equity risk premium is initially estimated for the overall market portfolio, and

[42] Subject to rounding differences.

is subsequently adjusted to reflect the specific risk profile of the applicable proxy group. Within the framework of the total market approach, I have conducted separate risk premium analyses on both a historical basis and a prospective basis, as reflected on page 4 of Attachment VVR-12. In contrast, the public utility index approach is considered a "direct" approach, since the expected equity risk premium is estimated by comparing average historical holding period returns for the S&P 500 Utility Index to historical yields on long-term public utility bonds, without the need for any further risk adjustments. The results of my public utility index approach analysis are presented on page 5 of Attachment VVR-12.

Q. In applying the total market approach to the Gas LDC Group, how did you arrive at the indicated equity risk premium of 6.44 percent?

A. As previously mentioned, in applying the total market approach, I conducted both historical and prospective risk premium analyses, each of which brings different strengths and perspectives into the evaluation process.

1. <u>Historical Risk Premium Analysis</u>

To facilitate a historical risk premium analysis under the total market approach, I have relied upon the historical holding period returns information published by the *SBBI Yearbook* for both large company stocks (S&P 500 Index) and for high-grade, long-term corporate bonds. When the average historical risk premium is used as a proxy for the prospective risk premium, its predictive value is enhanced when the longest possible historical period is evaluated. Accordingly, I have utilized the average historical holding period returns for the entire 95-year period (1926-2020) for which data is available from the *2021 SBBI Yearbook*. The arbitrary use of shorter time periods would subject the risk premium analysis to greater potential volatility from short-term market trends and/or aberrations, which would not reflect the long-term expectations of investors. Moreover, use of the longest possible historical period for which data is available will incorporate a greater number of business and interest rate cycles into the analysis, further enhancing its predictive value. Indeed, Morin provides support for this approach in *New Regulatory Finance* where he maintains:

> The historical risk premium approach assumes that the average realized return is an appropriate surrogate for expected return, or, in other words, that investor expectations are realized. However, realized returns can be substantially different from prospective returns anticipated by investors, especially when measured over short time periods. Therefore, an historical risk premium study should consider the longest possible period for which data are available…Clearly, the accuracy of the realized risk premium as an estimator of the prospective risk premium is enhanced by increasing the number of years used to estimate it[43].

Therefore, based upon the SBBI Yearbook holding period returns data for the period covering 1926-2020, a 5.70 percent historical equity risk premium is

[43] Roger A. Morin *New Regulatory Finance* (Public Utilities Reports, Inc., 2006), at 114.

indicated using the total market approach. As shown on page 4 of Attachment VVR-12, this result is based upon the arithmetic average annual return of 12.20 percent for large company stocks (S&P 500 Index), and the arithmetic average annual return of 6.50 percent for high-grade, long-term corporate bonds. Use of the arithmetic average risk premium is appropriate since it better reflects the forward-looking risk premium expectations of investors and the potential variability of expected returns. In contrast, the geometric mean is more suitable for reporting past investment performance, since it reflects a consistently compounded or "smoothed" rate of growth over a given historical period.

Further support for using the arithmetic average equity risk premium is also found in the *SBBI Yearbook*, a well-regarded and widely-cited investment guide, which states:

> The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building-block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building-block approach are additive models, in which the cost of capital is the sum of its parts. The geometric average is more appropriate for reporting past performance because it represents the compound average return[44].

[44] *2017 SBBI Yearbook* (Duff & Phelps, John Wiley & Sons, Inc.), at 10-22.

2. <u>Prospective Risk Premium Analysis</u>

A prospective risk premium analysis is also required to fully capture the forward-looking return expectations of investors. Indeed, it is often maintained that prospective risk premiums bear the greatest relevance to the cost of equity estimation process, since they incorporate both historical trends and changes expected to occur in the future. To facilitate a prospective risk premium analysis using the total market approach, it was necessary to estimate both the prospective market return expectations of investors and the prospective corporate bond yield on a time horizon matched basis. As previously referenced in the CAPM section of my testimony, and as illustrated on page 1 of Attachment VVR-11, I have estimated the prospective market return expectations of investors by completing DCF analyses for both the S&P 500 Index and the Value Line 1,700 stock universe. The results of these analyses are as follows:

<u>DCF Estimate of Market Return for the S&P 500 Index</u>

1.61% (D/P) + 12.32% (g) = 13.93% (K) or (R_M)

<u>DCF Estimate of Market Return for the Value Line 1,700 Stock Universe</u>

1.93% (D/P) + 6.70% (g) = 8.63% (K) or (R_M)

Based upon these DCF results, an 11.28 percent ((13.93% + 8.63%)/2 = 11.28%) prospective market return is indicated. As a proxy for the prospective corporate bond yield, I have relied upon the Blue Chip consensus forecast for Aaa rated corporate bonds, which indicates a 3.67 percent average yield for the 2022-2026 period, as further illustrated on pages 1 and 2 of Attachment VVR-12. Based upon these values, a 7.61 percent prospective total market equity risk premium is indicated (11.28% - 3.67% = 7.61%).

3. <u>Total Market Equity Risk Premium and Risk Adjustment</u>

To ensure a balanced approach in assessing the risk premium expectations of investors, I have placed equal emphasis on the historical risk premium and prospective risk premium results indicated above. Using this balanced approach, a 6.65 percent total market risk premium is indicated ((5.70%+7.61%)/2=6.65%)[45]. Considering that this result must be adjusted to recognize the risk differential between the overall market index and the Gas LDC Group, I have applied a re-levered beta value of 0.969 to the indicated market risk premium to derive a risk premium which is applicable to the Gas LDC Group. Consistent with my findings in the preceding CAPM analysis, a re-levered beta of 0.969 is appropriate for the Gas LDC Group, since it reflects the higher level of financial risk associated with the rate-setting capital structure to which the RPM-estimated cost of equity will be applied. Therefore, as reflected on page 4 of Attachment VVR-12, the indicated equity risk premium for the Gas LDC Group was determined to be 6.44 percent

[45] Subject to rounding differences.

(6.65% x 0.969 = 6.44%).

Q. In applying the public utility index approach to the Gas LDC Group, how did you arrive at the indicated equity risk premium of 5.45 percent?

A. The results of my public utility index approach analysis are presented on page 5 of Attachment VVR-12. As a proxy for the total return expectations of investors relative to utility stocks, I have evaluated both the average historical holding period returns for the S&P 500 Utilities Index, as well as the currently-implied equity risk premium for the same index. With regard to the average historical holding period returns, for the 95-year period covering 1926-2020, the average annual total return for this index was 10.83 percent. During this same period, the average annual yield for long-term utility bonds bearing an "A" rating from Moody's was 6.28 percent. Historical yields on "A" rated utility bonds were selected for evaluation since "A" rated bonds represent the mid-point credit rating among the historical utility bond yields that have been reported by Moody's and Mergent (historical yields on three credit ratings have been reported: "Aa," "A" and "Baa"). A detailed breakdown of these historical returns is presented on page 6 of Attachment VVR-12. Based upon the foregoing historical returns, a 4.55 percent equity risk premium is indicated for the Gas LDC Group (10.83% - 6.28% = 4.55%).

As further detailed in the bottom section of page 5 of Attachment VVR-12, I have also evaluated the currently-implied equity risk premium in the prevailing market environment, by conducting an analysis of the expected equity return for the S&P Utilities Index, which yielded an expected return of 9.35 percent. I then compared the recent yields on "A" rated utility bonds (3.00 percent) to the expected equity return, which yielded a currently-implied equity risk premium of 6.35 percent (9.35%-3.00%=6.35%). Finally, to ensure a balanced estimate of the equity risk premium under the Public Utility Index Approach, I referenced the average of the equity risk premium estimates derived under the historical approach and the currently-implied approach, which yielded an indicated equity risk premium of 5.45 percent ((4.55% +6.35%)/2 = 5.45%).

Q. Based upon your RPM analysis using both the total market approach and the public utility index approach, what level of equity risk premium and cost of equity are indicated for the Gas LDC Group?

A. Consistent with established practices, I have placed equal emphasis on the total market approach and the public utility index approach, and have concluded that 5.95 percent is a reasonable estimate of the investor-expected equity risk premium for the Gas LDC Group. Based upon an expected risk premium of 5.95 percent, and a 4.35 percent prospective long-term bond yield for the Gas LDC Group, I have also concluded that the unadjusted RPM-indicated cost of equity for the Gas LDC Group is 10.30 percent (5.95%+4.35%=10.30%). Consistent with the other market-based analytical models, to this result I added the required flotation cost adjustment of 0.03 percent, which yielded an adjusted RPM-indicated cost of equity of 10.33 percent for the Gas LDC Group.

Q. Under the RPM, what cost of equity was indicated for the Combination Utility Group and the Non-Regulated Group?

A. As reflected on page 7 of Attachment VVR-12, the unadjusted RPM-indicated cost of equity for the Combination Utility Group was determined to be 10.25 percent. Consistent with the other market-based analytical models, I added the required 0.03 percent flotation cost adjustment to this result, which yielded an adjusted RPM-indicated cost of equity of 10.28 percent for the Combination Utility Group. Lastly, as reflected on page 9 of Attachment VVR-12, the unadjusted RPM-indicated cost of equity for the Non-Regulated Group was determined to be 10.69 percent. Consistent with the other market-based analytical models, I added the required 0.03 percent flotation cost adjustment to this result, which yielded an adjusted RPM-indicated cost of equity of 10.72 percent for the Non-Regulated Group.

The results of my RPM evaluation are summarized in Table VVR-12 below.

Table VVR-12 Risk Premium Method Results			
Model Variant	**Gas LDC Group**	**Comb. Utility Group**	**Non-Reg. Group**
Risk Prem. Method	10.30%	10.25%	10.69%
+ Flotation cost adjust.	0.03%	0.03%	0.03%
Risk Premium Method	10.33%	10.28%	10.72%

Q. Can you please summarize the results of the various cost of equity analytical models you evaluated, as well as your proposed ROE recommendation in the instant proceeding?

A. Yes, I present Table VVR-1 and Table VVR-2 below, which were also presented earlier in my testimony, and which summarize the results of my cost of equity evaluation and ROE recommendations.

Table VVR-1 Indicated Cost of Equity for the Proxy Groups			
Method/Model	**Gas LDC Group**	**Combination Utility Group**	**Non-Reg. Group**
DCF	10.54%	9.84%	11.54%
Traditional CAPM	10.55%	10.29%	10.38%
CAPM (w/size adj.)	11.30%	10.78%	10.16%
ECAPM	10.61%	10.42%	10.49%
Risk Premium	10.33%	10.28%	10.72%

As reflected in Table VVR-2 below, an analysis of the above results yielded the following measures of central tendency for each of the analytical methods employed.

Table VVR-2 Cost of Equity Estimates for CKY Measures of Central Tendency	
Median DCF Result	10.54%
Average DCF Result	10.64%
Median CAPM Result	10.49%
Average CAPM Result	10.55%
Median RPM Result	10.33%
Average RPM Result	10.44%

Based upon these measures of central tendency, I have concluded that Columbia's cost of common equity is presently in the range of 10.30 - 10.80 percent. In view of this range estimate, it is my opinion that a reasonable point estimate of Columbia's cost of equity in the current market environment is 10.55 percent. However, as noted earlier, and as further discussed in the direct testimony of Columbia witness Cole, the Company has elected to request a 10.30 percent cost of equity in this proceeding, which is at the low-end of the range of reasonableness indicated by my comprehensive evaluation.

Q. Does this conclude your Prepared Direct Testimony?

A. Yes, it does. However, I reserve the right to submit rebuttal or other supplemental testimony in this proceeding.

APPENDIX A
DCF ANALYIS
DETAILED
DISCUSSION

Appendix A

DCF Analysis - Detailed Discussion

1. Determination of the Dividend Yield Component

Since the DCF model recognizes that investors value securities on the basis of prospective cash flows, it is essential that the analyst determine the amount of dividend payments (D_1) which are expected to be received over the next twelve months. Utilizing the current dividend amount (D_0) would not be appropriate under DCF principles, since current dividends are not forward-looking and could potentially underestimate the cost of equity. For this reason, estimates of dividends to be paid over the next twelve months by each company comprising the Gas LDC Group, Combination Utility Group and Non-Regulated Group were obtained from the Value Line Summary and Index, and serve as the expected dividend payment (D_1) within these two respective DCF analyses.

In selecting the appropriate stock price (P_0) to utilize in calculating the dividend yield, it is important to remember that under the iterative market valuation process, price equilibrium only occurs when investors have realized their expected rate of return, or "K." In other words, the current stock price (P_0) has embedded within it the current forward-looking return expectations of investors, although the latter cannot be directly observed. Therefore, to properly estimate the expected cost of equity, it is essential that the current stock price (P_0) be used when calculating the dividend yield component, since the "P" and "K" components of the model are simultaneously determined upon reaching equilibrium, and thus have a time dependency on one another. Consistent with the semi-strong version of the Efficient Market Hypothesis, use of the current stock price is appropriate, since it incorporates all relevant publicly-available information and thus captures the current forward-looking growth expectations of investors.

In contrast, using an average of stock prices over some historical period, such as six to twelve months, would reflect outdated market information and investor growth expectations, which would not be representative of current market conditions. Therefore, such an approach would be inconsistent with the core tenets of the Efficient Market Hypothesis. Moreover, using past averages of stock prices would also create a time period mismatch among the components of the DCF model, since the dividend yield component would be based upon past stock prices which reflect previous growth expectations, while the growth component ("g") of the model would reflect the current forward-looking growth expectations of investors.

Notwithstanding these valid arguments, simply referencing the most recent day's closing stock price can present a different challenge in the form of temporary price aberrations, which may be attributable to volatile market conditions, the unanticipated release of company information, or short-term supply and demand imbalances. Therefore, with respect to those companies comprising the Gas LDC Group, Combination Utility Group and Non-Regulated Group, I have defined the current stock price (P_0) as the average closing stock price for the most recent 40 trading days, or approximately two calendar months. Using this approach mitigates the effects of short-term price aberrations for the companies comprising these three proxy groups, while still recognizing the basic tenets of the Efficient Markets Hypothesis.

Finally, to determine the expected dividend yield for the companies comprising the Gas LDC Group, Combination Utility Group and Non-Regulated Group, the expected dividend (D_1) was simply divided by the current stock price (P_0) as defined above.

<u>2. Growth Component – General Approach</u>

There is no question that discerning the long-term growth expectations of investors is the most difficult and controversial aspect of implementing the DCF constant growth model, as it requires the analyst to get inside the "collective psyche" of a large universe of investors. Considering that the DCF model is technically focused on the growth of dividends into perpetuity, a reliable forecast of sequential dividend payments into the distant future would provide an appropriate indication of investors' long-term growth expectations. However, dividend forecasts for multi-decade periods are simply not available, so to implement the DCF model, the analyst must rely upon other available indicators which are likely to influence the growth expectations of investors. As such, in the initial stages of my DCF analysis, I evaluated a variety of historical and forward-looking growth indicators, each of which could potentially influence investor expectations.

Recognizing that historical growth trends can influence the future growth expectations of investors; rate of return analysts often consider historical trends when estimating the growth component of the DCF model. In so doing, the presumption is that investors extrapolate past growth patterns in forming their future expectations. In my judgment, evaluating historical growth indicators is a reasonable first step in the DCF growth rate evaluation process, particularly for companies with a history of stable performance. Nevertheless, while historical growth trends clearly provide a valuable point of reference, the analyst must guard against placing too much emphasis upon them, as they may no longer reflect the current growth expectations of investors. Indeed, the growth expectations of investors today may be very different from average growth rates realized in the past due to structural changes within the utility industry, changes in operating costs and expected profitability, and/or changes in general economic conditions. Also, it is often argued that historical growth trends are already factored into forward-looking growth projections, including analyst earnings forecasts, and that care should therefore be taken to ensure that historical data is not inadvertently double-counted.

Lastly, when evaluating historical growth trends, the analyst generally finds that the strict assumptions required under constant growth theory have not held true or been maintained, as is often reflected in differing historical growth rates between dividends per share ("DPS"), earnings per share ("EPS") and book value per share ("BVPS"). Thus, while the analyst implicitly accepts the strict assumptions of the constant growth model on a prospective basis, this is rarely the case in retrospect, which may call into question the usefulness of historical indicators in deriving the constant growth rate assumption.

Considering these multiple shortcomings, historical growth indicators should never be relied upon exclusively and significant emphasis should also be placed on forward-looking growth indicators. Therefore, consistent with accepted practices, I have evaluated both historical and forward-looking growth indicators for several key variables, including EPS, DPS, BVPS and the retention growth rate ("RGR"). More specifically, with regard to historical growth rates, for each member of the Gas LDC Group and Combination Utility Group, I have completed a traditional analysis of the 5-year and 10-year average historical growth rates for EPS, DPS, BVPS, and the RGR. All 5-year and 10-year historical growth rate information was sourced from the Value Line Investment Survey. The results of my historical growth rate analysis for EPS, DPS and BVPS for the Gas LDC Group and Combination Utility Group are presented on page 5 of Attachments VVR-7 and VVR-8, respectively, while the results of my RGR analysis for the two proxy groups are presented on page 6 of Attachments VVR-7 and VVR-8, respectively.

With regard to projected growth rates, for each member of the Gas LDC Group and Combination Utility Group, I have analyzed forward-looking projections for EPS, DPS, BVPS, and the RGR. Growth projections for each of these variables were derived from the Value Line Investment Survey, which publishes 3-to-5 year growth rate projections. In addition, EPS consensus estimate growth rates were sourced from Yahoo/Thomson Reuters and Zacks, both of which publish 5-year earnings growth estimates. The results of my projected growth rate analyses for EPS, DPS and BVPS for the Gas LDC Group and Combination Utility Group are presented on page 5 of Attachments VVR-7 and VVR-8, respectively, while the results of my RGR analysis for these two proxy groups are presented on page 6 of Attachments VVR-7 and VVR-8, respectively.

With regard to the 12 companies comprising the Non-Regulated Group, I have focused my analysis on projected growth rates for EPS and the RGR, and also on historical EPS growth rates. Growth projections for EPS and the RGR were sourced from the Value Line Investment Survey, while EPS consensus estimate growth rates were also sourced from Yahoo/Thomson Reuters and Zacks. Historical EPS growth rates were sourced from Value Line. With respect to the Non-Regulated Group, the results of my projected growth rate analyses are presented within pages 1 and 3 of Attachment VVR-9, while the results of my historical EPS growth rate analysis are presented on page 2 of Attachment VVR-9.

3. Growth Component
Dividend Growth Forecasts vs. Earnings Growth Forecasts

Notwithstanding the fact that the DCF model is conceptually a dividend-based model, in practice there exists a fundamental challenge in attempting to reference dividend forecasts to estimate the growth expectations of investors. Simply stated, dividend forecasts are not widely-referenced by investors, and for this reason, they are only published by a limited number of information service providers. In contrast, earnings growth forecasts are widely-available from a variety of internet-based and print media sources. As I will discuss later, earnings forecasts are widely-referenced by investors and are available to the general public from a variety of sources. It should also be noted that even Williams, who originally developed the long-form and constant growth versions of the DCF model, found "no contradiction" between his DCF formula which emphasized dividends, and the "common precept" that earnings constitute the source of value for stocks. Indeed, over the long-run, either valuation approach would be expected to produce the same end result. Lastly, Williams also recognized the challenges associated with developing long-term dividend forecasts, when he concluded in

The Theory of Investment Value: "How to estimate the future dividends for use in our formula is, of course, the difficulty[1]".

4. Growth Component
The Importance of Earnings Growth Forecasts

Among the various forms of growth estimates I evaluated, I place the greatest emphasis on the consensus earnings estimates of "sell-side" equity analysts, along with earnings forecasts published by the Value Line Investment Survey. Substantial academic research has demonstrated that equity analyst forecasts have a significant influence on the growth expectations of investors. By way of background, sell-side analysts compile investment research for the major brokerage firms and investment banks on behalf of their clients. This research includes both earnings forecasts and buy/hold/sell recommendations, which the analyst develops based upon a thorough analysis of the company's past performance and future prospects, along with an element of informed judgment. Sell-side analysts typically possess expert knowledge of the industry they cover, and are typically well-versed in key matters affecting the company being evaluated, including recent regulatory decisions, cost and profitability trends, and

[1] John Burr Williams, *The Theory of Investment Value* (Cambridge, MA, Harvard University Press, 1938) at 58.

infrastructure investment requirements. Substantial academic research has demonstrated that the earnings forecasts of equity analysts heavily influence the long-term growth expectations, and therefore investment decisions, of equity investors. For example, In "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," Harris concludes:

> …a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices…..Notions of shareholder required rates of return and risk premia are based in theory on investors' expectations about the future. Research has demonstrated the usefulness of financial analysts' forecasts for such expectations[2].

Similarly, in "Investor Growth Expectations: Analysts vs. History," Vander Weide and Carleton concluded:

> [First] we found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price. …Our results also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions[3].

In *New Regulatory Finance*, Morin sums up the academic literature on this topic very effectively where he states:

[2] Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, (Spring 1986), at 59, 66.

[3] James H. Vander Weide and William T. Carleton, "Investor Growth Expectations: Analysts vs. History," *The Journal of Portfolio Management* (Spring 1988), at 4.

> Because of the dominance of institutional investors and their influence on individual investors, analysts' forecasts of long-run growth rates provide a sound basis for estimating required returns. Financial analysts exert a strong influence on the expectations of many investors who do not possess the resources to make their own forecasts, that is, they are the cause of "g". Published studies in the academic literature demonstrate that growth forecasts made by security analysts represent an appropriate source of DCF growth rates, are reasonable indicators of investor expectations and are more accurate than forecasts based on historical growth. These studies show that investors rely on analysts' forecasts to a greater extent than on historic data only[4].

Clearly then, a substantial amount of academic research supports the use of analyst earnings forecasts as an appropriate proxy for the expected growth rate component of the DCF constant growth model. For these reasons, I have given considerable weight to the 5-year consensus earnings estimates available from Yahoo/Thomson Reuters and Zacks, along with Value Line's EPS growth forecasts, in deriving my estimates of long-term investor growth expectations.

5. Growth Component – Market-Based Evidence
The Influence of Analyst Estimates on Investor Growth Expectations

Analyst earnings forecasts are widely available through a variety of sources and are frequently referenced by both institutional and individual investors and the

[4] Roger A. Morin, *New Regulatory Finance* (Public Utility Reports, Inc., 2006), at 298.

financial press. Without question, a robust market exists for earnings estimates, which is driven by strong investor demand for such information. Considering that there is a significant monetary cost associated with producing these forecasts, investment firms would not continue to produce them if they were not valued by investors. This is further demonstrated by the ongoing success of the various information service providers who summarize analyst earnings forecasts into "consensus estimates" for the benefit of investors. These information service providers include Thomson Reuters, I/B/E/S, and FactSet, each of which are widely-referenced by institutional investors.

Moreover, the availability of consensus estimates to the general public through freely-accessible websites, such as Yahoo Finance, Zacks and Reuters.com, further demonstrates the pervasive influence that analyst forecasts have on market expectations, including those of individual investors. Lastly, it is important to note that, to date, investors have not demanded earnings forecasts for periods extending beyond five years. If investors had expressed a desire for such information, the robust information services marketplace would have certainly delivered longer-term forecasts by now. This strongly suggests that investors are reasonably confident that the 5-year earnings forecasts they presently utilize already provides a reasonably reliable longer-term growth estimate.

6. Growth Component
Earnings Growth Rates Currently Projected by Equity Analysts

Forecasts of EPS growth and the corresponding cost of equity estimates for each member of the Gas LDC Group, Combination Utility Group and Non-Regulated Group are presented on page 1 of Attachments VVR-7, VVR-8, and VVR-9, respectively.

7. Growth Component
Sustainable Growth Approach

I have also evaluated both historical and projected retention growth rates, which is often referred to as the "sustainable growth" approach. This method, which is credited to Gordon and is consistent with constant growth theory, maintains that future earnings and dividend growth for existing common equity shares is a function of: (1) the level of earnings retained by a company; and (2) the corresponding rate of return on book equity.[5] In accordance with constant growth theory, the retention growth rate model is premised upon many of the same underlying assumptions applicable to the DCF constant-growth model. Although

[5] Myron J. Gordon, *The Cost of Capital to a Public Utility* (East Lansing, Michigan, Michigan State University Public Utility Studies, 1974).

these strict assumptions often do not hold true in reality, the RGR model remains a useful tool for estimating a utility's future earnings and dividend growth rates. When the simplified version of the RGR model is utilized, the expected future rate of dividend growth ("g") is expressed as the product of the expected earnings retention ratio ("b"), and the expected rate of return on book equity ("r"). This simplified version of the model assumes that the retention of earnings represents the firm's only source of growth capital, and that the firm will not raise additional equity capital in the external markets. An alternative assumption of the simplified model is that if equity offerings do occur, they will be completed at book value, meaning that new stock sales will neither be accretive nor dilutive to existing shareholders. Therefore, the simplified version of the RGR model maintains that a firm's future dividend growth is entirely a function of the internal reinvestment of a company's undistributed earnings. The original version of the model developed by Gordon included two additional variables, which recognized the impact of external stock offerings on future earnings and dividend growth. When the original version of the model is used, the product of the fraction of new stock sales that are accretive to existing shareholders ("v"), and the percentage increase in the overall level of stock resulting from the new stock sale ("s"), are added to product of the ("b") and ("r") terms described above.

Accordingly, the comprehensive RGR equation is expressed as follows:

$$g = (b) \times (r) + (v) \times (s) \qquad \text{(Equation A.1)}$$

Where: g = expected retention growth rate;
b = expected earnings retention ratio;
r = expected return on book equity;
v = fraction of new stock sales accretive to existing shareholders;
s = percentage increase in stock outstanding from the new sale.

Whenever stock is issued at a price higher than book value, the product of the ("v") and ("s") components of the model will raise the book value per share and the future earnings and dividend growth rates for existing shareholders, but if shares are issued below book value, the opposite effect will occur. Nonetheless, the "v" x "s" component of model is often excluded from RGR analyses due to the practical limitations surrounding its implementation. For example, relative to future stock offerings, the timing of the offering, number of shares to be issued, and offering price can all be very difficult to estimate in advance of the offering, thus making it difficult to estimate the "v x s" component of the model. Considering these limitations, and that the "v x s" component does not normally constitute a major source of growth for most utility companies, I have utilized the historical and projected retention growth rates published by the Value Line

Investment Survey within my analysis, which are based upon the simplified "b" x "r" version of the RGR model.

For each company comprising the Gas LDC Group and the Combination Utility Group, I derived both the 5-year historical and 3-5 year projected average retention growth rates from the Value Line Investment Survey, as presented on page 6 of Attachments VVR-7 and VVR-8, respectively. Considering the greater of companies comprising the Non-Regulated Group, I have focused my analysis for this Group on the 3-5 year projected retention growth rates published by Value Line, as presented on page 3 of Attachment VVR-9.

APPENDIX B
DCF ESTIMATES – DETERMINATION OF OUTLIER RESULTS

Appendix B

DCF Estimates - Determination of "Outlier" Results

1. General Approach in Determining the "Low-End" Threshold for Outlier Results

While applying the DCF constant-growth model to the individual proxy group companies, I found both "low-end" and "high-end" outlier results which did not pass fundamental tests of economic logic. Therefore, to ensure logical and credible analytical results, I have eliminated unreasonably high and unreasonably low DCF estimates from my analysis, as further discussed herein.

It is a well-established financial principle that when the risk profile of a given investment increases, investors will demand a commensurately higher rate of return. This classic "risk-and-return" relationship explains why investors demand a higher return for investing in common stocks versus investing in corporate debt securities. Indeed, equity investors are not only compensated for the default risk inherent in fixed-income securities, but they must also be compensated for the residual claim risk they bear. Residual claim risk arises for two primary reasons. First, since common stock is the lowest ranking or most junior capital within a firm's capital structure, common stock investors are always positioned "last in line" behind fixed income investors and preferred stockholders to recover their investment in the event of a financial distress scenario. Second, common stock investors are also in a subordinated position relative to periodic cash distributions, since common stock dividends can only be paid after contractually-required debt service payments and preferred dividend payments have been made. Considering their junior position in the capital structure, common stock investors require additional compensation for bearing this residual claim risk, through what is known as an equity risk premium.

However, in those circumstances where the equity risk premium offered does not provide sufficient compensation for bearing the additional risks associated with common stocks, investors will seek a superior risk-return tradeoff elsewhere by either investing in the company's fixed-income securities, or in another company's common stock. Therefore, consistent with the risk-and-return investment principle and fundamental tests of economic logic, DCF estimates which are lower than, or only marginally higher than, yields available on corporate debt securities have been eliminated from my analysis. This is because investors cannot reasonably be expected to invest in common stocks if they are unable to earn a minimally sufficient equity risk premium as compensation for the additional risks they bear, vis-à-vis fixed income securities. Under these circumstances, investors would clearly show a preference for either holding the company's fixed-income securities or another company's stock, making it difficult for the company to attract new equity capital.

2. Regulatory Precedents Establishing the Minimum Equity Risk Premium for Setting the "Low-End" Outlier Threshold

In recent years, the FERC has compared DCF estimates to yields available on long-term corporate bonds and has excluded proxy group companies whose DCF estimates did not exceed a company's bond yield by a sufficient margin. In *Pioneer Transmission* (2009), the FERC ruled that low-end ROEs falling within about 100 basis points of the cost of debt should be excluded from cost of equity estimates. Specifically, in its Pioneer order, the FERC stated:

> …..the Commission will exclude from the proxy group companies whose low-end ROE is within about 100 basis points above the cost of debt, taking into account the extent to which the excluded low-end ROE's are outliers from the low-end ROEs of other proxy group companies[1].

Previously, in Opinion 445, the Commission had determined that:

> …..investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return[2].

[1] *Pioneer Transmission, LLC,* 126 FERC ¶ 61,281 at P 94 (March 27, 2009).
[2] *Southern California Edison Co.*, 92 FERC ¶ 61,266 (2000) (Opinion No. 445).

Furthermore, in *Southern California Edison*, the FERC reaffirmed its previous decisions concerning the treatment of low-end outliers, by stating:

> We find that, consistent with *Pioneer*, it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more[3].

Most recently, in *Opinion No. 569*, the FERC revised the methodology it employs in the determination of both low-end and high-end outlier estimates of the cost of equity under the DCF method. The FERC's revised low-end methodology no longer references a generic 100 basis point add-on to the cost of corporate debt, but instead now recognizes the dynamic nature of the equity risk premium, which is dependent upon ever-changing investor risk sentiments. The FERC will now reference Baa-rated corporate bond yields as the corporate bond component of the low-end outlier equation, but will now determine the minimally-required equity risk premium above the corporate bond yield by applying a 20 percent weighting factor to the market risk premium determined under the FERC's CAPM analysis. The FERC explained the rationale for these changes as follows:

> We will adjust the low-end outlier test to include a risk premium instead of the generic 100 basis points proposed in the Briefing Order, as discussed below. In particular, we will adopt a revised low-end outlier test that eliminates proxy group ROE results that are

[3] *Southern California Edison Co.*, 131 FERC ¶ 61020 at P 55 (April 15, 2010).

> less than the yields of generic corporate Baa bonds plus 20 percent of the CAPM risk premium.
>
> ….
>
> We find that 20 percent of the risk premium from the CAPM analysis described above is a reasonable risk premium to apply to the low-end outlier test. Because the risk premium that investors demand changes over time, it is imprecise to simply add 100 basis points to the bond yield. The methodology that we adopting in this order captures such changes because the risk premium from the CAPM analysis reflects investors' required risk premium under the prevailing market conditions[4].

In a subsequent Order[5], the FERC reaffirmed its approach of referencing 20 percent of the CAPM risk premium when conducting its low-end outlier evaluations.

In my judgement, the FERC's revised low-end outlier methodology for DCF estimates is an improvement over its previous approach, as it now better captures the dynamic nature of the market risk premium, thus enabling the cost of capital analyst to appropriately apply fundamental tests of economic logic to his/her preliminary DCF results.

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[4] *Association of Businesses Advocating Tariff Equity, et al., v. Midcontinent Independent System Operator, Inc., et al.,* 169 FERC ¶ 61,129, Opinion No. 569, at P 387 and P 388 (November 21, 2019).

[5] *Association of Businesses Advocating Tariff Equity, et al., v. Midcontinent Independent System Operator, Inc., et al.,* 171 FERC ¶ 61,154, Opinion No. 569-A, at P 161-162 (May 21, 2020).

3. Applying the FERC's Revised Approach in Determining the "Low-End" Outlier Threshold

As further described within page 7 of Attachment VVR-7, after applying the FERC's revised low-end outlier methodology as outlined above, I have determined that a reasonable low-end outlier threshold to apply to my preliminary DCF results is 5.30 percent. I have therefore eliminated outlier estimates falling below this minimum threshold level. Consistent with the risk-and-return investment principle, investors cannot reasonably be expected to accept equity returns below this threshold, since on a risk-adjusted basis, fixed-income securities would likely offer investors a superior investment alternative.

4. Regulatory Precedents for Determining the "High-End" Threshold for Outlier Results

In *Opinion No. 569*, the FERC also adopted a revised high-end outlier test, whereby companies having DCF estimates in excess of 150 percent of the median value of the initial proxy group results would be excluded from the final group. In a subsequent Order[6], the FERC elected to modify this approach by instead

[6] *Association of Businesses Advocating Tariff Equity, et al., v. Midcontinent Independent System Operator, Inc., et al.*, 171 FERC ¶ 61,154, Opinion No. 569-A, at P 154 (May 21, 2020).

referencing 200 percent of the median value of the initial proxy group results, and the FERC subsequently reaffirmed this decision in yet another Order[7]. I have taken a similar approach in identifying high-end outlier results in my DCF analyses, but have eliminated *individual* high-end estimates, rather than fully eliminating the company from the proxy group. In my judgement, this approach is appropriate in view of the relatively small number of regulated utility holding companies to choose from in forming a utility proxy group, which is largely attributable to recent merger and acquisition activity in the utility industry.

To further screen my DCF results for high-end outlier estimates, I have also considered the FERC's previous high-end outlier methodology in my DCF analyses. Specifically, in *ISO New England*,[8] the FERC determined that proxy group companies with DCF estimates in excess of 17.7 percent and/or growth estimates in excess of 13.3 percent should be excluded from DCF analyses. In that proceeding, the FERC concluded that growth rates in excess of 13.3 percent were not sustainable over time and therefore did not meet "threshold tests of economic logic." In *Southern California Edison*,[9] the FERC reaffirmed and further clarified its

[7] *Association of Businesses Advocating Tariff Equity, et al., v. Midcontinent Independent System Operator, Inc., et al.*, 173 FERC ¶ 61,159, Opinion No. 569-B, at P 140 (November 19, 2020).
[8] *ISO New England, Inc. et al.*, 109 FERC ¶ 61,147 at P 205 (November 3, 2004).
[9] *Southern California Edison*, 131 FERC ¶ 61,020 at P 57 (April 15, 2010).

ruling in *ISO New England,* when it emphasized that both its growth rate criteria (13.3 percent) and DCF estimate criteria (17.7 percent) should be observed when evaluating DCF results for potential "high-end" outliers. Accordingly, in establishing a high-end outlier threshold within my DCF analyses, I have also given some consideration to the precedents established in the *ISO New England* and *Southern California Edison* cases. The results of the high-end outlier screens for my DCF analyses can be found on pages 1 and 2 of Attachment VVR-7, Attachment VVR-8, and Attachment VVR-9, respectively.

APPENDIX C
FINANCIAL RISK ADJUSTMENTS TO DCF RESULTS

Appendix C

Financial Risk Adjustments to DCF Results
Recognizing Differences in Market Value vs. Book Value Capitalization Levels

1. Circumstances Under Which a Financial Risk Adjustment is Required for DCF Results

A financial risk or "leverage" adjustment to DCF results is required whenever the average market value equity capitalization of the proxy companies being analyzed is materially higher than the corresponding book value equity capitalization. Stated alternatively, a leverage adjustment is required whenever the average per-share market-to-book ratio of the group materially exceeds 1.0. Whenever a significant market-to-book value disparity exists for a utility, the level of financial risk implicit in the respective market value and book value capital structures can differ substantially. In particular, the market value based capital structure will reflect a higher relative equity capitalization, a lower relative debt capitalization, and therefore less financial risk as compared to the book value capital structure. In contrast, the book value capital structure will reflect a lower relative equity capitalization and a higher relative debt capitalization, thereby indicating a higher degree of financial risk.

To understand the need for a leverage adjustment, it must first be emphasized that DCF cost of equity estimates are market-based estimates which are derived by referencing the stock prices of comparable risk companies as direct inputs into the DCF model. DCF estimates therefore reflect the return expectations of investors based upon the level of financial risk embedded within the corresponding market value capital structure, as indicated by the current stock price. Equity investors are predominately concerned with a firm's market value capital structure, since it reflects the current value of their investment and therefore provides the basis for assessing a company's financial risk profile. To the extent that a book value based capital structure will be utilized in the rate-setting process, equity investors will expect an additional return premium to be compensated for the additional financial risk inherent within a book value capital structure. Multiple academic studies have demonstrated that a strong positive correlation exists between the amount of leverage in a firm's capital structure and its cost of equity capital, which Morin discusses in *New Regulatory Finance,* a widely-recognized authoritative guide on utility cost of capital matters, as follows:

> …..the one inescapable conclusion from the research is that debt affects the cost of equity and that a company has a different cost of equity at a different capital structure. Therefore, the capital

> structure used to estimate the cost of equity is an integral inseparable part of that estimate.[1]

Therefore, if market-based DCF estimates of the cost of equity are applied to a utility's book value capital structure in determining the utility's weighted average cost of capital, a leverage adjustment is required to recognize the increase in financial risk resulting from the use of the book value capital structure, rather than the market-value capital structure. It is clear that this adjustment is necessary, since as Morin explains above, *"a company has a different cost of equity at a different capital structure."* Absent this leverage adjustment, the DCF results will be incorrectly specified, since they will reflect the lower level of financial risk associated with a market value based capital structure, rather than the higher risk associated with the book value capital structure, to which the DCF results will be applied.

2. Regulatory Precedents Supporting the Use of Financial Risk Adjustments Based on Differences in Market-Value and Book-Value Capitalization Levels

On numerous occasions, the Pennsylvania Public Utility Commission has allowed upward adjustments to the cost of equity to recognize the difference in financial risk between market value based capital structures, which are the basis

[1] Roger A. Morin, *New Regulatory Finance* (Public Utility Reports, Inc., 2006), at 463-464.

of DCF estimates, and the book value capital structures used for rate-setting purposes.

3. Determining the Appropriate Financial Risk or "Leverage" Adjustment Utilizing Modigliani and Miller's Classic Financial Theorems

In formulating my proposed leverage adjustments, I have referenced the classic financial theorems of Nobel laureates Modigliani and Miller (M&M), which demonstrated the relationship between a firm's capital structure, its valuation, and its cost of capital.[2] Based on the M&M equation for the cost of equity, and the respective market value and book value capital structure ratios for the Gas LDC Group, the required financial risk or "leverage" adjustment was determined to be as reflected in Table C-1 below:

Table C-1	
Required Financial Leverage Adjustments	
Gas LDC Group	0.81%

[2] Franco Modigliani and Merton H. Miller, "Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53 (June 1963), 433-443; Franco Modigliani and Merton H. Miller, *The Cost of Capital, Corporation Finance and the Theory of Investments, American Economic Review* 48 (June 1958) at 261-297.

Combination Utility Group	0.81%[3]
Non-Regulated Group	0.81%[4]

Supporting calculations for the recommended leverage adjustment is as follows:

$$K_e = p + (p-i)\,(1-T)\,(B/S) + (p-d)\,P/S \qquad \text{(Equation C.1)}$$

Where:

K_e = Estimated cost of equity

p = Cost of equity for a firm financed with 100% equity capital

i = Long-term debt borrowing cost

T = Marginal corporate income tax rate

B = Debt to total capitalization ratio

S = Common stock to total capitalization ratio

d = Preferred stock dividend yield

P = Preferred stock to total capitalization ratio

<u>Gas LDC Group</u>

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[3] For both the Combination Utility Group and the Non-Regulated Group, the magnitude of the difference between the average market value and book value capital structures is significantly greater than the difference between the market value and book value capital structures of the Gas LDC Group. As such, under the M&M equation, the required leverage adjustment for the Combination Utility Group and the Non-Regulated Group would be significantly greater than that of the Gas LDC Group. To recognize this disparity and make the leverage adjustment relevant to a typical gas utility capital structure, I have applied the same adjustment that I applied to the Gas LDC Group (0.81%) to both the Combination Utility Group and the Non-Regulated Group. Utilizing this approach ensures a more conservative analysis.

[4] See footnote 3 above.

$K_e = p + (p-i)(1-T)(B/S) + (p-d)\,P/S$ (Equation C.1)

$9.70\% = 7.399\% + (7.399\% - 3.11\%)(1-0.27)(42.0/57.5) + (7.399\% - 6.05\%)(0.5/57.5)$

$10.51\% = 7.399\% + (7.399\% - 3.11\%)(1-0.27)(49.3/50.0) + (7.399\% - 6.05\%)(0.7/50.0)$

Leverage adjustment = 10.51% - 9.70% = 0.81%

APPENDIX D
FLOTATION COSTS

Appendix D

Flotation Costs

1. Adjusting the "Bare Bones" Cost of Equity for Flotation Costs

When common equity is employed to finance a utility's rate base, it is either derived from new stock sales or from the retention of undistributed earnings. In cases where a utility or its parent company "floats" a new equity issuance, significant issuance or flotation costs may be incurred, including underwriting discounts, legal fees, accounting fees and printing costs. After subtracting these out-of-pocket costs from the transaction's gross proceeds, the company is left with net proceeds which are materially lower than the amount invested by the company's equity investors. Considering that only net proceeds can be invested into a company's rate base, the amount invested by equity investors which funds flotation related costs will never earn a fair return for those investors unless an appropriate adjustment is made to the cost of equity. As such, if a flotation cost adjustment is not applied to the "bare-bones" cost of equity determined by the various market-based analytical models, the company's equity investors will not earn a fair return on their entire investment, thereby understating the company's legitimate revenue requirement. This is contrary to established regulatory practice for debt issuance costs, which are typically capitalized at the time of issuance and amortized over the life of the outstanding debt, therefore being fully recoverable through the cost of service ratemaking process.

2. Flotation Costs – Multiple of Cost of Equity Approach

Numerous adjustment methods have been proposed to incorporate equity issuance costs into rate proceedings, several of which have been accepted by state regulatory commissions, including the DCF formula approach, multiple of cost of equity approach, basis point approach, and the actual costs approach. For purposes of this proceeding, I have relied upon the "multiple of cost of equity" approach in determining the appropriate flotation cost adjustment for each of the three proxy groups.

In contrast to debt capital, equity capital is considered to have an infinite life, and it would therefore be inappropriate to amortize a company's flotation costs over a finite number of years. As such, rather than seeking a "return of" its flotation costs over some arbitrarily selected amortization period, it is more appropriate for a utility to seek a "return on" its flotation costs, as these costs constitute a permanent equity contribution by investors. Columbia's ultimate parent, NiSource Inc., has completed three major equity offerings over the past seventeen years which have benefitted NiSource's utility subsidiaries. Specifically, NiSource completed a $734.9 million equity offering during November, 2002 with an underwriting discount of 3.00 percent; a $348.0 million equity offering during September, 2010 with an underwriting discount of 3.25 percent; and a $606.0 million private placement of common equity during May 2018, with associated placement fees of approximately 1.00 percent.

During the years 2017-2020, NiSource issued additional shares of common stock under the company's "at-the market" (or "ATM") equity issuance program, which resulted in $972.8 million of cumulative net proceeds during the 2017-2020 period. Recent public disclosures made by NiSource have indicated that the company intends to continue issuing approximately $200.0 million to $300.0 million of new common equity shares annually (through 2023) under NiSource's ATM equity issuance program. To date, the distribution fees payable to the equity distribution agents facilitating these "at-the-market" transactions have approximated 1.00 percent of the notional value of these transactions.

Therefore, after considering both NiSource's past and future anticipated equity placements as discussed above, I have concluded that a reasonable overall or composite flotation cost value to reference for purposes of the instant proceeding should be closer to the more recent placement fees paid by NiSource for its equity issuance transactions, and have therefore referenced a value of 1.50 percent.

Considering that the contributed capital component of Columbia's common equity account has recently been in the range of 21 percent of the Company's total common equity balance, it is appropriate to apply a flotation cost adjustment to Columbia's cost of equity that is based on this 21 percent weighting, since the remaining 79 percent weighting allocated to undistributed retained earnings would not be subject to underwriting costs. Accordingly, in deriving my recommended flotation cost adjustment, I have applied a 21 percent weighting to the 1.50 percent composite flotation cost value previously discussed, which yields a flotation cost factor of 0.315 percent (1.50% x 21% = 0.315%). To properly apply this level of flotation costs to Columbia's cost of equity under the "multiple of cost of equity" approach, the 0.315 percent flotation cost factor must be added to 100 percent of Columbia's pre-adjusted cost of equity, which is derived in mathematical terms as follows: (1+.00315=1.00315%). Therefore, based upon the above approach, I have applied a 1.00315 percent multiple to the *pre-adjusted* indicated cost of equity for each of the proxy groups.

ATTACHMENT VVR-1
TESTIMONY HISTORY

Vincent V. Rea
Testimony in Utility Regulatory Proceedings

Applicant	Date	Docket/Type of Case	Subject
Testimony Before the Indiana Utility Regulatory Commission			
Northern Indiana Public Service Company	08/2020	Cause No. 45330-TDSIC-1 TDSIC Investments	Cost of Capital (ROE) Pre-tax Return on TDSIC Investments
Northern Indiana Public Service Company	10/2018	Cause No. 45159 Base Rate Proceeding (Electric)	Cost of Capital (ROE) Capital Structure
Northern Indiana Public Service Company	06/2018	Cause No. 45113 Financing Petition	Financing Authority ($470.0 million)
Northern Indiana Public Service Company	09/2017	Cause No. 44988 Base Rate Proceeding (Gas)	Cost of Capital (ROE) Capital Structure
Northern Indiana Public Service Company	12/2017	Cause No. 45020 Amendment to Financing Petition	Financing Authority ($700.0 million)
Northern Indiana Public Service Company	06/2016	Cause No. 44796 Financing Petition	Financing Authority ($500.0 million)
Northern Indiana Public Service Company	10/2015	Cause No. 44688 Base Rate Proceeding (Electric)	Overall Cost of Capital Capital Structure Credit Ratings
Northern Indiana Public Service Company	04/2012	Cause No. 44191 Financing Petition	Financing Authority for FGD Facilities ($400.0 million)
Northern Indiana Public Service Company	11/2010	Cause No. 43969 Base Rate Proceeding (Electric)	Financing Activities Credit Ratings Cost of Debt
Northern Indiana Public Service Co., Kokomo Gas & Fuel Co., Northern Indiana Fuel & Light Co.	09/2010	Cause No. 43941 Merger Petition and Transfer of Franchise	Benefits of Proposed Merger
Northern Indiana Public Service Company	05/2010	Cause No. 43894 Base Rate Proceeding (Gas)	Financing Activities Credit Ratings Cost of Debt
Northern Indiana Public Service Company	08/2008	Cause No. 43563 Financing Petition	Financing Authority for CCGT Generation ($120.0 million)
Northern Indiana Public Service Company	06/2008	Cause No. 43526 Base Rate Proceeding (Electric)	Financing Activities Credit Ratings Cost of Debt
Northern Indiana Public Service Company	10/2007	Cause No. 43370 Financing Petition	Financing Authority ($160.0 million)
Northern Indiana Public Service Company	12/2004	Cause No. 42763 Financing Petition	Financing Authority ($350.0 million)

Vincent V. Rea
Testimony in Utility Regulatory Proceedings

Applicant	Date	Docket/Type of Case	Subject
Testimony Before the Maryland Public Service Commission			
Columbia Gas of Maryland	05/2020	Case No. 9644 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	05/2019	Case No. 9609 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	04/2018	Case No. 9480 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	04/2017	Case No. 9447 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	04/2016	Case No. 9417 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	02/2013	Case No. 9316 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Testimony Before the Massachusetts Department of Public Utilities			
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	04/2018	D.P.U. 18-45 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	09/2017	D.P.U. 17-142 Financing Petition	Financing Authority ($155.0 million)
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	09/2015	D.P.U. 15-139 Financing Petition	Financing Authority ($95.0 million)
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	04/2015	D.P.U. 15-50 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	08/2013	D.P.U. 13-129 Financing Petition	Financing Authority ($50.0 million)
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	04/2013	D.P.U. 13-75 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure

Vincent V. Rea
Testimony in Utility Regulatory Proceedings

Applicant	Date	Docket/Type of Case	Subject
Testimony Before the Massachusetts Department of Public Utilities (continued)			
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	04/2012	D.P.U. 12-25 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	05/2011	D.P.U. 11-41 Financing Petition	Financing Authority ($100.0 million)
Bay State Gas Company	08/2004	D.T.E. 04-80 Financing Petition	Financing Authority ($120.0 million)
Bay State Gas Company	11/2002	D.T.E. 02-73 Financing Petition	Financing Authority ($50.0 million)
Bay State Gas Company	09/2001	D.T.E. 01-75 Participation in Intra-System Financing Vehicle	Participation in NiSource Money Pool System
Testimony Before the Virginia State Corporation Commission			
Columbia Gas of Virginia	08/2018	PUR-2018-00131 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Virginia	04/2016	PUE-2016-00033 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Virginia	04/2014	PUE-2014-00020 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Testimony Before the Maine / New Hampshire Public Utilities Commissions			
Northern Utilities, Inc.	03/2003	Case No. 2003-00222 (ME) Docket No. 03-080 (NH) Financing Petition	Financing Authority ($60.0 million)
Northern Utilities, Inc.	11/2002	Case No. 2002-00680 Financing Vehicle	Alternative Fuel Financing Arrangement
Northern Utilities, Inc.	09/2001	Case No. 2001-00646 Participation in Intra-System Financing Vehicle	Participation in a Funds Pooling Agreement
Testimony Before the Federal Energy Regulatory Commission			
Northern Indiana Public Service Company	03/2012	Docket No. EL12-49-000 Transmission Rate Incentives for MVP Projects	Incentive Rate Treatment - CWIP and Abandoned Plant

Vincent V. Rea
Subject Matter Support in Regulatory Proceedings
(Representative Cases)

Applicant	Date	Docket/Type of Case	Subject
Kentucky Public Service Commission			
Columbia Gas of Kentucky	10/2018	Case No. 2018-00356 Financing Petition	Financing Authority ($40.0 million)
Columbia Gas of Kentucky	10/2015	Case No. 2015-00354 Financing Petition	Financing Authority ($58.0 million)
Columbia Gas of Kentucky	09/2012	Case No. 2012-00418 Financing Petition	Financing Authority ($45.0 million)
Maryland Public Service Commission			
Columbia Gas of Maryland	12/2018	Case No. 9601 Financing Petition	Financing Authority ($21.0 million)
Columbia Gas of Maryland	09/2016	Case No. 9427 Financing Petition	Financing Authority ($20.0 million)
Columbia Gas of Maryland	07/2014	Case No. 9359 Financing Petition	Financing Authority ($10.0 million)
Public Utilities Commission of Ohio			
Columbia Gas of Ohio	09/2015	Case No. 15-1548-GA-AIS Financing Petition	Financing Authority ($300.0 million)
Columbia Gas of Ohio	08/2014	Case No. 14-1523-GA-AIS Financing Petition	Financing Authority ($300.0 million)
Columbia Gas of Ohio	07/2012	Case No. 12-2056-GA-AIS Financing Petition	Financing Authority ($300.0 million)
Pennsylvania Public Utility Commission			
Columbia Gas of Pennsylvania	11/2017	Docket No. S-2017-2632449	Financing Authority ($160.0 million)
Columbia Gas of Pennsylvania	11/2015	Docket No. S-2015-2515414	Financing Authority ($130.0 million)
Columbia Gas of Pennsylvania	11/2013	Docket No. S-2013-2395719 Financing Petition	Financing Authority ($150.0 million)
Columbia Gas of Pennsylvania	12/2011	Docket No. S-2012-2282635 Financing Petition	Financing Authority ($185.0 million)

Vincent V. Rea
Subject Matter Support in Regulatory Proceedings
(Representative Cases)

Applicant	Date	Docket/Type of Case	Subject
Virginia State Corporation Commission			
Columbia Gas of Virginia	10/2016	PUE-2016-00129 Financing Petition	Financing Authority ($60.0 million)
Columbia Gas of Virginia	10/2014	PUE-2014-00109 Financing Petition	Financing Authority ($240.0 million)
Columbia Gas of Virginia	10/2012	PUE-2012-00126 Financing Petition	Financing Authority ($175.0 million)
Federal Energy Regulatory Commission			
Northern Indiana Public Service Company	06/2015	Docket No. ES15-33-000 Short-Term Debt Authority Under Federal Power Act	Short-Term Debt Authority ($1.0 billion)
Northern Indiana Public Service Company	05/2013	Docket No. ES13-25-000 Short-Term Debt Authority Under Federal Power Act	Short-Term Debt Authority ($1.0 billion)
Securities and Exchange Commission - PUHCA Authority			
Columbia Energy Group and Columbia Gas of Ohio, Inc.	07/2004	HCAR No. 27899 Factoring Arrangement	Capital Contribution to Factoring Subsidiary
NiSource Inc. and Subsidiaries	11/2003	HCAR No. 27789 U-1 Financing Application	U-1 Financing PUHCA of 1935
NiSource Inc. and Subsidiaries	09/2002	HCAR No. 27567 Tax Allocation Agreement	U-1 Tax Allocation Agreement
Bay State Gas Company, Northern Utilities, Inc., and Granite State Gas Transmission, Inc.	08/2002 & 06/2002	HCAR Nos. 27559/27535 Intra-System Financing Vehicle	Release of Jurisdiction to Participate in NiSource Money Pool System
NiSource Inc. and Subsidiaries	12/2001	HCAR No. 27479 Intra-System Financing	Establish Money Pool System

Vincent V. Rea
Professional Experience in the Capital Markets

Transaction Type	Date	Company/Issuer	Transaction Size
Initial Public Offering (Equity)	02/2015	Columbia Pipeline Partners, L.P.	$1.2 billion
Public Debt Offering (30-year/10-year)	06/2012	NiSource Finance Corp.	$750.0 million
Revolving Credit Facility Amendment	05/2012	NiSource Finance Corp.	$1.5 billion
Tender Offer for Senior Unsecured Notes	12/2011	NiSource Finance Corp.	$250.0 million
Public Debt Offering (30-year/10-year)	11/2011	NiSource Finance Corp.	$500.0 million
Public Debt Offering (30-year)	06/2011	NiSource Finance Corp.	$400.0 million
Commercial Paper Program Implementation	06/2011	NiSource Finance Corp.	$500.0 million
Revolving Credit Facility	03/2011	NiSource Finance Corp.	$1.5 billion
Tender Offer for Senior Unsecured Notes	12/2010	NiSource Finance Corp.	$273.0 million
Public Debt Offering (30-year)	12/2010	NiSource Finance Corp.	$250.0 million
Equity Offering (Forward Equity Offering)	09/2010	NiSource Inc.	$400.0 million
Project Financing (Private Placement)	08/2010	Millennium Pipeline Company	$725.0 million
Accounts Receivable Securitization Program	03/2010	Columbia Gas of Pennsylvania	$75.0 million
Public Debt Offering (12-year)	12/2009	NiSource Finance Corp.	$500.0 million
Accounts Receivable Securitization Program	10/2009	Columbia Gas of Ohio	$275.0 million

Vincent V. Rea
Professional Experience in the Capital Markets

Transaction Type	Date	Company/Issuer	Transaction Size
Accounts Receivable Securitization Program	10/2009	Northern Indiana Public Service Company	$200.0 million
Term Loan Facility	04/2009	NiSource Finance Corp.	$385.0 million
Tender Offer for Senior Unsecured Notes	04/2009	NiSource Finance Corp.	$251.0 million
Public Debt Offering (7-year)	03/2009	NiSource Finance Corp.	$600.0 million
Open Market Repurchases of Senior Unsecured Notes	01/2009	NiSource Finance Corp.	$100.0 million
Revolving Credit Facility	09/2008	NiSource Finance Corp.	$500.0 million
Reoffering of Tax-Exempt Pollution Control Bonds	08/2008	Jasper County, Indiana (on behalf of Northern Indiana Public Service Company)	$254.0 million
Public Debt Offering (5-year/10-year)	05/2008	NiSource Finance Corp.	$700.0 million
Construction Financing Credit Facility	08/2007	Millennium Pipeline Company	$800.0 million
Public Debt Offering (10-year)	08/2007	NiSource Finance Corp.	$800.0 million
Project Financing (Private Placement)	06/2006	Hardy Storage Project (Hardy Storage Company)	$124.0 million
Private Placement Debt Offering (multiple tranches)	11/2005	NiSource Finance Corp.	$900.0 million
Bilateral Revolving Credit Facility	11/2005	NiSource Finance Corp.	$300.0 million
Public Debt Offering (12-year/15-year)	09/2005	NiSource Finance Corp.	$1.0 billion
Revolving Credit Facility	03/2005	NiSource Finance Corp.	$1.25 billion

Vincent V. Rea
Professional Experience in the Capital Markets

Transaction Type	Date	Company/Issuer	Transaction Size
Public Debt Offering (5-year floating rate notes)	11/2004	NiSource Finance Corp.	$450.0 million
Settlement of Forward Stock Purchase Agreements and Remarketing of Debentures	11/2004	NiSource Inc. (Mandatorily-Convertible Hybrid Securities)	$144.0 million
Accounts Receivable Securitization Program	05/2004	Columbia Gas of Ohio	$300.0 million
Revolving Credit Facilities (364-day/3-year)	03/2004	NiSource Finance Corp.	$1.25 billion
Refunding of Tax-Exempt Pollution Control Bonds	12/2003	Jasper County, Indiana (on behalf of Northern Indiana Public Service Company)	$55.0 million
Accounts Receivable Securitization Program	12/2003	Northern Indiana Public Service Company	$200.0 million
Public Debt Offering (1.5-year floating/3-year)	11/2003	NiSource Finance Corp.	$500.0 million
Public Debt Offering (11-year)	07/2003	NiSource Finance Corp.	$500.0 million
Settlement of Forward Stock Purchase Agreements and Remarketing of Debentures	02/2003	NiSource Inc. (Mandatorily-Convertible Hybrid Securities)	$345.0 million
Equity Offering	11/2002	NiSource Inc.	$735.0 million
Revolving Credit Facility (364-day)	03/2002	NiSource Finance Corp.	$500.0 million
Public Debt Offering (2-year)	04/2001	NiSource Finance Corp.	$300.0 million
Post-Merger Consolidation of Bank Credit Facilities and Commercial Paper Facilities	03/2001	NiSource Inc. Columbia Energy Group NiSource Finance Corp.	$2.5 billion

ATTACHMENT VVR-2
WEIGHTED AVERAGE COST OF CAPITAL AND FAIR RATE OF RETURN

Attachment VVR-2
Page 1 of 1

Columbia Gas of Kentucky, Inc.

Weighted Average Cost of Capital and Fair Rate of Return
13-Month Average through December 31, 2022

Form of Capitalization	Cap. Struct. Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	44.25%	4.56%	2.02%
Short-Term Debt	3.11%	1.40%	0.04%
Total Common Equity	52.64%	10.30%	5.42%
Total Capitalization	100.00%		7.48%

ATTACHMENT VVR-3
COMPARATIVE RISK ASSESSMENT

Columbia Gas of Kentucky, Inc.
Comparative Risk Assessment (1) - 2016-2020 and 5-Year Averages

Attachment VVR-3
Page 1 of 4

Business & Other Hybrid Metrics	**2020**	**2019**	**2018**	**2017**	**2016**	**5-Year Average**
Relative Size Comparison - Total Capital						
Permanent Capitalization (excl. OCI)	$ 340,638	$ 311,060	$ 280,708	$ 247,361	$ 234,680	$ 282,889
Current Maturities and Short-Term Debt	34,268	21,860	7,375	27,826	7,014	$ 19,668
Total Capitalization (excl. OCI)	$ 374,906	$ 332,919	$ 288,083	$ 275,187	$ 241,694	$ 302,558
Standard Deviation and Coefficient of Variation of Return on Book Equity						
Return on Avg. Book Equity, incl. AFUDC (2)	6.5%	9.5%	12.5%	10.0%	8.4%	9.4%

	Average	**Std. Dev.**	**Coff. Var.**
Return on Avg. Book Equity, incl. AFUDC (2)	**9.38%**	**1.97%**	**0.210**

Financial Risk/Credit Quality Metrics	**2019**	**2019**	**2018**	**2017**	**2016**	**5-Year Average**
Permanent Capitalization Ratios						
Long-Term Debt	45.3%	45.8%	45.4%	46.2%	48.7%	46.3%
Preferred Stock	-	-	-	-	-	-
Common Equity (2)	54.7%	54.2%	54.6%	53.8%	51.3%	53.7%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Total Capitalization Ratios						
Total Debt (incl. CMD and STD)	50.3%	49.3%	46.8%	51.7%	50.2%	49.7%
Preferred Stock	-	-	-	-	-	-
Common Equity (2)	49.7%	50.7%	53.2%	48.3%	49.8%	50.3%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
EBITDA Interest Coverage (3)						
EBITDA Interest Cov. (incl. AFUDC ded.)	4.97	5.36	6.18	5.47	4.87	5.37
FFO to Adjusted Total Debt (4)						
FFO to Adj. Debt (incl. AFUDC ded.)	15.7%	18.8%	29.0%	20.7%	21.3%	21.1%

(1) Columbia Gas of Kentucky standalone risk metrics.
(2) Excludes Other Comprehensive Income (Loss) component of Stockholders' Equity.
(3) Earnings before interest, taxes, depreciation and amortization, divided by interest expense (including capitalized AFUDC interest).
(4) Funds from Operations (net income, including AFUDC, plus depreciation, amortization and deferred income taxes) divided by Adjusted Total Debt (total debt, incl. current maturities and short-term debt, plus post-retirement obligations recognized within the balance sheet).

Source: Columbia Gas of Kentucky 2016-2020 Annual Report to the Kentucky PSC and Company-provided financial statements.

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Page 2 of 4

Gas LDC Group
Comparative Risk Assessment (1) - 2016-2020 and 5-Year Averages

Business & Hybrid Risk Metrics	**2020**	**2019**	**2018**	**2017**	**2016**	**5-Year Average**
Relative Size Comparison - Total Capital						
Permanent Capitalization (excl. OCI)	5,149,304	4,381,382	$ 3,818,402	$ 3,413,943	$ 3,099,941	$ 3,972,594
Current Maturities and Short-Term Debt	366,554	532,402	555,993	373,513	389,724	$ 443,637
Total Capitalization (excl. OCI)	5,515,858	4,913,784	$ 4,374,395	$ 3,787,456	$ 3,489,665	$ 4,416,232
Standard Deviation and Coefficient of Variation of Return on Book Equity						
Return on Avg. Book Equity (2)(incl. AFUDC)	9.5%	8.8%	9.6%	9.4%	9.1%	9.3%

	Average	**Std. Dev.**	**Coeff. Var.**
Return on Avg. Book Equity (2)(incl. AFUDC)	**9.29%**	**0.64%**	**0.071**

Financial Risk/Credit Quality Metrics	**2020**	**2019**	**2018**	**2017**	**2016**	**5-Year Average**
Permanent Capitalization Ratios						
Long-Term Debt	49.3%	46.2%	45.9%	45.8%	43.4%	46.1%
Preferred Stock	0.7%	0.7%	0.0%	0.0%	0.0%	0.3%
Common Equity (2)	50.0%	53.1%	54.1%	54.2%	56.6%	53.6%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Total Capitalization Ratios						
Total Debt (incl. CMD and STD)	53.6%	52.0%	52.4%	51.6%	49.2%	51.7%
Preferred Stock	0.6%	0.6%	0.0%	0.0%	0.0%	0.2%
Common Equity (2)	45.8%	47.4%	47.6%	48.4%	50.8%	48.0%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
EBITDA Interest Coverage (3)						
EBITDA Interest Cov. (incl. AFUDC deduction)	7.07	6.17	6.49	6.81	7.80	6.87
FFO to Adjusted Total Debt (4)						
FFO to Adj. Debt (incl. AFUDC deduction)	15.7%	15.2%	16.6%	18.6%	19.7%	17.2%

(1) All comparative risk metrics for the Gas LDC Group represent the arithmetic average of the calculated results for each of the individual companies within the Group.
(2) Excludes the Other Comprehensive Income (Loss) component of Stockholders' Equity.
(3) Earnings before interest, taxes, depreciation and amortization, divided by interest expense.
(4) Funds from Operations (net income, plus depreciation, amortization and deferred income taxes) divided by Adjusted Total Debt (total debt, including current maturities and short-term debt, plus post-retirement obligations recognized within the balance sheet).

Source: 10-K filings of the proxy group companies.

Capital Structure Ratios - Permanent Capitalization
Gas LDC Group - 2016-2020 and 5-Year Average

Witness: Rea
Attachment VVR-3
Page 3 of 4

	2020	2019	2018	2017	2016	5-Year Average
Atmos Energy Corp.						
Long-Term Debt	39.8%	37.6%	33.9%	43.4%	37.5%	38.4%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	60.2%	62.4%	66.1%	56.6%	62.5%	61.6%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
New Jersey Resources Corp.						
Long-Term Debt	54.5%	49.3%	45.2%	44.6%	47.4%	48.2%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	45.5%	50.7%	54.8%	55.4%	52.6%	51.8%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Northwest Natural Gas Co.						
Long-Term Debt	48.8%	47.9%	47.8%	47.6%	44.2%	47.3%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	51.2%	52.1%	52.2%	52.4%	55.8%	52.7%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
ONE Gas, Inc.						
Long-Term Debt	41.4%	37.6%	38.6%	37.8%	38.6%	38.8%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	58.6%	62.4%	61.4%	62.2%	61.4%	61.2%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
South Jersey Industries, Inc.						
Long-Term Debt	62.0%	58.7%	62.0%	47.7%	38.0%	53.7%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	38.0%	41.3%	38.0%	52.3%	62.0%	46.3%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Southwest Gas Corp.						
Long-Term Debt	50.0%	47.3%	47.8%	49.1%	47.5%	48.3%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	50.0%	52.7%	52.2%	50.9%	52.5%	51.7%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Spire, Inc.						
Long-Term Debt	48.6%	44.7%	45.8%	50.1%	50.8%	48.0%
Preferred Stock	4.9%	5.2%	-	-	-	2.0%
Common Equity (1)	46.5%	50.1%	54.2%	49.9%	49.2%	50.0%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Average of Gas LDC Proxy Group						
Long-Term Debt	49.3%	46.2%	45.9%	45.8%	43.4%	46.1%
Preferred Stock	0.7%	0.7%	-	-	-	0.3%
Common Equity (1)	50.0%	53.1%	54.1%	54.2%	56.6%	53.6%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Excludes Other Comprehensive Income (Loss) component of Stockholders' Equity.

Capital Structure Ratios - Total Capitalization
Gas LDC Group - 2016-2020 and 5-Year Average

Witness: Rea
Attachment VVR-3
Page 4 of 4

	2020	2019	2018	2017	2016	5-Year Average
Atmos Energy Corp.						
Total Debt (incl. CM and STD)	39.8%	40.5%	42.9%	46.7%	47.2%	43.4%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	60.2%	59.5%	57.1%	53.3%	52.8%	56.6%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
New Jersey Resources Corp.						
Total Debt (incl. CM and STD)	56.1%	50.0%	50.4%	53.5%	51.3%	52.3%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	43.9%	50.0%	49.6%	46.5%	48.7%	47.7%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Northwest Natural Gas Co.						
Total Debt (incl. CM and STD)	58.3%	54.0%	55.3%	52.6%	47.4%	53.5%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	41.7%	46.0%	44.7%	47.4%	52.6%	46.5%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
ONE Gas, Inc.						
Total Debt (incl. CM and STD)	47.2%	45.8%	43.6%	44.1%	41.4%	44.4%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	52.8%	54.2%	56.4%	55.9%	58.6%	55.6%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
South Jersey Industries, Inc.						
Total Debt (incl. CM and STD)	67.4%	69.9%	70.6%	55.5%	50.4%	62.8%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	32.6%	30.1%	29.4%	44.5%	49.6%	37.2%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Southwest Gas Corp.						
Total Debt (incl. CM and STD)	51.3%	51.1%	49.9%	52.3%	48.3%	50.6%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	48.7%	48.9%	50.1%	47.7%	51.7%	49.4%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Spire, Inc.						
Total Debt (incl. CM and STD)	55.1%	52.7%	53.9%	56.4%	58.3%	55.3%
Preferred Stock	4.2%	4.4%	-	-	-	1.7%
Common Equity (1)	40.8%	42.9%	46.1%	43.6%	41.7%	43.0%
Total Capitalization	100.1%	100.0%	100.0%	100.0%	100.0%	100.0%
Average of Gas LDC Proxy Group						
Total Debt (incl. CM and STD)	53.6%	52.0%	52.4%	51.6%	49.2%	51.7%
Preferred Stock	0.6%	0.6%	-	-	-	0.2%
Common Equity (1)	45.8%	47.4%	47.6%	48.4%	50.8%	48.0%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Excludes Other Comprehensive Income (Loss) component of Stockholders' Equity.

Abbreviations: "CM" denotes Current Maturities of Debt; "STD" denotes Short-Term Debt.

ATTACHMENT VVR-4
REGULATORY MECHANISMS BY JURISDICTION

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Regulatory Mechanisms by Jurisdiction
Atmos Energy Corp.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
CO	-	System Safety and Integrity Rider (SSIR)
KS	WNA and Modified Fixed-Variable Rate Design	Gas System Reliability Surcharge (GSRS)
KY	WNA and Modified Fixed-Variable Rate Design	Pipeline Replacement Program (PRP)
LA	WNA and Rate Stabilization Clause (RSC)	Safety and Reliability Deferral Mechanism (SIIP)
MS	WNA and Stable Rate Filing (SRF)	System Integrity Rider (SIR)
TN	WNA, Annual Rate Mechanism, and MFV	Annual Rate Mechanism (ARM)
TX (Mid)	WNA, Rate Review Mechanism, and MFV	Rule 8.209 System Safety and Reliability Capital Deferral Mechanism and Gas Reliability Infrastructure Program (GRIP)
TX (West)	WNA, Rate Review Mechanism, and MFV	Rule 8.209 System Safety and Reliability Capital Deferral Mechanism and Gas Reliability Infrastructure Program (GRIP)
VA	WNA	Steps to Advance Virginia Energy (SAVE)

Regulatory Mechanisms by Jurisdiction
New Jersey Resources Corp.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
NJ	Revenue Decoupling (Conservation Incentive Program (CIP), including WNA)	Safety Acceleration and Facility Enhancement Program (SAFE II), Reinvestment in System Enhancement (RISE) Program, Resiliency and Reliability Invest. (IIP).

(1) Revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment mechanisms); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

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Regulatory Mechanisms by Jurisdiction
Northwest Natural Gas Co.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
OR	WNA (WARM) and Revenue Decoupling	-
WA	-	-

Regulatory Mechanisms by Jurisdiction
ONE Gas, Inc.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
KS	WNA Clause	Gas System Reliability Surcharge (GSRS)
OK	WNA (Temperature Adjustment Clause)	PBRC - Incremental Capital Investment
TX	WNA Clause	Gas Reliability Infrastructure Program (GRIP) and Cost of Service Adjustment (COSA)

(1) Revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment mechanisms); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

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Regulatory Mechanisms by Jurisdiction
South Jersey Industries Inc.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
NJ	Decoupling (Conservation Incentive) and Weather Normalization Clause (WNC)	Accelerated Infrastructure Replacement Program (AIRP), Storm Hardening and Reliability Program (SHARP) and Infrastructure Investment Program (IIP)

Regulatory Mechanisms by Jurisdiction
Southwest Gas Corp.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
AZ	Decoupling (Delivery Charge Adjustment Mech.)	Customer Owned Yard Line (COYL) Program & Vintage Steel Pipe Replacement (VSP) Program
CA	Decoupling (Fixed Cost Adjustment Mech.)	Targeted Pipe Replacement Program and COYL program.
NV	Decoupling (General Revenues Adjustment Mech.)	Gas Infrastructure Replacement Program (GIR)

(1) Revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment mechanisms); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

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Regulatory Mechanisms by Jurisdiction
Spire Inc.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
AL	WNA (Temperature Adjustment Rider) and Rate Stabilization & Equalization (RSE)	Accelerated Infrastructure Modernization Program (AIM) and Cast Iron Main Replacement Factor (CIMFR)
MO	WNA	Infrastructure System Replacement Surcharge (ISRS)
MS	WNA and Rate Stabilization Adjustment (RSA)	-

(1) Revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment mechanisms); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

Attachment VVR-4
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Regulatory Mechanisms by Jurisdiction
Alliant Energy Corp.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
IA	-	-
WI	-	-

Regulatory Mechanisms by Jurisdiction
Black Hills Corp.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
AR	WNA and Revenue Decoupling (Gas)	Main Replacement Program Rider (Gas)
CO	-	System Safety Integrity Rider - (SSIR) (Gas)
IA	Modified Fixed-Variable Rate Design (Gas)	Capital Infrastructure Automatic Adjust. Mech. (Gas)
KS	WNA and Modified Fixed-Variable Rate Design	Gas System Reliability Surcharge (Gas)
MT	-	-
NE	Modified Fixed-Variable Rate Design	Infrastructure Repl. Cost Recovery Surcharge (Gas) and System Safety and Integrity Rider (Gas)
SD	-	Transmission Facility Adjustment (TFA)
WY	Partial Decoupling and Modified Fixed-Variable Rate Design	Integrity Rider

(1) Revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment mechanisms); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

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Regulatory Mechanisms by Jurisdiction
CMS Energy Corp.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
MI	Revenue Decoupling (Rate Adjustment Mech.) (Gas)	Investment Recovery Mechanism (Gas)

Regulatory Mechanisms by Jurisdiction
Consolidated Edison, Inc.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
NY	WNA (Gas & Electric), Revenue Decoupling (Gas & Electric) and Fixed - Variable Rate Design (Gas & Electric)	Infrastructure Cost Recovery Mechanism (Limited: Gas)
NJ	WNA (Gas)	-

Regulatory Mechanisms by Jurisdiction
Eversource Energy

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
MA	Revenue Decoupling (Gas & Electric)	Gas System Enhancement Program (Gas)
CT	Revenue Decoupling) (Gas & Electric)	Accelerated Replacement Program (Gas) and Electric System Improvements Charge (ESI), including System Resiliency Plan (Electric)
NH	Modified Fixed Variable Rate Design	

(1) Revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment mechanisms); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

Attachment VVR-4
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Regulatory Mechanisms by Jurisdiction
MGE Energy Inc.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
WI	Modified Fixed-Variable Rate Design (Gas)	-

Regulatory Mechanisms by Jurisdiction
Northwestern Corp.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
MT	Fixed Cost Recovery Mechanism (FCRM)	-
NE	-	-
SD	-	-

(1) Revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment mechanisms); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

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Regulatory Mechanisms by Jurisdiction
Sempra Energy

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
CA	Revenue Requirement Attrition (Decoupling)	Pipeline Safety Enhancement Plan (PSEP)

Regulatory Mechanisms by Jurisdiction
WEC Energy Group

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
IL	Revenue Decoupling (Gas) and Modified Fixed-Variable Rate Design (Gas)	Gas Pipeline Replacement Rider / Qualifying Infrastructure Plant Rider (Gas)
MI	-	-
MN	Revenue Decoupling (Gas)	Gas Utility Infrastructure Cost Rider Surcharge
WI	Fixed -Variable Rate Design (Gas & Electric)	-

(1) Revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment mechanisms); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

ATTACHMENT VVR-5
RATESETTING CAPITAL STRUCTURE AND RELATED RATIOS

Attachment VVR-5
Page 1 of 1

Columbia Gas of Kentucky, Inc.

Ratesetting Capital Structure and Related Ratios
Actual at February 28, 2021 and Projected at August 31, 2021 and December 31, 2022

Form of Capitalization	Actual at February 28, 2021 Amount Outstanding	Actual at February 28, 2021 Capital Structure Ratios	Projected at August 31, 2021 Amount Outstanding	Projected at August 31, 2021 Capital Structure Ratios	Projected at December 31, 2022 Amount Outstanding	Projected at December 31, 2022 Capital Structure Ratios	Thirteen Month Average December 31, 2022 Amount Outstanding	Thirteen Month Average December 31, 2022 Capital Structure Ratios
Long-Term Debt	$ 138,375,000	37.38%	$ 160,375,000	40.08%	$ 206,375,000	44.59%	$ 197,144,231	44.25%
Current Maturities - LT Debt	16,000,000	4.32%	16,000,000	4.00%	-	-	-	-
Total Long-Term Debt	$ 154,375,000	41.70%	$ 176,375,000	44.08%	$ 206,375,000	44.59%	$ 197,144,231	44.25%
Common Equity								
Common Stock Issued	$ 23,806,200		$ 23,806,200		$ 23,806,200		$ 23,806,200	
Additional Paid-In Capital	15,018,524		26,018,524		45,018,524		43,633,908	
OCI	-		-		-		-	
Retained Earnings	157,175,842		151,943,843		173,793,926		167,095,029	
Total Common Equity	$ 196,000,565	52.95%	$ 201,768,566	50.43%	$ 242,618,650	52.42%	$ 234,535,137	52.64%
Total Permanent Capital	$ 350,375,565	94.65%	$ 378,143,566	94.51%	$ 448,993,650	97.01%	$ 431,679,368	96.89%
Short-Term Debt (1)	$ 19,792,984	5.35%	$ 21,963,370	5.49%	$ 13,857,837	2.99%	$ 13,857,837	3.11%
Total Capitalization	$ 370,168,550	100.00%	$ 400,106,937	100.00%	$ 462,851,487	100.00%	$ 445,537,205	100.00%

(1) 13-month average short-term debt balance.

Source: Company provided information.

ATTACHMENT VVR-6
COST OF LONG TERM DEBT

Attachment VVR-6
Page 1 of 1

Columbia Gas of Kentucky, Inc.
Embedded Cost of Long-Term Debt
Actual at February 28, 2021 and Projected at August 31, 2021 and December 31, 2022

Debt Instrument	Maturity Date	Interest Rate	Principal Value	Annual Interest Expense
6.0150% Notes, due November 1, 2021	11/1/2021	6.0150%	16,000,000	962,400
5.9200% Notes, due January 5, 2026	1/5/2026	5.9200%	12,375,000	732,600
6.0200% Notes, due December 16, 2030	12/16/2030	6.0200%	10,000,000	602,000
5.7700% Notes, due January 7, 2043	1/7/2043	5.7700%	20,000,000	1,154,000
6.2000% Notes, due December 23, 2043	12/23/2043	6.2000%	20,000,000	1,240,000
4.4300% Notes, due December 16, 2044	12/16/2044	4.4300%	5,000,000	221,500
3.8425% Notes, due September 30, 2046	9/30/2046	3.8425%	31,000,000	1,191,175
4.6436% Notes, due December 31, 2048	12/31/2048	4.6436%	13,000,000	603,668
3.7485% Notes, due December 31, 2049	12/31/2049	3.7485%	15,000,000	562,275
3.1742% Notes, due June 30, 2050	6/30/2050	3.1742%	12,000,000	380,904
Long-Term Debt at February 28, 2021			$ 154,375,000	$ 7,650,522
		Embedded Cost of Long-Term Debt		4.96%
3.9000% Notes, due June 30, 2051	6/30/2051	3.9000%	22,000,000	858,000
Long-Term Debt at August 31, 2021			$ 176,375,000	$ 8,508,522
		Embedded Cost of Long-Term Debt		4.82%
3.9000% Notes, due September 30, 2051	9/30/2051	3.9000%	22,000,000	858,000
6.0150% Notes, due November 1, 2021	11/1/2021	6.0150%	(16,000,000)	(962,400)
4.0000% Notes, due March 31, 2052	3/31/2052	4.0000%	16,000,000	640,000
4.0000% Notes, due June 30, 2052	6/30/2052	4.0000%	8,000,000	320,000
Long-Term Debt at December 31, 2022			$ 206,375,000	$ 9,364,122
		Embedded Cost of Long-Term Debt		4.54%

Columbia Gas of Kentucky, Inc.
Embedded Cost of Long-Term Debt
Thirteen Month Average through December 31, 2022

Debt Instrument	Maturity Date	Interest Rate	Principal Value	Annual Interest Expense
5.9200% Notes, due January 5, 2026	1/5/2026	5.9200%	12,375,000	732,600
6.0200% Notes, due December 16, 2030	12/16/2030	6.0200%	10,000,000	602,000
5.7700% Notes, due January 7, 2043	1/7/2043	5.7700%	20,000,000	1,154,000
6.2000% Notes, due December 23, 2043	12/23/2043	6.2000%	20,000,000	1,240,000
4.4300% Notes, due December 16, 2044	12/16/2044	4.4300%	5,000,000	221,500
3.8425% Notes, due September 30, 2046	9/30/2046	3.8425%	31,000,000	1,191,175
4.6436% Notes, due December 31, 2048	12/31/2048	4.6436%	13,000,000	603,668
3.7485% Notes, due December 31, 2049	12/31/2049	3.7485%	15,000,000	562,275
3.1742% Notes, due June 30, 2050	6/30/2050	3.1742%	12,000,000	380,904
3.9000% Notes, due June 30, 2051	6/30/2051	3.9000%	22,000,000	858,000
3.9000% Notes, due September 30, 2051	9/30/2051	3.9000%	22,000,000	858,000
4.0000% Notes, due March 31, 2052	3/31/2052	4.0000%	11,076,923	443,077
4.0000% Notes, due June 30, 2052	6/30/2052	4.0000%	3,692,308	147,692
Thirteen Month Average through December 31, 2022			$ 197,144,231	$ 8,994,891
		Embedded Cost of Long-Term Debt		4.56%

ATTACHMENT VVR-7
DCF METHOD GAS

DCF Method
Gas LDC Group
Projected Growth Rates and Cost of Equity Estimates

Vincent V. Rea
Case No. 2021-00183
Attachment VVR-7
Page 1 of 8

	(1)	(2)	(3)	(4)	(5)	(6)	(6)	(6)	(6)
Gas LDC Group	Dividend Yield	Yahoo Finance EPS Growth	Zacks EPS Growth	Value Line EPS Growth	Value Line Retention Growth	Yahoo Finance EPS COE	Zacks EPS COE	Value Line EPS COE	Value Line Ret. Growth COE
Atmos Energy Corp.	2.9%	7.1%	7.5%	7.0%	3.7%	10.0%	10.4%	9.9%	6.6%
New Jersey Resources Corp.	3.5%	6.0%	6.0%	1.5%	3.2%	9.5%	9.5%	5.0%	6.7%
Northwest Natural Gas Co.	4.0%	3.1%	n/a	5.5%	2.2%	7.1%	n/a	9.5%	6.2%
ONE Gas, Inc.	3.3%	5.0%	6.0%	6.5%	3.7%	8.3%	9.3%	9.8%	7.0%
South Jersey Industries Inc.	5.1%	24.5%	24.5%	10.5%	3.8%	29.6%	29.6%	15.6%	8.9%
Southwest Gas Corp.	3.8%	4.0%	5.0%	8.0%	4.7%	7.8%	8.8%	11.8%	8.5%
Spire Inc.	4.0%	5.7%	5.0%	9.0%	2.3%	9.7%	9.0%	13.0%	6.3%
Average (7)	3.8%	7.9%	9.0%	6.9%	3.4%	8.7%	9.4%	11.6%	7.2%

Low-End and High-End Outlier Tests				
Low-End Threshold (5.30%) (7)	5.3%	5.3%	5.3%	5.3%
Median Result (excluding negative values)(7)	9.5%	9.4%	9.9%	6.7%
200% of Median Result (7)	19.0%	18.8%	19.8%	13.4%
High-End Threshold - 200% of Median (average)	17.7%	17.7%	17.7%	17.7%

(1) See page 3 of this Attachment.
(2) www.finance.yahoo.com. Consensus earnings estimates provided by Thomson Reuters (retrieved March 1, 2021).
(3) www.zacks.com (retrieved March 1, 2021).
(4) See page 5 of this Attachment.
(5) See page 6 of this Attachment.
(6) Sum of dividend yield and applicable projected growth rate.
(7) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 5.30% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 7 of this Attachment and FERC Opinion No. 569, 169 FERC ¶, 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020). FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc., 109 FERC ¶ 61,147 at P 205 (November 3, 2004).

n/a - information not available.

DCF Method
Gas LDC Group
Historical EPS Growth Rates and Cost of Equity Estimates

Vincent V. Rea
Case No. 2021-00183
Attachment VVR-7
Page 2 of 8

	(1)	(2)	(3)	(4)	(5)
Gas LDC Group	Dividend Yield	5-Year Historical EPS Growth	10-Year Historical EPS Growth	Average Historical EPS Growth	Cost of Equity - Hist. EPS
Atmos Energy Corp.	2.9%	9.0%	8.0%	8.5%	11.4%
New Jersey Resources Corp.	3.5%	6.0%	7.0%	6.5%	10.0%
Northwest Natural Gas Co.	4.0%	-17.0%	-11.0%	-14.0%	-10.0%
ONE Gas, Inc.	3.3%	9.5%	n/a	n/a	n/a
South Jersey Industries Inc.	5.1%	-4.0%	1.0%	-1.5%	3.6%
Southwest Gas Corp.	3.8%	4.5%	8.0%	6.3%	10.0%
Spire Inc.	4.0%	4.5%	1.5%	3.0%	7.0%
Average (6)	3.8%	1.8%	2.4%	1.5%	9.6%

Low-End and High-End Outlier Tests	
Low-End Threshold (5.30%) (6)	5.3%
Median Result (excluding negative values)(6)	10.0%
200% of Median Result (6)	20.0%
High-End Threshold - 200% of Median (average)	20.0%

(1) See page 3 of this Attachment.
(2) See page 5 of this Attachment.
(3) See page 5 of this Attachment.
(4) Average of (2) and (3) above.
(5) Sum of (1) and (4) above.
(6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 5.30% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% higher than the average of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 7 of this Attachment and FERC Opinion No. 569, 169 FERC ¶, 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020).

DCF Method
Gas LDC Group
Dividend Yield Calculations

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Gas LDC Group	(a) 40-Day Avg. Stock Price	(b) Next 12-Mo. Dividends	(b)/(a) Dividend Yield
Atmos Energy Corp.	$ 89.83	$ 2.60	2.9%
New Jersey Resources Corp.	$ 37.97	$ 1.33	3.5%
Northwest Natural Gas Co.	$ 47.45	$ 1.92	4.0%
ONE Gas, Inc.	$ 72.19	$ 2.36	3.3%
South Jersey Industries Inc.	$ 24.32	$ 1.25	5.1%
Southwest Gas Corp.	$ 62.94	$ 2.38	3.8%
Spire Inc.	$ 65.79	$ 2.63	4.0%
Average	-	-	3.8%

(a) See page 4 of this Attachment; 40-day average closing stock price.

(b) Value Line Investment Survey, Summary and Index, March 19, 2021. Estimated dividends, next twelve months.

DCF Method
Gas LDC Group
Average Closing Stock Price Through March 15, 2021

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Averages	Atmos Energy	New Jersey Resources	Northwest Natural Gas	ONE Gas, Inc.	South Jersey Indust.	Southwest Gas	Spire Inc.
10-Day Average	$ 90.26	$ 40.53	$ 51.40	$ 72.87	$ 27.31	$ 66.64	$ 71.28
20-Day Average	$ 89.98	$ 39.86	$ 49.84	$ 71.85	$ 26.01	$ 65.34	$ 69.21
40-Day Average	$ 89.83	$ 37.97	$ 47.45	$ 72.19	$ 24.32	$ 62.94	$ 65.79

Date	Atmos Energy	New Jersey Resources	Northwest Natural Gas	ONE Gas, Inc.	South Jersey Indust.	Southwest Gas	Spire Inc.
3/15/2021	93.19	42.42	54.15	77.03	28.64	66.27	74.64
3/12/2021	91.42	41.48	53.22	75.13	27.93	65.33	75.13
3/11/2021	89.88	40.69	52.12	73.75	27.46	65.51	72.87
3/10/2021	90.81	40.86	53.01	74.44	28.80	67.95	72.47
3/9/2021	89.34	40.24	52.25	73.39	28.05	68.69	71.97
3/8/2021	91.64	41.05	53.74	75.02	28.34	71.08	72.77
3/5/2021	91.71	40.22	51.71	73.60	26.68	69.28	70.92
3/4/2021	88.90	39.27	48.57	68.79	25.11	65.17	67.98
3/3/2021	88.45	39.65	47.47	68.77	26.23	63.73	67.28
3/2/2021	87.24	39.39	47.80	68.78	25.87	63.38	66.81
3/1/2021	85.75	40.29	48.25	69.55	25.61	63.64	66.97
2/26/2021	84.61	39.29	47.99	66.97	25.11	62.35	66.42
2/25/2021	88.23	39.48	48.79	69.01	25.51	64.11	67.94
2/24/2021	88.67	39.14	49.16	69.85	25.25	65.01	68.06
2/23/2021	89.63	39.31	49.06	70.01	25.37	65.86	68.69
2/22/2021	89.41	39.26	47.69	70.02	24.50	64.26	66.74
2/19/2021	93.56	39.60	48.88	74.06	24.26	64.80	67.67
2/18/2021	93.69	38.97	48.22	73.58	23.92	64.34	67.61
2/17/2021	92.43	38.87	47.82	72.97	23.94	63.66	66.47
2/16/2021	91.13	37.81	46.83	72.23	23.55	62.36	64.81
2/12/2021	91.05	36.62	46.32	72.69	23.66	61.83	63.97
2/11/2021	91.04	37.18	47.32	73.35	23.49	62.53	63.82
2/10/2021	91.85	37.38	46.67	73.73	23.48	61.73	63.22
2/9/2021	89.60	37.21	46.71	72.54	23.60	61.25	64.24
2/8/2021	89.08	36.30	45.79	72.55	22.76	61.39	64.75
2/5/2021	89.05	36.62	46.14	72.90	23.04	62.55	65.10
2/4/2021	88.78	36.05	45.09	72.41	22.76	61.91	64.02
2/3/2021	87.05	35.57	43.75	71.91	22.36	60.51	62.26
2/2/2021	88.66	35.94	44.38	73.46	22.64	60.62	62.97
2/1/2021	88.65	35.66	45.26	73.83	23.06	60.76	62.35
1/29/2021	89.00	35.01	46.71	73.13	23.10	59.96	61.19
1/28/2021	88.57	34.91	44.17	73.05	22.15	60.33	60.46
1/27/2021	90.83	35.46	46.50	74.60	23.08	60.42	60.89
1/26/2021	90.95	35.26	45.16	72.31	22.05	60.85	60.32
1/25/2021	90.44	35.80	44.40	72.48	22.66	60.56	61.59
1/22/2021	89.09	35.43	43.24	70.79	21.64	58.62	61.75
1/21/2021	89.45	34.96	42.92	70.62	21.10	57.55	61.09
1/20/2021	90.09	35.72	42.44	71.00	21.20	58.27	60.75
1/19/2021	90.08	36.52	43.49	71.35	21.96	58.89	61.16
1/15/2021	90.03	37.73	44.71	71.99	22.72	60.11	61.65
40-Day Average	89.83	37.97	47.45	72.19	24.32	62.94	65.79

Source: Yahoo Finance; accessed March 16, 2021.

DCF Method
Gas LDC Group
Per Share Annual Growth Rates - Historical and Projected

Vincent V. Rea
Case No. 2021-00183
Attachment VVR-7
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	Past 5-Years Historical Growth Rates				Estimated '18-'20 to '24-'26 Growth Rates			
Gas LDC Group	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Atmos Energy Corp.	9.0%	7.5%	10.0%	8.8%	7.0%	7.5%	10.5%	8.3%
New Jersey Resources	6.0%	6.5%	8.5%	7.0%	1.5%	5.5%	5.0%	4.0%
Northwest Natural Gas Co.	-17.0%	0.5%	-0.5%	-5.7%	5.5%	0.5%	8.0%	4.7%
ONE Gas, Inc.	9.5%	17.0%	2.5%	9.7%	6.5%	7.0%	4.5%	6.0%
South Jersey Industries Inc.	-4.0%	5.0%	3.5%	1.5%	10.5%	4.0%	5.0%	6.5%
Southwest Gas Corp.	4.5%	9.5%	6.5%	6.8%	8.0%	4.5%	6.0%	6.2%
Spire Inc.	4.5%	6.0%	5.5%	5.3%	9.0%	4.5%	8.5%	7.3%
Average	1.8%	7.4%	5.1%	4.8%	6.9%	4.8%	6.8%	6.1%

	Past 10-Years Historical Growth Rates			
Gas LDC Group	EPS	DPS	BVPS	Average
Atmos Energy Corp.	8.0%	5.0%	7.5%	6.8%
New Jersey Resources	7.0%	7.0%	7.0%	7.0%
Northwest Natural Gas Co.	-11.0%	2.0%	1.5%	-2.5%
ONE Gas, Inc.	n/a	n/a	n/a	n/a
South Jersey Industries Inc.	1.0%	7.5%	5.5%	4.7%
Southwest Gas Corp.	8.0%	8.5%	6.0%	7.5%
Spire Inc.	1.5%	4.5%	7.0%	4.3%
Average	2.4%	5.8%	5.8%	4.6%

Source: Value Line Investment Survey, Ratings & Reports, February 26, 2021.

DCF Method
Gas LDC Group
Retention Growth Rates - Historical and Projected

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Case No. 2021-00183
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							Projected			
Gas LDC Group	2016	2017	2018	2019	2020	Average	2021	2022	'24 - '26	Average
Atmos Energy Corp.	5.1%	4.9%	4.8%	4.6%	4.4%	4.8%	4.0%	4.0%	3.5%	3.7%
New Jersey Resources Corp.	4.8%	5.0%	10.2%	4.6%	4.2%	5.8%	1.5%	4.0%	3.5%	3.2%
Northwest Natural Gas Co.	0.9%	n/a	2.1%	1.4%	1.0%	1.4%	1.5%	2.0%	2.5%	2.2%
ONE Gas, Inc.	3.5%	3.7%	3.7%	3.8%	3.5%	3.6%	3.5%	3.0%	4.0%	3.7%
South Jersey Industries Inc.	1.6%	0.9%	1.7%	n/a	2.5%	1.7%	2.5%	3.0%	4.5%	3.8%
Southwest Gas Corp.	4.1%	4.5%	3.6%	3.9%	3.5%	3.9%	4.0%	4.5%	5.0%	4.7%
Spire Inc.	3.3%	3.3%	4.7%	2.7%	n/a	3.5%	2.0%	2.0%	2.5%	2.3%
Average						3.5%				3.4%

Source: Value Line Investment Survey, Ratings & Reports, February 26, 2021.

DCF Method - Gas LDC Group
Determination of "Low-End" Outlier Threshold for DCF Estimates

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Recent Baa (Moody's) 30-Year Corporate Bond Yield (1)	3.74%
Indicated Equity Market Risk Premium per CAPM Analysis (2)	7.82%
20% Weighting Factor per FERC Opinion No. 569 (3)	20.0%
Equity Risk Premium Factor to Apply to Baa/BBB Bond Yield (3)(4)	1.56%
Low-End Outlier Threshold (3)(5)	5.30%

Footnotes:

(1) Mergent Bond Record, April 2021.

(2) See Mr. Rea's CAPM analysis (Attachment VVR-11).

(3) See FERC Opinion No. 569, 169 FERC ¶ 61,129, at P. 387-389 (Nov. 21, 2019), and FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.161-162 (May 21, 2020).

(4) Product of (2) x (3) above.

(5) Sum of (1) and (4) above.

DCF Method
Gas LDC Group
Investment Risk Indicators

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	Value Line Risk Indicators					Long-Term Credit Ratings				Market Cap	
Gas LDC Group	Beta	Safety Rank	Financial Strength	Fin. Str. Weight	Stk Price Stability	S&P LT Rating	S&P Weight	Moody's LT Rating	Moody's Weight	Billions ($) 2/26/2021	
Atmos Energy Corp.	0.80	1	A+	2	95	A-	7	A1	5	$	11.70
New Jersey Resources Corp. (1)	0.95	2	A+	2	80	n/r	n/r	A1	5		3.50
Northwest Natural Gas Co.	0.80	1	A	3	85	A+	5	Baa1	8		1.40
ONE Gas, Inc.	0.80	2	A	3	95	BBB+	8	A3	7		3.90
South Jersey Industries Inc. (2)	1.05	3	B++	4	70	BBB	9	A3	7		2.40
Southwest Gas Corp.	0.95	3	A	3	85	BBB+	8	Baa1	8		3.50
Spire Inc.	0.85	2	B++	4	95	A-	7	Baa2	9		3.30
Averages	0.89	2.0	A	3.0	86	A-	7.3	A3	7.0	$	4.24

Source of Information: Value Line Investment Survey, Ratings & Reports, February 26, 2021. S&P and Moody's long-term credit ratings accessed February 24, 2021.
Footnotes: (1) Moody's credit rating is for New Jersey Natural Gas Co.; (2) Moody's credit rating is for South Jersey Gas Co.
n/r - no credit rating.

S&P Credit Rating Weightings		Moody's Credit Rating Weightings		Value Line Fin. Str. Weightings	
AAA	1	Aaa	1	A++	1
AA+	2	Aa1	2	A+	2
AA	3	Aa2	3	A	3
AA-	4	Aa3	4	B++	4
A+	5	A1	5	B+	5
A	6	A2	6	B	6
A-	7	A3	7	C++	7
BBB+	8	Baa1	8	C+	8
BBB	9	Baa2	9	C	9
BBB-	10	Baa3	10		
BB+	11	Ba1	11		
BB	12	Ba2	12		
BB-	13	Ba3	13		

ATTACHMENT VVR-8
DCF METHOD
COMBINATION
UTILITY

DCF Method
Combination Utility Group
Projected Growth Rates and Cost of Equity Estimates

Vincent V. Rea
Case No. 2021-00183
Attachment VVR-8
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	(1)	(2)	(3)	(4)	(5)	(6)	(6)	(6)	(6)
Combination Utility Group	Dividend Yield	Yahoo Finance EPS Growth	Zacks EPS Growth	Value Line EPS Growth	Value Line Retention Growth	Yahoo Finance EPS COE	Zacks EPS COE	Value Line EPS COE	Value Line Ret. Growth COE
Alliant Energy Corp.	3.3%	5.7%	5.8%	5.5%	4.0%	9.0%	9.1%	8.8%	7.3%
Black Hills Corp.	3.8%	4.7%	5.2%	3.5%	3.2%	8.4%	9.0%	7.3%	7.0%
CMS Energy Corp.	3.1%	7.3%	7.0%	7.5%	5.5%	10.4%	10.1%	10.6%	8.6%
Consolidated Edison, Inc.	4.5%	3.0%	2.0%	2.5%	2.2%	7.4%	6.5%	7.0%	6.7%
Eversource Energy	2.9%	7.1%	6.8%	6.5%	3.3%	9.9%	9.6%	9.4%	6.2%
MGE Energy Inc.	2.3%	4.7%	4.7%	4.5%	4.0%	7.0%	7.0%	6.8%	6.4%
Northwestern Corp.	4.3%	4.7%	5.3%	2.5%	2.7%	8.9%	9.5%	6.8%	7.0%
Sempra Energy	3.6%	8.5%	7.3%	11.0%	4.6%	12.1%	10.9%	14.6%	8.2%
WEC Energy Group	3.2%	6.1%	6.1%	6.5%	4.3%	9.4%	9.3%	9.7%	7.5%
Average (7)	3.4%	5.7%	5.6%	5.6%	3.8%	9.2%	9.0%	9.0%	7.2%

Low-End and High-End Outlier Tests				
Low-End Threshold (5.30%) (7)	5.3%	5.3%	5.3%	5.3%
Median Result (excluding negative values)(7)	9.0%	9.3%	8.8%	7.0%
200% of Median Result (7)	18.0%	18.7%	17.6%	14.0%
High-End Threshold - 200% of Median (average)	17.0%	17.0%	17.0%	17.0%

(1) See page 3 of this Attachment.
(2) www.yahoo.com (retrieved March 1, 2021).
(3) www.zacks.com (retrieved March 1, 2021).
(4) See page 5 of this Attachment.
(5) See page 6 of this Attachment.
(6) Sum of dividend yield and applicable projected growth rate.
(7) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 5.30% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 7 of Attachment VVR-7 and FERC Opinion No. 569, 169 FERC ¶, 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020). FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc., 109 FERC ¶ 61,147 at P 205 (November 3, 2004).

DCF Method
Combination Utility Group
Historical EPS Growth Rates and Cost of Equity Estimates

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Combination Utility Group	(1) Dividend Yield	(2) 5-Year Historical EPS Growth	(3) 10-Year Historical EPS Growth	(4) Average Historical EPS Growth	(5) Cost of Equity - Hist. EPS
Alliant Energy Corp.	3.3%	6.0%	6.0%	6.0%	9.3%
Black Hills Corp.	3.8%	7.0%	7.0%	7.0%	10.8%
CMS Energy Corp.	3.1%	7.0%	7.5%	7.3%	10.4%
Consolidated Edison, Inc.	4.5%	2.0%	2.5%	2.3%	6.7%
Eversource Energy	2.9%	7.0%	6.0%	6.5%	9.4%
MGE Energy Inc.	2.3%	3.0%	5.0%	4.0%	6.3%
Northwestern Corp.	4.3%	6.0%	7.0%	6.5%	10.8%
Sempra Energy	3.6%	4.0%	2.0%	3.0%	6.6%
WEC Energy Group	3.2%	7.5%	8.0%	7.8%	11.0%
Average (6)	3.4%	5.5%	5.7%	5.6%	9.0%

Low-End and High-End Outlier Tests	
Low-End Threshold (5.30%) (6)	5.3%
Median Result (excluding negative values)(6)	9.4%
200% of Median Result (6)	18.7%
High-End Threshold - 200% of Median (average)	18.7%

(1) See page 3 of this Attachment.
(2) See page 5 of this Attachment.
(3) See page 5 of this Attachment.
(4) Average of (2) and (3) above.
(5) Sum of (1) and (4) above.
(6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 5.30% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 7 of Attachment VVR-7 and FERC Opinion No. 569, 169 FERC ¶, 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020). FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc., 109 FERC ¶ 61,147 at P 205 (November 3, 2004).

DCF Method
Combination Utility Group
Dividend Yield Calculation

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	(a)	(b)	(b)/(a)
Combination Utility Group	40-Day Avg. Stock Price	Next 12-Mo. Dividends	Dividend Yield
Alliant Energy Corp.	$ 48.86	$ 1.61	3.3%
Black Hills Corp.	$ 61.32	$ 2.31	3.8%
CMS Energy Corp.	$ 56.61	$ 1.77	3.1%
Consolidated Edison, Inc.	$ 69.61	$ 3.10	4.5%
Eversource Energy	$ 84.23	$ 2.41	2.9%
MGE Energy Inc.	$ 65.99	$ 1.54	2.3%
Northwestern Corp.	$ 57.98	$ 2.48	4.3%
Sempra Energy	$ 123.31	$ 4.50	3.6%
WEC Energy Group	$ 85.71	$ 2.76	3.2%
Average			3.4%

(a) See page 4 of this Attachment; 40-day average closing stock price.

(b) Value Line Investment Survey, Summary and Index, March 19, 2021. Estimated dividends during the next 12-months.

DCF Method
Combination Utility Group
Average Closing Stock Price through March 15, 2021

10-Day Average	$ 49.34	$ 63.09	$ 56.06	$ 69.19	$ 80.61	$ 67.96	$ 61.20	$ 123.08	$ 85.66
20-Day Average	$ 48.46	$ 61.82	$ 55.68	$ 68.62	$ 80.80	$ 66.62	$ 59.92	$ 122.53	$ 83.99
40-Day Average	$ 48.86	$ 61.32	$ 56.61	$ 69.61	$ 84.23	$ 65.99	$ 57.98	$ 123.31	$ 85.71

Date	Alliant Energy Corp.	Black Hills Corp.	CMS Energy Corp.	Consolidated Edison, Inc.	Eversource Energy	MGE Energy Inc.	Northwestern Corp.	Sempra Energy	WEC Energy Group
3/15/2021	52.70	66.40	58.50	71.82	82.75	72.74	64.05	132.00	88.91
3/12/2021	51.12	65.79	57.54	70.94	82.10	72.15	63.12	128.75	88.49
3/11/2021	49.99	64.05	56.76	69.82	80.83	70.27	62.03	126.91	86.86
3/10/2021	50.39	65.11	57.09	70.37	81.69	70.27	62.20	126.49	87.22
3/9/2021	49.88	63.57	56.53	69.69	81.66	68.58	60.61	123.43	86.75
3/8/2021	49.71	64.15	56.15	69.50	80.62	68.06	61.61	122.91	86.33
3/5/2021	48.39	62.55	55.37	68.30	80.66	65.52	60.91	119.17	84.48
3/4/2021	47.20	59.90	53.91	66.96	77.27	63.66	59.20	116.99	82.28
3/3/2021	46.91	59.45	53.88	67.43	77.78	63.90	58.78	116.97	82.26
3/2/2021	47.11	59.96	54.88	67.08	80.72	64.48	59.53	117.13	83.03
3/1/2021	47.09	59.86	54.82	67.04	80.73	65.47	59.78	117.90	82.79
2/26/2021	46.16	59.16	54.11	65.65	79.48	63.70	58.48	115.98	80.64
2/25/2021	47.37	60.21	55.06	67.15	80.56	64.95	59.73	119.08	81.78
2/24/2021	47.53	60.79	54.57	66.65	80.11	65.07	60.30	122.57	81.93
2/23/2021	48.23	61.24	55.69	67.67	80.19	66.59	59.46	123.56	84.02
2/22/2021	47.13	59.38	54.78	67.97	78.65	65.74	57.24	122.66	82.04
2/19/2021	47.63	61.35	55.98	68.18	81.46	65.83	58.63	124.57	83.23
2/18/2021	48.61	61.22	56.62	70.02	82.55	65.63	58.19	124.27	83.48
2/17/2021	48.23	61.21	55.83	70.16	82.34	65.11	57.55	124.61	82.03
2/16/2021	47.82	61.13	55.45	70.05	83.89	64.74	56.90	124.68	81.18
2/12/2021	48.29	61.62	56.38	71.06	85.17	65.64	56.44	124.50	83.05
2/11/2021	48.71	61.86	56.58	71.82	86.23	65.92	57.47	125.80	83.95
2/10/2021	49.12	61.98	56.93	72.31	87.27	65.73	57.54	126.85	85.89
2/9/2021	48.84	62.48	56.58	71.35	85.74	65.16	57.11	125.34	85.46
2/8/2021	49.06	61.68	56.44	71.28	85.51	65.17	56.18	124.85	85.17
2/5/2021	49.68	61.93	57.45	71.50	87.80	65.35	56.44	126.24	86.82
2/4/2021	49.46	61.01	56.86	70.59	88.28	65.05	55.40	126.07	86.75
2/3/2021	49.11	60.21	57.20	70.51	88.00	64.24	54.80	123.33	87.22
2/2/2021	49.02	60.91	57.42	70.26	88.23	64.73	55.45	124.58	87.79
2/1/2021	48.95	60.29	57.18	70.75	87.80	64.21	54.95	124.94	88.55
1/29/2021	48.65	59.12	56.88	70.78	87.50	63.68	54.47	123.76	88.90
1/28/2021	48.96	59.60	57.25	70.21	89.14	64.55	54.90	124.69	89.50
1/27/2021	48.98	58.97	57.30	71.54	88.53	63.61	54.58	119.95	90.84
1/26/2021	49.84	60.05	58.78	70.28	89.89	65.77	54.92	124.59	89.34
1/25/2021	50.50	61.10	59.52	70.64	90.29	66.83	56.00	125.97	89.44
1/22/2021	49.41	59.16	58.41	68.83	87.41	65.95	55.43	121.45	87.38
1/21/2021	49.75	60.26	58.11	69.15	87.13	65.88	55.91	122.37	87.83
1/20/2021	49.92	60.98	58.70	69.94	87.62	66.05	56.32	122.87	88.35
1/19/2021	49.63	60.99	58.25	69.48	87.14	66.27	57.32	121.48	87.87
1/15/2021	49.47	61.97	58.62	69.60	88.57	67.29	59.13	122.16	88.69
40-Day Average	48.86	61.32	56.61	69.61	84.23	65.99	57.98	123.31	85.71

DCF Method
Combination Utility Group
Per Share Annual Growth Rates - Historical and Projected

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	Past 5-Years Historical Growth Rates				Estimated '18-'20 to '24-'26 Growth Rates			
Combination Utility Group	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Alliant Energy Corp.	6.0%	7.0%	5.5%	6.2%	5.5%	6.0%	6.0%	5.8%
Black Hills Corp.	7.0%	5.0%	4.0%	5.3%	3.5%	6.0%	5.0%	4.8%
CMS Energy Corp.	7.0%	7.0%	5.5%	6.5%	7.5%	7.0%	8.0%	7.5%
Consolidated Edison, Inc.	2.0%	3.0%	4.5%	3.2%	2.5%	3.0%	3.0%	2.8%
Eversource Energy	7.0%	7.0%	3.5%	5.8%	6.5%	6.0%	5.5%	6.0%
MGE Energy Inc.	3.0%	4.5%	6.0%	4.5%	4.5%	5.5%	4.5%	4.8%
Northwestern Corp.	6.0%	7.5%	7.0%	6.8%	2.5%	4.0%	3.0%	3.2%
Sempra Energy	4.0%	7.5%	4.5%	5.3%	11.0%	7.5%	8.5%	9.0%
WEC Energy Group	7.5%	8.5%	8.0%	8.0%	6.5%	6.5%	4.0%	5.7%
Average	5.5%	6.3%	5.4%	5.7%	5.6%	5.7%	5.3%	5.5%

	Past 10-Years Historical Growth Rates			
Combination Utility Group	EPS	DPS	BVPS	Average
Alliant Energy Corp.	6.0%	7.0%	4.5%	5.8%
Black Hills Corp.	7.0%	3.5%	3.0%	4.5%
CMS Energy Corp.	7.5%	11.5%	5.0%	8.0%
Consolidated Edison, Inc.	2.5%	2.0%	4.0%	2.8%
Eversource Energy	6.0%	9.0%	6.5%	7.2%
MGE Energy Inc.	5.0%	3.5%	5.5%	4.7%
Northwestern Corp.	7.0%	5.5%	6.0%	6.2%
Sempra Energy	2.0%	10.0%	5.0%	5.7%
WEC Energy Group	8.0%	13.5%	7.5%	9.7%
Average	5.7%	7.3%	5.2%	6.1%

Source: Value Line Investment Survey, January 22, 2021, February 12, 2021, March 12, 2021.
n/a = Data not published or not applicable.

DCF Method
Combination Utility Group
Retention Growth Rates - Historical and Projected

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							Projected			
Combination Utility Group	2015	2016	2017	2018	2019	Average	2020	2021	'23 - '25	Average
Alliant Energy Corp.	3.6%	2.8%	4.0%	4.4%	4.2%	3.8%	4.2%	4.0%	4.0%	4.0%
Black Hills Corp.	3.8%	3.3%	5.3%	3.9%	3.8%	4.0%	3.5%	3.5%	3.0%	3.2%
CMS Energy Corp.	5.2%	4.8%	5.2%	5.3%	4.9%	5.1%	5.3%	5.5%	5.5%	5.5%
Consolidated Edison, Inc.	3.5%	3.0%	3.0%	3.5%	2.3%	3.1%	1.5%	2.0%	2.5%	2.2%
Eversource Energy	3.4%	3.5%	3.5%	3.4%	3.6%	3.5%	3.0%	3.0%	3.5%	3.3%
MGE Energy Inc.	4.5%	4.7%	4.2%	4.7%	4.6%	4.5%	4.2%	4.0%	4.0%	4.0%
Northwestern Corp.	3.0%	4.1%	3.4%	3.2%	3.1%	3.4%	2.0%	2.5%	3.0%	2.7%
Sempra Energy	5.8%	2.9%	3.3%	4.1%	3.9%	4.0%	3.5%	4.5%	5.0%	4.6%
WEC Energy Group	2.1%	3.5%	3.6%	3.7%	3.8%	3.3%	3.8%	4.0%	4.5%	4.3%
Average						3.9%				3.8%

Source: Value Line Investment Survey, January 22, 2021, February 12, 2021, March 12, 2021.

DCF Method
Combination Utility Group
Investment Risk Indicators

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	Value Line Risk Indicators					Long-Term Credit Ratings				Market Cap
Combination Utility Group	Beta	Safety Rank	Financial Strength	Fin. Str. Weight	Stk Price Stability	S&P LT Rating	S&P Weight	Moody's LT Rating	Moody's Weight	Billions ($) per Value Line
Alliant Energy Corp. (LNT)	0.85	2	A	3	95	A-	7	Baa2	9	11.80
Black Hills Corp. (BKH)	1.00	2	A	3	80	BBB+	8	Baa2	9	3.70
CMS Energy Corp. (CMS)	0.75	2	B++	4	95	A-	7	Baa1	8	16.00
Consolidated Edison, Inc. (ED)	0.75	1	A+	2	85	A-	7	Baa2	9	24.00
Eversource Energy (ES)	0.90	1	A	3	85	A-	7	Baa1	8	30.00
MGE Energy Inc. (1) (MGEE)	0.70	1	A+	2	95	AA-	4	A1	5	2.40
Northwestern Corp.	0.95	2	B++	4	90	BBB	9	Baa2	9	2.90
Sempra Energy (SRE)	1.00	2	A	3	90	BBB+	8	Baa2	9	34.00
WEC Energy Group (WEC)	0.80	1	A+	2	85	A-	7	Baa1	8	26.00
Averages	0.86	1.6	A	2.9	89	A-	7.1	Baa1	8.2	16.76

Source: Value Line Investment Survey, January 22, 2021, February 12, 2021, and March 12, 2021. S&P and Moody's ratings accessed on February 24, 2021 and February 25, 2021. at www.standardandpoors.com and www.moodys.com.

Footnotes: (1) S&P and Moody's credit ratings for Madison Gas & Electric Company, (2) Moody's credit rating for Vectren Corp. is for subsidiaries Indiana Gas and Southern Indiana Gas & Electric.

S&P Credit Rating Weightings		Moody's Credit Rating Weightings		Value Line Fin. Str. Weightings	
AAA	1	Aaa	1	A++	1
AA+	2	Aa1	2	A+	2
AA	3	Aa2	3	A	3
AA-	4	Aa3	4	B++	4
A+	5	A1	5	B+	5
A	6	A2	6	B	6
A-	7	A3	7	C++	7
BBB+	8	Baa1	8	C+	8
BBB	9	Baa2	9	C	9
BBB-	10	Baa3	10		
BB+	11	Ba1	11		
BB	12	Ba2	12		
BB-	13	Ba3	13		

ATTACHMENT VVR-9
DCF METHOD NON-REGULATED GROUP

DCF Method
Non-Regulated Group
Projected Growth Rates and Cost of Equity Estimates

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		(1)	(2)	(3)	(4)	(4)	(5)	(5)	(5)	(5)
			Projected Growth Rates				Cost of Equity (COE) - Projected Growth Rates			
Non-Regulated Proxy Group	Ticker	Dividend Yield	Yahoo Finance EPS Growth	Zacks EPS Growth	Value Line EPS Growth	Value Line Retention Growth	Yahoo Finance EPS COE	Zacks EPS COE	Value Line EPS COE	Value Line Ret. Growth COE
AT&T Inc.	T	7.2%	1.2%	2.5%	2.5%	4.8%	8.4%	9.6%	9.7%	12.0%
Air Products and Chemicals, Inc.	APD	2.2%	9.0%	8.2%	12.5%	8.7%	11.3%	10.4%	14.7%	11.0%
Coca-Cola Co.	KO	3.4%	5.2%	5.4%	6.5%	14.1%	8.6%	8.8%	9.9%	17.5%
Comcast Corp.	CMCSA	1.9%	14.4%	13.8%	11.5%	11.4%	16.3%	15.7%	13.4%	13.3%
Hershey Company	HSY	2.2%	7.6%	7.7%	5.0%	19.3%	9.8%	9.8%	7.2%	21.5%
International Flavors & Fragrances, Inc.	IFF	2.4%	10.0%	10.0%	6.5%	4.6%	12.4%	12.4%	8.9%	7.0%
J.B. Hunt Transport Services	JBHT	0.8%	20.7%	15.0%	6.5%	15.1%	21.5%	15.8%	7.3%	15.9%
McCormick & Co.	MKC	1.5%	5.5%	6.6%	6.5%	10.0%	7.0%	8.1%	8.0%	11.5%
McDonald's Corp.	MCD	2.5%	12.8%	8.7%	8.0%	n/a	15.2%	11.1%	10.5%	n/a
PepsiCo, Inc.	PEP	3.0%	7.8%	6.9%	6.0%	21.0%	10.8%	10.0%	9.0%	24.0%
Sherwin-Williams Co.	SHW	1.0%	10.0%	10.7%	10.0%	34.3%	10.9%	11.6%	11.0%	35.3%
United Parcel Service	UPS	2.6%	10.1%	8.7%	8.0%	52.0%	12.7%	11.3%	10.6%	54.6%
Average (6)		2.6%	9.52%	8.68%	7.46%	17.8%	11.2%	11.2%	10.0%	12.6%

Low-End and High-End Outlier Tests				
Low-End Threshold (5.30%) (7)	5.3%	5.3%	5.3%	5.3%
Median Result (excluding negative values)(7)	11.1%	10.8%	9.8%	15.9%
200% of Median Result (7)	22.2%	21.6%	19.5%	31.8%
High-End Threshold - 200% of Median (average)	21.1%	21.1%	21.1%	21.1%

(1) See page 3 of this Attachment.
(2) Consensus estimates provided by Yahoo Finance (retrieved March 1, 2021).
(3) Consensus estimates provided by Zacks (retrieved March 1, 2021).
(4) Value Line Investment Survey, Ratings and Reports; multiple report dates between January 15, 2021 and March 19, 2021.
(5) Sum of dividend yield and applicable projected growth rate.
(6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 5.30% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates).
See page 7 of Attachment VVR-7 and FERC Opinion No. 569, 169 FERC ¶, 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020).
FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc., 109 FERC ¶ 61,147 at P 205 (November 3, 2004).

n/a - information not available.

DCF Method
Non-Regulated Group
Historical EPS Growth Rates and Cost of Equity Estimates

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Non-Regulated Proxy Group	(1) Dividend Yield	(2) 5-Year Historical EPS Growth	(3) 10-Year Historical EPS Growth	(4) Average Historical EPS Growth	(5) Cost of Equity Historical EPS Growth
AT&T Inc.	7.2%	6.5%	3.5%	5.0%	12.2%
Air Products and Chemicals, Inc.	2.2%	5.5%	5.0%	5.3%	7.5%
Coca-Cola Co.	3.4%	n/a	3.5%	3.5%	6.9%
Comcast Corp.	1.9%	13.5%	17.0%	15.3%	17.2%
Hershey Company	2.2%	8.0%	10.0%	9.0%	11.2%
International Flavors & Fragrances, Inc.	2.4%	6.0%	8.5%	7.3%	9.7%
J.B. Hunt Transport Services	0.8%	11.0%	13.5%	12.3%	13.0%
McCormick & Co.	1.5%	9.0%	8.5%	8.8%	10.3%
McDonald's Corp.	2.5%	7.5%	8.0%	7.8%	10.2%
PepsiCo, Inc.	3.0%	5.5%	5.0%	5.3%	8.3%
Sherwin-Williams Co.	1.0%	19.0%	18.5%	18.8%	19.7%
United Parcel Service	2.6%	8.5%	7.5%	8.0%	10.6%
Average (6)	2.6%	9.1%	9.0%	8.8%	10.6%

Low-End and High-End Outlier Tests	
Low-End Threshold (5.30%) (6)	5.3%
Median Result (excluding negative values)(6)	10.4%
200% of Median Result (6)	20.9%
High-End Threshold - 200% of Median (average)	20.9%

(1) See page 3 of this Attachment.
(2) Value Line Investment Survey, Ratings and Reports; multiple report dates between January 15, 2021 and March 19, 2021.
(3) See (2) above.
(4) Average of (2) and (3) above.
(5) Sum of (1) and (4) above, which is the sum of the dividend yield and the average historical earnings growth rate.
(6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 5.30% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 7 of Attachment VVR-7 and FERC Opinion No. 569, 169 FERC ¶, 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020). FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc.,

DCF Method
Non-Regulated Group
Dividend Yield Calculations

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Non-Regulated Proxy Group	Ticker	Dividend Next 12-Mon. (1)	40-Day Stock Price Average	Dividend Yield
AT&T Inc.	T	$ 2.08	$ 29.02	7.2%
Air Products and Chemicals, Inc.	APD	6.00	267.36	2.2%
Coca-Cola Co.	KO	1.68	49.79	3.4%
Comcast Corp.	CMCSA	1.00	52.42	1.9%
Hershey Company	HSY	3.22	148.75	2.2%
International Flavors & Fragrance	IFF	3.12	129.41	2.4%
J.B. Hunt Transport Services	JBHT	1.15	147.82	0.8%
McCormick & Co.	MKC	1.36	88.14	1.5%
McDonald's Corp.	MCD	5.22	211.26	2.5%
PepsiCo, Inc.	PEP	4.09	135.55	3.0%
Sherwin-Williams Co.	SHW	6.90	707.41	1.0%
United Parcel Service	UPS	4.19	161.23	2.6%
Average				2.6%

(1) Source: Value Line Summary and Index, March 19, 2021.

DCF Method
Non-Regulated Group
Average Closing Stock Price Through March 15, 2021

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Averages	AT&T	Air Products	Coca-Cola	Comcast Corp.	Hershey Co.	IFF, Inc.	J.B. Hunt	McCormick	McDonald's	PepsiCo	Sherwin Williams	UPS
10-Day Average	$ 29.44	$ 267.35	$ 50.70	$ 55.68	$ 149.88	$ 133.88	$ 156.89	$ 85.05	$ 210.20	$ 131.93	$ 692.75	$ 163.26
20-Day Average	$ 29.18	$ 264.50	$ 50.46	$ 54.30	$ 149.28	$ 135.99	$ 151.60	$ 85.02	$ 211.01	$ 132.14	$ 696.73	$ 161.86
40-Day Average	$ 29.02	$ 267.36	$ 49.79	$ 52.42	$ 148.75	$ 129.41	$ 147.82	$ 88.14	$ 211.26	$ 135.55	$ 707.41	$ 161.23

Date	AT&T	Air Products	Coca-Cola	Comcast Corp.	Hershey Co.	IFF, Inc.	J.B. Hunt	McCormick	McDonald's	PepsiCo	Sherwin Williams	UPS
3/15/2021	29.93	272.96	51.03	57.53	153.32	136.79	161.46	87.34	220.46	133.03	716.97	162.64
3/12/2021	29.81	273.26	50.36	57.09	152.44	134.84	162.83	86.81	212.34	133.04	708.13	167.69
3/11/2021	29.54	272.69	50.88	56.89	151.90	135.87	159.29	85.82	211.57	133.22	704.00	167.24
3/10/2021	29.99	271.62	51.44	57.21	152.65	135.29	157.00	85.90	213.31	133.58	706.10	165.23
3/9/2021	29.64	267.51	50.86	55.57	150.56	131.31	160.69	85.02	208.55	132.25	706.04	163.27
3/8/2021	29.99	266.88	51.64	55.48	151.79	131.23	159.39	84.15	209.11	132.13	688.11	160.87
3/5/2021	29.62	263.82	50.79	55.09	150.38	133.72	155.63	84.43	207.37	133.03	675.69	164.40
3/4/2021	28.92	256.43	49.94	53.93	146.09	130.89	149.29	82.90	204.84	128.83	659.56	159.45
3/3/2021	28.72	262.34	49.98	53.73	144.37	131.73	152.59	83.19	205.82	129.14	673.21	160.43
3/2/2021	28.22	266.00	50.10	54.25	145.35	137.15	150.73	84.90	208.67	131.07	689.68	161.37
3/1/2021	28.09	261.19	49.90	54.45	145.19	139.15	149.39	84.55	208.25	130.62	693.84	161.47
2/26/2021	27.89	255.62	48.99	52.72	145.65	135.51	146.87	84.28	206.14	129.19	680.34	157.83
2/25/2021	28.63	260.38	50.17	52.24	147.57	136.63	146.48	84.41	210.95	130.00	673.17	157.51
2/24/2021	29.38	263.26	50.71	53.40	147.57	138.15	146.66	84.80	213.27	132.09	682.03	160.07
2/23/2021	29.18	263.33	50.54	53.34	147.98	138.92	144.51	84.37	211.32	132.78	696.59	160.81
2/22/2021	29.32	265.48	50.63	52.50	148.25	140.56	145.55	83.96	212.06	131.99	708.63	161.60
2/19/2021	29.00	263.88	50.11	52.10	148.85	139.50	146.56	84.12	212.24	132.51	716.91	160.54
2/18/2021	29.23	262.65	50.77	52.56	152.99	137.95	146.90	86.49	215.43	135.37	726.76	162.12
2/17/2021	29.57	260.01	50.13	52.99	151.29	137.67	143.82	85.95	213.45	134.46	721.40	161.00
2/16/2021	28.97	260.73	50.27	52.84	151.38	136.89	146.32	86.93	215.03	134.38	707.42	161.75
2/12/2021	28.80	260.55	50.69	53.23	151.38	134.06	148.32	89.65	213.90	133.87	721.05	163.39
2/11/2021	28.69	257.69	50.30	53.23	150.42	136.77	147.32	89.88	214.27	134.97	719.29	162.37
2/10/2021	28.55	253.58	49.60	52.75	150.00	135.57	146.72	90.80	214.40	137.70	712.32	165.66
2/9/2021	28.62	254.44	49.70	52.72	149.62	127.95	148.35	90.77	215.98	139.60	713.01	166.92
2/8/2021	28.77	253.64	49.92	51.85	149.33	127.25	146.02	90.83	211.58	140.40	724.01	163.45
2/5/2021	28.93	253.15	49.65	51.11	146.60	127.06	144.65	90.29	212.58	140.96	716.58	164.38
2/4/2021	28.89	256.70	49.01	51.45	147.22	126.94	142.07	88.88	211.03	139.68	710.32	162.26
2/3/2021	28.51	276.60	48.77	50.47	146.58	128.27	139.05	88.72	208.71	138.02	701.34	159.71
2/2/2021	28.54	273.95	48.96	51.18	147.12	124.23	140.60	89.48	209.76	138.38	710.54	160.29
2/1/2021	28.65	268.95	48.48	50.15	145.11	130.15	136.91	89.18	207.93	136.98	698.10	156.26
1/29/2021	28.63	266.76	48.15	49.57	145.44	112.38	134.66	89.54	207.84	136.57	691.80	155.00
1/28/2021	28.80	275.86	49.15	51.60	148.21	115.02	136.78	91.02	206.82	139.19	712.05	157.27
1/27/2021	29.14	269.98	48.53	48.42	146.19	110.94	135.73	94.07	207.00	138.04	717.54	157.65
1/26/2021	29.75	277.99	49.29	50.09	149.52	113.78	143.46	96.09	215.38	141.80	723.64	161.43
1/25/2021	29.11	279.02	48.78	48.97	147.53	116.33	146.74	94.55	213.34	140.18	734.28	161.75
1/22/2021	28.93	283.60	48.49	48.68	148.20	115.81	146.14	91.87	213.38	138.59	732.17	158.99
1/21/2021	28.83	282.61	48.95	49.13	148.98	116.00	147.30	91.46	213.53	139.61	736.35	160.10
1/20/2021	28.96	286.56	48.68	48.88	149.63	120.08	150.02	91.75	213.63	141.33	736.22	159.84
1/19/2021	28.95	285.66	48.51	48.85	148.75	120.34	148.52	93.01	209.09	142.06	725.61	156.28
1/15/2021	29.17	286.91	48.70	48.69	148.46	117.72	151.51	93.43	209.91	141.39	725.55	158.90
40-Day Average	$ 29.02	$ 267.36	$ 49.79	$ 52.42	$ 148.75	$ 129.41	$ 147.82	$ 88.14	$ 211.26	$ 135.55	$ 707.41	$ 161.23

Source: Yahoo Finance; accessed March 16, 2021.

DCF Method
Non-Regulated Group
Projected Retention Growth Rates

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		Projected (1)			
Non-Regulated Group	Ticker	2021	2022	'24-'26	Average
AT&T	T	4.5%	4.5%	5.0%	4.8%
Air Products and Chemicals, Inc.	APD	5.7%	6.5%	10.5%	8.7%
Coca-Cola Co.	KO	5.0%	8.5%	19.0%	14.1%
Comcast Corp.	CMCSA	8.5%	11.0%	12.5%	11.4%
Hershey Company	HSY	28.5%	24.5%	14.5%	19.3%
International Flavors & Fragrances, Inc.	IFF	4.0%	4.0%	5.0%	4.6%
J.B. Hunt Transport Services	JBHT	17.5%	17.5%	13.5%	15.1%
McCormick & Co.	MKC	11.5%	10.0%	9.5%	10.0%
McDonald's Corp.	MCD	n/a	n/a	n/a	n/a
PepsiCo, Inc.	PEP	16.0%	17.0%	24.0%	21.0%
Sherwin-Williams Co.	SHW	45.5%	45.0%	27.0%	34.3%
United Parcel Service	UPS	66.5%	54.0%	46.5%	52.0%
Average		19.4%	18.4%	17.0%	17.8%

n/a = Data not available/meaningful.

(1) Value Line Investment Survey, Ratings and Reports; multiple report dates between January 15, 2021 and March 19, 2021.

DCF Method
Non-Regulated Proxy Group
Investment Risk Indicators

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	Value Line Risk Indicators						Long-Term Credit Ratings				Market Cap.
Non-Regulated Group	Beta	Safety Rank	Financial Strength	Fin. Str. Weight	Stk Price Stability	Percent % Debt/Cap.	S&P LT Rating	S&P Weight	Moody's LT Rating	Moody's Weight	Billions ($) Value Line
AT&T Inc.	0.85	1	A++	1	100	46.2%	BBB	9	Baa2	9	$ 200.0
Air Products and Chemicals, Inc.	0.90	1	A++	1	95	36.0%	A	6	A2	6	$ 63.4
Coca-Cola Co.	0.90	1	A++	1	100	68.0%	A+	5	A1	5	$ 227.0
Comcast Corp.	0.80	1	A+	2	100	54.0%	A-	7	A3	7	$ 249.0
Hershey Company	0.85	1	A+	2	95	62.0%	A	6	A1	5	$ 31.4
International Flavors & Fragrances, Inc.	0.95	1	A+	2	80	39.0%	BBB	9	Baa3	10	$ 34.2
J.B. Hunt Transport Services	0.95	1	A+	2	90	34.0%	BBB+	8	Baa1	8	$ 15.4
McCormick & Co.	0.80	1	A+	2	95	49.0%	BBB	9	Baa2	9	$ 25.1
McDonald's Corp.	0.95	1	A++	1	95	100.0%	BBB+	8	Baa1	8	$ 160.0
PepsiCo, Inc.	0.80	1	A++	1	100	75.0%	A+	5	A1	5	$ 199.0
Sherwin-Williams Co.	0.90	1	A+	2	90	70.0%	BBB-	10	Baa2	9	$ 61.7
United Parcel Service	0.80	1	A+	2	90	81.0%	A-	7	A2	6	$ 141.0
Averages	0.871	1	A+	1.6	94	59.5%	A-	7.4	A3	7.3	$ 117.3

S&P Credit Rating Weightings		Moody's Credit Rating Weightings		Value Line Fin. Str. Weightings	
AAA	1	Aaa	1	A++	1
AA+	2	Aa1	2	A+	2
AA	3	Aa2	3	A	3
AA-	4	Aa3	4	B++	4
A+	5	A1	5	B+	5
A	6	A2	6	B	6
A-	7	A3	7	C++	7
BBB+	8	Baa1	8	C+	8
BBB	9	Baa2	9	C	9
BBB-	10	Baa3	10		
BB+	11	Ba1	11		
BB	12	Ba2	12		
BB-	13	Ba3	13		

Source: Value Line Investment Survey - Ratings & Reports - Various report dates between January 17, 2020 and March 20, 2020. Credit ratings sourced from www.standardandpoors.com and www.moodys.com, and were accessed on March 12, 2020.

ATTACHMENT VVR-10
CAPITAL STRUCTURE RATIOS

Capital Structure Ratios - Book vs. Market Capitalization Ratios for Leverage Calculations
Gas LDC Group - 12/31/2020 or Fiscal Year End

Witness: Rea
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$ in thousands	[Source is 10-K] Carrying Values (Book Value) Dollars 2020	Percentage 2020	[Source is 10-K and Yahoo Finance] Market Values (Fair Value) Dollars 2020	Percentage 2020	Common Shares Outstanding at Fiscal Y/E	Recent 40-Day Average Stock Price
Atmos Energy Corp.						
Long-Term Debt (1)	4,531,779	39.8%	5,568,962	33.0%	@ 9/30/2020	
Preferred Stock	-	-	-	-		
Common Equity (2)	6,848,792	60.2%	11,308,025	67.0%		
Total Permanent Capitalization	$ 11,380,571	100.0%	$ 16,876,987	100.0%	125,882.5	$ 89.83
New Jersey Resources Corp.						
Long-Term Debt (1)	2,259,466	54.5%	2,395,499	39.7%	@ 9/30/2020	
Preferred Stock	-	-	-	-		
Common Equity (2)	1,889,007	45.5%	3,643,191	60.3%		
Total Permanent Capitalization	$ 4,148,473	100.0%	$ 6,038,690	100.0%	95,949.2	$ 37.97
Northwest Natural Gas Co.						
Long-Term Debt (1)	860,081	48.8%	1,040,967	41.8%	@ 12/31/2020	
Preferred Stock	-	-	-	-		
Common Equity (2)	901,635	51.2%	1,451,448	58.2%		
Total Permanent Capitalization	$ 1,761,716	100.0%	$ 2,492,415	100.0%	30,589.0	$ 47.45
ONE Gas, Inc.						
Long-Term Debt (1)	1,582,428	41.4%	1,982,428	34.1%	@ 12/31/2020	
Preferred Stock	-	-	-	-		
Common Equity (2)	2,241,088	58.6%	3,838,104	65.9%		
Total Permanent Capitalization	$ 3,823,516	100.0%	$ 5,820,532	100.0%	53,166.7	$ 72.19
South Jersey Industries, Inc.						
Long-Term Debt (1)	2,776,400	62.0%	3,009,423	55.2%	@ 12/31/2020	
Preferred Stock	-	-	-	-		
Common Equity (2)	1,699,097	38.0%	2,446,395	44.8%		
Total Permanent Capitalization	$ 4,475,497	100.0%	$ 5,455,818	100.0%	100,591.9	$ 24.32
Southwest Gas Corp.						
Long-Term Debt (1)	2,732,200	50.0%	3,101,097	46.3%	@ 12/31/2020	
Preferred Stock	-	-	-	-		
Common Equity (2)	2,735,956	50.0%	3,599,721	53.7%		
Total Permanent Capitalization	$ 5,468,156	100.0%	$ 6,700,818	100.0%	57,192.9	$ 62.94
Spire, Inc.						
Long-Term Debt (1)	2,423,700	48.6%	2,848,200	43.9%	@ 9/30/2020	
Preferred Stock	242,000	4.9%	242,000	3.7%		
Common Equity (2)	2,321,500	46.5%	3,394,764	52.3%		
Total Permanent Capitalization	$ 4,987,200	100.0%	$ 6,484,964	100.0%	51,600.0	$ 65.79
Average of Gas LDC Proxy Group						
Long-Term Debt (1)	2,452,293	49.3%	2,849,511	42.0%		
Preferred Stock	34,571	0.7%	34,571	0.5%		
Common Equity (2)	2,662,439	50.0%	4,240,235	57.5%		
Total Permanent Capitalization	$ 5,149,304	100.0%	$ 7,124,318	100.0%		

(1) Long-term debt balances exclude the current portion of long-term debt and short-term debt. In cases where a company's SEC debt disclosure for fair value vs. carrying value only discloses total debt (including short-term debt and current maturities), the difference between fair value and carrying value was fully applied to the long-term debt balance.

(2) Includes common stock account and retained earnings account; excludes other comprehensive income (loss) and shares in a deferred compensation trust.

ATTACHMENT VVR-11

CAPM METHOD

CAPM Method
Gas LDC Group - Cost of Equity Estimates

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Prospective Market Return

DCF Approach - S&P 500 Index	
Dividend Yield (1)	1.61%
Growth Rate (2)	12.32%
DCF Market Return - S&P 500 (3)	13.93%
DCF Approach - Value Line 1,700 Stock Universe	
Dividend Yield (4)	1.93%
Growth Rate (5)	6.70%
DCF Market Return - Value Line 1,700 Stock Universe (6)	8.63%
Prospective Market Return (Average) (7)	11.28%

Prospective Risk-Free Rate of Return

Blue Chip Financial Forecasts - 30-Year U.S. Treasury Bond Yield Forecast (2022-2026 average) (8)	2.94%
Prospective Market Risk Premium (Average) (9)	8.34%

Historical Market Risk Premium (SBBI Yearbook)

SBBI Yearbook Annual Total Returns (1926-2020) (10)	12.20%
SBBI Yearbook LT Gov't Bond Annual Income Return (1926-2020) (11)	4.90%
Historical Average Market Risk Premium (1926-2019) (12)	7.30%

Currently Implied Market Risk Premium (Supporting Information Only)

SBBI Yearbook LT Gov't Bond Annual Income Return (1926-2019) (11)	4.90%
Recent Average 30-Year U.S. Treasury Bond Yield (13)	2.36%
Historical Gov't Bond Income Return vs. Recent 30-Year Treasury Bond Yield (14)	2.54%
Implied Increase in Market Risk Premium Based on the Finance Literature (15)	1.27%
Currently Implied Market Risk Premium (Supporting Information Only) (16)	8.57%
Indicated Market Risk Premium (17)	7.82%

CAPM Method
Gas LDC Group - Cost of Equity Estimates

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Indicated Market Risk Premium (17)	7.82%
Gas LDC Group Relevered Beta (18)	0.969
Gas LDC Group Risk Premium (19)	7.58%
Prospective Risk-Free Rate of Return (Average) (8)	2.94%
Unadjusted CAPM Result (20)	**10.52%**
Size Premium Adjustment (21)	0.75%
Implied Cost of Equity (CAPM with Size Adjustment) (22)	**11.27%**

Empirical CAPM Model (ECAPM)

Prospective Risk-Free Rate of Return (Average) (8)	2.94%
25% Weighting of Market Risk Premium (23)	1.96%
75% Weighting of Beta x Market Risk Premium (24)	5.69%
Implied Cost of Equity (ECAPM Model) (25)	**10.58%**

Footnotes:

(1) D/P = [$14.64 (cash dividends for Q4, 2020) x 4 (quarters) x (1+(.5) growth rate)]/[$3,862.64) (40-day average closing price through March 15, 2021. Source: www.standardandpoors.com and www.finance.yahoo.com, respectively.

(2) Source: Bloomberg Finance L.P. and Yahoo Finance (accessed March 12, 2021). Average long-term consensus earnings growth estimates for the S&P 500 Index. Average value (12.32%) of EPS growth estimates reported by Bloomberg L.P (13.44%) and Yahoo Finance (11.21%).

(3) (1) + (2) above.

(4) See page 6 of this Attachment. Median estimated dividend yield for the next 12 months for all dividend paying stocks. Value Line Summary & Index; average estimated dividend yield from 13 consecutive weekly reports (December 25, 2020 - March 19, 2021).

(5) See page 6 of this Attachment. The Value Line average median price appreciation potential 3 to 5 years hence is 29.62%. The annual expected price appreciation growth rate based upon the four-year average horizon is 6.70% [(1+.2962)^.25) - 1]. Source: Value Line Summary & Index; average of 13 consecutive weekly reports (December 25, 2020 - March 19, 2021).

(6) (4) + (5) above.

(7) Average of (3) and (6) above.

CAPM Method
Gas LDC Group - Cost of Equity Estimates

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Footnotes (continued)

(8) Interest rate forecasts from Blue Chip Financial Forecasts, Vol. 40, No. 4 (April 1, 2021) and Vol. 39, No. 12 (December 1, 2020).

(9) (7) - (8) above. Result may reflect rounding differences.

(10) SBBI Yearbook (2021, Duff & Phelps), Arithmetic average of total returns for large company (S&P 500) stocks (1926-2020).

(11) SBBI Yearbook (2021, Duff & Phelps), Arithmetic average of the income return for long-term government bonds (1926-2020).

(12) (10) - (11).

(13) Avg. 30-Year U.S. Treasury Bond yield for the period between March 5, 2021 and April 5, 2021 (Source: Federal Reserve Board website).

(14) (11) - (13) above.

(15) (14) x 50%. Reflects historically observed inverse relationship between government interest rates and the market (equity) risk premium, as documented in the finance literature. See the CAPM section of Mr. Rea's direct testimony for a further discussion.

(16) (12) + (15) above. Supporting information only, not included in the determination of the indicated market risk premium in (17) below.

(17) Average of (9) and (12) above.

(18) See CAPM section of Mr. Rea's testimony. Beta adjusted for financial leverage differential in capital structure using the Hamada equation.

(19) (17) x (18) above.

(20) (19) + (8) above.

(21) Duff & Phelps, Cost of Capital Navigator. Size premium (return in excess of CAPM) for Decile 4 portfolios.

(22) (20) + (21) above.

(23) (17) above x 25%.

(24) (17) x (18) above x 75%.

(25) (8) + (23) + (24) above.

CAPM Method
Combination Utility Group - Cost of Equity Estimates

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Indicated Market Risk Premium (26)	7.82%
Combination Utility Group Relevered Beta (27)	0.936
Combination Utility Group Risk Premium (28)	7.32%
Prospective Risk-Free Rate of Return (Average) (29)	2.94%
Unadjusted CAPM Result (30)	**10.26%**
Size Premium Adjustment (31)	0.49%
Implied Cost of Equity (CAPM with Size Adjustment) (32)	**10.75%**

Empirical CAPM Model (ECAPM)

Prospective Risk-Free Rate of Return (Average) (29)	2.94%
25% Weighting of Market Risk Premium (33)	1.96%
75% Weighting of Beta x Market Risk Premium (34)	5.49%
Implied Cost of Equity (ECAPM Model) (35)	**10.39%**

Footnotes:

(26) See pages 1-3 of this Attachment and footnotes 1-17 therein.
(27) See CAPM section of Mr. Rea's testimony. Beta adjusted for financial leverage differential using the Hamada equation.
(28) (26) x (27) above.
(29) See pages 1-3 of this Attachment and footnote 8 therein.
(30) (28) + (29) above.
(31) Duff & Phelps, Cost of Capital Navigator. Size premium (return in excess of CAPM) for Decile 2 portfolios.
(32) (30) + (31) above.
(33) (26) above x 25%.
(34) (26) x (27) above x 75%.
(35) (29) + (33) + (34) above.

CAPM Method
Non-Regulated Group - Cost of Equity Estimates

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Indicated Market Risk Premium (36)	7.82%
Non-Regulated Group Relevered Beta (37)	0.948
Non-Regulated Group Risk Premium (38)	7.42%
Prospective Risk-Free Rate of Return (Average) (39)	2.94%
Unadjusted CAPM Result (40)	**10.35%**
Size Premium Adjustment (41)	-0.22%
Implied Cost of Equity (CAPM with Size Adjustment) (42)	**10.13%**

<u>Empirical CAPM Model (ECAPM)</u>

Prospective Risk-Free Rate of Return (Average) (39)	2.94%
25% Weighting of Market Risk Premium (43)	1.96%
75% Weighting of Beta x Market Risk Premium (44)	5.56%
Implied Cost of Equity (ECAPM Model) (45)	**10.46%**

<u>Footnotes:</u>

(36) See pages 1-3 of this Attachment and footnotes 1-17 therein.
(37) See CAPM section of Mr. Rea's testimony. Beta adjusted for financial leverage differential using the Hamada equation.
(38) (36) x (37) above.
(39) See pages 1-3 of this Attachment and footnote 8 therein.
(40) (38) + (39) above.
(41) Duff & Phelps, Cost of Capital Navigator. Size premium (return in excess of CAPM) for Decile 1 portfolios.
(42) (40) + (41) above.
(43) (36) above x 25%.
(44) (36) x (37) above x 75%.
(45) (39) + (43) + (44) above.

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CAPM Method
Value Line Investment Survey
Median Estimated Dividend Yields and Price Appreciation Potential

Value Line Report Date	Median Estimated Dividend Yields (1)	Median Price Apprec. Potential (2)
3/19/21	1.80%	30.00%
3/12/21	1.90%	30.00%
3/5/21	1.90%	30.00%
2/26/21	1.90%	30.00%
2/19/21	1.90%	30.00%
2/12/21	2.00%	35.00%
2/5/21	1.90%	25.00%
1/29/21	1.90%	25.00%
1/22/21	1.90%	25.00%
1/15/21	2.00%	30.00%
1/8/21	2.00%	30.00%
1/1/21	2.00%	30.00%
12/25/20	2.00%	35.00%
13-Week Average	1.93%	29.62%

Annual Appreciation Return (3-year realization)	9.03%
Annual Appreciation Return (4-year realization)	6.70%
Annual Appreciation Return (5-year realization)	5.33%

Source: Value Line Investment Survey, Summary & Index. Averages derived from 13 consecutive weekly reports, from December 25, 2020 to March 19, 2021.

(1) The Value Line median of estimated dividend yields (for the next 12 months) of all dividend paying stocks under review.

(2) The Value Line estimated median price appreciation potential of all 1,700 stocks in the hypothesized economic environment, 3 to 5 years hence.

ATTACHMENT VVR-12
RPM METHOD

Risk Premium Method (RPM)
Gas LDC Group - Indicated Cost of Equity

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Prospective "Aaa" Rated Corporate Bond Yield (1)	3.67%
Yield/Credit Spread Adjustment Between "Aaa" Rated Corporate Bond Yields and "A" Rated Public Utility Bond Yields (2)	0.55%
Prospective "A" Rated Public Utility Bond Yield (3)	4.23%
Yield/Credit Spread Adjustment Between "A" Rated Public Utility Bonds and A-/A3 Average Rating of the Gas LDC Group (4)	0.12%
Prospective Bond Yield for Gas LDC Group (5)	4.35%
Equity Risk Premium	
- Total Market Index Approach (6)	6.44%
- Public Utility Index Approach (7)	5.45%
Indicated Equity Risk Premium (8)	5.95%
Indicated Cost of Equity - Gas LDC Group (9)	10.30%

(1) See page 2 of this Attachment. Average prospective "Aaa" bond yield for the 2022-2026 period from the Blue Chip Financial Forecasts.
(2) See page 3 of this Attachment. Yield adjustment derived from historical corporate bond yield data (recent 12 months) found in the Mergent Bond Record.
(3) Sum of (1) and (2) above.
(4) Adjustment to reflect credit spread differential between "A" rated public utility bonds and "A-"/"A3" rating of the Gas LDC Group, as reflected on page 3 of this Attachment. The 0.12% adjustment was derived via simple linear interpolation between the yield spread differential for the "Baa" rated and "A" rated public utility bonds, respectively ((0.92%-0.55%)/3) = 0.123%).
(5) Sum of (3) and (4) above, subject to rounding.
(6) See page 4 of this Attachment.
(7) See page 5 of this Attachment.
(8) Average of (6) and (7) above.
(9) Sum of (5) and (8) above.

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Risk Premium Method (RPM)
Blue Chip Financial Forecasts - Consensus Forecasts

Six Quarter Forecast (Q2, 2021 - Q3, 2022)

Quarter/Year	"Aaa" Rated Corp. Bonds	"Baa" Rated Corp. Bonds
Q2, 2021 (1)	3.00%	3.90%
Q3, 2021 (1)	3.10%	4.00%
Q4, 2021 (1)	3.20%	4.10%
Q1, 2022 (1)	3.30%	4.20%
Q2, 2022 (1)	3.40%	4.30%
Q3, 2022 (1)	3.40%	4.40%
Six-Quarter Avg.	3.20%	4.10%

Three and Five Year Forecasts

Year	"Aaa" Rated Corp. Bonds	"Baa" Rated Corp. Bonds
2022 (1)	3.37%	4.30%
2023 (2)	3.20%	4.30%
2024 (2)	3.60%	4.70%
2025 (2)	4.00%	5.00%
2026 (2)	4.20%	5.20%
2022-2024 Avg.	3.39%	4.43%
2022-2026 Avg.	3.67%	4.70%

(1) Blue Chip Financial Forecasts, Vol. 40, No. 4, April 1, 2021 (6-quarter consensus forecast).

(2) Blue Chip Financial Forecasts, Vol. 39, No. 12, December 1, 2020 (long-range consensus forecast).

Risk Premium Method (RPM)
Historical Corporate Bond Yield Spread Differentials (March 2020 - February 2021)
Based on Moody's Long-Term Credit Ratings

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	Corporate Bonds			Public Utility Bonds			Bond Yield Spread Differentials		
Period	"Aaa" Rated	"A" Rated	"Baa" Rated	"Aa" Rated	"A" Rated	"Baa" Rated	"Aa" (Pub. Util.) vs. "Aaa" Corp.	"A" (Pub. Util.) vs. "Aaa" Corp.	"Baa" (Pub. Util.) vs. "Aaa" Corp.
Mar-20	3.02%	3.43%	4.29%	3.30%	3.50%	3.96%	0.28%	0.48%	0.94%
Apr-20	2.43%	3.12%	4.13%	2.93%	3.19%	3.82%	0.50%	0.76%	1.39%
May-20	2.49%	3.12%	3.95%	2.89%	3.14%	3.63%	0.40%	0.65%	1.14%
Jun-20	2.44%	3.02%	3.64%	2.80%	3.07%	3.44%	0.36%	0.63%	1.00%
Jul-20	2.14%	2.69%	3.31%	2.46%	2.74%	3.09%	0.32%	0.60%	0.95%
Aug-20	2.25%	2.68%	3.27%	2.49%	2.73%	3.06%	0.24%	0.48%	0.81%
Sep-20	2.31%	2.79%	3.36%	2.62%	2.84%	3.17%	0.31%	0.53%	0.86%
Oct-20	2.35%	2.88%	3.44%	2.72%	2.95%	3.27%	0.37%	0.60%	0.92%
Nov-20	2.30%	2.79%	3.30%	2.63%	2.85%	3.17%	0.33%	0.55%	0.87%
Dec-20	2.26%	2.72%	3.16%	2.57%	2.77%	3.05%	0.31%	0.51%	0.79%
Jan-21	2.45%	2.84%	3.24%	2.73%	2.91%	3.18%	0.28%	0.46%	0.73%
Feb-21	2.70%	3.03%	3.42%	2.93%	3.09%	3.37%	0.23%	0.39%	0.67%
12-Month Average	2.43%	2.93%	3.54%	2.76%	2.98%	3.35%	0.33%	0.55%	0.92%

Source: Mergent Bond Record, March 2021, Volume 87, No. 3. Moody's Long-Term Corporate Bond Yield averages reference corporate and utility bonds with maturities as close as possible to 30 years.

Risk Premium Method (RPM)
Equity Risk Premium Using Total Market Approach
Gas LDC Group

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Historical Equity Risk Premium

Annual Total Returns for S&P 500 Composite Index, Arithmetic Average (1926-2020) (1)	12.20%
Annual Total Returns for Long-Term Corporate Bonds, Arithmetic Average (1926-2020) (2)	6.50%
Historical Equity Risk Premium - Total Market (3)	5.70%

Prospective Equity Risk Premium

Prospective Equity Market Annual Return (Next 3-5 years) (4)	11.28%
Prospective "Aaa" Rated Corporate Bond Yield (5)	3.67%
Prospective Equity Risk Premium - Total Market (6)	7.61%
Indicated Equity Risk Premium - Total Market (7)	6.65%
Relevered Beta - Gas LDC Group (8)	0.9690
Equity Risk Premium (with Relevered Beta) (9)	6.44%

(1) Source: 2021 SBBI Yearbook (Duff & Phelps); arithmetic average of total returns for large company stocks (S&P 500 Index) (1926-2020).
(2) Source: 2021 SBBI Yearbook (Duff & Phelps), arithmetic average of total returns for long-term high-grade corporate bonds (1926-2020).
(3) (1) - (2) above.
(4) From page 1 of Attachment VVR-11.
(5) From pages 1 and 2 of this Attachment.
(6) (4) - (5) above.
(7) Average of (3) and (6) above.
(8) See CAPM section of Mr. Rea's testimony.
(9) (7) x (8) above.

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Risk Premium Method (RPM)
Equity Risk Premium - Public Utility Index Approach
Gas LDC Group and Combination Utility Group

Historical Equity Risk Premium - Public Utility Index Approach

Annual Holding Period Returns for S&P 500 Utilities Index, Arithmetic Average (1926-2020) (1)	10.83%
Annual Yield on Moody's "A" Rated Public Utility Bonds, Arithmetic Average (1926-2020) (2)	6.28%
Equity Risk Premium (Historical) - Public Utility Index Approach (3)	4.55%

Currently Implied Equity Risk Premium - Public Utility Index Approach

DCF Approach - S&P 500 Utilities Index	
Dividend Yield (4)	3.63%
Growth Rate (5)	5.72%
DCF Market Return - S&P Utilities Index (6)	9.35%
Most Recent 2-Month Average of Moody's "A" Rated Public Utility Bond Yields (7)	3.00%
Equity Risk Premium (Currently Implied) - S&P 500 Utilities (8)	6.35%
Indicated Equity Risk Premium - Public Utility Index Approach (9)	5.45%

(1) Source: S&P 500 Utilities Index historical data (currently comprised of 28 utility companies). See page 6 of this Attachment.
(2) Source: Moody's Public Utility Manual and Mergent Bond Record. Historical yields on "A" rated utility bonds, representing the midpoint of Moody's reported utility credit ratings (Aa/A/Baa). See page 6 of this Attachment.
(3) (1) - (2) above.
(4) Source: www.spindices.com. Most recently reported dividend yield for S&P 500 Utilities Index companies.
(5) Source: Bloomberg Finance LP and Yahoo Finance (accessed March 12, 2021). Average long-term consensus earnings growth estimate for the S&P 500 Utilities Index (negative growth rates removed from average values.
(6) (4) + (5) above.
(7) See page 3 of this Attachment.
(8) (6) - (7) above. Subject to rounding differences.
(9) Average of (3) and (8) above.

Risk Premium Method (RPM)
Historical Returns for Utility Indices (1926-2020)

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Year	S&P 500 Utilities Index	Moody's "A" Rated Utility Bond Yields	Moody's "Baa" Rated Utility Bond Yields
1926	5.38%	5.17%	5.67%
1927	28.99%	5.02%	5.46%
1928	56.94%	4.95%	5.33%
1929	11.98%	5.22%	5.76%
1930	-20.89%	5.06%	5.88%
1931	-34.45%	5.12%	6.90%
1932	-0.85%	6.46%	8.78%
1933	-20.30%	6.32%	9.38%
1934	-18.08%	5.55%	7.49%
1935	74.61%	4.61%	5.56%
1936	20.99%	4.08%	4.67%
1937	-35.64%	3.98%	5.09%
1938	21.92%	3.90%	5.26%
1939	11.71%	3.52%	4.50%
1940	-16.30%	3.24%	4.05%
1941	-30.50%	3.07%	3.84%
1942	14.25%	3.09%	3.73%
1943	47.07%	2.99%	3.58%
1944	18.23%	2.97%	3.52%
1945	53.66%	2.87%	3.39%
1946	2.66%	2.71%	3.03%
1947	-11.85%	2.78%	3.08%
1948	4.67%	3.02%	3.36%
1949	30.99%	2.90%	3.28%
1950	3.26%	2.79%	3.18%
1951	18.02%	3.11%	3.39%
1952	18.55%	3.24%	3.53%
1953	7.45%	3.49%	3.73%
1954	24.18%	3.16%	3.51%
1955	11.07%	3.22%	3.43%
1956	5.05%	3.56%	3.78%
1957	6.33%	4.24%	4.46%
1958	39.86%	4.20%	4.43%
1959	7.46%	4.78%	4.96%
1960	19.85%	4.78%	4.97%
1961	29.04%	4.62%	4.83%
1962	-2.61%	4.54%	4.75%
1963	12.26%	4.39%	4.67%
1964	15.69%	4.52%	4.74%
1965	4.67%	4.58%	4.78%
1966	-4.60%	5.39%	5.60%
1967	-0.59%	5.87%	6.15%
1968	5.45%	6.51%	6.87%
1969	-11.28%	7.54%	7.93%
1970	15.67%	8.69%	9.18%
1971	2.22%	8.16%	8.63%
1972	7.57%	7.72%	8.17%
1973	-17.59%	7.84%	8.17%

Year	S&P 500 Utilities Index	Moody's "A" Rated Utility Bond Yields	Moody's "Baa" Rated Utility Bond Yields
1974	-21.13%	9.50%	9.84%
1975	43.23%	10.09%	10.96%
1976	30.48%	9.29%	9.82%
1977	8.37%	8.61%	9.06%
1978	-3.53%	9.29%	9.62%
1979	13.27%	10.49%	10.96%
1980	14.27%	13.34%	13.95%
1981	11.19%	15.95%	16.60%
1982	24.90%	15.86%	16.45%
1983	19.47%	13.66%	14.20%
1984	24.47%	14.03%	14.53%
1985	31.64%	12.47%	12.96%
1986	28.08%	9.58%	10.00%
1987	-2.51%	10.10%	10.53%
1988	17.75%	10.49%	11.00%
1989	45.82%	9.77%	9.97%
1990	-2.83%	9.86%	10.06%
1991	13.98%	9.36%	9.55%
1992	7.64%	8.69%	8.86%
1993	14.38%	7.59%	7.91%
1994	-7.88%	8.31%	8.63%
1995	40.86%	7.89%	8.29%
1996	2.90%	7.75%	8.17%
1997	23.68%	7.60%	7.95%
1998	14.39%	7.04%	7.26%
1999	-8.67%	7.62%	7.88%
2000	58.55%	8.24%	8.36%
2001	-30.05%	7.76%	8.03%
2002	-29.99%	7.37%	8.02%
2003	26.26%	6.58%	6.84%
2004	24.28%	6.16%	6.40%
2005	16.84%	5.65%	5.92%
2006	20.99%	6.07%	6.32%
2007	19.38%	6.07%	6.33%
2008	-28.98%	6.52%	7.23%
2009	11.91%	6.05%	7.06%
2010	5.46%	5.45%	5.95%
2011	19.91%	5.04%	5.57%
2012	1.29%	4.13%	4.86%
2013	13.21%	4.48%	4.98%
2014	28.98%	4.28%	4.80%
2015	-4.85%	4.12%	5.03%
2016	16.29%	3.93%	4.68%
2017	12.11%	4.00%	4.38%
2018	4.11%	4.25%	4.67%
2019	26.35%	3.77%	4.19%
2020	0.48%	3.02%	3.39%
Average	10.83%	6.28%	6.81%

Risk Premium Method (RPM)
Combination Utility Group - Indicated Cost of Equity

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Prospective "Aaa" Rated Corporate Bond Yield (1)	3.67%
Yield/Credit Spread Adjustment Between "Aaa" Rated Corporate Bond Yields and "A" Rated Public Utility Bond Yields (2)	0.55%
Prospective "A" Rated Public Utility Bond Yield (3)	4.23%
Yield/Credit Spread Adjustment Between "A" Rated Public Utility Bonds and A- /Baa1 Rating of the Combination Utility Group (4)	0.19%
Prospective Bond Yield for Combination Utility Group (5)	4.41%
Equity Risk Premium	
- Total Market Index Approach (6)	6.23%
- Public Utility Index Approach (7)	5.45%
Indicated Equity Risk Premium (8)	5.84%
Indicated Cost of Equity - Combination Utility Group (9)	10.25%

(1) See pages 2, 11 and 12 of this Attachment. Average prospective Aaa bond yield for the 2022-2026 period from the Blue Chip Financial Forecasts.

(2) See page 3 of this Attachment. Yield adjustment derived from historical corporate bond yield data (recent 12 months) found in Mergent Bond Record Monthly Update.

(3) Sum of (1) and (2) above.

(4) Adjustment to reflect bond yield/credit spread differential between "A" rated Public Utility Bonds and "A-"/"Baa1" rating of the Combination Utility Group, as reflected on page 3 of this Attachment. The 0.19% adjustment was derived via linear interpolation between the yield spread differential for the "A" rated and "Baa" rated Public Utility Bonds ((0.92% -0.55%)/3*1.5=0.19%).

(5) (3) + (4) above. May reflect rounding differences.

(6) See page 8 of this Attachment.

(7) See page 5 of this Attachment.

(8) Average of (6) and (7) above.

(9) Sum of (5) and (8) above.

Risk Premium Method (RPM)
Equity Risk Premium Using Total Market Approach
Combination Utility Group

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Historical Equity Risk Premium	
Annual Total Returns for S&P 500 Index, Arithmetic Average (1926-2020) (1)	12.20%
Annual Total Returns for Long-Term Corporate Bonds, Arithmetic Average (1926-2020) (2)	6.50%
Historical Equity Risk Premium - Total Market (3)	5.70%
Prospective Equity Risk Premium	
Prospective Annual Market Return (Next 3-5 years) (4)	11.28%
Prospective Aaa Rated Corporate Bond Yield (5)	3.67%
Prospective Equity Risk Premium - Total Market (6)	7.61%
Indicated Equity Risk Premium - Total Market (7)	6.65%
Relevered Beta - Combination Utility Group (8)	0.936
Equity Risk Premium (with Relevered Beta) (9)	6.23%

(1) Source: 2021 SBBI Yearbook (Duff & Phelps); arithmetic average of total returns for large company stocks (S&P 500 Index) (1926-2020).
(2) Source: 2021 SBBI Yearbook (Duff & Phelps); arithmetic average of total returns for long-term high-grade corporate bonds (1926-2020).
(3) (1) - (2) above.
(4) From page 1 of Attachment VVR-11.
(5) From pages 1 and 2 of this Attachment.
(6) (4) - (5) above.
(7) Average of (3) and (6) above.
(8) See CAPM section of Mr. Rea's testimony.
(9) (7) x (8) above.

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Case No. 2021-00183
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Risk Premium Method (RPM)
Non-Regulated Group - Indicated Cost of Equity

Prospective "Aaa" Rated Corporate Bond Yield (1)	3.67%
Yield/Credit Spread Adjustment Between "Aaa" Rated Corporate Bond Yield and Average "A- /A3" Rated Corp. Bond Yield of Non-Regulated Group (2)	0.70%
Prospective Bond Yield for Non-Regulated Group (3)	4.38%
Equity Risk Premium	
- Total Market Index Approach (4)	6.31%
Indicated Equity Risk Premium	6.31%
Indicated Cost of Equity - Non-Regulated Group (5)	10.69%

(1) See pages 2, 11 and 12 of this Attachment. Average prospective Aaa bond yield for the 2022-2026 period from the Blue Chip Financial Forecasts.

(2) See page 3 of this Attachment. Yield adjustment derived from historical corporate bond yield data (recent 12 months) found in Mergent Bond Record (March 2021). Yield differential between "Aaa" corporate bonds and "A3" rated corporate bonds.

(3) (1) + (2) above.

(4) See page 10 of this Attachment.

(5) Sum of (3) and (4) above.

Risk Premium Method (RPM)
Equity Risk Premium Using Total Market Approach
Non-Regulated Group

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Historical Equity Risk Premium

Annual Total Returns for S&P 500 Index, Arithmetic Average (1926-2020) (1)	12.20%
Annual Total Returns for Long-Term Corporate Bonds, Arithmetic Average (1926-2020) (2)	6.50%
Historical Equity Risk Premium - Total Market (3)	5.70%

Prospective Equity Risk Premium

Prospective Annual Market Return (Next 3-5 years) (4)	11.28%
Prospective Aaa Rated Corporate Bond Yield (5)	3.67%
Prospective Equity Risk Premium - Total Market (6)	7.61%
Indicated Equity Risk Premium - Total Market (7)	6.66%
Relevered Beta - Non-Regulated Group (8)	0.948
Equity Risk Premium (with Relevered Beta) (9)	6.31%

(1) Source: 2021 SBBI Yearbook (Duff & Phelps); arithmetic average of total returns for large company stocks (S&P 500 Index) (1926-2020).
(2) Source: 2021 SBBI Yearbook (Duff & Phelps), arithmetic average of total returns for long-term high-grade corporate bonds (1926-2020).
(3) (1) - (2) above.
(4) From page 1 of Attachment VVR-11.
(5) From pages 1 and 2 of this Attachment.
(6) (4) - (5) above.
(7) Average of (3) and (6) above.
(8) See CAPM section of Mr. Rea's testimony.
(9) (7) x (8) above.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of John J. Spanos attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

John J. Spanos

Columbia Exhibit No. 25

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFI-CATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

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

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	
	)	

VERIFICATION OF JOHN SPANOS

STATE OF PENNSYLVANIA	)
	)
COUNTY OF CUMBERLAND	)

John Spanos, President of Gannett Fleming Valuation and Rate Consultants, LLC, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of his Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

John J. Spanos

John Spanos

The foregoing Verification was signed, acknowledged and sworn to before me this 17th day of May, 2021, by John Spanos.

Commonwealth of Pennsylvania - Notary Seal
MEGAN LYNN ECKRICH - Notary Public
Cumberland County
My Commission Expires Sep 16, 2023
Commission Number 1264513

My Lynn Eckrich

Notary Commission No. 1264513

Commission expiration: Sep. 16, 2023

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Attachments

PREPARED DIRECT TESTIMONY OF JOHN J. SPANOS

I. INTRODUCTION

Q. Please state your name and address.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

Q. Are you associated with any firm?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since June 1986.

Q. What is your position with the firm?

A. I am President.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of Columbia Gas of Kentucky, Inc. ("Columbia" or "Company").

Q. Please state your qualifications.

A. I have over 34 years of depreciation experience, which includes expert testimony in over 360 cases before 41 regulatory commissions. The cases include depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have also supervised over 700 other depreciation or valuation assignments. Please refer to Attachment JJS-1 for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony will support and explain the Depreciation Study performed for Columbia in accordance with the Filing Requirement under 807 KAR 5:001 Section 16-(7)(s). The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of December 31, 2020. I also support the deprecation accrual rates by account for the forecasted period as of December 31, 2022. I also sponsor and support 807 KAR 5:001 Section 16-(7)(c).

Q. Please summarize the results of your Depreciation Study.

A. The depreciation rates as of December 31, 2020 appropriately reflect the rates at which the value of Columbia's assets has been consumed over their useful lives to date. These rates are based on the most commonly used methods and procedures for determining depreciation rates. The life and salvage parameters are based on widely used techniques and the depreciation rates are based on the average service life procedure and remaining life method.

Q. Are the recommended depreciation accrual rates presented in your study reasonable and applicable to the plant in service as of December 31, 2020?

A. Yes, they are. Based on the Depreciation Study, I am recommending depreciation rates using the December 31, 2020 plant and reserve balances for approval. I am also recommending depreciation rates using the forecasted December 31, 2022 plant and reserve balances.

Q. What is the Effect of the Recommended Depreciation Accrual Rates as Compared to Currently Approved Accrual Rates?

A. The Depreciation Study results establish an increase of approximately $1.0 million in depreciation expense as of December 31, 2020 related to the depreciable plant in service. The amortizable plant expense was provided by the Company on an individual asset basis so there is not change for those assets. This increase is primarily the result of changes in some life parameters and net salvage accruals as well as the complete recovery of general plant assets.

III. DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. Was your Depreciation Study included as part of the application filed in this case?

A. Yes, it is included as a report entitled "2020 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2020." This report sets forth the results of my Depreciation Study for Columbia.

Q. Is the study a true and accurate copy of your Depreciation Study?

A. Yes.

Q. Was the Depreciation Study prepared under your direction and control?

A. Yes.

Q. In preparing the Depreciation Study, did you follow generally accepted practices in the field of depreciation valuation?

A. Yes.

Q. What is the purpose of the Depreciation Study?

A. The purpose of my Deprecation Study was to estimate the annual depreciation accruals for Columbia's plant in service for financial and ratemaking purposes and to determine appropriate average service lives and net salvage percentages for each plant account.

Q. Are the methods and procedures of this Depreciation Study consistent with Columbia's past practices?

A. The depreciation methods and procedures of this study are the same as those utilized in the past by Columbia. The rates determined in this Depreciation Study are based on the average service life procedure and the remaining life method.

Q. Please describe the contents of the Depreciation Study.

A. The Depreciation Study is presented in nine parts: Part I, Introduction, presents the scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining service life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account.

Table 1 on pages VI-4 through VI-6 of the Depreciation Study presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2020, the book reserve, and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2020.

Q. Please explain how you performed your Depreciation Study.

A. I used the straight line remaining life method of depreciation, with the equal life group procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner.

For General Plant Accounts 391.1,391.11, 391.12, 394, 395 and 398, I used the straight line remaining life method of amortization.[1] The annual amortization is

[1] The account numbers identified throughout my testimony represent those in effect as of December 31, 2020.

based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. How did you determine the recommended annual depreciation accrual rates?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

Q. Please describe the first phase of the Depreciation Study, in which you estimated the service life and net salvage characteristics for each depreciable group.

A. The service life and net salvage study consisted of compiling historical data from records related to Columbia's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from Columbia's management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the data and the estimates used by other gas utilities to form judgments of average service life and net salvage characteristics.

Q. What historical data did you analyze for the purpose of estimating service life characteristics?

A. I analyzed Columbia's accounting entries that record plant transactions during the period 1939 through 2020, to the extent available. The transactions I analyzed included additions, retirements, transfers, sales, and the related balances. Columbia's records included surviving dollar value by year installed for each plant account as of December 31, 2020.

Q. What method did you use to analyze these service life data?

A. I used the retirement rate method for most plant accounts. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by Columbia during the period of time covered by the Depreciation Study.

Q. Please describe how you used the retirement rate method to analyze Columbia's service life data.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The "Iowa-type survivor curves" were used to perform these interpretations.

Q. What are "Iowa-type survivor curves" and how did you use such curves to estimate the service life characteristics for each property group?

A. Iowa-type survivor curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. These curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type survivor curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in the Columbia Depreciation Study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 69-R1.5 indicates an average service life of sixty-nine years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 1.5, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. Did you physically observe Columbia's plant and equipment as part of your depreciation assignments?

A. Yes. I have made field reviews of Columbia's property on March 18 and 19, 2002, October 27 and 28, 2008, February 4 and 5, 2013 and April 7, 2021 to observe representative portions of plant. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge, as well as information from other discussions with Columbia management, was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. How did your experience in development of other depreciation studies affect your work in this case for Columbia?

A. Because I customarily conduct field reviews for my depreciation studies, I have had the opportunity to visit scores of similar facilities and meet with operations personnel at many other companies. The knowledge I have accumulated from those visits and meetings provides me with useful information to draw upon to confirm or challenge my numerical analyses concerning asset condition and remaining life estimates.

Q. Please explain the concept of "net salvage."

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire the asset exceeds the salvage value, the result is negative net salvage.

Because depreciation expense is the loss in service value of an asset during a defined period (*e.g.*, one year), it must include a ratable portion of both the original cost of the asset and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost, so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

For example, the full service value of a $500 regulator will include not only the $500 of original cost, but also, on average $100 to remove the regulator at the end of its life and $25 in salvage value. In this example, the net salvage component is negative $75 ($25 - $100), and the net salvage percent is negative 15% (($25 - $100)/$500).

Q. Please describe how you estimated net salvage percentages.

A. I estimated the net salvage percentages by incorporating Columbia' actual historical data for the period 1969 through 2020; considered information provided to me by the Company's operating personnel; and reviewed industry experience of net salvage estimates for other gas companies. Thus, net salvage percentages in the Depreciation Study are based on a combination of statistical analyses and informed judgment. The statistical analyses consider the cost of removal and gross salvage ratios to the associated retirements during the 52-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Q. Please describe the second phase of the process that you used in the Depreciation Study in which you calculated composite remaining lives and annual depreciation accrual rates.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group using the straight line remaining life method, and using remaining lives weighted consistent with the equal life group procedure. The calculation of annual depreciation accrual rates was developed as of December 31, 2020.

Q. Please describe the straight line remaining life method of depreciation.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please describe the average service life procedure for calculating remaining life accrual rates.

A. The average service life procedure defines the group or account for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and the rate is then applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. The sum of the future book accruals is then divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. Please describe amortization accounting in contrast to depreciation accounting.

A. Amortization accounting is used for accounts with a large number of units, but small asset values. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, depreciation accounting is difficult for these types of assets because depreciation accounting requires periodic inventories to properly reflect plant in service. Consequently, amortization accounting is used for these types of assets, such that retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement in amortization accounting. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period that represents an anticipated life during which the asset will render full benefit. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off Columbia's books at that time, but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. Is amortization accounting being utilized for certain plant accounts?

A. Yes. However, amortization accounting is only appropriate for certain General Plant accounts. These accounts are 391.1, 391.11, 391.12, 394, 395 and 398, which represent slightly more than one percent of Columbia's depreciable plant.

Q. Please use an example to illustrate how the annual depreciation accrual rate for a particular group of property is presented in your Depreciation Study.

A. I will use Account 380.00, Services, as an example because it is one of the larger depreciable accounts and represents approximately 29 percent of depreciable plant. The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1939 through 2020 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1939-2020, 1981-2020 and 2001-2020 experience bands are presented on pages VII-51 through VII-56 of the Depreciation Study. The life tables display the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-51 of the study shows $665,961 retired at age 0.5 with $179,245,982 exposed to retirement. Consequently, the retirement ratio is 0.0037 and the surviving ratio is 0.9963. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 41-R1 on page VII-50 of the study.

The net salvage analyses for Account 380.00, Services, is presented on pages VIII-17 through VIII-19 of the Depreciation Study. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1969 through 2020. This 52-year period experienced $18,412,166 ($73,097 - $18,485,262) in negative net salvage for $27,360,798 plant retired. The result is negative net salvage of 67 percent ($18,412,166/$27,360,798). Based on the overall negative 67 percent net salvage and the most recent five years of negative 69 percent, as well as industry ranges and Columbia's expectations, it was determined that negative 70 percent is the most appropriate estimate.

My calculation of the annual depreciation related to the original cost as of December 31, 2020, of gas plant is presented on pages IX-22 and IX-23 of the study. The calculation is based on the 41-R1 survivor curve, 70 percent negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page VI-4 of the Depreciation Study.

Q. Was there separate life and net salvage analysis performed for the sub-accounts of Account 376, Mains?

A. No, there was not. The historical data did not maintain a type pipe identifier, but historical balances were available by type pipe therefore, separate life characteristics could not be accurately studied. Thus, one common service life and net salvage estimate for all mains. The common survivor curve and net salvage percent was applied to the surviving balance as of December 31, 2020 by subaccount.

Q. Explain what was different at the subaccount level.

A. A main replacement program has been established for bare steel and cast iron mains. The program is a 30-year program, starting at the beginning of 2008, and at the end of the 30 years all bare steel and cast iron pipe will have been replaced. Therefore, the depreciation rates must be established to match capital recovery to life expectancy. In order to accomplish the appropriate matching principle, the surviving bare steel and cast iron investment must be recovered by year-end 2037. Consequently, the annual depreciation rate for bare steel and cast iron in Account 376 has a truncation date of December 2037. This is consistent with the current practices and depreciation rates.

Q. Please explain how you calculated the forecasted depreciation rates as of December 31, 2022.

A. First, the plant in service and book reserve were brought forward from December 31, 2020 to December 31, 2022 based on the capital budget by account and by year. The book reserve by account as of December 31, 2022 was developed by adding the annual accruals and gross salvage each month and subtracting retirements and cost of removal each month for the two-year period. Once the plant in service as of December 31, 2022 was developed by vintage within account and the book reserve is developed by account, then the December 31, 2022 depreciation rates were calculated using the same methods and procedures as in the 2020 Depreciation Study. Attachment JJS-2 sets forth the depreciation rates and expense as of December 31, 2022.

Q. Does this complete your Prepared Direct testimony?

A. Yes, it does.

ATTACHMENT JJS-1
DEPRECIATION EXPERIENCE

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013 and February 2018.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso

Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of

Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire and Newtown Artesian Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana

Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

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	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Corporation	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Cause No. 45029	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
331.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
334.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
335.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
336.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
337.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
338.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
339.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
340.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
341.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
342.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
343.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
344.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
345.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
346.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
347.	2020	OR PSC	UE 374	Pacificorp	Depreciation
348.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
349.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
350.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy	Depreciation
351.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
352.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
353.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
354.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
355.	2020	OR PSC	UE 388	Northwest Natural Gas Company	Depreciation
356.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
357.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
358.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
359.	2021	NC Util. Com.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
360.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
361.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation

ATTACHMENT JJS-2
2022 CALCULATED ANNUAL DEPRECIATION ACCRURALS

Columbia Gas of Kentucky
A NiSource Company

2022 CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

Prepared by:

Gannett Fleming

Excellence Delivered ***As Promised***

RESULTS OF STUDY

COLUMBIA GAS OF KENTUCKY, INC.

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

	DEPRECIABLE GROUP (1)	SURVIVOR CURVE (2)	NET SALVAGE (3)	ORIGINAL COST AS OF DECEMBER 31, 2022 (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE BOOK ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
DEPRECIABLE PLANT									
DISTRIBUTION PLANT									
	LAND AND LAND RIGHTS								
374.40	LAND RIGHTS	75-R2	0	1,388,835.56	308,653	1,080,183	17,585	1.27	61.4
374.50	RIGHTS OF WAY	80-S4	0	2,655,883.52	1,112,689	1,543,195	29,470	1.11	52.4
	TOTAL LAND AND LAND RIGHTS			4,044,719.08	1,421,342	2,623,378	47,055	1.16	
	STRUCTURES AND IMPROVEMENTS								
375.34	MEASURING AND REGULATING	55-S0	(25)	3,015,161.90	609,098	3,159,854	69,734	2.31	45.3
375.70	OTHER DISTRIBUTION SYSTEM								
	DISTRIBUTION SYSTEM STRUCTURES	SQUARE *	0	14,136,188.68	4,474,304	9,661,884	297,332	2.10	32.5
	OTHER BUILDINGS	40-S2.5	0	506,347.21	80,656	425,691	12,775	2.52	33.3
	TOTAL OTHER DISTRIBUTION SYSTEM			14,642,535.89	4,554,960	10,087,575	310,107	2.12	
	TOTAL STRUCTURES AND IMPROVEMENTS			17,657,697.79	5,164,058	13,247,429	379,841	2.15	
376.00	MAINS								
	CAST IRON	69-R1.5 *	(20)	93,161.71	91,045	20,749	1,659	1.78	12.5
	BARE STEEL	69-R1.5 *	(20)	15,981,010.62	15,358,004	3,819,209	297,986	1.86	12.8
	COATED STEEL	69-R1.5	(20)	82,595,259.80	18,389,416	80,724,896	1,464,791	1.77	55.1
	PLASTIC	69-R1.5	(20)	305,347,633.26	29,851,324	336,565,836	5,423,262	1.78	62.1
	TOTAL MAINS			404,017,065.39	63,689,789	421,130,690	7,187,698	1.78	
378.00	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	42-O1	(15)	24,068,130.63	4,438,113	23,240,237	603,678	2.51	38.5
379.10	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	44-R1.5	(15)	1,554,144.06	343,303	1,443,963	37,259	2.40	38.8
380.00	SERVICES	41-R1	(70)	187,829,178.68	74,480,919	244,828,685	7,483,144	3.98	32.7
381.00	METERS	37-S0.5	3	17,009,757.05	5,451,145	11,048,319	436,456	2.57	25.3
381.10	METERS - AMI	15-S2.5	0	9,675,401.94	4,578,646	5,096,756	689,394	7.13	7.4
382.00	METER INSTALLATIONS	45-R3	(5)	9,895,104.53	5,652,953	4,736,907	175,565	1.77	27.0
383.00	HOUSE REGULATORS	50-S1.5	(5)	7,060,998.88	2,263,896	5,150,153	138,383	1.96	37.2
384.00	HOUSE REGULATOR INSTALLATIONS	43-S2.5	0	2,085,058.65	1,711,016	374,043	20,056	0.96	18.6
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	33-R0.5	(15)	5,523,092.66	1,294,352	5,057,205	198,920	3.60	25.4
387.40	OTHER EQUIPMENT - CUSTOMER INFORMATION SERVICES	34-R2	(5)	6,801,894.37	2,034,975	5,107,014	217,302	3.19	23.5
387.50	OTHER EQUIPMENT - GPS PIPE LOCATORS	10-L3	0	213,381.19	79,760	133,621	27,494	12.88	4.9
TOTAL DISTRIBUTION PLANT				**697,435,624.90**	**172,604,267**	**743,218,400**	**17,642,245**	**2.53**	
GENERAL PLANT									
	OFFICE FURNITURE AND EQUIPMENT								
391.10	FURNITURE	20-SQ	0	878,751.56	247,268	631,484	43,932	5.00	14.4
391.12	INFORMATION SYSTEMS	5-SQ	0	78,704.61	62,961	15,744	15,744	20.00	1.0
	TOTAL OFFICE FURNITURE AND EQUIPMENT			957,456.17	310,229	647,228	59,676	6.23	

COLUMBIA GAS OF KENTUCKY, INC.

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, NET SALVAGE PERCENT, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AS OF DECEMBER 31, 2022

	DEPRECIABLE GROUP	SURVIVOR CURVE	NET SALVAGE	ORIGINAL COST AS OF DECEMBER 31, 2022	BOOK DEPRECIATION RESERVE	FUTURE BOOK ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
392.20	TRANSPORTATION EQUIPMENT - TRAILERS	17-L4	10	120,240.20	101,253	6,963	1,041	0.87	6.7
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	4,518,616.22	1,484,323	3,034,293	180,777	4.00	16.8
395.00	LABORATORY EQUIPMENT	20-SQ	0	4,162.05	3,850	312	208	5.00	1.5
396.00	POWER OPERATED EQUIPMENT	19-S0.5	20	185,547.00	149,011	(573)	0	-	-
398.00	MISCELLANEOUS EQUIPMENT	15-SQ	0	101,687.15	71,949	29,738	6,779	6.67	4.4
TOTAL GENERAL PLANT				**5,887,708.79**	**2,120,615**	**3,717,961**	**248,481**	**4.22**	
UNRECOVERED RESERVE TO BE AMORTIZED									
391.10	FURNITURE				(92,663)		92,663 **		
391.11	EQUIPMENT				(10,327)		10,327 **		
391.12	INFORMATION SYSTEMS				(34,085)		34,085 **		
394.00	EQUIPMENT				22,347		(22,347) **		
395.00	LABORATORY EQUIPMENT				(4)		4 **		
398.00	MISCELLANEOUS EQUIPMENT				(5,741)		5,741 **		
TOTAL UNRECOVERED RESERVE TO BE AMORTIZED					**(120,473)**		**120,473**		
TOTAL DEPRECIABLE PLANT				**703,323,333.69**	**174,604,409**	**746,936,361**	**18,011,199**	**2.56**	
AMORTIZABLE PLANT									
303.00	MISCELLANEOUS INTANGIBLE PLANT			10,661,877.21	4,745,167	5,916,511	1,993,429	***	
303.99	MISCELLANEOUS INTANGIBLE PLANT - CLOUD			2,717,564.99	324,077	2,393,488	116,974	***	
375.71	STRUCTURES AND IMPROVEMENTS - LEASEHOLDS			1,144,250.40	549,616	594,634	51,636	***	
378.21	MEASURING AND REGULATING STATION EQUIPMENT - FMV			(777,092.00)	(179,949)	(597,143)	(25,903)	****	
TOTAL AMORTIZABLE PLANT				**13,746,600.60**	**5,438,911**	**8,307,489**	**2,136,136**		
NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED									
301.00	ORGANIZATION			521.20					
374.10	LAND			206.00					
374.02	LAND			876,991.23	(522)				
375.90	LEASE			399,999.92	429,088				
376.02	MAINS - ARO				397,955				
376.03	MAINS - ARO				24,307				
TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED				**1,277,718.35**	**850,828**				
TOTAL GAS PLANT				**718,347,652.64**	**180,894,148**	**755,243,850**	**20,147,335**		

* Indicates the use of an interim survivor curve. Each asset class has a probable retirement date.
** 1-Year amortization of unrecovered reserve related to implementation of amortization accounting.
*** Accrual rate based on individual asset amortization.
**** Fair Market Value recovered over 30 years.

Note: Assets added in Account 391.11 as of January 1, 2023 will utilize and annual accrual rate of 6.67% consist with a 15-year amortization period and 0% net salvage.

COLUMBIA GAS OF KENTUCKY, INC.

TABLE 2. SUMMARY OF THE FORECASTED PLANT IN SERVICE FOR THE PERIOD ENDED DECEMBER 31, 2022

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2020	2021 ADDITIONS	2021 RETIREMENTS	2022 ADDITIONS	2022 RETIREMENTS	ORIGINAL COST AS OF DECEMBER 31, 2022
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
DEPRECIABLE PLANT							
DISTRIBUTION PLANT							
	LAND AND LAND RIGHTS						
374.40	LAND RIGHTS	1,308,835.56	40,000.00		40,000.00		1,388,835.56
374.50	RIGHTS OF WAY	2,666,577.16		(5,346.82)		(5,346.82)	2,655,883.52
	TOTAL LAND AND LAND RIGHTS	3,975,412.72	40,000.00	(5,346.82)	40,000.00	(5,346.82)	4,044,719.08
	STRUCTURES AND IMPROVEMENTS						
375.34	MEASURING AND REGULATING	2,746,577.91	154,051.84	(20,592.19)	155,973.39	(20,849.05)	3,015,161.90
375.70	OTHER DISTRIBUTION SYSTEM						
	DISTRIBUTION SYSTEM STRUCTURES	8,779,243.68	67,575.00		5,289,370.00		14,136,188.68
	OTHER BUILDINGS	195,808.52	202,725.00	(15,369.50)	133,110.00	(9,926.81)	506,347.21
	TOTAL OTHER DISTRIBUTION SYSTEM	8,975,052.20	270,300.00	(15,369.50)	5,422,480.00	(9,926.81)	14,642,535.89
	TOTAL STRUCTURES AND IMPROVEMENTS	11,721,630.11	424,351.84	(35,961.69)	5,578,453.39	(30,775.86)	17,657,697.79
376.00	MAINS						
	CAST IRON	97,145.99		(2,034.24)		(1,950.04)	93,161.71
	BARE STEEL	16,682,244.36		(358,026.74)		(343,207.00)	15,981,010.62
	COATED STEEL	70,662,839.00	7,609,166.27	(1,516,867.10)	7,294,201.29	(1,454,079.66)	82,595,259.80
	PLASTIC	228,390,369.43	45,228,233.87	(4,903,881.47)	41,333,807.33	(4,700,895.90)	305,347,633.26
	TOTAL MAINS	315,832,598.78	52,837,400.14	(6,780,809.55)	48,628,008.62	(6,500,132.60)	404,017,065.39
378.00	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	22,283,491.97	1,030,000.00	(137,680.67)	1,030,000.00	(137,680.67)	24,068,130.63
379.10	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	1,554,144.06					1,554,144.06
380.00	SERVICES	167,920,106.46	11,748,418.98	(1,507,715.97)	11,160,152.99	(1,491,783.78)	187,829,178.68
381.00	METERS	16,027,448.82	556,990.40	(74,453.21)	576,883.35	(77,112.31)	17,009,757.05
381.10	METERS - AMI	9,502,053.44	98,292.42	(13,138.80)	101,802.94	(13,608.06)	9,675,401.94
382.00	METER INSTALLATIONS	9,624,784.38	152,224.35	(20,347.91)	159,804.92	(21,361.21)	9,895,104.53
383.00	HOUSE REGULATORS	6,624,953.55	268,502.24	(35,890.84)	234,822.83	(31,388.90)	7,060,998.88
384.00	HOUSE REGULATOR INSTALLATIONS	2,085,058.65					2,085,058.65
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	4,830,029.10	400,000.00	(53,468.22)	400,000.00	(53,468.22)	5,523,092.66
387.40	OTHER EQUIPMENT - CUSTOMER INFORMATION SERVICES	5,873,189.20	625,000.00	(83,544.09)	447,000.00	(59,750.74)	6,801,894.37
387.50	OTHER EQUIPMENT - GPS PIPE LOCATORS	213,381.19					213,381.19
TOTAL DISTRIBUTION PLANT		**578,068,282.43**	**68,181,180.37**	**(8,748,357.77)**	**68,356,929.04**	**(8,422,409.17)**	**697,435,624.90**

COLUMBIA GAS OF KENTUCKY, INC.

TABLE 2. SUMMARY OF THE FORECASTED PLANT IN SERVICE FOR THE PERIOD ENDED DECEMBER 31, 2022

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2020	2021 ADDITIONS	2021 RETIREMENTS	2022 ADDITIONS	2022 RETIREMENTS	ORIGINAL COST AS OF DECEMBER 31, 2022
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
GENERAL PLANT							
	OFFICE FURNITURE AND EQUIPMENT						
391.10	FURNITURE	760,260.16		(4,721.24)	145,000.00	(21,787.36)	878,751.56
391.12	INFORMATION SYSTEMS	1,048,392.51		(266,898.41)		(702,789.49)	78,704.61
	TOTAL OFFICE FURNITURE AND EQUIPMENT	1,808,652.67	0.00	(271,619.65)	145,000.00	(724,576.85)	957,456.17
392.20	TRANSPORTATION EQUIPMENT - TRAILERS	120,240.20					120,240.20
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	4,026,792.43	300,000.00	(184,152.34)	450,000.00	(74,023.87)	4,518,616.22
395.00	LABORATORY EQUIPMENT	4,162.05					4,162.05
396.00	POWER OPERATED EQUIPMENT	185,547.00					185,547.00
398.00	MISCELLANEOUS EQUIPMENT	101,687.15					101,687.15
TOTAL GENERAL PLANT		**6,247,081.50**	**300,000.00**	**(455,771.99)**	**595,000.00**	**(798,600.72)**	**5,887,708.79**
TOTAL DEPRECIABLE PLANT		**584,315,363.93**	**68,481,180.37**	**(9,204,129.76)**	**68,951,929.04**	**(9,221,009.89)**	**703,323,333.69**
AMORTIZABLE PLANT							
303.00	MISCELLANEOUS INTANGIBLE PLANT	6,948,597.57	3,385,688.14	(1,379,216.51)	2,432,252.00	(725,443.99)	10,661,877.21
303.99	MISCELLANEOUS INTANGIBLE PLANT - CLOUD	445,509.80	843,707.19		1,428,348.00		2,717,564.99
375.71	STRUCTURES AND IMPROVEMENTS - LEASEHOLDS	738,334.69	259,700.00	(14,766.77)	170,520.00	(9,537.52)	1,144,250.40
378.21	MEASURING AND REGULATING STATION EQUIPMENT - FMV	(777,092.00)					(777,092.00)
TOTAL AMORTIZABLE PLANT		**7,355,350.06**	**4,489,095.33**	**(1,393,983.28)**	**4,031,120.00**	**(734,981.51)**	**13,746,600.60**
NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED							
301.00	ORGANIZATION	521.20					521.20
374.10	LAND	206.00					206.00
374.02	LAND	876,991.23					876,991.23
375.90	LEASE	399,999.92					399,999.92
TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED		**1,277,718.35**	**0.00**	**0.00**	**0.00**	**0.00**	**1,277,718.35**
TOTAL GAS PLANT		**592,948,432.34**	**72,970,275.70**	**(10,598,113.04)**	**72,983,049.04**	**(9,955,991.40)**	**718,347,652.64**

COLUMBIA GAS OF KENTUCKY, INC.

TABLE 3. SUMMARY OF BOOK RESERVE BRINGFORWARD FROM DECEMBER 31, 2020 TO DECEMBER 31, 2022

	ACCOUNT	BOOK RESERVE AS OF DECEMBER 31, 2020	2021 ANNUAL ACCRUAL	2021 RETIREMENTS	2021 NET SALVAGE	2022 ANNUAL ACCRUAL	2022 RETIREMENTS	2022 NET SALVAGE	BOOK RESERVE AS OF DECEMBER 31, 2022
	(1)	(2) +	(3) +	(4) +	(5) +	(6) +	(7) +	(8) =	(9)
DEPRECIABLE PLANT									
DISTRIBUTION PLANT									
	LAND AND LAND RIGHTS								
374.40	LAND RIGHTS	274,393	16,876			17,384			308,653
374.50	RIGHTS OF WAY	1,064,836	29,303	(5,347)		29,244	(5,347)		1,112,689
	TOTAL LAND AND LAND RIGHTS	1,339,229	46,179	(5,347)	0	46,628	(5,347)	0	1,421,342
	STRUCTURES AND IMPROVEMENTS								
375.34	MEASURING AND REGULATING	527,246	65,269	(20,592)	(5,148)	68,384	(20,849)	(5,212)	609,098
375.70	OTHER DISTRIBUTION SYSTEM								
	DISTRIBUTION SYSTEM STRUCTURES	3,999,178	206,225			268,901			4,474,304
	OTHER BUILDINGS	87,597	7,237	(15,370)		11,119	(9,927)		80,656
	TOTAL OTHER DISTRIBUTION SYSTEM	4,086,775	213,462	(15,370)		280,020	(9,927)		4,554,960
	TOTAL STRUCTURES AND IMPROVEMENTS	4,614,021	278,731	(35,962)	(5,148)	348,404	(30,776)	(5,212)	5,164,058
376.00	MAINS								
	CAST IRON	92,439	1,711	(2,034)	(407)	1,676	(1,950)	(390)	91,045
	BARE STEEL	15,595,351	305,310	(358,027)	(71,605)	298,823	(343,207)	(68,641)	15,358,004
	COATED STEEL	19,316,344	1,267,795	(1,516,867)	(303,373)	1,370,413	(1,454,080)	(290,816)	18,389,416
	PLASTIC	32,111,458	4,299,959	(4,903,881)	(980,776)	4,965,639	(4,700,896)	(940,179)	29,851,324
	TOTAL MAINS	67,115,592	5,874,775	(6,780,809)	(1,356,161)	6,636,551	(6,500,133)	(1,300,026)	63,689,789
378.00	MEASURING AND REGULATING STATION EQUIPMENT - GENERAL	3,586,718	572,787	(137,681)	(20,652)	595,274	(137,681)	(20,652)	4,438,113
379.10	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	268,083	37,610			37,610			343,303
380.00	SERVICES	65,409,858	6,887,010	(1,507,716)	(1,055,401)	7,283,201	(1,491,784)	(1,044,249)	74,480,919
381.00	METERS	4,722,905	431,121	(74,453)	2,234	444,137	(77,112)	2,313	5,451,145
381.10	METERS - AMI	3,171,033	713,938	(13,139)		720,422	(13,608)		4,578,646
382.00	METER INSTALLATIONS	5,351,303	171,526	(20,348)	(1,017)	173,918	(21,361)	(1,068)	5,652,953
383.00	HOUSE REGULATORS	2,068,750	130,780	(35,891)	(1,795)	135,010	(31,389)	(1,569)	2,263,896
384.00	HOUSE REGULATOR INSTALLATIONS	1,669,732	20,642			20,642			1,711,016
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	1,031,156	186,623	(53,468)	(8,020)	199,549	(53,468)	(8,020)	1,294,352
387.40	OTHER EQUIPMENT - CUSTOMER INFORMATION SERVICES	1,772,264	199,063	(83,544)	(4,177)	214,108	(59,751)	(2,988)	2,034,975
387.50	OTHER EQUIPMENT - GPS PIPE LOCATORS	21,422	29,169			29,169			79,760
TOTAL DISTRIBUTION PLANT		**162,142,066**	**15,579,954**	**(8,748,358)**	**(2,450,137)**	**16,884,623**	**(8,422,409)**	**(2,381,471)**	**172,604,268**
GENERAL PLANT									
	OFFICE FURNITURE AND EQUIPMENT								
391.10	FURNITURE	195,024	37,895	(4,721)		40,857	(21,787)		247,268
391.12	INFORMATION SYSTEMS	736,265	182,989	(266,898)		113,394	(702,789)		62,961
	TOTAL OFFICE FURNITURE AND EQUIPMENT	931,289	220,884	(271,619)	0	154,251	(724,577)	0	310,228
392.20	TRANSPORTATION EQUIPMENT - TRAILERS	99,089	1,082			1,082			101,253
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	1,405,885	163,389	(184,152)		173,225	(74,024)		1,484,323
395.00	LABORATORY EQUIPMENT	3,435	208			207			3,850
396.00	POWER OPERATED EQUIPMENT	149,011				0			149,011
398.00	MISCELLANEOUS EQUIPMENT	58,390	6,783			6,776			71,949
TOTAL GENERAL PLANT		**2,647,099**	**392,346**	**(455,771)**	**0**	**335,541**	**(798,601)**	**0**	**2,120,614**

COLUMBIA GAS OF KENTUCKY, INC.

TABLE 3. SUMMARY OF BOOK RESERVE BRINGFORWARD FROM DECEMBER 31, 2020 TO DECEMBER 31, 2022

	ACCOUNT	BOOK RESERVE AS OF DECEMBER 31, 2020	2021 ANNUAL ACCRUAL	2021 RETIREMENTS	2021 NET SALVAGE	2022 ANNUAL ACCRUAL	2022 RETIREMENTS	2022 NET SALVAGE	BOOK RESERVE AS OF DECEMBER 31, 2022
	(1)	(2) +	(3) +	(4) +	(5) +	(6) +	(7) +	(8) =	(9)
UNRECOVERED RESERVE TO BE AMORTIZED									
391.10	FURNITURE	(277,989)	92,663			92,663			(92,663)
391.11	EQUIPMENT	(30,982)	10,327			10,327			(10,328)
391.12	INFORMATION SYSTEMS	(102,255)	34,085			34,085			(34,085)
394.00	EQUIPMENT	67,040	(22,347)			(22,347)			22,346
395.00	LABORATORY EQUIPMENT	(11)	4			4			(3)
398.00	MISCELLANEOUS EQUIPMENT	(17,222)	5,741			5,741			(5,740)
TOTAL UNRECOVERED RESERVE TO BE AMORTIZED		**(361,419)**	**120,473**	**0**	**0**	**120,473**	**0**	**0**	**(120,473)**
TOTAL DEPRECIABLE PLANT		**164,427,746**	**16,092,773**	**(9,204,129)**	**(2,450,137)**	**17,340,637**	**(9,221,010)**	**(2,381,471)**	**174,604,409**
AMORTIZABLE PLANT									
303.00	MISCELLANEOUS INTANGIBLE PLANT	3,829,185	1,388,719	(1,379,217)		1,631,924	(725,444)		4,745,167
303.99	MISCELLANEOUS INTANGIBLE PLANT - CLOUD	90,129	116,974			116,974			324,077
375.71	STRUCTURES AND IMPROVEMENTS - LEASEHOLDS	470,649	51,636	(14,767)		51,636	(9,538)		549,616
378.21	MEASURING AND REGULATING STATION EQUIPMENT - FMV	(128,143)	(25,903)			(25,903)			(179,949)
TOTAL AMORTIZABLE PLANT		**4,261,820**	**1,531,426**	**(1,393,984)**	**0**	**1,774,631**	**(734,982)**	**0**	**5,438,911**
NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED									
374.02	LAND	(522)							(522)
375.90	LEASE	429,088							429,088
376.02	MAINS - ARO	397,955							397,955
376.03	MAINS - ARO	24,307							24,307
TOTAL NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED		**850,828**	**0**	**0**	**0**	**0**	**0**	**0**	**850,828**
TOTAL GAS PLANT		**169,540,394**	**17,624,199**	**(10,598,113)**	**(2,450,137)**	**19,115,268**	**(9,955,991)**	**(2,381,471)**	**180,894,148**

DETAILED DEPRECIATION CALCULATIONS

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 374.40 LAND AND LAND RIGHTS - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R2						
NET SALVAGE PERCENT.. 0						
1940	631.74	485	569	63	17.40	4
1946	26.12	19	22	4	20.04	
1949	318.25	227	266	52	21.47	2
1954	1,417.34	964	1,131	286	24.01	12
1955	645.29	434	509	136	24.54	6
1956	719.59	479	562	158	25.08	6
1957	307.00	202	237	70	25.62	3
1958	1,494.06	973	1,142	352	26.18	13
1959	1,468.93	945	1,109	360	26.74	13
1960	262.71	167	196	67	27.31	2
1961	636.06	400	469	167	27.89	6
1962	1,753.87	1,088	1,277	477	28.47	17
1963	3,172.75	1,943	2,281	892	29.07	31
1964	3,424.35	2,070	2,430	994	29.67	34
1965	706.66	421	494	213	30.27	7
1966	848.01	499	586	262	30.89	8
1967	488.18	283	332	156	31.51	5
1968	530.52	303	356	175	32.14	5
1969	525.72	296	347	179	32.78	5
1970	1,612.58	894	1,049	564	33.42	17
1971	964.42	526	617	347	34.07	10
1972	4,729.85	2,540	2,981	1,749	34.72	50
1974	2,820.09	1,464	1,718	1,102	36.06	31
1976	334.72	168	197	138	37.42	4
1977	502.91	247	290	213	38.11	6
1978	2,922.50	1,411	1,656	1,266	38.80	33
1980	3,039.01	1,410	1,655	1,384	40.21	34
1981	6,212.73	2,823	3,313	2,900	40.92	71
1982	9,762.89	4,343	5,098	4,665	41.64	112
1983	17,318.14	7,535	8,844	8,474	42.37	200
1984	33,629.96	14,304	16,789	16,841	43.10	391
1985	20,976.82	8,715	10,229	10,748	43.84	245
1986	24,833.25	10,072	11,822	13,011	44.58	292
1987	61,472.42	24,318	28,543	32,929	45.33	726
1988	23,203.80	8,947	10,501	12,703	46.08	276
1989	38,118.77	14,312	16,798	21,321	46.84	455
1990	15,601.41	5,698	6,688	8,913	47.61	187
1991	9,950.28	3,532	4,146	5,804	48.38	120
1992	7,297.89	2,514	2,951	4,347	49.16	88
1993	1,640.72	548	643	998	49.94	20
1994	50,580.17	16,374	19,219	31,361	50.72	618
1995	16,269.77	5,096	5,981	10,289	51.51	200
1997	22,942.04	6,696	7,859	15,083	53.11	284

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 374.40 LAND AND LAND RIGHTS - LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R2						
NET SALVAGE PERCENT.. 0						
1998	7,537.57	2,119	2,487	5,051	53.92	94
1999	15,063.18	4,071	4,778	10,285	54.73	188
2000	27,537.06	7,145	8,386	19,151	55.54	345
2001	110,944.79	27,573	32,363	78,582	56.36	1,394
2002	15,890.64	3,774	4,430	11,461	57.19	200
2003	10,755.44	2,436	2,859	7,896	58.01	136
2004	16,873.25	3,633	4,264	12,609	58.85	214
2005	2,445.73	499	586	1,860	59.69	31
2007	1,986.50	361	424	1,562	61.37	25
2008	25,783.52	4,390	5,153	20,631	62.23	332
2009	48,492.88	7,707	9,046	39,447	63.08	625
2010	52,809.89	7,788	9,141	43,669	63.94	683
2011	14,602.00	1,986	2,331	12,271	64.80	189
2012	22,039.05	2,742	3,218	18,821	65.67	287
2013	23,242.14	2,622	3,078	20,164	66.54	303
2014	16,047.46	1,622	1,904	14,143	67.42	210
2016	85,167.03	6,609	7,757	77,410	69.18	1,119
2017	10,387.47	684	803	9,584	70.06	137
2018	121,639.57	6,569	7,710	113,930	70.95	1,606
2019	206,461.79	8,671	10,177	196,285	71.85	2,732
2020	77,014.31	2,320	2,723	74,291	72.74	1,021
2021	40,000.00	725	851	39,149	73.64	532
2022	40,000.00	240	282	39,718	74.55	533
	1,388,835.56	262,971	308,653	1,080,183		17,585

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 61.4   1.27

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 374.50 LAND AND LAND RIGHTS - RIGHTS OF WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 80-S4
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1900	3.31	3	3			
1905	3,727.83	3,581	3,728			
1906	367.06	352	367			
1908	418.59	400	419			
1910	27.26	26	27			
1911	32.88	31	33			
1912	140.59	133	141			
1913	33,625.40	31,847	33,625			
1914	376.09	356	376			
1915	14.90	14	15			
1916	3,206.05	3,018	3,206			
1917	2.19	2	2			
1918	193.77	182	194			
1920	7.81	7	8			
1921	3.54	3	3	1	5.53	
1922	490.19	455	490			
1927	524.17	480	524			
1928	6,975.36	6,369	6,975			
1929	8,613.83	7,842	8,614			
1930	271.10	246	271			
1931	70.17	63	70			
1932	10.63	10	11			
1933	113.76	102	114			
1934	36.09	32	36			
1936	40.36	36	40			
1937	139.41	123	139			
1938	277.57	244	276	2	9.63	
1939	51.67	45	51	1	9.95	
1940	1,345.23	1,172	1,328	17	10.29	2
1941	2,958.72	2,565	2,906	53	10.64	5
1942	79.36	68	77	2	11.00	
1943	172.46	148	168	4	11.38	
1944	53.90	46	52	2	11.77	
1945	34.14	29	33	1	12.17	
1946	53.89	45	51	3	12.59	
1947	378.39	317	359	19	13.03	1
1948	1,201.72	999	1,132	70	13.48	5
1949	2,730.04	2,254	2,554	176	13.95	13
1950	3,125.54	2,562	2,902	224	14.43	16
1951	7,749.54	6,302	7,140	610	14.94	41
1952	1,344.11	1,084	1,228	116	15.46	8
1953	4,038.16	3,231	3,660	378	16.00	24
1954	5,644.39	4,476	5,071	573	16.56	35

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 374.50 LAND AND LAND RIGHTS - RIGHTS OF WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 80-S4						
NET SALVAGE PERCENT.. 0						
1955	310.81	244	276	35	17.14	2
1956	1,887.40	1,469	1,664	223	17.74	13
1957	1,165.65	898	1,017	149	18.36	8
1958	20,826.52	15,878	17,988	2,839	19.01	149
1959	5,215.58	3,933	4,456	760	19.67	39
1960	5,963.14	4,446	5,037	926	20.35	46
1961	11,642.26	8,579	9,719	1,923	21.05	91
1962	3,645.05	2,653	3,006	639	21.78	29
1963	5,740.66	4,125	4,673	1,068	22.52	47
1964	3,592.65	2,547	2,885	708	23.28	30
1965	2,909.39	2,034	2,304	605	24.06	25
1966	27,734.36	19,112	21,652	6,082	24.87	245
1967	4,668.29	3,169	3,590	1,078	25.69	42
1968	4,991.75	3,337	3,780	1,212	26.52	46
1969	42,801.79	28,153	31,894	10,908	27.38	398
1970	28,477.03	18,421	20,869	7,608	28.25	269
1971	16,202.43	10,303	11,672	4,530	29.13	156
1972	27,960.75	17,465	19,786	8,175	30.03	272
1973	5,477.79	3,359	3,805	1,673	30.94	54
1974	1,657.68	998	1,131	527	31.86	17
1975	9,578.86	5,652	6,403	3,176	32.80	97
1976	5,162.04	2,985	3,382	1,780	33.74	53
1977	4,194.08	2,375	2,691	1,503	34.69	43
1978	2,875.61	1,594	1,806	1,070	35.65	30
1979	13,431.63	7,283	8,251	5,181	36.62	141
1980	12,766.44	6,768	7,667	5,099	37.59	136
1981	10,563.92	5,471	6,198	4,366	38.57	113
1982	1,162.60	588	666	497	39.55	13
1983	9,009.33	4,444	5,035	3,974	40.54	98
1984	68,730.81	33,051	37,443	31,288	41.53	753
1985	12,854.16	6,022	6,822	6,032	42.52	142
1986	32,814.87	14,964	16,953	15,862	43.52	364
1987	21,389.67	9,489	10,750	10,640	44.51	239
1988	97,330.23	41,961	47,538	49,792	45.51	1,094
1989	76,247.86	31,919	36,161	40,087	46.51	862
1990	86,482.59	35,134	39,803	46,680	47.50	983
1991	52,430.72	20,645	23,389	29,042	48.50	599
1992	60,042.05	22,891	25,933	34,109	49.50	689
1993	50,941.53	18,785	21,281	29,661	50.50	587
1994	214,024.93	76,246	86,379	127,646	51.50	2,479
1995	177,926.35	61,162	69,290	108,636	52.50	2,069
1996	30,598.73	10,136	11,483	19,116	53.50	357
1998	8,061.70	2,469	2,797	5,265	55.50	95

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 374.50 LAND AND LAND RIGHTS - RIGHTS OF WAY

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 80-S4						
NET SALVAGE PERCENT.. 0						
2000	10,513.30	2,957	3,350	7,163	57.50	125
2001	145,613.01	39,133	44,334	101,279	58.50	1,731
2002	1,125,585.22	288,431	326,764	798,821	59.50	13,426
2005	2,009.13	439	497	1,512	62.50	24
	2,655,883.52	985,417	1,112,689	1,543,195		29,470

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 52.4 1.11

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 375.34 STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-S0						
NET SALVAGE PERCENT.. -25						
1928	481.51	539	505	97	5.75	17
1929	315.42	350	328	66	6.13	11
1930	141.66	156	146	31	6.51	5
1936	191.59	201	189	50	8.82	6
1937	21.52	22	21	6	9.21	1
1939	278.85	285	267	82	9.99	8
1940	365.00	370	347	109	10.38	11
1941	741.97	746	700	227	10.78	21
1943	34.81	34	32	12	11.57	1
1947	194.69	185	174	69	13.18	5
1948	55.72	52	49	21	13.58	2
1950	2,265.79	2,091	1,961	871	14.40	60
1951	4,437.40	4,053	3,801	1,746	14.81	118
1952	2,138.90	1,934	1,814	860	15.22	57
1953	2,726.64	2,440	2,288	1,120	15.63	72
1954	4,757.41	4,211	3,949	1,998	16.05	124
1955	3,211.03	2,812	2,637	1,377	16.47	84
1956	5,539.41	4,799	4,501	2,423	16.88	144
1957	2,836.79	2,430	2,279	1,267	17.31	73
1958	5,754.55	4,874	4,571	2,622	17.73	148
1959	5,227.25	4,377	4,105	2,429	18.16	134
1960	6,060.73	5,017	4,705	2,871	18.58	155
1961	373.95	306	287	180	19.01	9
1962	2,530.36	2,044	1,917	1,246	19.45	64
1963	2,438.70	1,947	1,826	1,222	19.88	61
1964	10,043.66	7,916	7,424	5,131	20.32	253
1965	5,750.10	4,475	4,197	2,991	20.76	144
1966	6,088.79	4,677	4,386	3,225	21.20	152
1967	2,453.57	1,860	1,744	1,323	21.64	61
1968	2,611.47	1,953	1,832	1,432	22.09	65
1970	11,629.29	8,460	7,934	6,603	22.99	287
1971	13,210.90	9,473	8,884	7,630	23.45	325
1972	6,840.74	4,834	4,534	4,017	23.91	168
1973	6,722.95	4,680	4,389	4,015	24.37	165
1974	2,129.72	1,460	1,369	1,293	24.83	52
1976	62.68	42	39	39	25.77	2
1978	3,132.18	2,012	1,887	2,028	26.73	76
1979	2,765.81	1,747	1,638	1,819	27.21	67
1980	11,068.77	6,870	6,443	7,393	27.69	267
1981	4,793.81	2,922	2,740	3,252	28.18	115
1982	42,736.11	25,574	23,984	29,436	28.67	1,027
1983	14,267.99	8,376	7,855	9,980	29.17	342
1984	36,024.18	20,739	19,450	25,580	29.67	862

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 375.34 STRUCTURES AND IMPROVEMENTS - MEASURING AND REGULATING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 55-S0
NET SALVAGE PERCENT.. -25

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1985	58,392.50	32,938	30,891	42,100	30.18	1,395
1986	27,847.56	15,386	14,430	20,379	30.69	664
1987	98,529.52	53,296	49,983	73,179	31.20	2,345
1988	8,605.71	4,553	4,270	6,487	31.72	205
1989	9,813.77	5,074	4,759	7,508	32.25	233
1990	24,452.01	12,348	11,581	18,984	32.78	579
1991	4,229.02	2,085	1,955	3,331	33.31	100
1992	446.35	215	202	356	33.85	11
1993	339.01	159	149	275	34.40	8
1994	3,241.69	1,477	1,385	2,667	34.95	76
1995	8,220.07	3,641	3,415	6,860	35.51	193
1996	30,269.25	13,023	12,214	25,623	36.07	710
1997	1,860.27	776	728	1,597	36.65	44
1998	14,396.94	5,818	5,456	12,540	37.22	337
1999	6,623.40	2,588	2,427	5,852	37.81	155
2000	2,348.35	886	831	2,104	38.40	55
2001	33,598.30	12,218	11,459	30,539	39.00	783
2002	24,506.86	8,572	8,039	22,595	39.61	570
2003	1,420.08	477	447	1,328	40.23	33
2004	4,284.17	1,377	1,291	4,064	40.86	99
2005	5,109.55	1,568	1,471	4,916	41.50	118
2006	20,402.85	5,963	5,592	19,912	42.14	473
2007	27,028.73	7,494	7,028	26,758	42.80	625
2008	33,393.52	8,751	8,207	33,535	43.47	771
2009	15,040.27	3,709	3,478	15,322	44.15	347
2010	137,845.87	31,830	29,852	142,455	44.84	3,177
2011	109,842.40	23,591	22,125	115,178	45.55	2,529
2012	156,417.84	31,035	29,106	166,416	46.27	3,597
2013	170,234.24	30,951	29,027	183,766	47.00	3,910
2014	108,799.16	17,927	16,813	119,186	47.75	2,496
2015	507,736.31	74,777	70,129	564,541	48.52	11,635
2016	101,422.68	13,139	12,322	114,456	49.30	2,322
2017	96,629.19	10,739	10,072	110,714	50.11	2,209
2018	124,350.88	11,502	10,787	144,652	50.93	2,840
2019	116,069.81	8,495	7,967	137,120	51.78	2,648
2020	376,164.15	20,007	18,764	451,441	52.66	8,573
2021	153,852.33	5,000	4,689	187,626	53.57	3,502
2022	155,942.92	1,737	1,629	193,300	54.51	3,546
	3,015,161.90	649,467	609,098	3,159,854		69,734

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.3   2.31

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 375.70 STRUCTURES AND IMPROVEMENTS - OTHER DISTRIBUTION SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PARIS AREA OFFICE - VINE STREET						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 6-2028						
NET SALVAGE PERCENT.. 0						
1950	3,575.48	3,323	3,332	244	5.50	44
1974	502.19	451	452	50	5.50	9
1975	469.01	420	421	48	5.50	9
1977	2,458.15	2,193	2,199	259	5.50	47
1985	678.43	592	594	85	5.50	15
2001	23,425.95	18,654	18,704	4,722	5.50	859
	31,109.21	25,633	25,702	5,407		983
WINCHESTER SERVICE CENTER AND OFFICE						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 6-2042						
NET SALVAGE PERCENT.. 0						
1992	567,413.50	346,122	347,055	220,359	19.50	11,300
2003	10,253.37	5,127	5,141	5,113	19.50	262
2009	4,308.86	1,763	1,768	2,541	19.50	130
2014	12,581.47	3,819	3,829	8,752	19.50	449
2016	61,809.21	15,452	15,494	46,316	19.50	2,375
2017	72,205.61	15,885	15,928	56,278	19.50	2,886
2018	5,960.77	1,118	1,121	4,840	19.50	248
2019	17,263.23	2,627	2,634	14,629	19.50	750
	751,796.02	391,913	392,969	358,827		18,400
LEXINGTON HEADQUARTERS						
INTERIM SURVIVOR CURVE.. SQUARE						
PROBABLE RETIREMENT YEAR.. 6-2044						
NET SALVAGE PERCENT.. 0						
1924	239.38	196	197	43	21.50	2
1949	748.22	579	581	168	21.50	8
1994	6,179,394.33	3,522,255	3,531,744	2,647,650	21.50	123,147
1998	26,669.93	14,205	14,243	12,427	21.50	578
2000	9,603.96	4,911	4,924	4,680	21.50	218
2001	126,272.90	63,136	63,306	62,967	21.50	2,929
2003	8,863.24	4,215	4,226	4,637	21.50	216
2005	36,210.95	16,249	16,293	19,918	21.50	926
2006	3,323.54	1,443	1,447	1,877	21.50	87
2009	6,157.10	2,375	2,381	3,776	21.50	176

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 375.70 STRUCTURES AND IMPROVEMENTS - OTHER DISTRIBUTION SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
LEXINGTON HEADQUARTERS INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 6-2044 NET SALVAGE PERCENT.. 0						
2010	6,651.14	2,445	2,452	4,200	21.50	195
2011	15,565.37	5,424	5,439	10,127	21.50	471
2013	7,125.00	2,183	2,189	4,936	21.50	230
2014	176,824.83	50,100	50,235	126,590	21.50	5,888
2015	588,327.79	152,153	152,563	435,765	21.50	20,268
2016	232,044.92	53,867	54,012	178,033	21.50	8,281
2017	165,706.39	33,754	33,845	131,861	21.50	6,133
2018	307,736.59	53,263	53,406	254,330	21.50	11,829
2019	71,883.22	10,064	10,091	61,792	21.50	2,874
2020	26,989.65	2,812	2,820	24,170	21.50	1,124
2021	67,575.00	4,407	4,419	63,156	21.50	2,937
2022	44,370.00	1,009	1,012	43,358	21.50	2,017
	8,108,283.45	4,001,045	4,011,824	4,096,459		190,534
TRAINING CENTER INTERIM SURVIVOR CURVE.. SQUARE PROBABLE RETIREMENT YEAR.. 6-2082 NET SALVAGE PERCENT.. 0						
2022	5,245,000.00	43,691	43,809	5,201,191	59.50	87,415
	5,245,000.00	43,691	43,809	5,201,191		87,415
OTHER SMALL STRUCTURES SURVIVOR CURVE.. IOWA 40-S2.5 NET SALVAGE PERCENT.. 0						
1951	38.05	37	36	2	1.56	1
1952	184.37	176	173	11	1.74	6
1953	97.17	92	91	7	1.93	4
1954	173.88	165	163	11	2.12	5
1955	247.82	234	231	17	2.31	7
1957	1,894.97	1,768	1,742	153	2.68	57
1958	1,282.04	1,190	1,172	110	2.87	38
1959	1,588.84	1,467	1,445	143	3.06	47
1960	1,183.90	1,088	1,072	112	3.25	34
1961	1,911.88	1,747	1,721	191	3.44	56
1962	63.65	58	57	7	3.63	2
1963	176.81	160	158	19	3.83	5

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 375.70 STRUCTURES AND IMPROVEMENTS - OTHER DISTRIBUTION SYSTEM

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
OTHER SMALL STRUCTURES						
SURVIVOR CURVE.. IOWA 40-S2.5						
NET SALVAGE PERCENT.. 0						
1965	892.82	798	786	107	4.23	25
1967	610.13	539	531	79	4.64	17
1968	3,457.81	3,038	2,993	465	4.86	96
1970	2,086.56	1,810	1,783	303	5.31	57
1972	340.19	291	287	53	5.80	9
1973	2,315.91	1,966	1,937	379	6.05	63
1985	1,102.76	827	815	288	10.02	29
1987	16,714.81	12,156	11,977	4,738	10.91	434
1988	4,165.24	2,980	2,936	1,229	11.38	108
1996	28,578.21	17,154	16,901	11,677	15.99	730
2000	8,337.46	4,400	4,335	4,002	18.89	212
2003	1,787.29	835	823	965	21.31	45
2009	11,371.80	3,784	3,728	7,644	26.69	286
2013	69.20	16	16	53	30.54	2
2015	45,425.58	8,495	8,370	37,056	32.52	1,139
2016	29,242.61	4,745	4,675	24,568	33.51	733
2018	5,170.54	582	573	4,597	35.50	129
2021	202,724.91	7,602	7,490	195,235	38.50	5,071
2022	133,110.00	1,664	1,639	131,471	39.50	3,328
	506,347.21	81,864	80,656	425,691		12,775
	14,642,535.89	4,544,146	4,554,960	10,087,575		310,107

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.5   2.12

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
CAST IRON						
INTERIM SURVIVOR CURVE.. IOWA 69-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2037						
NET SALVAGE PERCENT.. -20						
1940	3,924.43	3,940	4,022	687	10.95	63
1941	438.10	439	448	78	11.05	7
1944	861.04	856	874	159	11.35	14
1945	1,546.33	1,534	1,566	290	11.44	25
1949	326.38	320	327	65	11.82	5
1950	112.86	111	113	22	11.90	2
1951	7,584.87	7,409	7,564	1,538	11.99	128
1952	244.36	238	243	50	12.08	4
1953	9,250.84	8,986	9,174	1,927	12.16	158
1954	21,744.89	21,060	21,500	4,594	12.25	375
1955	445.86	431	440	95	12.33	8
1956	1,328.40	1,279	1,306	288	12.41	23
1959	373.33	356	363	85	12.64	7
1960	2,699.07	2,566	2,620	619	12.71	49
1961	192.06	182	186	45	12.78	4
1962	7,445.85	7,032	7,179	1,756	12.85	137
1963	7,928.70	7,462	7,618	1,897	12.92	147
1964	15,657.92	14,682	14,989	3,801	12.99	293
1965	9,427.56	8,808	8,992	2,321	13.05	178
1968	99.24	92	94	25	13.23	2
1969	48.86	45	46	13	13.29	1
1970	1,278.74	1,171	1,195	339	13.35	25
1972	202.02	183	187	56	13.45	4
	93,161.71	89,182	91,045	20,749		1,659
BARE STEEL						
INTERIM SURVIVOR CURVE.. IOWA 69-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2037						
NET SALVAGE PERCENT.. -20						
1901	218.12	242	247	15	5.31	3
1905	4,349.58	4,760	4,851	369	6.08	61
1906	653.88	713	727	58	6.26	9
1908	38.45	42	43	3	6.60	
1910	17.64	19	19	2	6.93	
1913	518.49	555	566	57	7.44	8
1914	165.50	177	180	18	7.61	2
1915	5,104.35	5,435	5,539	586	7.77	75
1918	105.15	111	113	13	8.25	2

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BARE STEEL						
INTERIM SURVIVOR CURVE.. IOWA 69-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2037						
NET SALVAGE PERCENT.. -20						
1920	1,659.22	1,743	1,776	215	8.56	25
1921	69.47	73	74	9	8.71	1
1923	998.85	1,042	1,062	137	8.99	15
1924	47.45	49	50	7	9.12	1
1925	107.86	112	114	15	9.26	2
1926	4,636.59	4,803	4,895	669	9.38	71
1927	6,174.67	6,381	6,503	907	9.51	95
1928	67,023.57	69,110	70,430	9,998	9.63	1,038
1929	49,742.58	51,176	52,154	7,538	9.75	773
1930	8,208.19	8,426	8,587	1,263	9.87	128
1931	9,396.10	9,623	9,807	1,469	9.99	147
1932	5,095.24	5,207	5,306	808	10.10	80
1933	248,602.21	253,524	258,367	39,956	10.21	3,913
1934	1,234.02	1,256	1,280	201	10.32	19
1935	21,374.43	21,701	22,116	3,534	10.43	339
1936	8,078.61	8,183	8,339	1,355	10.54	129
1937	25,872.76	26,153	26,653	4,395	10.64	413
1938	10,841.50	10,933	11,142	1,868	10.75	174
1939	18,244.80	18,359	18,710	3,184	10.85	293
1940	33,771.67	33,906	34,554	5,972	10.95	545
1941	25,680.09	25,722	26,213	4,603	11.05	417
1942	3,771.58	3,769	3,841	685	11.15	61
1943	3,878.32	3,866	3,940	714	11.25	63
1944	1,610.31	1,601	1,632	301	11.35	27
1945	8,994.92	8,924	9,094	1,699	11.44	149
1946	23,280.09	23,038	23,478	4,458	11.54	386
1947	21,511.43	21,235	21,641	4,173	11.63	359
1948	56,824.95	55,953	57,022	11,168	11.72	953
1949	72,055.13	70,753	72,104	14,362	11.82	1,215
1950	147,421.54	144,398	147,156	29,750	11.90	2,500
1951	307,617.07	300,477	306,217	62,924	11.99	5,248
1952	136,910.54	133,355	135,902	28,390	12.08	2,350
1953	343,434.24	333,608	339,980	72,141	12.16	5,933
1954	270,640.07	262,117	267,124	57,644	12.25	4,706
1955	393,872.51	380,363	387,628	85,019	12.33	6,895
1956	540,966.64	520,860	530,809	118,351	12.41	9,537
1957	1,080,849.44	1,037,486	1,057,303	239,716	12.49	19,193
1958	971,436.61	929,688	947,446	218,278	12.56	17,379
1959	783,603.48	747,473	761,751	178,573	12.64	14,128
1960	725,518.50	689,838	703,015	167,607	12.71	13,187
1961	683,449.18	647,688	660,060	160,079	12.78	12,526

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
BARE STEEL						
INTERIM SURVIVOR CURVE.. IOWA 69-R1.5						
PROBABLE RETIREMENT YEAR.. 12-2037						
NET SALVAGE PERCENT.. -20						
1962	592,426.42	559,516	570,204	140,708	12.85	10,950
1963	788,393.78	741,976	756,149	189,924	12.92	14,700
1964	918,219.76	860,985	877,431	224,433	12.99	17,277
1965	805,284.23	752,345	766,716	199,625	13.05	15,297
1966	1,272,940.74	1,184,858	1,207,490	320,039	13.11	24,412
1967	534,349.07	495,444	504,908	136,311	13.17	10,350
1968	786,650.12	726,440	740,316	203,664	13.23	15,394
1969	989,280.04	909,714	927,091	260,045	13.29	19,567
1970	421,347.31	385,786	393,155	112,462	13.35	8,424
1971	542,099.97	494,220	503,660	146,860	13.40	10,960
1972	531,572.39	482,434	491,649	146,238	13.45	10,873
1973	192,719.71	174,093	177,418	53,845	13.50	3,989
1974	123,987.38	111,458	113,587	35,198	13.55	2,598
1975	19,837.82	17,743	18,082	5,723	13.60	421
1976	20,103.12	17,885	18,227	5,897	13.65	432
1977	33,342.81	29,508	30,072	9,940	13.69	726
1978	199,261.83	175,378	178,728	60,386	13.73	4,398
1979	73,516.53	64,335	65,564	22,656	13.77	1,645
	15,981,010.62	15,070,144	15,358,004	3,819,209		297,986
COATED STEEL						
SURVIVOR CURVE.. IOWA 69-R1.5						
NET SALVAGE PERCENT.. -20						
1951	577.37	482	451	242	21.03	12
1953	450.90	369	345	196	21.95	9
1955	1,525.31	1,223	1,143	687	22.89	30
1957	3,240.68	2,544	2,378	1,511	23.87	63
1958	1,877.55	1,457	1,362	891	24.37	37
1959	9,937.65	7,625	7,128	4,797	24.88	193
1960	14,042.40	10,650	9,956	6,895	25.39	272
1961	11,858.97	8,885	8,306	5,925	25.92	229
1962	4,306.21	3,187	2,979	2,188	26.45	83
1963	677.92	495	463	351	26.98	13
1964	6,137.11	4,426	4,138	3,227	27.53	117
1965	25,196.65	17,931	16,762	13,474	28.08	480
1966	26,626.90	18,690	17,472	14,480	28.64	506
1967	15,650.21	10,830	10,124	8,656	29.21	296
1968	29,371.05	20,034	18,728	16,517	29.78	555

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
COATED STEEL						
SURVIVOR CURVE.. IOWA 69-R1.5						
NET SALVAGE PERCENT.. -20						
1969	33,061.25	22,217	20,769	18,905	30.36	623
1970	145,095.53	96,016	89,758	84,357	30.95	2,726
1971	190,953.39	124,402	116,294	112,850	31.54	3,578
1972	455,921.96	292,264	273,215	273,892	32.14	8,522
1973	218,423.26	137,701	128,726	133,382	32.75	4,073
1974	245,572.30	152,170	142,252	152,435	33.37	4,568
1975	238,710.04	145,343	135,870	150,582	33.99	4,430
1976	369,852.06	221,206	206,788	237,034	34.61	6,849
1977	309,254.03	181,519	169,688	201,417	35.25	5,714
1978	325,276.61	187,305	175,097	215,235	35.89	5,997
1979	483,398.45	272,973	255,181	324,897	36.53	8,894
1980	528,033.85	292,210	273,164	360,476	37.18	9,695
1981	1,123,205.66	608,674	569,002	778,845	37.84	20,583
1982	714,834.67	379,174	354,460	503,342	38.50	13,074
1983	926,072.16	480,431	449,117	662,169	39.17	16,905
1984	1,483,243.58	751,933	702,923	1,076,969	39.85	27,026
1985	502,799.04	248,952	232,726	370,633	40.53	9,145
1986	1,350,929.50	652,904	610,349	1,010,767	41.21	24,527
1987	6,554,569.77	3,089,169	2,887,822	4,977,661	41.90	118,799
1988	965,552.28	443,478	414,573	744,090	42.59	17,471
1989	761,588.16	340,530	318,335	595,571	43.29	13,758
1990	715,182.42	310,950	290,683	567,536	44.00	12,899
1991	729,463.25	308,152	288,067	587,289	44.71	13,136
1992	1,314,506.86	539,063	503,928	1,073,480	45.42	23,635
1993	1,164,923.78	463,127	432,941	964,967	46.14	20,914
1994	1,060,509.42	408,343	381,728	890,883	46.86	19,012
1995	644,800.87	240,090	224,441	549,320	47.59	11,543
1996	1,008,136.75	362,578	338,946	870,818	48.32	18,022
1997	1,325,003.50	459,495	429,546	1,160,458	49.06	23,654
1998	1,067,626.21	356,493	333,257	947,894	49.80	19,034
1999	3,618,221.81	1,161,623	1,085,910	3,255,956	50.54	64,423
2000	952,105.58	293,252	274,138	868,388	51.29	16,931
2001	853,100.57	251,631	235,230	788,491	52.04	15,152
2002	2,456,435.39	692,508	647,372	2,300,351	52.79	43,576
2003	594,852.05	159,832	149,414	564,408	53.55	10,540
2004	420,473.52	107,423	100,421	404,147	54.31	7,441
2005	305,803.37	74,083	69,254	297,710	55.07	5,406
2006	4,487,372.53	1,026,998	960,060	4,424,787	55.84	79,240
2007	1,472,924.38	317,392	296,705	1,470,804	56.61	25,981
2008	2,186,317.79	441,444	412,671	2,210,910	57.39	38,524
2009	1,525,832.50	287,650	268,901	1,562,098	58.16	26,859
2010	1,088,885.29	190,315	177,911	1,128,752	58.95	19,148

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
COATED STEEL						
SURVIVOR CURVE.. IOWA 69-R1.5						
NET SALVAGE PERCENT.. -20						
2011	1,507,982.55	243,117	227,271	1,582,308	59.73	26,491
2012	1,268,350.88	187,056	174,864	1,347,157	60.52	22,260
2013	1,515,221.72	202,646	189,438	1,628,828	61.31	26,567
2014	1,204,386.53	144,324	134,917	1,310,347	62.11	21,097
2015	1,886,266.83	200,118	187,075	2,076,446	62.90	33,012
2016	2,070,303.45	190,476	178,061	2,306,303	63.71	36,200
2017	1,898,617.23	148,252	138,589	2,139,751	64.51	33,169
2018	2,284,513.82	146,200	136,671	2,604,746	65.32	39,877
2019	4,379,124.82	218,553	204,308	5,050,642	66.13	76,374
2020	2,678,034.87	95,477	89,254	3,124,388	66.95	46,667
2021	7,554,757.34	161,642	151,106	8,914,602	67.77	131,542
2022	7,277,397.49	51,873	48,492	8,684,385	68.59	126,613
	82,595,259.80	19,671,575	18,389,416	80,724,896		1,464,791
PLASTIC						
SURVIVOR CURVE.. IOWA 69-R1.5						
NET SALVAGE PERCENT.. -20						
1967	17,678.37	12,234	10,248	10,966	29.21	375
1968	83,603.75	57,025	47,770	52,555	29.78	1,765
1969	266,663.39	179,198	150,114	169,882	30.36	5,596
1970	147,177.86	97,393	81,586	95,028	30.95	3,070
1971	253,481.09	165,138	138,336	165,842	31.54	5,258
1972	181,605.41	116,416	97,521	120,405	32.14	3,746
1973	93,228.17	58,774	49,235	62,639	32.75	1,913
1974	90,544.68	56,107	47,001	61,653	33.37	1,848
1975	79,965.22	48,688	40,786	55,172	33.99	1,623
1976	147,954.97	88,491	74,129	103,417	34.61	2,988
1977	201,503.86	118,274	99,078	142,727	35.25	4,049
1978	453,079.86	260,898	218,554	325,142	35.89	9,059
1979	745,862.81	421,186	352,827	542,209	36.53	14,843
1980	964,620.39	533,813	447,174	710,371	37.18	19,106
1981	709,015.38	384,221	321,861	528,957	37.84	13,979
1982	1,201,267.78	637,196	533,778	907,744	38.50	23,578
1983	584,951.95	303,464	254,211	447,731	39.17	11,430
1984	1,001,453.20	507,689	425,290	776,454	39.85	19,484
1985	815,524.55	403,792	338,256	640,374	40.53	15,800
1986	1,581,933.96	764,549	640,461	1,257,860	41.21	30,523
1987	3,099,716.29	1,460,896	1,223,789	2,495,870	41.90	59,567
1988	2,482,494.55	1,140,210	955,151	2,023,842	42.59	47,519

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 376.00 MAINS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
PLASTIC						
SURVIVOR CURVE.. IOWA 69-R1.5						
NET SALVAGE PERCENT.. -20						
1989	2,030,792.70	908,032	760,656	1,676,295	43.29	38,722
1990	1,918,717.97	834,228	698,831	1,603,631	44.00	36,446
1991	1,187,858.92	501,794	420,352	1,005,079	44.71	22,480
1992	1,226,682.72	503,048	421,402	1,050,617	45.42	23,131
1993	1,083,596.68	430,795	360,876	939,440	46.14	20,361
1994	1,050,135.15	404,348	338,721	921,441	46.86	19,664
1995	1,691,701.30	629,902	527,667	1,502,374	47.59	31,569
1996	1,269,175.28	456,461	382,376	1,140,634	48.32	23,606
1997	2,886,455.53	1,000,988	838,525	2,625,221	49.06	53,510
1998	2,683,465.17	896,041	750,611	2,469,547	49.80	49,589
1999	1,979,915.66	635,648	532,481	1,843,418	50.54	36,474
2000	2,655,762.85	817,986	685,225	2,501,691	51.29	48,775
2001	2,103,308.65	620,392	519,701	2,004,269	52.04	38,514
2002	2,174,027.66	612,893	513,419	2,095,414	52.79	39,693
2003	1,559,517.31	419,030	351,020	1,520,400	53.55	28,392
2004	1,223,098.26	312,477	261,761	1,205,957	54.31	22,205
2005	1,828,812.60	443,041	371,134	1,823,441	55.07	33,111
2006	2,035,203.68	465,785	390,187	2,052,057	55.84	36,749
2007	2,402,369.62	517,672	433,653	2,449,191	56.61	43,264
2008	5,433,940.70	1,097,178	919,103	5,601,625	57.39	97,606
2009	4,083,759.22	769,870	644,918	4,255,593	58.16	73,170
2010	3,045,298.36	532,257	445,870	3,208,488	58.95	54,427
2011	4,967,294.99	800,827	670,851	5,289,903	59.73	88,564
2012	9,322,813.43	1,374,929	1,151,775	10,035,601	60.52	165,823
2013	10,363,707.33	1,386,042	1,161,084	11,275,365	61.31	183,907
2014	10,992,668.48	1,317,273	1,103,476	12,087,726	62.11	194,618
2015	13,927,480.94	1,477,594	1,237,777	15,475,200	62.90	246,029
2016	16,683,066.20	1,534,909	1,285,790	18,733,890	63.71	294,049
2017	16,148,035.32	1,260,903	1,056,255	18,321,387	64.51	284,008
2018	18,969,284.11	1,213,958	1,016,930	21,746,211	65.32	332,918
2019	29,685,847.77	1,481,561	1,241,100	34,381,917	66.13	519,914
2020	25,476,510.05	908,289	760,872	29,810,941	66.95	445,272
2021	44,839,366.22	959,383	803,673	53,003,567	67.77	782,110
2022	41,214,634.94	293,778	246,097	49,211,465	68.59	717,473
	305,347,633.26	35,634,964	29,851,324	336,565,836		5,423,262
	404,017,065.39	70,465,865	63,689,789	421,130,690		7,187,698

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 58.6   1.78

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-O1						
NET SALVAGE PERCENT.. -15						
1923	282.63	325	325			
1928	659.87	759	759			
1929	209.21	241	241			
1933	366.62	422	422			
1937	36.74	42	42			
1938	83.07	96	96			
1939	205.27	235	236			
1940	403.78	456	464			
1941	807.59	901	929			
1944	27.88	30	32			
1946	137.36	144	158			
1948	35.42	36	41			
1949	434.49	437	500			
1950	3,215.50	3,192	3,698			
1951	1,717.85	1,682	1,976			
1952	1,189.29	1,148	1,368			
1953	1,953.93	1,859	2,247			
1954	5,716.51	5,361	6,574			
1955	6,449.75	5,960	7,417			
1956	6,121.96	5,574	7,040			
1957	2,005.14	1,798	2,306			
1958	2,056.03	1,816	2,364			
1959	4,735.73	4,117	5,446			
1960	5,318.45	4,551	6,116			
1961	5,195.71	4,375	5,975			
1962	4,486.95	3,716	5,160			
1963	3,548.21	2,890	4,080			
1964	6,456.83	5,171	7,425			
1965	5,601.34	4,409	6,442			
1966	5,023.05	3,885	5,777			
1967	4,836.09	3,675	5,562			
1968	12,363.15	9,225	14,218			
1969	12,278.64	8,993	14,065	55	15.25	4
1970	9,170.56	6,591	10,308	238	15.75	15
1971	36,645.89	25,838	40,411	1,732	16.25	107
1972	134,577.31	93,043	145,519	9,245	16.75	552
1973	24,625.87	16,689	26,102	2,218	17.25	129
1974	13,372.07	8,879	13,887	1,491	17.75	84
1975	13,976.75	9,089	14,215	1,858	18.25	102
1976	2,438.47	1,552	2,427	377	18.75	20
1977	1,186.75	739	1,156	209	19.25	11
1978	5,521.52	3,364	5,261	1,089	19.75	55
1979	13,821.37	8,231	12,873	3,022	20.25	149

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 42-O1
NET SALVAGE PERCENT.. -15

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1980	11,749.18	6,836	10,691	2,821	20.75	136
1981	53,129.59	30,186	47,211	13,888	21.25	654
1982	60,908.14	33,771	52,818	17,226	21.75	792
1983	48,965.85	26,480	41,415	14,896	22.25	669
1984	73,332.85	38,652	60,452	23,881	22.75	1,050
1985	124,032.92	63,678	99,592	43,046	23.25	1,851
1986	112,656.55	56,294	88,044	41,511	23.75	1,748
1987	383,921.89	186,591	291,828	149,682	24.25	6,172
1988	228,105.75	107,738	168,502	93,820	24.75	3,791
1989	187,082.42	85,802	134,194	80,951	25.25	3,206
1990	64,018.08	28,484	44,549	29,072	25.75	1,129
1991	68,170.82	29,399	45,980	32,416	26.25	1,235
1992	110,193.44	46,013	71,964	54,758	26.75	2,047
1993	216,259.65	87,340	136,599	112,100	27.25	4,114
1994	111,938.45	43,677	68,311	60,418	27.75	2,177
1995	216,273.92	81,424	127,347	121,368	28.25	4,296
1996	148,288.73	53,799	84,141	86,391	28.75	3,005
1997	154,013.22	53,767	84,091	93,024	29.25	3,180
1998	64,843.85	21,750	34,017	40,553	29.75	1,363
1999	42,134.01	13,556	21,202	27,252	30.25	901
2000	37,433.77	11,531	18,034	25,015	30.75	813
2001	200,904.79	59,135	92,487	138,554	31.25	4,434
2002	229,897.64	64,522	100,912	163,470	31.75	5,149
2004	110,882.51	28,084	43,923	83,592	32.75	2,552
2005	58,614.54	14,043	21,963	45,444	33.25	1,367
2006	47,632.76	10,760	16,829	37,949	33.75	1,124
2007	71,856.94	15,248	23,848	58,787	34.25	1,716
2008	169,785.26	33,705	52,714	142,539	34.75	4,102
2009	106,169.30	19,622	30,689	91,406	35.25	2,593
2010	45,186.39	7,733	12,094	39,870	35.75	1,115
2011	185,078.37	29,138	45,572	167,268	36.25	4,614
2012	673,463.50	96,810	151,410	623,073	36.75	16,954
2013	259,543.07	33,757	52,796	245,679	37.25	6,595
2014	422,158.24	49,126	76,833	408,649	37.75	10,825
2015	4,005,811.34	411,331	643,320	3,963,363	38.25	103,617
2016	290,330.19	25,836	40,407	293,473	38.75	7,573
2017	484,418.21	36,478	57,051	500,030	39.25	12,740
2018	1,804,816.33	111,187	173,896	1,901,643	39.75	47,840
2019	4,711,675.49	225,786	353,129	5,065,298	40.25	125,846

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 378.00 MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 42-O1						
NET SALVAGE PERCENT.. -15						
2020	5,264,670.48	180,178	281,798	5,772,573	40.75	141,658
2021	1,021,335.31	20,977	32,808	1,141,728	41.25	27,678
2022	1,027,150.29	7,028	10,992	1,170,231	41.75	28,029
	24,068,130.63	2,848,788	4,438,113	23,240,237		603,678

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.5 2.51

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 379.10 MEASURING AND REGULATING EQUIPMENT - CITY GATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 44-R1.5						
NET SALVAGE PERCENT.. -15						
1929	20.64	24	24			
1935	168.99	193	194			
1936	95.41	108	110			
1965	522.68	481	601			
1982	4,951.22	3,642	4,706	988	15.86	62
1983	1,594.90	1,151	1,487	347	16.38	21
1987	243,572.89	161,953	209,251	70,858	18.56	3,818
1992	1,609.59	945	1,221	630	21.54	29
2019	1,301,607.74	97,295	125,709	1,371,140	41.14	33,329
	1,554,144.06	265,792	343,303	1,443,963		37,259

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.8   2.40

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 41-R1						
NET SALVAGE PERCENT.. -70						
1957	23,318.70	34,479	38,100	1,542	5.34	289
1958	46,984.32	68,847	76,078	3,795	5.66	670
1959	65,600.94	95,228	105,229	6,293	5.99	1,051
1960	56,795.40	81,669	90,246	6,306	6.32	998
1961	57,537.43	81,925	90,529	7,285	6.66	1,094
1962	54,805.29	77,262	85,376	7,793	7.00	1,113
1963	72,989.72	101,808	112,500	11,583	7.36	1,574
1964	108,973.43	150,418	166,216	19,039	7.71	2,469
1965	117,298.92	160,159	176,980	22,428	8.07	2,779
1966	82,154.37	110,913	122,562	17,100	8.44	2,026
1967	122,599.47	163,584	180,764	27,655	8.82	3,135
1968	165,514.59	218,237	241,157	40,218	9.20	4,372
1969	120,950.19	157,522	174,066	31,549	9.59	3,290
1970	123,981.34	159,412	176,154	34,614	9.99	3,465
1971	134,142.71	170,254	188,135	39,908	10.39	3,841
1972	198,890.46	249,051	275,208	62,906	10.80	5,825
1973	69,538.46	85,894	94,915	23,300	11.21	2,079
1974	49,987.69	60,854	67,245	17,734	11.64	1,524
1975	47,916.44	57,478	63,515	17,943	12.07	1,487
1976	90,804.65	107,267	118,533	35,835	12.51	2,865
1977	205,728.78	239,274	264,404	85,335	12.95	6,590
1978	299,767.64	342,928	378,944	130,661	13.41	9,744
1979	516,499.56	581,014	642,035	236,014	13.87	17,016
1980	405,978.02	448,771	495,903	194,260	14.34	13,547
1981	365,320.59	396,562	438,211	182,834	14.82	12,337
1982	596,556.83	635,698	702,462	311,685	15.30	20,372
1983	515,532.45	538,665	595,238	281,167	15.80	17,795
1984	686,087.76	702,655	776,451	389,898	16.30	23,920
1985	892,091.54	894,768	988,741	527,815	16.81	31,399
1986	940,734.86	923,279	1,020,246	579,003	17.33	33,410
1987	1,167,188.70	1,119,874	1,237,489	746,732	17.86	41,810
1988	1,219,148.29	1,142,930	1,262,966	809,586	18.39	44,023
1989	2,237,791.69	2,046,874	2,261,847	1,542,399	18.94	81,436
1990	2,066,044.03	1,842,645	2,036,169	1,476,106	19.49	75,737
1991	1,707,136.20	1,482,206	1,637,875	1,264,257	20.06	63,024
1992	2,092,906.85	1,767,692	1,953,344	1,604,598	20.63	77,780
1993	2,547,909.51	2,091,785	2,311,475	2,019,971	21.20	95,282
1994	3,182,269.59	2,534,735	2,800,946	2,608,912	21.79	119,730
1995	3,152,976.78	2,432,931	2,688,450	2,671,611	22.39	119,322
1996	3,386,698.19	2,529,047	2,794,660	2,962,727	22.99	128,870
1997	3,382,120.62	2,440,075	2,696,344	3,053,261	23.60	129,375
1998	3,352,687.02	2,332,662	2,577,650	3,121,918	24.22	128,898
1999	2,913,805.33	1,952,410	2,157,462	2,796,007	24.84	112,561

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 380.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 41-R1						
NET SALVAGE PERCENT.. -70						
2000	3,287,995.25	2,115,884	2,338,105	3,251,487	25.48	127,609
2001	2,694,566.60	1,663,596	1,838,315	2,742,448	26.11	105,034
2002	2,563,297.44	1,513,484	1,672,438	2,685,168	26.76	100,343
2003	2,652,819.33	1,494,816	1,651,809	2,857,984	27.41	104,268
2004	3,151,903.63	1,689,827	1,867,301	3,490,935	28.07	124,365
2005	2,432,195.65	1,237,401	1,367,359	2,767,374	28.73	96,323
2006	2,464,396.24	1,185,328	1,309,817	2,879,657	29.40	97,948
2007	2,762,612.80	1,252,024	1,383,518	3,312,924	30.07	110,174
2008	3,230,006.22	1,374,070	1,518,382	3,972,629	30.74	129,233
2009	4,120,158.79	1,636,618	1,808,504	5,195,766	31.42	165,365
2010	3,435,756.90	1,267,860	1,401,017	4,439,770	32.10	138,311
2011	4,374,904.15	1,489,252	1,645,661	5,791,676	32.79	176,629
2012	5,487,033.48	1,710,841	1,890,523	7,437,434	33.48	222,146
2013	6,188,740.49	1,752,670	1,936,745	8,584,114	34.17	251,218
2014	7,329,643.58	1,862,954	2,058,611	10,401,783	34.87	298,302
2015	8,052,391.43	1,812,980	2,003,389	11,685,676	35.57	328,526
2016	8,847,661.28	1,731,523	1,913,376	13,127,648	36.28	361,843
2017	10,574,505.24	1,758,117	1,942,764	16,033,895	36.99	433,466
2018	12,230,095.75	1,668,283	1,843,495	18,947,668	37.71	502,457
2019	13,670,887.20	1,456,715	1,609,707	21,630,801	38.43	562,862
2020	15,843,952.36	1,208,830	1,335,787	25,598,932	39.16	653,701
2021	11,658,538.65	536,514	592,861	19,226,655	39.89	481,992
2022	11,131,350.87	170,688	188,615	18,734,681	40.63	461,105
	187,829,178.68	67,402,016	74,480,919	244,828,685		7,483,144

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.7 3.98

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 37-S0.5
NET SALVAGE PERCENT.. +3

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1939	147.88	143	143			
1940	12.50	12	12			
1941	993.52	964	964			
1942	247.76	240	240			
1943	65.22	63	63			
1944	32.56	32	32			
1945	319.39	310	310			
1946	696.70	676	676			
1947	4,051.23	3,930	3,930			
1948	4,307.84	4,179	4,179			
1949	2,689.88	2,595	2,609			
1950	5,329.30	5,093	5,169			
1951	3,258.93	3,084	3,159	2	0.90	2
1952	3,349.91	3,141	3,217	32	1.24	26
1953	4,049.40	3,759	3,850	78	1.59	49
1954	13,592.07	12,497	12,800	384	1.93	199
1955	2,713.29	2,470	2,530	102	2.27	45
1956	11,282.38	10,172	10,419	525	2.61	201
1957	12,261.98	10,949	11,215	679	2.94	231
1958	8,330.76	7,364	7,543	538	3.28	164
1959	39,721.63	34,771	35,614	2,916	3.61	808
1960	37,124.92	32,167	32,947	3,064	3.95	776
1961	21,677.96	18,595	19,046	1,982	4.28	463
1962	27,905.96	23,689	24,264	2,805	4.62	607
1963	16,186.51	13,600	13,930	1,771	4.95	358
1964	36,533.83	30,371	31,108	4,330	5.29	819
1965	17,333.75	14,255	14,601	2,213	5.63	393
1966	32,609.17	26,527	27,170	4,461	5.97	747
1967	58,149.35	46,786	47,921	8,484	6.31	1,345
1968	54,492.83	43,344	44,395	8,463	6.66	1,271
1969	48,922.67	38,464	39,397	8,058	7.01	1,150
1970	60,460.27	46,981	48,121	10,525	7.36	1,430
1971	94,936.25	72,899	74,667	17,421	7.71	2,260
1972	86,016.94	65,238	66,821	16,615	8.07	2,059
1973	51,848.29	38,834	39,776	10,517	8.43	1,248
1974	34,151.89	25,257	25,870	7,257	8.79	826
1975	34,691.55	25,320	25,934	7,717	9.16	842
1976	12,325.15	8,876	9,091	2,864	9.53	301
1977	15,509.60	11,019	11,286	3,758	9.90	380
1978	17,058.48	11,949	12,239	4,308	10.28	419
1979	113,464.29	78,321	80,221	29,839	10.67	2,797
1980	182,432.21	124,063	127,073	49,886	11.06	4,510
1981	169,871.26	113,784	116,544	48,231	11.45	4,212

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 37-S0.5
NET SALVAGE PERCENT.. +3

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1982	178,130.25	117,448	120,297	52,489	11.85	4,429
1983	107,288.72	69,615	71,304	32,766	12.25	2,675
1984	101,007.50	64,427	65,990	31,987	12.67	2,525
1985	157,575.16	98,815	101,212	51,636	13.08	3,948
1986	211,302.97	130,123	133,280	71,684	13.51	5,306
1987	166,185.13	100,466	102,903	58,297	13.94	4,182
1988	140,193.64	83,136	85,153	50,835	14.38	3,535
1989	217,561.10	126,507	129,576	81,458	14.82	5,496
1990	234,068.68	133,344	136,579	90,468	15.27	5,925
1991	212,895.53	118,714	121,594	84,915	15.73	5,398
1992	189,894.30	103,548	106,060	78,137	16.20	4,823
1993	126,580.74	67,431	69,067	53,716	16.68	3,220
1994	332,349.79	172,779	176,970	145,409	17.17	8,469
1995	0.23					
1996	497,855.73	245,768	251,730	231,190	18.17	12,724
1997	20,639.96	9,907	10,147	9,874	18.69	528
1998	461,728.78	215,344	220,568	227,309	19.21	11,833
1999	280,578.48	126,887	129,965	142,196	19.75	7,200
2000	25,423.09	11,130	11,400	13,260	20.30	653
2001	240,058.11	101,514	103,976	128,880	20.87	6,175
2002	150,726.90	61,485	62,976	83,229	21.44	3,882
2003	433,851.07	170,266	174,396	246,440	22.03	11,187
2004	572,990.23	215,862	221,098	334,703	22.63	14,790
2005	389,003.46	140,225	143,627	233,706	23.25	10,052
2006	318,107.22	109,414	112,068	196,496	23.88	8,228
2007	433,071.95	141,693	145,130	274,950	24.52	11,213
2008	364,365.68	112,908	115,647	237,788	25.18	9,444
2009	573,872.31	167,598	171,664	384,992	25.86	14,888
2010	320,516.31	87,724	89,852	221,049	26.56	8,323
2011	293,927.83	74,975	76,794	208,316	27.27	7,639
2012	429,800.68	101,296	103,753	313,154	28.01	11,180
2013	409,441.56	88,447	90,593	306,565	28.76	10,659
2014	432,248.56	84,649	86,702	332,579	29.53	11,262
2015	884,861.70	154,960	158,719	699,597	30.32	23,074
2016	610,991.58	94,026	96,307	496,355	31.13	15,945
2017	841,114.56	110,919	113,610	702,271	31.97	21,967
2018	670,482.57	73,296	75,074	575,294	32.83	17,523
2019	1,418,806.56	122,375	125,343	1,250,899	33.71	37,108

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 381.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 37-S0.5						
NET SALVAGE PERCENT.. +3						
2020	1,085,516.85	68,010	69,660	983,291	34.61	28,411
2021	556,745.65	21,164	21,677	518,366	35.55	14,581
2022	576,838.67	7,408	7,588	551,946	36.51	15,118
	17,009,757.05	5,322,386	5,451,145	11,048,319		436,456

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.3   2.57

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 381.10 METERS - AMI

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 15-S2.5						
NET SALVAGE PERCENT.. 0						
2011	316,532.92	210,599	197,282	119,251	5.02	23,755
2012	360,846.16	225,410	211,157	149,689	5.63	26,588
2013	373,273.03	216,498	202,808	170,465	6.30	27,058
2014	6,774,630.25	3,599,564	3,371,956	3,402,674	7.03	484,022
2015	853,269.46	407,863	382,073	471,196	7.83	60,178
2016	51,022.51	21,464	20,107	30,916	8.69	3,558
2017	15,075.46	5,427	5,084	9,991	9.60	1,041
2018	403,138.92	119,865	112,285	290,854	10.54	27,595
2019	202,178.47	46,905	43,939	158,239	11.52	13,736
2020	125,339.53	20,890	19,569	105,771	12.50	8,462
2021	98,292.29	9,829	9,208	89,084	13.50	6,599
2022	101,802.94	3,393	3,178	98,625	14.50	6,802
	9,675,401.94	4,887,707	4,578,646	5,096,756		689,394

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.4 7.13

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. -5						
1952	3.24	3	3			
1955	10.40	10	11			
1956	1.24	1	1			
1957	59.45	59	62			
1959	4,541.90	4,442	4,769			
1960	12,241.29	11,897	12,853			
1961	9,652.31	9,324	10,135			
1962	10,683.40	10,255	11,218			
1963	12,443.17	11,869	13,065			
1964	21,053.07	19,954	22,106			
1965	29,471.21	27,747	30,945			
1966	25,207.77	23,574	26,468			
1967	29,489.39	27,379	30,964			
1968	52,693.09	48,566	55,328			
1969	62,990.80	57,616	66,140			
1970	58,381.81	52,964	61,301			
1971	67,420.46	60,629	70,791			
1972	96,372.21	85,878	101,191			
1973	41,386.83	36,522	43,456			
1974	4,525.64	3,954	4,719	33	7.56	4
1975	8,837.74	7,636	9,113	167	7.97	21
1976	13,447.66	11,484	13,705	415	8.40	49
1977	18,926.90	15,965	19,053	820	8.85	93
1978	20,739.59	17,266	20,605	1,172	9.32	126
1979	25,194.42	20,687	24,688	1,766	9.81	180
1980	34,500.36	27,918	33,317	2,908	10.32	282
1981	58,097.23	46,294	55,247	5,755	10.85	530
1982	55,125.83	43,206	51,562	6,320	11.41	554
1983	59,032.07	45,482	54,278	7,706	11.98	643
1984	69,156.14	52,331	62,452	10,162	12.57	808
1985	83,568.13	62,027	74,023	13,724	13.19	1,040
1986	103,778.53	75,502	90,104	18,863	13.82	1,365
1987	243,195.83	173,302	206,819	48,537	14.46	3,357
1988	241,847.55	168,560	201,160	52,780	15.13	3,488
1989	306,052.00	208,453	248,768	72,587	15.81	4,591
1990	336,809.95	223,900	267,203	86,447	16.51	5,236
1991	313,286.05	203,071	242,345	86,605	17.22	5,029
1992	367,623.60	232,116	277,008	108,997	17.94	6,076
1993	355,280.94	218,190	260,388	112,657	18.68	6,031
1994	397,158.35	236,865	282,675	134,341	19.44	6,911
1995	382,579.96	221,386	264,203	137,506	20.20	6,807
1996	450,311.71	252,386	301,198	171,629	20.98	8,181
1997	230,027.28	124,682	148,796	92,733	21.77	4,260

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 382.00 METER INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
NET SALVAGE PERCENT.. -5						
1998	376,266.21	196,923	235,008	160,072	22.57	7,092
1999	261,752.20	132,044	157,582	117,258	23.38	5,015
2000	311,682.51	151,197	180,439	146,828	24.21	6,065
2001	226,635.32	105,553	125,967	112,000	25.04	4,473
2002	226,251.83	100,886	120,398	117,166	25.89	4,526
2003	268,466.70	114,385	136,507	145,383	26.74	5,437
2004	247,396.54	100,384	119,798	139,968	27.61	5,069
2005	126,719.11	48,817	58,258	74,797	28.49	2,625
2006	272,808.59	99,492	118,734	167,715	29.37	5,710
2007	231,656.40	79,619	95,018	148,221	30.27	4,897
2008	148,340.07	47,869	57,127	98,630	31.17	3,164
2009	145,647.27	43,908	52,400	100,530	32.08	3,134
2010	153,313.48	42,928	51,230	109,749	33.00	3,326
2011	129,360.41	33,414	39,876	95,952	33.93	2,828
2012	177,090.99	41,899	50,002	135,944	34.86	3,900
2013	164,672.94	35,311	42,140	130,767	35.81	3,652
2014	143,808.03	27,683	33,037	117,961	36.75	3,210
2015	516,846.23	87,916	104,920	437,769	37.71	11,609
2016	143,707.32	21,226	25,331	125,562	38.67	3,247
2017	122,060.36	15,294	18,252	109,911	39.63	2,773
2018	235,831.50	24,213	28,896	218,727	40.60	5,387
2019	111,376.45	8,914	10,638	106,307	41.57	2,557
2020	128,243.09	7,331	8,749	125,906	42.55	2,959
2021	152,175.82	5,220	6,230	153,555	43.53	3,528
2022	159,788.66	1,827	2,180	165,598	44.51	3,720
	9,895,104.53	4,755,605	5,652,953	4,736,907		175,565

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.0 1.77

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S1.5						
NET SALVAGE PERCENT.. -5						
1950	186.13	168	193	2	7.10	
1955	99.29	87	100	4	8.49	
1960	57.86	49	56	5	9.98	1
1961	110.35	92	105	11	10.29	1
1962	256.87	212	243	27	10.61	3
1963	132.01	108	124	15	10.94	1
1964	134.82	110	126	16	11.27	1
1965	249.74	201	230	32	11.61	3
1966	505.19	404	463	67	11.95	6
1967	518.57	411	471	73	12.30	6
1968	12,058.68	9,456	10,840	1,822	12.66	144
1969	20,545.34	15,955	18,290	3,283	13.02	252
1970	21,477.63	16,508	18,924	3,628	13.40	271
1971	21,432.47	16,302	18,688	3,816	13.78	277
1972	28,749.59	21,638	24,805	5,382	14.16	380
1973	7,193.12	5,353	6,136	1,417	14.56	97
1974	2,597.64	1,911	2,191	537	14.97	36
1975	683.92	497	570	148	15.38	10
1976	6,397.96	4,594	5,266	1,452	15.81	92
1977	5,233.21	3,710	4,253	1,242	16.24	76
1978	9,012.92	6,305	7,228	2,236	16.69	134
1979	11,105.95	7,664	8,786	2,875	17.14	168
1980	9,876.41	6,718	7,701	2,669	17.61	152
1981	18,859.77	12,642	14,492	5,311	18.08	294
1982	32,993.56	21,777	24,964	9,679	18.57	521
1983	32,938.61	21,395	24,526	10,060	19.07	528
1984	35,266.84	22,529	25,826	11,204	19.58	572
1985	56,736.50	35,613	40,825	18,748	20.11	932
1986	56,793.85	35,017	40,141	19,493	20.64	944
1987	56,525.39	34,198	39,203	20,149	21.19	951
1988	42,990.65	25,495	29,226	15,914	21.76	731
1989	49,943.69	29,021	33,268	19,173	22.33	859
1990	50,152.80	28,521	32,695	19,965	22.92	871
1991	45,281.38	25,171	28,855	18,690	23.53	794
1992	58,227.09	31,609	36,235	24,903	24.15	1,031
1993	54,792.63	29,019	33,266	24,266	24.78	979
1994	43,866.52	22,634	25,946	20,114	25.43	791
1995	37,153.48	18,647	21,376	17,635	26.10	676
1996	72,029.03	35,123	40,263	35,367	26.78	1,321
1997	15,286.30	7,229	8,287	7,764	27.48	283
1998	7,181.01	3,289	3,770	3,770	28.19	134
1999	20,513.94	9,081	10,410	11,130	28.92	385
2000	14,351.44	6,130	7,027	8,042	29.66	271

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 383.00 HOUSE REGULATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 50-S1.5						
NET SALVAGE PERCENT.. -5						
2001	16,705.01	6,869	7,874	9,666	30.42	318
2002	37,241.62	14,703	16,855	22,249	31.20	713
2003	318,778.95	120,565	138,208	196,510	31.99	6,143
2004	695,617.60	251,257	288,026	442,372	32.80	13,487
2005	360,794.37	124,106	142,268	236,566	33.62	7,036
2006	397,166.19	129,611	148,578	268,446	34.46	7,790
2007	325,356.95	100,369	115,057	226,568	35.31	6,417
2008	359,754.65	104,408	119,687	258,055	36.18	7,133
2009	302,539.02	82,212	94,243	223,423	37.06	6,029
2010	504,386.91	127,529	146,192	383,414	37.96	10,100
2011	181,304.92	42,376	48,577	141,793	38.87	3,648
2012	339,578.38	72,809	83,464	273,093	39.79	6,863
2013	239,817.33	46,736	53,575	198,233	40.72	4,868
2014	192,349.32	33,688	38,618	163,349	41.66	3,921
2015	195,689.28	30,369	34,813	170,661	42.61	4,005
2016	173,979.36	23,456	26,889	155,789	43.58	3,575
2017	242,747.12	27,782	31,848	223,036	44.55	5,006
2018	211,728.57	19,875	22,783	199,532	45.53	4,382
2019	305,678.70	22,403	25,682	295,281	46.51	6,349
2020	195,966.38	10,247	11,746	194,019	47.51	4,084
2021	268,495.54	8,458	9,696	272,224	48.50	5,613
2022	234,822.56	2,466	2,827	243,737	49.50	4,924
	7,060,998.88	1,974,887	2,263,896	5,150,153		138,383

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.2 1.96

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 384.00 HOUSE REGULATOR INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 43-S2.5						
NET SALVAGE PERCENT.. 0						
1973	216.76	179	217			
1975	2,826.80	2,292	2,827			
1976	21,094.53	16,944	21,095			
1977	31,052.60	24,705	31,053			
1978	37,691.51	29,680	37,692			
1979	42,871.79	33,390	42,872			
1980	40,766.03	31,390	40,766			
1981	87,762.98	66,781	87,737	26	10.28	3
1982	81,396.17	61,142	80,328	1,068	10.70	100
1983	59,401.97	44,041	57,861	1,541	11.12	139
1984	64,964.67	47,485	62,386	2,579	11.57	223
1985	86,803.28	62,498	82,110	4,693	12.04	390
1986	69,271.47	49,102	64,510	4,761	12.52	380
1987	73,903.91	51,510	67,674	6,230	13.03	478
1988	63,444.69	43,437	57,068	6,377	13.56	470
1989	60,983.14	40,986	53,847	7,136	14.10	506
1990	63,537.01	41,861	54,997	8,540	14.67	582
1991	61,110.67	39,409	51,776	9,335	15.27	611
1992	83,216.78	52,485	68,955	14,262	15.88	898
1993	79,837.16	49,165	64,593	15,244	16.52	923
1994	122,269.98	73,419	96,458	25,812	17.18	1,502
1995	95,362.56	55,732	73,221	22,142	17.87	1,239
1996	145,436.70	82,595	108,513	36,924	18.58	1,987
1997	122,097.88	67,267	88,375	33,723	19.31	1,746
1998	129,614.44	69,148	90,847	38,767	20.06	1,933
1999	109,553.26	56,458	74,174	35,379	20.84	1,698
2000	40,904.07	20,319	26,695	14,209	21.64	657
2001	20,583.15	9,832	12,917	7,666	22.46	341
2002	92,533.60	42,393	55,696	36,838	23.30	1,581
2003	92,619.49	40,580	53,315	39,304	24.16	1,627
2015	1,929.60	336	441	1,489	35.51	42
	2,085,058.65	1,306,561	1,711,016	374,043		20,056

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 18.6   0.96

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 33-R0.5						
NET SALVAGE PERCENT.. -15						
1949	69.20	80	80			
1950	125.39	144	144			
1951	36.64	42	42			
1955	139.28	160	160			
1956	11.70	13	13			
1957	1,520.27	1,735	1,613	135	0.25	135
1958	47.93	54	50	5	0.74	5
1959	3,254.14	3,604	3,350	392	1.22	321
1960	361.04	394	366	49	1.70	29
1961	1,187.88	1,277	1,187	179	2.16	83
1962	2,455.19	2,599	2,416	407	2.62	155
1963	1,046.67	1,092	1,015	189	3.07	62
1964	3,652.68	3,755	3,491	710	3.50	203
1965	3,615.01	3,663	3,405	752	3.92	192
1966	4,416.15	4,411	4,101	978	4.34	225
1967	4,213.73	4,148	3,856	990	4.75	208
1968	8,238.62	7,996	7,433	2,041	5.15	396
1969	8,921.47	8,531	7,931	2,329	5.56	419
1970	19,374.27	18,263	16,978	5,302	5.95	891
1971	43,862.92	40,736	37,870	12,572	6.35	1,980
1972	5,795.35	5,301	4,928	1,737	6.75	257
1973	14,716.30	13,262	12,329	4,595	7.14	644
1974	7,478.90	6,636	6,169	2,432	7.54	323
1975	5,460.97	4,769	4,433	1,847	7.94	233
1976	1,262.09	1,085	1,009	442	8.34	53
1978	2,264.17	1,881	1,749	855	9.16	93
1980	13,105.15	10,509	9,770	5,301	9.99	531
1981	30,213.45	23,785	22,112	12,633	10.41	1,214
1982	11,530.47	8,904	8,278	4,982	10.84	460
1983	26,813.89	20,305	18,876	11,960	11.27	1,061
1984	48,351.28	35,873	33,349	22,255	11.71	1,901
1985	19,471.90	14,141	13,146	9,247	12.16	760
1986	24,786.58	17,612	16,373	12,132	12.61	962
1987	78,734.65	54,684	50,837	39,708	13.07	3,038
1988	1,244.60	844	785	646	13.54	48
1989	36,566.75	24,199	22,496	19,556	14.01	1,396
1990	23,052.63	14,870	13,824	12,687	14.49	876
1991	25,443.50	15,978	14,854	14,406	14.98	962
1992	33,584.93	20,517	19,073	19,550	15.47	1,264
1993	32,035.67	19,012	17,674	19,167	15.97	1,200
1994	40,781.04	23,478	21,826	25,072	16.48	1,521
1995	48,750.85	27,199	25,285	30,778	16.99	1,812
1996	112,698.71	60,835	56,555	73,049	17.51	4,172

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 385.00 INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. IOWA 33-R0.5
NET SALVAGE PERCENT.. -15

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1997	75,976.89	39,609	36,822	50,551	18.04	2,802
1998	15,353.96	7,716	7,173	10,484	18.58	564
1999	26,034.94	12,593	11,707	18,233	19.12	954
2000	62,901.03	29,219	27,163	45,173	19.67	2,297
2001	37,722.68	16,800	15,618	27,763	20.22	1,373
2002	105,005.92	44,716	41,570	79,187	20.78	3,811
2003	47,772.17	19,411	18,045	36,893	21.34	1,729
2004	126,926.37	49,053	45,602	100,363	21.91	4,581
2005	624,240.80	228,629	212,543	505,334	22.49	22,469
2006	4,137.73	1,432	1,331	3,427	23.07	149
2007	46,469.01	15,141	14,076	39,363	23.65	1,664
2008	43,722.05	13,363	12,423	37,857	24.23	1,562
2009	61,863.04	17,635	16,394	54,748	24.82	2,206
2010	21,390.63	5,650	5,252	19,347	25.42	761
2011	193,529.52	47,142	43,825	178,734	26.01	6,872
2012	137,174.01	30,547	28,398	129,352	26.61	4,861
2013	48,561.74	9,798	9,109	46,737	27.21	1,718
2014	93,948.31	16,992	15,796	92,245	27.81	3,317
2015	139,803.91	22,362	20,789	139,985	28.41	4,927
2016	257,606.08	35,819	33,299	262,948	29.01	9,064
2017	1,111,624.22	130,930	121,718	1,156,650	29.62	39,050
2018	326,305.63	31,499	29,283	345,968	30.23	11,445
2019	33,873.52	2,550	2,371	36,584	30.84	1,186
2020	336,629.32	18,183	16,903	370,221	31.45	11,772
2021	395,344.99	12,812	11,911	442,736	32.07	13,805
2022	398,480.18	4,303	4,000	454,252	32.69	13,896
	5,523,092.66	1,392,280	1,294,352	5,057,205		198,920

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.4 3.60

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 387.40 OTHER EQUIPMENT - CUSTOMER INFORMATION SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 34-R2						
NET SALVAGE PERCENT.. -5						
1984	3,308.81	2,714	2,571	903	7.44	121
1985	52,341.50	42,270	40,050	14,909	7.85	1,899
1986	36,568.80	29,057	27,531	10,866	8.27	1,314
1987	42,780.92	33,412	31,657	13,263	8.71	1,523
1988	68,669.03	52,656	49,890	22,212	9.17	2,422
1989	75,871.96	57,055	54,058	25,608	9.65	2,654
1990	80,903.31	59,613	56,482	28,466	10.14	2,807
1991	49,460.84	35,666	33,793	18,141	10.65	1,703
1992	121,543.18	85,656	81,157	46,463	11.18	4,156
1993	64,264.27	44,217	41,895	25,582	11.72	2,183
1994	249,554.59	167,315	158,528	103,504	12.29	8,422
1995	23,243.79	15,168	14,371	10,035	12.87	780
1996	75,497.11	47,890	45,375	33,897	13.46	2,518
1998	140,787.55	83,914	79,507	68,320	14.70	4,648
1999	282,990.00	163,076	154,511	142,628	15.34	9,298
2000	84,134.55	46,769	44,313	44,028	16.00	2,752
2001	2,853.22	1,526	1,446	1,550	16.68	93
2002	586,060.86	301,165	285,348	330,016	17.36	19,010
2003	338,098.37	166,433	157,692	197,311	18.06	10,925
2004	270,894.26	127,329	120,642	163,797	18.78	8,722
2005	6,246.53	2,795	2,648	3,911	19.51	200
2006	15,029.05	6,382	6,047	9,734	20.25	481
2007	29,688.99	11,919	11,293	19,880	21.00	947
2009	31,085.77	11,002	10,424	22,216	22.54	986
2010	12,087.94	3,983	3,774	8,918	23.33	382
2011	70,583.13	21,536	20,405	53,707	24.12	2,227
2012	181,862.30	50,939	48,264	142,691	24.93	5,724
2013	257,339.27	65,566	62,122	208,084	25.75	8,081
2014	317,142.93	72,674	68,857	264,143	26.58	9,938
2015	357,881.31	72,724	68,904	306,871	27.42	11,192
2016	410,455.83	72,633	68,818	362,161	28.27	12,811
2017	215,326.82	32,386	30,685	195,408	29.13	6,708
2018	779,724.92	96,321	91,262	727,449	30.00	24,248
2019	155,668.33	15,047	14,257	149,195	30.87	4,833
2020	242,971.37	16,807	15,924	239,196	31.76	7,531
2021	622,512.99	25,956	24,593	629,046	32.65	19,266
2022	446,459.97	6,207	5,881	462,902	33.55	13,797
	6,801,894.37	2,147,778	2,034,975	5,107,014		217,302

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 23.5   3.19

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 387.50 OTHER EQUIPMENT - GPS PIPE LOCATORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 10-L3						
NET SALVAGE PERCENT.. 0						
2017	213,381.19	109,678	79,760	133,621	4.86	27,494
	213,381.19	109,678	79,760	133,621		27,494

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.9   12.88

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 391.10 OFFICE FURNITURE AND EQUIPMENT - FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2011	12,228.11	7,031	7,033	5,195	8.50	611
2013	22,550.07	10,711	10,714	11,836	10.50	1,127
2015	490,295.76	183,861	183,919	306,377	12.50	24,510
2016	35,870.72	11,658	11,662	24,209	13.50	1,793
2017	5,852.15	1,609	1,610	4,242	14.50	293
2018	11,759.06	2,646	2,647	9,112	15.50	588
2019	132,982.13	23,272	23,279	109,703	16.50	6,649
2020	22,213.56	2,777	2,778	19,436	17.50	1,111
2022	145,000.00	3,625	3,626	141,374	19.50	7,250
	878,751.56	247,190	247,268	631,484		43,932

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.4 5.00

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 391.12 OFFICE FURNITURE AND EQUIPMENT - INFORMATION SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 5-SQUARE NET SALVAGE PERCENT.. 0						
2018	78,704.61	70,834	62,961	15,744	0.50	15,744
	78,704.61	70,834	62,961	15,744		15,744

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.0   20.00

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 392.20 TRANSPORTATION EQUIPMENT - TRAILERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 17-L4						
NET SALVAGE PERCENT.. +10						
1998	1,494.24	1,191	1,345			
2004	45,359.00	33,307	40,823			
2011	24,462.20	14,181	20,717	1,299	6.05	215
2012	48,924.76	26,264	38,368	5,664	6.86	826
	120,240.20	74,943	101,253	6,963		1,041

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 6.7 0.87

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

SURVIVOR CURVE.. 25-SQUARE
NET SALVAGE PERCENT.. 0

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
1998	142,623.01	139,771	138,456	4,167	0.50	4,167
1999	26,525.45	24,934	24,699	1,826	1.50	1,217
2000	55,442.14	49,898	49,429	6,013	2.50	2,405
2001	57,333.67	49,307	48,843	8,491	3.50	2,426
2002	213,892.58	175,392	173,742	40,151	4.50	8,922
2003	19,351.62	15,094	14,952	4,400	5.50	800
2004	87,815.91	64,984	64,373	23,443	6.50	3,607
2006	21,390.02	14,117	13,984	7,406	8.50	871
2007	21,155.23	13,116	12,993	8,162	9.50	859
2008	195,331.69	113,292	112,226	83,106	10.50	7,915
2009	57,235.97	30,907	30,616	26,620	11.50	2,315
2010	96,292.90	48,146	47,693	48,600	12.50	3,888
2011	129,991.20	59,796	59,234	70,757	13.50	5,241
2012	161,998.60	68,039	67,399	94,600	14.50	6,524
2013	436,365.86	165,819	164,259	272,107	15.50	17,555
2014	223,303.32	75,923	75,209	148,094	16.50	8,975
2015	374,620.11	112,386	111,329	263,291	17.50	15,045
2016	341,898.74	88,894	88,058	253,841	18.50	13,721
2017	166,838.29	36,704	36,359	130,479	19.50	6,691
2018	250,778.62	45,140	44,715	206,064	20.50	10,052
2019	272,918.37	38,209	37,849	235,069	21.50	10,933
2020	415,512.92	41,551	41,160	374,353	22.50	16,638
2021	300,000.00	18,000	17,831	282,169	23.50	12,007
2022	450,000.00	9,000	8,915	441,085	24.50	18,003
	4,518,616.22	1,498,419	1,484,323	3,034,293		180,777

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.8 4.00

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 395.00 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 20-SQUARE						
NET SALVAGE PERCENT.. 0						
2004	4,162.05	3,850	3,850	312	1.50	208
	4,162.05	3,850	3,850	312		208

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 1.5 5.00

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 19-S0.5						
NET SALVAGE PERCENT.. +20						
2002	83,056.36	44,728	66,445			
2004	102,490.64	51,612	82,566	573-		
	185,547.00	96,340	149,011	573-		

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0   0.00

COLUMBIA GAS OF KENTUCKY, INC.

ACCOUNT 398.00 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 15-SQUARE						
NET SALVAGE PERCENT.. 0						
2009	20,748.53	18,674	18,674	2,075	1.50	1,383
2010	8,738.69	7,282	7,282	1,457	2.50	583
2011	46,730.80	35,827	35,827	10,904	3.50	3,115
2014	4,263.86	2,416	2,416	1,848	6.50	284
2016	11,920.76	5,166	5,166	6,755	8.50	795
2017	5,184.51	1,901	1,901	3,284	9.50	346
2020	4,100.00	683	683	3,417	12.50	273
	101,687.15	71,949	71,949	29,738		6,779

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 4.4   6.67

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Chun-Yi Lai attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky’s President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Chun-Yi Lai

Columbia Exhibit No. 26

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF CO-LUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; AP-PROVAL OF DEPRECIATION STUDY; AP-PROVAL OF TARIFF REVISIONS; ISSU-ANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

PREPARED DIRECT TESTIMONY OF
CHUN-YI LAI
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	

VERIFICATION OF CHUN-YI LAI

STATE OF OHIO	)
	)
COUNTY OF FRANKLIN	)

Chun-Yi Lai, Financial Planning Manager for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of her Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Chun Y. Lai

Chun-Yi Lai

The foregoing Verification was signed, acknowledged and sworn to before me this 19th day of May, 2021, by Chun-Yi Lai.

John R Ryan III
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

Notary Commission No. N/A

Commission expiration: N/A

PREPARED DIRECT TESTIMONY OF CHUN-YI LAI

A. Introduction

Q: Please state your name and business address.

A: My name is Chun-Yi Lai. My business address is 290 West Nationwide Blvd., Columbus, Ohio 43215.

Q: What is your current position and what are your responsibilities?

A: I am employed by NiSource Corporate Services Company ("NCSC") as Financial Planning Manager. I am responsible for analysis and support in the Operations and Maintenance ("O&M") expense budgeting process for NiSource gas distribution companies, including Columbia Gas of Kentucky, Inc. ("CKY" or "Columbia"), and coordination with the NCSC financial planning and budgeting processes.

Q: What is your educational background and professional experience?

A: I graduated from the Ohio State University in June of 2006, with a Bachelor of Science Degree in Business Administration with a major in Finance. My career with NiSource began as a Financial Analyst in the Accounting department with Columbia Gas Transmission in June 2007, and I was later promoted to a Senior Financial Analyst in October 2008. In May 2011, I accepted a position as Senior Regulatory Analyst in NCSC's Regulatory Strategy and Support Department and held positions of increasing responsibility in the Regulatory Department from 2011 to 2021, most recently as Regulatory Manager. I assumed my current position in March 2021.

Q. Have you previously testified before any regulatory commissions?

A. Yes. I have testified before the Massachusetts Department of Public Utilities where I have submitted testimony on behalf of Columbia Gas of Massachusetts in support of its Gas System Enhancement Program filings. I have also submitted direct testimony on behalf of NCSC in matters before the Pennsylvania Public Utility Commission and the Virginia State Corporation Commission.

Q. What is the purpose of your testimony?

A. My testimony supports Columbia's projected O&M expenses for the Forecasted Test Period, that have been incorporated in Columbia witness Gore's cost of service analysis. I will sponsor and support the following Filing Requirements:

Filing Requirement	**Description**
807 KAR 5:001 Section 16-(6)(a)	Financial Data
807 KAR 5:001 Section 16-(6)(b)	Forecasted Adjustments
807 KAR 5:001 Section 16-(7)(c)	Factors Used in Preparing Forecast

807 KAR 5:001 Section 16-(7)(d)	Annual and Monthly Budget Income Statement
807 KAR 5:001 Section 16-(7)(h)	Financial Forecasts
807 KAR 5:001 Section 16-(7)(h)1	Operating Income Statement
807 KAR 5:001 Section 16-(7)(h)2	Balance Sheet
807 KAR 5:001 Section 16-(7)(h)3	Statement of Cash Flows
807 KAR 5:001 Section 16-(7)(h)8	Mix of Gas Supply (Gas)
807 KAR 5:001 Section 16-(7)(h)9	Employee Level
807 KAR 5:001 Section 16-(7)(h)10	Labor Cost Changes
807 KAR 5:001 Section 16-(7)(n)	Monthly Managerial Reports
807 KAR 5:001 Section 16-(7)(o)	Monthly Budget Variance Reports
807 KAR 5:001 Section 16-(8)(g)	Payroll Cost Analysis
807 KAR 5:001 Section 16-(8)(d)-2.2 & 2.3	Pro Forma Adjustments
807 KAR 5:001 Section 16-(8)(i)	Comparative Income Statements

Q. For each of the documents included within the Filing Requirements that you are supporting, were they prepared by you or someone working under your supervision?

A. Yes.

B. Test Period

Q. What is the test period in this proceeding?

A. Columbia is requesting an adjustment in rates based on a Forecasted Test Period ("Forecasted Test Period") for the twelve months ended December 31, 2022. The financial data for the Forecasted Test Period is presented in the form of pro forma adjustments to a Base Period ("Base Period") which is the twelve months ended August 31, 2021. The Base Period includes actual data for the period September 2020 through February 2021 and forecasted data for the period March 2021 through August 2021.

Q: What is the basis for the forecasted O&M expense included in the Base Period and Forecasted Test Period net operating income?

A: The forecasted O&M expense included in the base and test periods is derived from Columbia's most recent O&M budget and subsequent rate making adjustments, as described by Columbia witness Gore.

C. Process for Determining O&M Budgets

Q: Please describe the annual budget development process.

A: The overall NiSource O&M targets, including NCSC, are established by the Chief Financial Officer, Senior Vice President of Strategy & Chief Risk Officer, and Vice President of Corporate Financial and Regulatory Planning, and approved by the Executive Leadership Team. Operating

Company targets for CKY and departmental O&M are refined and aligned to detailed work plans. The NiSource Financial Planning and Analysis ("FP&A") management team establishes financial goals and planning objectives in conjunction with NiSource Inc.'s senior management team and Board of Directors. FP&A leads the process, working with the stakeholders to ensure that goals and objectives (1) are developed in accordance with state and corporate strategies and goals and (2) balance safety, reliability, compliance, customer service, and financial commitments.

Q: How is O&M expense developed for Columbia's budget?

A: The O&M budget for Columbia is based on a grass roots concept in which individuals who are responsible for approving expenditures are also responsible for budgeting the expenditures. The process generally follows organizational responsibility. Department heads are responsible for overseeing the development of O&M budgets for all cost centers under their control. Columbia's O&M budget is developed by department and by cost element, with the assistance of the FP&A department. This includes a comparison of a series of data points based on most recent experience. Specifically, the proposed O&M budget is compared to the most recent year's O&M budget as well as compared to the prior year's actual, experienced amounts. These comparisons help identify trends and allow for measurement against the Company and parent company management's expectations. Once finalized, the departmental O&M expense budget is incorporated into the business unit's operating plan.

Budgets originate in operating center locations in the field and other departments representing Columbia's major business functions; these budgets are then combined with a corporate-level budget to arrive at a total company budget.

Q. What is meant by the term corporate-level budget?

A. The corporate-level budget represents categories that are budgeted at a NiSource-level, and not at an individual Columbia department level. This allows for each corporate-level department to focus exclusively on the expenditures for which they are directly responsible. Examples of O&M expenses included at the corporate-level are employee benefits, benefits administration fees, audit fees, financial planning and accounting, in-house legal, human resources, and corporate insurance.

Q. Is the budget reviewed throughout the year?

A. Yes, the current year detailed O&M budget is reviewed against actual results each month throughout the year to determine the reasons for variances and to take appropriate action. If known variances are the result of timing that will be resolved within the year, then those variances are monitored closely but no further action is taken, unless it is deemed, at some point during the year, that the variance will result in a true budget variance at the end of the year. When the review of monthly budget versus actual reveals variances that are expected to last throughout the year, the NCSC FP&A department will work with Columbia management to determine the drivers of the variances and steps to be taken to reduce the variance to the overall budget. In certain cases, budget variances will occur to address or take advantage of unforeseen general or operational conditions. In cases where a variance is driven by unforeseen general or operational conditions, the variance may not be reduced or mitigated, but may result in a departmental overrun or underrun. In this case, documentation of the drivers of the variance is maintained and evaluated in future planning cycles to ensure proper consideration of new and developing forecast items.

D. Base Period O&M

Q. Has the process you described above for calculating O&M been used in the development of O&M expense for the Base Period?

A. Yes. Columbia used the same process that we used in our ordinary course of business when developing the O&M expense for the Base Period.

Q. Please describe any notable variance experienced year-to-date in the current year.

A. Columbia has experienced a favorable variance related to uncollectible expense through year-to-date March 2021. The development of uncollectible expense for current year 2021 was based on the assumption of a full twelve months of COVID-19 impacts in 2021. Since the original estimate was developed, Columbia has established payment plans to assist customers with accumulated arrearage from service rendered on or after March 16, 2020 through September 30, 2020. In addition, the federal government has issued stimulus payments and the economy is slowly reopening with positive economic news.

Q. Is the uncollectible expense in the Forecasted Test Period developed with COVID-19 assumptions?

A. No, the uncollectible expense in the Forecasted Test Period does not include any COVID-19 assumptions.

E. Forecasted Test Period O&M

Q. Has the process you described above for calculating O&M been used in the development of O&M expense for the Forecasted Test Period?

A. Yes. Columbia used the same process that we used in our ordinary course of business when developing the O&M expense for the Forecasted Test Period.

Q: Let's discuss some of the more significant components of the O&M forecast. What are the principal assumptions used in the development of the labor cost element budgets included in the Forecasted Test Period O&M expenses?

A: Labor expense is based on projected headcount and wage increase assumptions. More detailed labor budgets are developed by projecting the year's labor based on a trend analysis. The projection includes estimates for headcount, gross salary, overtime, vacation and sick time, and labor charges in from other departments. This results in a sub-total for total labor dollars available by month, which will then be allocated between O&M accounts, capital, and charges to other departments. That allocation involves developing an estimate for the following year's O&M labor budget based on the projected work by activity, and using the estimate to determine how much of the labor budget should be allocated to O&M

accounts. The remaining labor resources are then allocated to capital or charged out to other departments where work may be performed.

Q: Does your budgeting analysis include any projections regarding Columbia headcount?

A. Yes, Columbia is projecting 209 full-time employees for 2022, and an overall wage increase guideline of 3% for exempt and non-exempt employees. Wages and benefits are described in greater detail in the testimony of Witness Cartella.

Q. Please explain how non-workforce activities or events are taken into account in the development of the O&M expense budget.

A. Non-workforce expenses start with the assumption that amounts are to be held relatively flat year to year reflecting normal, ongoing level of expenses and further adjusted for incremental activities or events that are reasonably expected to occur, or adjusted for expenses that are not expected to recur.

Q: Please describe the basis for the corporate-level budgets included in Columbia's overall O&M budget.

A: Corporate-level budgets provided to Columbia include several major categories. Employee benefits expenses are based on information provided by NiSource's independent actuary, AON. Corporate insurance expenses are based on estimated property and casualty premium costs developed by

NCSC's Insurance Department. Audit fees are based on estimates developed by NiSource Accounting. Telecommunications expenses are based on estimates developed by NCSC Information Technology. Corporate Services fee expenses are based on estimates of services to be performed by NCSC for Columbia. Benefits administration fees, and incentive plan expenses are based on estimates developed by NCSC's Human Resources.

Q: Are there any ratemaking adjustments made to the Forecasted Test Period for the Columbia direct O&M?

A: Yes. I am proposing to make one ratemaking adjustment to the Forecasted Test Period related to Columbia's incentive plans. More specifically, the adjustment is to reduce the short-term Corporate Incentive Plan ("CIP"), which is planned at target level, to the lower trigger level amount. The adjustment also reduces stock compensation to reflect a payout consistent with levels paid in the previous three historical calendar years.

Q: Does the O&M expense budgeting methodology (before any ratemaking adjustments) described in your testimony result in an accurate estimate of expenses to be incurred during the Forecasted Test Period?

A: Yes. Please refer to the table below for a comparison of actual versus the annual original O&M budget (excluding trackers) for the years 2017 through 2020. As with any budget, conditions may change over the course of a year, thus requiring adjustments to budgets subsequent to the original budget. Overall, Table 1 below indicates a level of O&M budgeting accuracy by Columbia and, accordingly, provides confidence as to the accuracy of the O&M expenses included in the Forecasted Test Period.

Table 1

Year	Original Budget	Actual	Increase / (Decrease)	% Variance	Major Variance by Category
2017	$43,887	$45,838	$1,950	4.4%	Net Labor, Employee Benefits
2018	$44,252	$42,956	($1,295)	-2.9%	Employee Benefits, Materials & Supplies, Outside Services
2019	$44,143	$48,732	$3,769	8.4%	Net Labor, Outside Services
2020	$46,924	$49,313	$2,390	5.1%	Uncollectible expense related to COVID-19

Q: Have you excluded certain cost categories from your comparison?

A: Yes, O&M expenses categorized as trackers, such as Energy Efficiency Conservation Program, are designed to match, or track, revenues related to specific programs that have been previously approved in order to ensure that there is no impact on net operating income for such programs. The accounting treatment generally allows expenses to be deferred as incurred and reclassified to expense when the recovery of program costs is recorded in revenue. While O&M tracker expense variances may be material, there is a corresponding offsetting revenue variance. For that reason, I have excluded trackers from the comparison so as not to distort the accuracy of the budget.

Q. Please identify the key variances in O&M expense levels between calendar year 2017 and the Forecasted Test Period in the current proceeding.

A. Table 2 below identifies the key variances in O&M expense levels.

Table 2

Category	Actual December 31, 2017	Budget 2021 Rate Case December 31, 2022	Variance
Labor	$9,413	$12,970	$3,557
Medical Insurance	$996	$1,852	$856
Corporate Insurance	$677	$2,321	$1,645
Outside Services	$5,567	$7,802	$2,235

Labor costs reflect the salaries and wages for Columbia employees that report and charge their time directly to Columbia. The increase is driven by Columbia's increase in headcounts over the period to support its ongoing operational activities to provide safe, reliable service to customers. The headcount level increased due to the hiring of additional employees in Construction Services to support Columbia's capital program and System Operations to comply with additional operational requirements. While employees in Construction Services charge most of their time to capital, any training associated with onboarding and ongoing education is charged to

O&M. The increase also includes the transfer of NiSource Corporate Service employees to Columbia in Large Customer Relations and Safety Compliance & Risk Management. Columbia's headcount level at February 28, 2021 was 201, and CKY anticipates it will fill 8 vacancies during the Forecasted Test Period to support its ongoing operations.

Medical Insurance costs in the Forecasted Test Period are based on the information provided by NiSource's independent actuary, AON. The underlying assumptions for the current AON study were based upon the 2018 and 2019 experience, coupled with the headcount growth from 2019 to 2020 and annual medical trends.

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

utility insurance and, those that are, have very limited capacity. The decrease in available capacity has significantly impacted insurance premiums.

Outside Services costs reflect the payments made to consultants and contractors for various services. One service performed that has increased over the period is locates and turnbacks. The number of ticket volumes associated with locating has increased over the last years. This has a substantial impact to Columbia's O&M over the period due to the resource requirements to meet locate timing requirements.

Q. In your opinion, is the O&M information presented in Columbia's forecasted test year accurate and reliable?

A. Yes.

Q. And to the best of your knowledge and understanding, is the information presented in the filing requirements you are sponsoring also accurate and reliable?

A. Yes.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony if necessary

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Susanne M. Taylor attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky’s President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Susanne M. Taylor

Columbia Exhibit No. 27

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF CO-LUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVI-SIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NE-CESSITY; AND OTHER RELIEF	))))))))	Case No. 2021-00183

PREPARED DIRECT TESTIMONY OF
SUSAN TAYLOR
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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David S. Samford
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Attorneys for Applicant

May 28, 2021 **COLUMBIA GAS OF KENTUCKY, INC.**

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF	)	
COLUMBIA GAS OF KENTUCKY, INC. FOR AN	)	
ADJUSTMENT OF RATES; APPROVAL OF	)	
DEPRECIATION STUDY; APPROVAL OF TARIFF	)	Case No. 2021-00183
REVISIONS; ISSUANCE OF A CERTIFICATE OF	)	
PUBLIC CONVENIENCE AND NECESSITY; AND	)	
OTHER RELIEF	)	

VERIFICATION OF SUSAN TAYLOR

STATE OF OHIO	)
	)
COUNTY OF FRANKLIN	)

Susan Taylor, Director of Financial Planning for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of her Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Susanne M. Taylor

Susan Taylor

The foregoing Verification was signed, acknowledged and sworn to before me this 19th day of May, 2021, by Susan Taylor.

John R Ryan III
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

Notary Commission No. N/A

Commission expiration: ______________

PREPARED DIRECT TESTIMONY OF SUSAN TAYLOR

Q: Please state your name and business address.

A: My name is Susan Taylor. My business address is 290 W Nationwide Blvd, Columbus, Ohio 43215.

Q: What is your current position and what are your responsibilities?

A: I am Director of Financial Planning for NiSource Corporate Services Company ("NCSC"). As Director of Financial Planning, my current responsibility is leading an enterprise wide financial planning system and process enhancement. Other principal responsibilities over the past couple of years include providing timely and accurate budgets and analysis that produces meaningful insights against prior year and the current year budget. In carrying out these duties, I was responsible for a number of activities, including budgeting and forecasting for the operations and maintenance ("O&M") functions including NCSC, monthly reporting and variance analysis, updating the current year forecast, consolidating financial budget data, and other ad hoc financial support for NiSource.

Q: What is your educational background?

A: I received a Bachelor of Science degree in Accounting in 1991 from Ohio University, Athens, Ohio. I am a Certified Public Accountant and a member of the Ohio Society of Certified Public Accountants ("OSCPA"). I regularly attend accounting and accounting-related seminars sponsored by various organizations including the American Gas Association, OSCPA and Deloitte.

Q: What is your employment history?

A: I was employed at KPMG Peat Marwick from August 1991 through June 1993 where I held various accounting positions ranging from Staff Accountant to In-Charge Accountant. In July 1993, I was hired by the Columbia Energy Group's Service Corporation as a Staff Auditor. From May 1994 to May 2000, I held various analyst positions in the Regulatory Department. In June 2000, I took a position as Lead Financial Analyst in the Financial Planning Support Department. Subsequent to the merger between Columbia Energy Group and NiSource Inc. ("NiSource"), I was promoted to Manager of Corporate Accounting on November 1, 2000 and then to Controller of NCSC in April 2005. Effective August 1, 2015, I assumed a new role as Director, Transition Service Agreement ("TSA") Financials & Governance.

After serving in the TSA Governance role, on August 1, 2016, I assumed the role of Director of Performance Management. Effective January 1, 2017, I assumed my new role as Director of Financial Planning.

Q. Have you previously testified before any regulatory commissions?

Yes. I have submitted testimony in the following state jurisdictions: Kentucky, Indiana (both Gas and Electric), Massachusetts, Pennsylvania and Virginia. I testified on NCSC before the Kentucky Regulatory Commission ("Commission") in Columbia's Case No. 2013-00167.

Q: What Schedules are you are supporting in this filing?

A: I will be supporting the following Filing Requirements:

Filing Requirement	Description
807 KAR 5:001 Sections 16-(6)(a)	Financial Data
807 KAR 5:001 Sections 16-(6)(b)	Forecasted Adjustments
807 KAR 5:001 Sections 16-(7)(c)	Factors Used in Preparing Forecast
807 KAR 5:001 Sections 16-(7)(u)	Affiliate, et. al., Allocations/Charges
807 KAR 5:001 Sections 16-(8)(d)	Summary of Income Adjustments
807 KAR 5:001 Sections 16-(8)(g)	Analysis of Payroll Costs

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to provide background on the relationship between NCSC and Columbia Gas of Kentucky, Inc. ("Columbia"). I also support the O&M expenses associated with the Corporate and Operating services provided by NCSC to Columbia, and any adjustments to those expenses for the period beginning September 1, 2020 and ending August 31, 2021 (the "Base Period") including 6 months of actuals and 6 months of budget data, and the period beginning January 1, 2022 and ending December 31, 2022 (the "Forecasted Test Period").

Q: Are you including any attachments to your testimony?

A. Yes. They are as follows: Attachment ST-1 is a list of NCSC associate billing companies, Attachment ST-2 is the service agreement between NCSC and Columbia, Attachment ST-3 is the normalized adjustments to the Forecasted Test Period, and Attachment ST-4 is the inflation adjustment calculated on NCSC 2017 historical costs.

Q: Were each of these attachments prepared by you or by someone working under your supervision?

A: Yes.

Relationship between NCSC and Columbia

Q: Please explain the structure and role of NCSC.

A: NCSC was established to provide centralized services to its affiliates. The rendering of services on a centralized basis enables the affiliates to realize benefits, including use of personnel and equipment, and the availability of personnel with specialized areas of expertise. Thus, NCSC offers Columbia, as well as the other individual distribution companies, access to the depth and breadth of professional experience that may not otherwise be available, or available from consultants at much higher costs. A list of the NCSC associate billing companies is shown in Attachment ST-1.

Q: How are costs billed to affiliates?

A: There are two types of billings made to affiliates, including Columbia: (1) contract billing; and (2) convenience billing.

Q: Can you please explain contract and convenience billing?

A: Contract billings represent NCSC labor and costs billed to the respective affiliates, and are identified by billing pools. Contract billed charges may be direct-billed (billed directly to a single affiliate or function), or allocated (split between or among several affiliates), depending upon the nature of the expense.

Convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate is billed for its proportional share of the payments made in that respective month. As the name implies, convenience billing is intended as a convenience to vendors because it eliminates the need for a separate invoice to be generated for each affiliate entity receiving the same services. NCSC makes the payment to the vendor and the charges for the services are recorded directly on the books of the affiliate. Of note, all of the charges listed on my attachments are O&M costs generated by contract billings, as described in this section of my testimony.

Q: Is contract billing rendered pursuant to an executed contract?

A: Yes. NCSC has executed an individual Service Agreement with each affiliate, which designates the types of services to be performed and the method of calculating the charges for those services. The Service Agreement is updated from time to time so that all affiliates that receive service from NCSC are subject to the same Service Agreement. A copy of the current Service Agreement, effective January 1, 2015 between NCSC and Columbia, was submitted to this Commission as an affiliate agreement on January 15, 2015 (the "2015 Agreement"). A copy of the 2015 Agreement is attached hereto as Attachment ST-2. The services provided to Columbia are described in the 2015 Agreement in Article 1 and in Appendix A (Article 2).

NCSC Cost Allocation to Columbia

Q: How does NCSC determine charges applicable to Columbia?

A: NCSC is regulated by the Federal Energy Regulatory Commission ("FERC"). Pursuant to FERC Order No. 684 issued October 19, 2006, centralized service companies (like NCSC) must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. In compliance with FERC, NCSC uses a billing pool system to collect costs that are applicable and billable to affiliates, including Columbia. Costs are directly charged to a particular affiliate whenever possible. Some projects or services necessarily involve more than one affiliate, and in that case, the billing pool system details how expenses are allocated among the participating affiliates.

1

Q: What controls are in place to ensure that an affiliate is consistently and appropriately billed?

A: NCSC allocates costs for a particular billing pool in accordance with the bases of allocation filed annually with FERC. A description of each of the bases of allocations are provided in the 2015 Agreement. NCSC currently updates the statistical data used in the approved allocation bases, at minimum, on a semi-annual basis; and furthermore, prior to publishing the new allocation percentages, NCSC provides Columbia's leadership team the opportunity to review, discuss, and provide feedback. There are system controls in place that allow certain departments, or groups of departments, to only use billing pools that allocate to companies benefitting from the services being provided. Essentially, a department that supports only the operating affiliates would only be allowed to use billing pools that include the operating affiliates. If an individual would attempt to use a different billing pool, the related accounting systems would prompt an immediate error and not allow data to be input. Additionally, Columbia's Internal Audit group conducts an annual review of cost allocation procedures and makes recommendations related to contract and convenience billing processing.

NiSource Inc., including NCSC, underwent a FERC audit, Docket No. FA11-5-000 covering the period January 1, 2009 through December 31, 2010. The Final Audit Report was issued by the FERC on October 24, 2012. As indicated in the Final Audit Report, the Audit Staff reviewed and tested the supporting details for NCSC's cost allocation methods. They then sampled and selected supporting documents to ensure that NCSC's billings and accounting comply within the USOA (Uniform System of Accounts). FERC did not issue any adverse comments to NCSC related to its allocation methods. NCSC continues to use the same allocation methods reviewed and tested during the FERC Audit.

Q: What are the Bases of Allocation?

A: NCSC allocates costs for a particular billing pool in accordance with the following Bases of Allocation that are filed annually with the FERC:

BASIS 1	Gross Fixed Assets and Total Operating Expenses
BASIS 2	Gross Fixed Assets
BASIS 3	Number of Meters Serviced
BASIS 4	Number of Accounts Payable Invoices Processed
BASIS 7	Gross Depreciable Property & Total Operating Expense
BASIS 8	Gross Depreciable Property

BASIS 9	Automotive Units
BASIS 10	Number of Retail Customers
BASIS 11	Number of Regular Employees
BASIS 13	Fixed Allocation
BASIS 14	Number of Transportation Customers
BASIS 15	Number of Commercial Customers
BASIS 16	Number of Residential Customers
BASIS 17	Number of High Pressure Customers
BASIS 20	Direct Costs (direct and allocated corporate contract bill costs)

A description of each Basis of Allocation is included in Attachment ST-2.

Q: Please provide the breakdown of direct and allocated costs for the past three historical years 2020, 2019 and 2018?

A: Please see Table ST-1 for the breakdown by direct and allocated costs (by Basis of Allocation) for the three past historical calendar years.

Table ST-1	**2018**	**2019**	**2020**
Direct Billed	4,760,494	4,688,992	4,837,801
Basis 1	1,277,182	2,283,930	1,376,915
Basis 2	13,998	5,543	10,946
Basis 3	11		121
Basis 4	135,578	175,730	90,785
Basis 7	58,019	74,494	95,212
Basis 8			82
Basis 9	22,501	5,046	11,179
Basis 10	3,235,261	3,360,674	3,106,112
Basis 11	901,402	1,008,969	1,267,709
Basis 13	1,179,311	1,149,040	1,398,791
Basis 14	304	1,139	230
Basis 20	4,580,966	4,572,711	4,678,352
Direct NCSC	578,039	621,888	641,017
Total O&M Billed from NCSC to Columbia	16,743,067	17,948,157	17,515,253
Direct Billed O&M Charges	32%	30%	31%
Allocated Billed O&M Charges	68%	70%	69%

Q: Are charges for services rendered to Columbia billed at cost?

A: Yes. In accordance with the 2015 Agreement (Section 2.2) all services are provided at cost, including compensation for use of capital.

<u>NCSC Budget Development Process</u>

Q: Can you describe the NCSC annual budget development process?

A: The NCSC budget development process, in regard to timing and duration, is consistent with the Columbia planning process, as discussed by Columbia Witness Lai.

Q: How is O&M expense developed for the NCSC budget?

A: The O&M planning process is ongoing through the year. The overall NiSource O&M targets, including NCSC, are established by the Chief Financial Officer, SVP of Strategy & Chief Risk Officer, and Vice President of Corporate Financial and Regulatory Planning, and approved by the Executive Leadership Team. Department O&M targets are refined and updated as necessary for changes during the year. Material changes to the O&M plan must be approved by the responsible Executive Council leader, of the Executive Leadership Team, and Chief Financial Officer. O&M expense budgeting methodology used by NCSC is a combination of a "top down" and "grass roots" systematic approach.

Q: Please explain.

A: Using the Function O&M targets set by the Executive Leadership Team as a guidepost, it is the responsibility of the NCSC Financial Planning team along with NCSC functional leaders to work together to ensure that NCSC O&M expenses are developed in accordance with overall financial goals and objectives.

NCSC budgeted expenses are grounded in a trailing 12-month historical spend with merit increases and inflation adjusted for each year thereafter, delineated by cost categories such as labor, materials, and outside services. NCSC's indirect costs, such as benefits, taxes, depreciation, and other expenses are distributed to each department based on labor. NCSC expenses are allocated to each operating company using historical distributions, and then adjusted as necessary for any specific allocations for one-time items, future planned work, or strategic initiatives in line with overall management objectives.

Q: Is the budget reviewed throughout the year?

A: Yes, on a monthly basis an analysis that compares budget to actual results is completed and reviewed. This analysis provides key drivers for monthly variances. Function leaders and their direct reports have accountability to review and approve labor, invoices and employee expenses for their respective departments. These same leaders have access to reports that provide their respective department budget to actual results. In addition to reviewing monthly variance analysis, updates are conducted with Function leaders that provide forecast updates for the current year and any impact to future years. Function leaders are responsible for reporting operational and financial risks, as well as mitigation strategies within their respective Function to Corporate Financial. Additionally, quarterly reviews with Senior Management, including State Presidents, are held to discuss quarter to date results and year to date results.

<u>NCSC Projected O&M Expenses in Forecasted Test Period</u>

Q. What is the forecasted test period in this proceeding?

A. Columbia is requesting an adjustment in rates based on a Forecasted Test Period ("Forecasted Test Period") for the 12-months ended December 31, 2022.

Q: What is the basis for the O&M expense in the Forecasted Test Period?

A: The O&M expense included in the Forecasted Test Period in derived from the planned expenses plus any known changes for one-time items, future planned work, strategic initiatives, merit increases, and inflation adjustment.

Q: What is the level of NCSC costs expected to be billed to Columbia during the Forecasted Test Period, before any adjustments?

A: The level of NCSC O&M costs in the Forecasted Test Period to Columbia, before any adjustments, is $20,913,572 as seen on Attachment ST-3.

Q: Were there any adjustments made to the Forecasted Test Period for the NCSC O&M for Columbia?

A: Yes. There are multiple adjustments made to the Forward Test Year that result in a decrease to O&M expense in the amount of $1,592,648, and included in Schedule D-2.4. As shown on Attachment ST-3, the adjustments are comprised of (1) efficiency savings of $666,016, (2) compensation incentive pay decrease of $543,109, (3) stock compensation pay decrease of $266,575, and (4) other ratemaking adjustments decrease of $116,948 for promotional advertising and other miscellaneous adjustments that

Columbia is not seeking to recover. Detail related to these adjustment amounts are included in Attachment ST-3.

Q: Please explain the efficiency adjustment on Attachment ST-3.

A: As part of continual business decision making, efficiency initiatives are on-going with a focus on building organizational capabilities, and delivering key market based business support services, while reducing costs and driving efficiency to enable continued investments in safety and modernization. Two recent efficiency initiatives include the evolution of business services and connected customer experience. The evolution of business services will allow corporate business services work to be done through a standardized process using an experienced vendor for activities in the supply chain, procure to pay, tax, human resources, hire to retire, billings and payments, record to report, and corporate accounting functions. The connected customer experience consists of improving customer digitization for 24/7 access and investing in mobile apps, chat bots, and improving overall web capabilities, while reducing handle time, utilizing robotic processes to automate manual processes around billing exceptions, and improving revenue management on collections and payment options with predictive analytics and customer education. In addition to the $666,016 efficiency adjustment proposed,

$302,544 is already included for those noted efficiencies in the Forecasted Test Period.

Q: Please explain the Corporate Incentive Payout ("CIP") and Stock Compensation Adjustments on Attachment ST-3.

A: The CIP budget is planned at target level, and therefore, the reduction noted above is to bring CIP in line with the lower trigger level amount. The stock compensation adjustments reduce NCSC expense to reflect a payout consistent with levels paid in the three previous historical calendar periods.

Q: Is the Forecasted Period level of $19,320,924, after adjustments, on <u>Attachment ST-3</u>, representative of the NCSC O&M expense necessary to provide ongoing safe and reliable service at reasonable rates?

A: Yes. The Forecasted Test Period level of O&M expense of $19,320,924, after pro-forma adjustments, is reasonable and representative of Columbia's ongoing cost of providing service. The Forward Test Period level of O&M expense is justified by the projected needs of Columbia to serve its customers.

Q: Is the level of O&M expense, net of pro-forma adjustments, in line with inflation from the future test year in the last rate case, Columbia's Case No. 2016-00162?

A: Yes. The level of O&M costs included in the Forecasted Test Period of $19,320,924, after pro forma adjustments, is within .001% of the GDP index for related merits and inflation on labor, materials and outside services, respectively. Using the IHS Global Insight GDP Implicit Price Deflator as of March 2021, the total inflation rate over the period between the two test periods is 9.94%. Using 2017 normalized actuals of $17,574,214, the GDP calculated inflation amount is $19,320,739, which is directionally in line with the Forecasted Test Period of $19,320,924. Please refer to Attachment ST-4, Sheets for detail calculation.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony.

ATTACHMENT ST-1
LIST OF ASSOCIATE BILLING COMPANIES

Attachment No. ST-1
Page 1 of 1

NiSource Corporate Services Company

List of Associate Billing Companies

	Company Name	Billing Company No.
	NiSource Insurance Corporation Limited	22
	Energy USA-TPC Corp.	24
	Columbia Gas of Kentucky, Inc.	32
	Columbia Gas of Ohio, Inc.	34
	Columbia Gas of Maryland, Inc.	35
	Columbia Gas of Pennsylvania, Inc.	37
	Columbia Gas of Virginia, Inc.	38
	NiSource Inc.	58
	Northern Indiana Public Service Company	59
	NiSource Development Company, Inc.	60
	NiSource Capital Markets, Inc.	62
	Energy USA, Inc. (IN)	68
	NiSource Retail Services, Inc.	71
	NiSource Finance Corp.	75
	NiSource Energy Technology, Inc.	78
	Columbia Gas of Massachusetts, Inc.	80
*	Columbia Pipeline Group Services	82
	Columbia of Ohio Receivables Corporation	93
	Columbia Gas of Pennsylvania Receivables Corporation	94
	NIPSCO Accounts Receivables Corporation	95

* Servcies performed for Columbia Pipeline Group billed to Business Unit 82.

ATTACHMENT ST-2
SERVICE AGREEMENT

Service Agreement

BETWEEN

NISOURCE CORPORATE SERVICES COMPANY

AND

COLUMBIA GAS OF KENTUCKY, INC.

Dated January 1, 2015

(To Take Effect Pursuant to Article 3 Hereof)

SERVICE AGREEMENT

This SERVICE AGREEMENT (the "Service Agreement" or "Agreement") is made and entered into effective the 1st day of January, 2015 by and between Columbia Gas of Kentucky, Inc., its subsidiaries, affiliates and associates ("Client", and together with other associate companies that have or may in the future execute this form of Service Agreement, the "Clients") and NiSource Corporate Services Company ("Company").

WITNESSETH:

WHEREAS, each Company and Client is a direct or indirect wholly owned subsidiary of NiSource Inc., a Delaware corporation and a "holding company" as defined in the Public Utility Holding Company Act of 2005 ("Act") that is subject to regulations adopted by the Federal Energy Regulatory Commission ("FERC") pursuant to the Act;

WHEREAS, the Client is an affiliate of the Company; and

WHEREAS, the Company and Client agree to enter into this Service Agreement whereby the Client may seek certain services from the Company and the Company agrees to provide such services upon request and upon the Company's conclusion that it is able to perform such services. Further, the Client agrees to pay for the services as provided herein at cost; and

WHEREAS, the rendition of such services set forth in Article 2 of Appendix A on a centralized basis enables the Clients to realize economic and other benefits through (1) efficient use of personnel and equipment, (2) coordination of analysis and planning, and (3) availability of specialized personnel and equipment which the Clients cannot economically maintain on an individual basis.

NOW THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Service Agreement covenant and agree as follows:

ARTICLE 1

SERVICES

1.1 The Company shall furnish to Client, as requested by Client, upon the terms and conditions hereinafter set forth, such of the services described in Section 2 of Appendix A hereto (the "Services"), at such times, for such periods and in such manner as Client may from time to time request and that the Company concludes it is able to perform. The Company shall also provide Client with such services, in addition to those services described in Appendix A hereto, as may be requested by Client and that the Company concludes it is able to perform. In supplying such services, the Company may arrange, where it deems appropriate in consultation with Client, for the services of such experts, consultants, advisers, and other persons with necessary qualifications as are required for or pertinent to the provision of such services ("Additional Services").

1.2 Client shall take from the Company such of the Services, and such Additional Services, whether or not now contemplated, as are requested from time to time by Client and that the Company concludes it is able to perform.

1.3 The cost of the Services described herein or contemplated to be performed hereunder shall be allocated to Client in accordance with Exhibit A, which is filed annually with the FERC. Client shall have the right from time to time to amend or alter any activity, project, program or work order provided that (i) Client pays and remunerates the Company the full cost for the services covered by the activity, project, program or work order, including therein any expense incurred by the Company as a direct result of such amendment or alteration of the activity, project, program or work order, and (ii) Client accepts that no amendment or alteration of an activity, project, program or work order shall release Client from liability for all costs already incurred by or contracted for by the Company pursuant to the activity, project, program or work order, regardless of whether the services associated with such costs have been completed.

1.4 The Company shall hire, train and maintain an experienced staff able to perform the Services, or shall obtain experience through third-party resources, as it shall determine in consultation with Client.

1.5 The Company routinely makes payments on behalf of affiliates on an ongoing basis, including payroll, employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate receives on a monthly basis a Convenience Bill for its proportional share of the payments made in that respective month. As the name implies, convenience billing is intended as a convenience to vendors because it eliminates the need for a separate invoice to be generated for each affiliate entity receiving the same services. Therefore, the Company makes the payment to the vendor and the charges for the services are recorded directly on the books of the affiliate and not by the Company.

ARTICLE 2

COMPENSATION

2.1 As compensation for the Services to be rendered hereunder, Client shall compensate and pay to the Company all costs, reasonably identifiable and related to particular Services performed by the Company for or on Client's behalf. The methods for allocating the Company costs to Client, as well as to other associate companies, are set forth in Appendix A.

2.2 It is the intent of this Service Agreement that charges for Services shall be billed, to the extent reasonably possible, directly to the Client or Clients benefiting from such Service. Any amounts remaining after such direct billing shall be allocated using the methods identified in Appendix A. The methods of allocation of cost shall be subject to review annually, or more frequently if appropriate. Such methods of allocation of costs may be modified or changed by the Company without the necessity of an amendment to this Service Agreement; provided that, in each instance, all services rendered hereunder shall be at actual cost and include compensation for use of capital thereof, fairly and equitably allocated. The Company shall review with the

Client any proposed change in the methods of allocation of costs hereunder and the parties must agree to any such changes before they are implemented.

2.3 The Company shall make available monthly billing information to the Client that shall reflect all information necessary to identify the costs charged and Services rendered for that month. Client shall undertake a review of the charges and identify all questions or concerns regarding the charges reflected within a reasonable period of time. Client shall remit to the Company all charges billed to it within a period of time not exceeding 30 days of receipt of the monthly billing information.

2.4 Client agrees to provide the Company, from time to time, as requested such financial and statistical information as the Company may need to compute the charges payable by Client consistent with the method of allocation set forth on Appendix A.

2.5 It is the intent of this Service Agreement that the payment for services rendered by the Company to Client under this Service Agreement shall cover all the costs of its doing business including, but not limited to, salaries and wages, office supplies and expenses, outside services employed, insurance, injuries and damages, employee and retiree pensions and benefits, taxes, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization, and reasonable compensation for use of capital.

ARTICLE 3

TERM

3.1 This Service Agreement shall become effective as of the date first written above, subject only to the receipt of any required regulatory approvals from the State Commissions and federal agencies as needed, and shall continue in force until terminated by the Company or Client, upon not less than one year's prior written notice to the other party. This Service Agreement shall also be subject to termination or modification at any time, without notice, if and to the extent performance under this Service Agreement may conflict with (1) the Act or with any rule, regulation or order of the FERC adopted before or after the date of this Service Agreement, or (2) any state or federal statute, or any rule, decision, or order of any state or federal regulatory agency having jurisdiction over one or more Clients. Further, this Service Agreement shall be terminated with respect to the Client immediately upon the Client ceasing to be an associate company of the Company. The parties' obligations under this Service Agreement which by their nature are intended to continue beyond the termination or expiration of this Service Agreement shall survive such termination or expiration.

ARTICLE 4

SERVICE REVIEW

4.1 Upon request of the Client, the Company shall meet with the Client to review and assess the quality, costs, and/or allocations of the services being provided pursuant to this

Service Agreement. The Client shall also have the right to amend the scope of services as it determines to be necessary or desirable.

4.2 NiSource maintains an Internal Audit Department that will conduct periodic audits of the Company administration and accounting processes ("Audits"). The Audits will include examinations of Service Agreements, accounting systems, source documents, methods of allocation of costs and billings to ensure all Services are properly accounted for and billed to the appropriate Client. In addition, the Company's policies, operating procedures and controls will be evaluated annually. Copies of the reports generated by the Company as part of the Audits will be provided to Client upon request.

ARTICLE 5

MISCELLANEOUS

5.1 All accounts and records of the Company shall be kept in accordance with the FERC's Uniform System of Accounts ("USofA") for centralized service companies .

5.2 New direct or indirect subsidiaries of NiSource Inc., which may come into existence after the effective date of this Service Agreement, may become additional Clients of the Company and subject to a service agreement with the Company. The parties hereto shall make such changes in the scope and character of the services to be rendered and the method of allocating costs of such services as specified in Appendix A, subject to the requirements of Section 2.2, as may become necessary to achieve a fair and equitable allocation of the Company's costs among all Clients including any new subsidiaries. The parties shall make similar changes if any Client ceases to be associated with the Company.

5.3 The Company shall permit Client reasonable access to its accounts and records including the basis and computation of allocations.

5.4 The Company and Client shall comply with the terms and conditions of all applicable contracts managed by the Company for the Client, individually, or for one or more Clients, collectively, including without limitation terms and conditions preserving the confidentiality and security of proprietary information of vendors.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date and year first above written.

NISOURCE CORPORATE SERVICES COMPANY

By: Susanne M Taylor
Name: Susanne M. Taylor
Its: Controller

COLUMBIA GAS OF KENTUCKY, INC.

By: Herbert A. Miller
Name: Herbert A. Miller
Its: President

APPENDIX A

NISOURCE CORPORATE SERVICES COMPANY

Services Available to Clients
Methods of Charging Therefor and
Miscellaneous Terms and Conditions of Service Agreement

ARTICLE 1

DEFINITIONS

1 The term "Company" shall mean NiSource Corporate Services Company and its successors.

2 The term "Service Agreement" shall mean an agreement, of which this Appendix A constitutes a part, for the rendition of services by the Company.

3 The term "Client" shall mean any corporation to which services may be rendered by the Company under a Service Agreement.

ARTICLE 2

DESCRIPTION OF SERVICES

Descriptions of the expected services to be provided by the Company are detailed below. The descriptions are deemed to include services associated with, or related or similar to, the services contained in such descriptions. The details listed under each heading are intended to be illustrative rather than inclusive and are subject to modification from time to time in accordance with the state of the art and the needs of the Clients.

1 *Accounting and Statistical Services.* The Company will advise and assist the Clients in all aspects of accounting, including financial accounting, asset accounting, regulatory accounting, tax accounting, maintenance of books and records, safeguarding of assets, accounts payable, accounts receivable, reconciliations, accounting research, reporting, operations and maintenance analysis, payroll services, business applications support, and other related accounting functions. The Company will also provide services related to developing, analyzing and interpreting financial statements, directors' reports, regulatory reports, operating statistics and other financial reports. The Company will ensure compliance with generally accepted accounting principles and provide guidance on exposure drafts, financial accounting standards, and interpretations issued by the Financial Accounting Standards Board. The Company will advise and assist the Clients in the formulation of accounting practices and policies and will conduct special studies as may be requested by the Clients.

2 *Auditing Services.* The Company will conduct periodic audits of the general records of the Clients, will supervise the auditing of local and field office records of the Client, and will coordinate the audit programs of the Clients with those of the independent accountants

in the annual examination of their accounts. The Company will ensure compliance, monitor business risk, and coordinate internal control structure.

3 *Budget Services.* The Company will advise and assist the Clients in matters involving the preparation and development of forecasts, budgets and budgetary controls, and other financial planning activities.

4 *Business Services.* The Company will advise and assist the Clients in the preparation and use of educational and advertising materials; in the development of processes to increase residential, commercial and industrial customers, as well as maintenance of business in those areas; and providing information to customers regarding Clients' products and services.

5 *Corporate Services.* The Company will advise and assist the Clients in connection with corporate matters including corporate secretary services, business continuity planning, shareholder services, corporate records management, proceedings involving regulatory bodies, and other corporate matters.

6 *Customer Billing, Collection, and Contact Services.* The Company will render calculating, bill exception processing, back office processing, posting, printing, inserting, mailing and related services to Client associated with the preparation and issuance of customer bills, notices, inserts and similar mailings. The Company will provide cash processing, revenue recovery, account reconciliations and adjustments, and related services to Client associated with the collection of revenue and management of accounts receivable. The Company will provide customer contact and related services to Client, including alternative pricing services, customer contact center management, operation and administration; management of key customer relationships; communications associated with the commencement, transfer, maintenance and disconnection of service; sales of optional products and services; the receipt and processing of emergency calls; the handling of customer complaints; and responses to customer billing, credit, collection, order take and inquiry, outage, meter reading, retail choice and other inquiries.

7 *Depreciation Services.* The Company will advise and assist the Clients in matters pertaining to depreciation practices, including (1) the making of studies to determine the estimated service life of various types of plant, annual depreciation accrual rates, salvage experience, and trends in depreciation reserves indicated by such studies; (2) assistance in the organization and training of the depreciation departments of the Clients; and (3) dissemination to the Clients of information concerning current developments in depreciation practices.

8 *Economic Services.* The Company will advise and assist the Clients in matters involving economic research and planning and in the development of specific economic studies.

9 *Electronic Communications Services.* The Company will advise and assist the Clients in connection with the planning, installation and operation of radio networks, remote control and telemetering devices, microwave relay systems and all other applications of electronics to the fields of communication and control.

10 *Employee Services.* The Company will advise and assist the Clients in connection with organizational, leadership, and strategic development, employee relations matters, including recruitment, employee placement and retention, training, compensation, safety, labor relations

and health, welfare and employee benefits. The Company will also advise and assist the Clients in connection with temporary labor matters, including assessment, selection, contract negotiation, administration, service provider relationships, compliance, review and reporting.

11 *Engineering and Research Services.* The Company will advise and assist the Clients in connection with the engineering phases of all construction and operating matters, including estimates of costs of construction, preparation of plans and designs, engineering and supervision of the fabrication of natural gas facilities, standardization of engineering procedures, and supervision and inspection of construction. The Company will also conduct both basic and specific research in fields related to the operations of the Clients.

12 *Facility Services.* The Company will manage and effectively execute facility operations, facility maintenance, provide suitable space in its offices for the use of the Clients and their officers and employees, provide delivery services, security services, print services, and other facility services.

13 *Gas Dispatching Services.* The Company will advise and assist the Clients in the dispatching of the gas supplies available to the Clients, and in determining and effecting the most efficient routing and distribution of such supplies in the light of the respective needs therefor and the applicable laws and regulations of governmental bodies. If requested by the Clients, the Company will provide a central dispatcher or dispatchers to handle the routing and dispatching of gas.

14 *Information Services.* The Company will advise and assist the Clients in matters involving the furnishing of information to customers, employees, investors and other interested groups, and to the public generally, including the preparation of booklets, photographs, motion pictures and other means of presentation, and assistance to Clients in their advertising programs.

15 *Information Technology Services.* The Company will advise and assist Clients in matters involving information technology, including management, operations, control, monitoring, testing, evaluation, data access security, disaster recovery planning, technical research, and support services. The Company will also provide and assist the Client with application development, maintenance, modifications, upgrades and ongoing production support for a portfolio of systems and software that are used by the Clients. In addition, the Company will identify and resolve problems, ensure efficient use of software and hardware, and ensure that timely upgrades are made to meet the demands of the Clients. The Company will also maintain information concerning the disposition and location of Information Technology assets.

16 *Insurance Services.* The Company will advise and assist the Clients in general insurance matters, in obtaining policies, making inspections and settling claims.

17 *Land/Surveying Services.* The Company will provide land asset management, land contract management, and surveying services in connection with Clients' acquisition, leasing, maintenance, and disposal of interests in real property, including the maintenance of land records and the recording of instruments relating to such interests in real property, where necessary.

18 *Legal Services*. The Company will provide Clients with legal services (including legal services, as necessary or advisable, in connection with or in support of any of the other services provided hereunder), including, but not limited to, general corporate matters and internal corporate maintenance, contract drafting and negotiation, litigation, liability and risk assessment, financing, securities offerings, state and federal regulatory compliance, state and federal regulatory support and rule interpretation and advice, including, without limitation, interpretation and advice concerning the regulations or orders of the Securities and Exchange Commission, the Federal Energy Regulatory Commission, the Environmental Protection Agency, and the Pipeline and Hazardous Materials Safety Administration, bankruptcy and collection matters, employment and labor relations investigations, union contracting, Equal Employment Opportunity Commission issues, compliance with state and federal legislative requirements, and all other matters for which Clients require legal services.

19 *Officers*. Any Client may, with the consent of the Company, elect to any office of the Client any officer or employee of the Company whose compensation is paid, in whole or in part, by the Company. Services rendered to the Client by such person as an officer shall be billed by the Company to the Client and paid for as provided in Articles 3 and 4, and the Client shall not be required to pay any compensation directly to any such person.

20 *Operations Support and Planning Services*. The Company will advise and assist the Clients in connection with operations support and planning, including logistics, scheduling & dispatching; workforce planning; corrosion and leakage programs; estimates of gas requirements and gas availability; gas transmission, measurement, storage and distribution; construction requirements; construction management; operating standards and practices; regulatory and environmental compliance; pipeline safety and compliance; employee and system safety programs; sustainability; training; management of transportation and sales programs; negotiation of gas purchase and sale contracts; energy marketing and trading, including off-system sales and capacity release activities contemplated in a Client's revenue sharing mechanism; security services; measurement, regulation and conditioning equipment; meter testing, calibration and repair; hydraulic gas network modeling, facility mapping and GIS technologies; and other operating matters.

21 *Purchasing, Storage and Disposition Services*. The Company will render advice and assistance to the Clients in connection with supply chain activities, including the standardization, purchase, lease, license and acquisition of equipment, materials, supplies, services, software, intellectual property and other assets, as well as shipping, storage and disposition of same. The Company will also render advice and assistance to the Client in connection with the negotiation of the purchase, sale, acquisition or disposition of assets and services and the placing of purchase orders for the account of the Client.

22 *Regulatory Services*. The Company will advise and assist the Clients in all regulatory and rate matters, including the design and preparation of schedules and tariffs, the analysis of rate filings, the preparation and presentation of testimony and exhibits to regulatory authorities, and other regulatory activities.

23 *Tax Services*. The Company will advise and assist the Clients in tax matters, in the preparation of tax returns and in connection with proceedings relating to taxes.

24 *Transportation Services.* The Company will advise and assist the Clients in connection with the purchase, lease, operation and maintenance of motor vehicles and the operation of aircraft owned or leased by the Company or the Clients.

25 *Treasury Services.* The Company provides services such as risk management, cash management, long and short term financing for all Clients, investment of temporarily available cash, retirement of long term debt, investment management oversight of all benefits plans, and special economic studies as requested.

26 *Miscellaneous Services.* The Company will render to any Client such other services, not hereinabove described, , as from time to time the Company may be equipped to render and such Client may desire to have performed.

ARTICLE 3

ALLOCATION METHODS

1 *Specific Direct Salary Charges to Clients.* To the extent that time spent by the officers and employees of the Company rendering services hereunder is related to services rendered to a specific Client, a direct salary charge, computed as provided in Article 4, shall be made to such Client.

2 *Apportioned Direct Salary Charges to Clients.* To the extent that the time spent by such officers and employees is related to services rendered to the Clients generally, or to any specified group of the Clients, a direct salary charge, computed as provided in Article 4, shall be made to the Clients generally, or to such specified group of the Clients, and allocated to each such Client using an allocation method as set forth on Exhibit A hereto.

3 *Direct Salary Charges for Services to the Company.* To the extent that time spent by any officer or employee of the Company is related to services rendered to the Company, a direct salary charge computed as provided in Article 4 shall be allocated among the Clients in the same proportions which the direct salary charges to such Clients made pursuant to Sections 1 and 2 of this Article III, for services of officers and employees, bear to the aggregate of such direct salary charges.

4 *Apportionment of Employee Benefits.* The employee benefit expenses that are related to direct salary charges made pursuant to sub-paragraphs (1), (2) and (3) of Article 3 shall be apportioned among the Clients, as applicable, in the proportions that the respective direct salary charges made pursuant to the rendering of such services to each such Client bear to the aggregate of such direct salary charges.

5 *Other Expenses.* All expenses, other than salaries and employee benefit expenses incurred by the Company in connection with services rendered to a specific Client shall be charged directly to such Client. All such expenses incurred by the Company in connection with services rendered to the Clients generally or to any specified group of Clients shall be apportioned in the manner set forth in Section 2 of this Article 3 for the apportionment of salary charges. All such expenses incurred by the Company in connection with services rendered to the

Company shall be apportioned in the manner set forth in Section 3 of this Article 3 for the apportionment of salary charges.

ARTICLE 4

COMPUTATION OF SALARY CHARGES

Direct Salary Charges The direct salary charge per hour which shall be made for the time of any officer or employee for services rendered in any calendar month shall be computed by dividing his total compensation for such month by the aggregate of (1) the number of scheduled working hours for which he was compensated, including hours paid for but not worked, and (2) hours worked in excess of his regular work schedule, whether or not compensated for.

Exhibit A

DIRECT BILLING AND BASES OF ALLOCATION

The Company will bill charges directly to a Client to the extent possible while any remaining costs are then allocated. When it is impractical or inappropriate to charge a Client directly, the Company allocates costs in accordance with the following Bases of Allocation which are filed annually with the FERC. The Company works cooperatively with department sponsors or project leaders through meetings and discussions to ensure costs are properly allocated to the Clients that will benefit from the service provided. Provided below are the Bases of Allocation for the Company, including a description of each basis and its numerator and denominator.

BASIS 1

GROSS FIXED ASSETS AND TOTAL OPERATING EXPENSES

- Fifty percent of the total charges will be allocated on the basis of the relation of the affiliate's gross fixed assets to the total gross fixed assets of all benefited affiliates; the remaining 50% will be allocated on the basis of the relation of the affiliate's total operating expenses to the total operating expenses of all benefited affiliates. All companies may be included in this allocation.

BASIS 2

GROSS FIXED ASSETS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its total gross fixed assets to the sum of the total gross fixed assets of all benefited affiliates. All companies may be included in this allocation.

BASIS 3

NUMBER OF METERS SERVICED

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of meters serviced to the total number of all meters serviced of the benefited affiliates. This allocation may only be used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 4

NUMBER OF ACCOUNTS PAYABLE INVOICES PROCESSED

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of accounts payable invoices processed (interface invoices excluded) to the total number of all accounts payable invoices processed of the benefited affiliates. All companies may be included in this allocation.

BASIS 7

GROSS DEPRECIABLE PROPERTY AND TOTAL OPERATING EXPENSE

- Fifty percent of the total charges will be allocated on the basis of the relation of the affiliate's total operating expenses to the total of all the benefited affiliates' total operating expense; the remaining 50% will be allocated on the basis of the relation of the affiliate's gross depreciable property to the gross depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 8

GROSS DEPRECIABLE PROPERTY

- Charges will be allocated to each benefited affiliate on the basis of the relation of its total depreciable property to the sum of the total depreciable property of all benefited affiliates. All companies may be included in this allocation.

BASIS 9

AUTOMOBILE UNITS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of automobile units to the total number of all automobile units of the benefited affiliates. All companies may be included in this allocation.

BASIS 10

NUMBER OF RETAIL CUSTOMERS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of retail customers to the total number of all retail customers of the benefited affiliates. All companies may be included in this allocation.

BASIS 11

NUMBER OF REGULAR EMPLOYEES

- Charges will be allocated to each benefited affiliate on the basis of the relation of its number of regular employees to the total number of all regular employees of the benefited affiliates. All companies may be included in this allocation.

BASIS 13

FIXED ALLOCATION

- Charges will be allocated to each benefited affiliate on the basis of fixed percentages on an individual project basis. All companies may be included in this allocation.

BASIS 14

NUMBER OF TRANSPORTATION CUSTOMERS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its Transportation Customers to the total of all Transportation Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 15

NUMBER OF COMMERCIAL CUSTOMERS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its Commercial Customers to the total of all Commercial Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 16

NUMBER OF RESIDENTIAL CUSTOMERS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its Residential Customers to the total of all Residential Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 17

NUMBER OF HIGH PRESSURE CUSTOMERS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its High Pressure Customers to the total of all High Pressure Customers of the benefited affiliates. This allocation is only used by the following companies: Columbia Gas of Virginia, Columbia Gas of Kentucky, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, Columbia Gas of Maryland, and Bay State Gas Company.

BASIS 20

SERVICE COMPANY BILLING (DIRECT AND ALLOCATED) COSTS

- Charges will be allocated to each benefited affiliate on the basis of the relation of its Service Corporation billing costs, in total or by functional group (e.g. IT, Legal, HR, Finance, Audit), to the corresponding total of all Service Company billing costs, (i.e. in total or by functional group). The calculation of Basis 20 will include only those billings for services provided to all NiSource affiliates, excluding Business Unit specific shared service functions (i.e. functions that serve only one particular Business Unit). All companies may be included in this allocation.

ATTACHMENT ST-3
NCSC TEST-YEAR EXPENSES

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021-00183
FORWARD TEST PERIOD ADJUSTMENT FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2022

ATTACHMENT ST-3
PAGE 1 OF 1
WITNESS RESPONSIBLE:
TAYLOR

NiSource Corporate Services Company (NCSC) Test Year Expenses - Normalized with Pro-forma Adjustments

Line No.	Description	Amount
1	2022 Forward Test Year, before adjustments	20,913,572
2	Efficiency Reductions not included in the Forward Test Year on Line 1	(666,016)
3	Compensation Incentive Pay Adjustment	(543,109)
4	Stock Compensation Adjustment	(266,575)
5	Ratemaking Adjustment	(116,948)
6 = Lines 1 through 5	2022 Normalized Forward Test Year	19,320,924

ATTACHMENT ST-4
CALCULATION OF
INFLATION FACTOR

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021-00183
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2022
CALCULATION OF INFLATION FACTOR

ATTACHMENT ST-4
PAGE 1 OF 4
WITNESS RESPONSIBLE:
TAYLOR

Line No.	Description			Factor (1) %
1	Calculation of Inflation Rate			
2	GDPIPD Index* - Average 2017	Sheet 2 of 4		1.0771
3	GDPIPD Index* - Average FTY 2022	Sheet 2 of 4		1.1841
4	**Inflation Factor % (Line 3 divided by Line 2 Less 100%)**			**9.94%**
5	2017 Historical Costs, Normalized	Sheet 4 of 4	$	17,574,214
6	Inflation Factor (per Line 4 above)			9.94%
7	2022 Forecasted Costs using Inflation Factor	Line 5 x 6	$	19,320,739
8	2022 Forecasted Test Period, after adjustments	Attachment ST-3	$	19,320,924
9	Difference using GDP Inflation Factor	Line 8 - 7	$	185
10	% Difference using GDP Inflation Factor	Line 9 / Line 7		**0.001%**

* Gross Domestic Product Implicit Price Deflator (GDPIPD)
Source for GDPIPD Index is IHS Global Insight
As of March 2021 (Sheet 3 of 4)

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021-00183
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2022
CALCULATION OF INFLATION FACTOR

ATTACHMENT ST-4
PAGE 2 OF 4
WITNESS RESPONSIBLE:
TAYLOR

GDP Deflators as of March 2021

GDPIPD Index - Average 2017	1.077050070	**1.88%**	Per Sheet 3 of 4
GDPIPD Index - Average 2018	1.102919152	**2.40%**	Per Sheet 3 of 4
GDPIPD Index - Average 2019	1.122615499	**1.79%**	Per Sheet 3 of 4
GDPIPD Index - Average 2020	1.136166761	**1.21%**	Per Sheet 3 of 4
GDPIPD Index - Average 2021	1.161406895	**2.22%**	Per Sheet 3 of 4
GDPIPD Index - Average 2022	1.184085675	**1.95%**	Per Sheet 3 of 4

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021-00183
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2022
CALCULATION OF INFLATION FACTOR

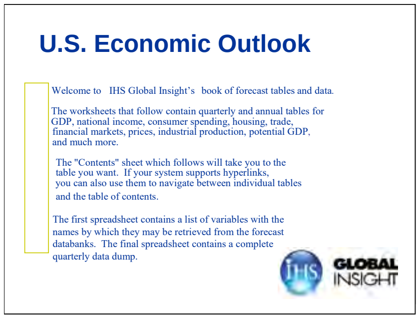
ATTACHMENT ST-4
PAGE 3 OF 4
WITNESS RESPONSIBLE:
TAYLOR

March 2021
Summary of the US Economy

	2017:1	2017:2	2017:3	2017:4	2018:1	2018:2	2018:3	2018:4	2019:1	2019:2	2019:3	2019:4
Real GDP	17977.3	18054.1	18185.6	18359.4	18530.5	18654.4	18752.4	18813.9	18950.3	19020.6	19141.7	19254.0
Nominal GDP	19237.4	19379.2	19617.3	19938.0	20242.2	20552.7	20742.7	20909.9	21115.3	21329.9	21540.3	21747.4
GDP Deflator	1.0701	1.0734	1.0787	1.0860	1.0924	1.1018	1.1061	1.1114	1.1142	1.1214	1.1253	1.1295
GDP Deflator, consecutive quarter-to-quarter change, annual rate	2.05%	1.24%	2.00%	2.72%	2.38%	3.48%	1.60%	1.92%	1.03%	2.60%	1.40%	1.50%
GDP Deflator, same quarter year-to-year change	2.05%	1.66%	1.81%	2.00%	2.08%	2.64%	2.54%	2.34%	2.00%	1.78%	1.73%	1.63%
Summary - Prices & Wages, Percent Change, Annual Rate												
GDP Deflator	1.99	1.27	2.25	2.50	2.43	3.23	1.85	1.78	1.22	2.48	1.51	1.38
	1.0771				1.1029				1.1226			

	2020:1	2020:2	2020:3	2020:4	2021:1	2021:2	2021:3	2021:4	2022:1	2022:2	2022:3	2022:4
Real GDP	19010.8	17302.5	18596.5	18783.9	19008.6	19333.8	19653.9	19891.1	20084.2	20225.7	20348.0	20460.4
Nominal GDP	21561.1	19520.1	21170.3	21487.9	21925.5	22395.2	22876.3	23270.1	23603.9	23886.6	24150.0	24414.3
GDP Deflator	1.1341	1.1282	1.1384	1.1440	1.1535	1.1583	1.1640	1.1699	1.1752	1.1810	1.1868	1.1932
GDP Deflator, consecutive quarter-to-quarter change, annual rate	1.66%	-2.09%	3.68%	1.97%	3.36%	1.71%	1.95%	2.05%	1.85%	1.97%	2.00%	2.17%
GDP Deflator, same quarter year-to-year change	1.79%	0.60%	1.16%	1.28%	1.70%	2.67%	2.24%	2.27%	1.89%	1.96%	1.97%	2.00%
Summary - Prices & Wages, Percent Change, Annual Rate												
GDP Deflator	1.39	-1.82	3.51	2.14	3.20	1.71	1.95	2.05	1.85	1.97	2.00	2.17
	1.1362				1.1614				1.1841			

March 2021 - US Economic Outlook



COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021-00183
FORWARD TEST PERIOD ADJUSTMENT FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2022

ATTACHMENT ST-4
PAGE 4 OF 4
WITNESS RESPONSIBLE:
TAYLOR

NiSource Corporate Services Company (NCSC) Test Year Expenses - 2017 Actuals Normalized with Pro-forma Adjustments

Line No.	Description	Amount
1	2017 Actuals, before adjustments	19,337,075
2	Transformation One Time Costs	(963,939)
3	Compensation Incentive Pay Adjustment	(792,229)
4	Stock Compensation Adjustment	(6,693)
5 = Lines 1 through 4	Normalized 2017 Actuals, after adjustments	17,574,214

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Michael A. Rozsa attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Michael A. Rozsa

Columbia Exhibit No. 28

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

PREPARED DIRECT TESTIMONY OF
MICHAEL ROZSA
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF) Case No. 2021-00183

VERIFICATION OF MICHAEL ROZSA

STATE OF OHIO)
)
COUNTY OF FRANKLIN)

Michael Rozsa, Chief Information Officer for NiSource Corporate Services, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that he has supervised the preparation of his Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of his knowledge, information and belief, formed after reasonable inquiry.

Michael Rozsa
Michael Rozsa

The foregoing Verification was signed, acknowledged and sworn to before me this 18 day of May, 2021, by Michael Rozsa.

NOTARIAL SEAL STATE OF OHIO

REBECCA J VANSICKLE
Notary Public
In and for the State of Ohio
My Commission Expires November 22, 2024

Rebecca J Vansickle

Notary Commission No. ______

Commission expiration: 11-22-2024

PREPARED DIRECT TESTIMONY OF MICHAEL ROZSA

Q: Please state your name and business address.

A: My name is Michael (Mike) A. Rozsa. My business address is 290 W. Nationwide Blvd., Columbus, Ohio 43215

Q: What is your current position and what are your responsibilities?

A: My position is the Chief Information Officer (CIO). The responsibilities of the CIO are to oversee NiSource's information technology strategies and computer systems to ensure that they support the company's goals. Additionally, I am responsible for streamlining operations by implementing relevant technologies, developing technological systems that will improve customer and employee satisfaction, and implement cyber security protocols to help keep the company protected against malicious cyber activities.

Q: What is your educational background?

A: I have a Bachelor of Science (BS) degree in Computer Science from The Franciscan University of Steubenville in Steubenville, Ohio. Additionally, I participated in the American Electric Power Leadership Development Program at The Ohio State University.

Q: What is your employment history?

A: I have been the CIO at NiSource since 2017. Prior to NiSource, I spent 20 years with American Electric Power (AEP). I was the Managing Director of

Business Applications from July 2010 until 2017. Prior to that role, I held the position of Managing Director, Enterprise Architecture and Development from March 2009 – June 2010. I held the position of Director, Utilities IT Systems Planning from June 2004 – Feb 2009. I held other IT roles of increasing responsibility prior to that role.

Q: Have you previously testified before the Kentucky Public Service Commission?

A: I have not testified previously before the Kentucky Public Service Commission.

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my direct testimony is to discuss the Information Technology (IT) organization's planned investments to replace its existing legacy systems. I will address the future system architecture as part of the efforts of Columbia Gas of Kentucky ("Columbia") and NiSource to modernize its IT systems. I also sponsor KAR 5:001 Section 16-(7)(c).

Q: What kinds of IT-related threats face Columbia and its customers?

A: We are reliant on technology to run our business, which is dependent upon financial and operational computer systems to process critical information necessary to conduct various elements of our business, including the operation of our gas pipeline facilities; and the recording and reporting of commercial and financial transactions to regulators, investors and other stakeholders. In addition to general information and cyber risks that all large corporations face (e.g., malware, unauthorized access attempts, phishing attacks, malicious intent by insiders, third-party software vulnerabilities and inadvertent disclosure of sensitive information), the utility industry faces evolving and increasingly complex cybersecurity risks associated with protecting sensitive and confidential customer and employee information, and natural gas physical infrastructure. Deployment of new business technologies, along with maintaining legacy technology, represent a large-scale opportunity for attacks on our information systems and confidential customer and employee information, as well as on the integrity of the natural gas infrastructure. Increasing large-scale corporate attacks in conjunction with more sophisticated threats continue to challenge utility companies. Any failure of our computer systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business and could result in a financial loss and possibly do harm to our reputation.

Our information systems experience ongoing, often sophisticated, cyber-attacks by a variety of sources, including foreign sources, with the apparent aim to breach our cyber-defenses. Although we attempt to maintain adequate defenses to these attacks and work through industry groups and trade associations to identify common threats and assess our countermeasures, a security breach of our information systems, or a security breach of the information systems of our customers, suppliers or others with whom we do business, that could (i) impact the reliability of our transmission and distribution systems and potentially negatively impact our compliance with certain mandatory reliability standards, (ii) subject us to reputational and other harm or liabilities associated with theft or inappropriate release of certain types of information such as system operating information or information, personal or otherwise, relating to our customers or employees, (iii) impact our ability to manage our businesses, and/or (iv) subject us to legal and regulatory proceedings and claims from third parties, in addition to remediation costs, any of which, in turn, could have a material adverse effect on our businesses, cash flows, financial condition, results of operations and/or prospects.

Q: What steps is Columbia taking to address these threats?

A: NiSource has a Cybersecurity Governance model that is used to manage and mitigate cybersecurity risks, leveraging the National Institute of Standards and Technology (NIST) Cybersecurity Framework (NCF). Executive leadership and the NiSource Board of Directors are informed by the cybersecurity team on a quarterly basis. NiSource has also developed policies and procedures to support the management of information security related risks, which are reviewed annually. All end users, including employees and contractors are required to complete training related to cybersecurity on an annual basis. Over the past 2 years, NiSource employees dedicated to addressing cybersecurity issues ("Cyber Security team") has been engaged in determining the future-state roadmap for the program. This roadmap has driven an increase in resources in people, tools, and technology. The Cyber Security team has been working to mature foundational tools and processes and has developed a future-state Security Operations Center (SOC), which includes real-time incident response technologies along with a strong security awareness program to educate employees. In addition, we have established an IT Risk Management program with the development and implementation of a risk management process for tracking and resolution of risks. The Cyber Security team has also implemented a Third-party Risk Management program to begin to evaluate vendor risk and the impact to the NiSource environment. The Identity and Access Management (IAM) team has been working toward taking NiSource from legacy IAM technologies to advanced technologies that will further secure our tools and data with access controls. Along with looking at new technologies and creating a robust and secure environment, the team also oversees the vulnerability and patch management process to reduce risks to the current infrastructure.

Q: How do IT investments create operational efficiencies?

A: These IT investments create operational efficiencies for both our customers and our employees. For our customers, we intend to improve our customer experience by investing in a mobile application and enhancing our web capabilities. We will leverage these digital tools to increase our paperless adoption and enhancing our online bill-pay features. We are also enhancing our digital service by adding chat features on both our website and our mobile platforms. We also plan to offer options to allow our customers to electronically start/stop/transfer their service and other self-service features using communication channels that are most convenient for the customer. For our employees, these investments will help our employees work safer and more efficiently using mobile solutions. Leveraging tablet computers (such as an iPad) for access to data, processes, and safety requirements allowing for real-time mobile access and data capture. Throughout 2021 and 2022, we will deploy digital forms and checklists to reduce paper data entry and support process adherence. Enhanced availability of accurate, real-time data such as service line records will help ensure safe execution of our work. Automation of workflows and notifications and data will reduce unnecessary truck rolls and ensure our job sites are ready for work. Finally, we intend to implement the Microsoft 365 platform for enhanced collaboration and capabilities. All of these tools will allow our employees flexibility to interact directly with our key back office systems such as HR systems or financial and budgeting systems from wherever the employee is working with heightened cybersecurity controls.

Q: What specific IT investments has Columbia made or plan to make to create these efficiencies?

A: We are improving our customer self-service features by enhancing our Interactive Voice Response (IVR) system to become more of a conversational IVR and updating our user interface on our customer websites. We also are planning a mobile application to enhance our customer interactions as well. We are implementing chat capabilities on our websites and our mobile platform. We also continue to evolve our payment options for the convenience of our customers. For our field employees, we are deploying iPads or other tablet computing devices the enable them to leverage mobile forms with procedural workflows and checklists to detail status and Quality Assurance (QA) checkpoints. These devices will also enable capture of more complete and accurate asset data in the field, automating repetitive manual tasks. This will enable our field workforce to focus on safety and process adherence.

Q: What are the other categories of the Company's IT investments in the Base Period and Forecasted Test Year?

A: We have categorized the IT investments as follows: Safety, Business Strategic priorities, Strategic Technology priorities, Critical Upgrades, and general IT Modernization priorities.

Q: What are the investments in the Safety category and how do they benefit Columbia and its customers?

A: We have investments in what we call Asset Knowledge Management (AKM). The AKM program intends to minimize asset risks by using quantitative models to calculate risk scores and supporting these models with data and system enhancements. Part of AKM is the establishment of a data governance program. Data governance is a framework of policies and processes aimed at defining and managing the quality, consistency, usability, security, and availability of information practiced at the enterprise level and across the information lifecycle. These set of guiding principles for ensuring information quality and availability *via* an agreed upon process and set of practices which describe how information requirements will be met and reporting objectives will be achieved. The program's objective is to build a sustainable and scalable foundation to assess current data quality levels in preparation of conversion activities. The testimony of Witness David Roy introduced one example of AKM investment when discussing the new project creation tool used to prioritize project initiation to maximize risk mitigation in inputs to investment planning for the Distribution Integrity Management Program (DIMP) called Uptime MRP. Use of this software enhance asset related data to ensure risk models can be deployed in an effective manner with optimized output and implement data governance structure to ensure the long-term integrity of the data. This investment comes as a result of the manufacturer's discontinuation of currently utilized software called Optimain DS. The Company plans to implement the Utility Pipeline Data Model (UPDM) for simplified capital closeout and data access from an integrated transmission and distribution data model, and ArcPro/ data model to promote data integrity and improved data quality through limiting desktop data editing. Using Geospatial Information Systems (GIS), we will implement standardization and implementation of a positionally more accurate commercial street centerline network by state for the entire NiSource service territory. NiSource's existing GIS street centerline features will be conflated to that commercial database. Finally, we continue to make enhancements to an IT system from DevonWay that is used to by employees to enter risks through our Corrective Action Program (CAP) system, which is explained in the testimony of Witness David Roy.

Q: What are the investments in the Business Strategic priorities category and how do they benefit Columbia and its customers?

A: NiSource is implementing a new Human Capital Management (HCM) system from software called "Workday". This will allow our employees easier access to their own information, and our leaders easier self-service access to HR features such as hiring requisitions or workflow tasks. Our plans also include changing our Learning Management System (LMS), a software platform that implements mandatory training to employees and contractors, to a new, more robust platform. We are also implementing a new self-service budget analysis tool for our leaders that will allow them to perform a budget variance analysis using the right level of detail and the right timeliness to model key scenario planning for strategic decisions. Finally, we plan to invest in an enterprise wide Governance, Risk, and Compliance (GRC) tool to track and monitor the resolution of all enterprise risks.

Q: What are the investments in the Strategic Technology priorities category and how do they benefit Columbia and its customers?

A: In addition to the cybersecurity investments outlined above, we are also investing in a more modern IT Disaster Recovery (DR) platform. Our current DR process uses legacy off-site tapes. With this investment, we will be transmitting and storing our most critical operational data securely using electronic file transfers. This will allow for faster recovery of the data in the event of a disaster. We are making strategic investments in Robotic Process Automation (RPA) tools to increase the adoption of automating manual processes. This automation should decrease the frequency of human errors that occur in manual processes. Finally, we are making investments in our core network and switches to increase bandwidth and wireless access across our service territory in order to properly leverage the new digital technology being deployed to our field personnel.

Q: What are the investments in the Critical Upgrades category and how do they benefit Columbia and its customers?

A: We are investing in our customer contact center technology to allow for better, more reliable interactions with our customers. We are upgrading the telephony core infrastructure, as well as the Interactive Voice Response (IVR) to allow for the customer interactions with the IVR to be easier and more natural for our customers (called Natural Language IVR). Generally speaking, this these investments are included in our customer contact center modernization project. We are also upgrading our application that facilitates the capture, management, delivery, and storage of electronic customer information such as bills, remittances, statements, notices, checks, work orders, easements, fees, etc. We are also performing software upgrades to our gas supervisory control and data acquisition (SCADA) system and our industrial customer billing system because the software previously utilized will become obsolete and unsupported by vendors if these upgrades do not occur on a regular basis.

Q: What are the investments in the Modernization category and how do they benefit Columbia and its customers?

A: Our Connected Customer initiative investments include adding new features to our customer websites to start, stop, and transfer service. We will be creating a mobile application that customers can use to connect with us using their smart phone or tablets. We will add the option for the customer to interact with us using Chat from either the website or their mobile device. We are making investments to drive several efficiencies within our Customer Care Centers and the Meter to Cash processes for our employees. We intend reduce the call handle time number by simplifying the agent scripts, conversational IVR, and workflow automation. The employees will use analytics to better forecast demand within the call centers and schedule agents to handle those calls. We are modernizing our back-office billing processes by automating manual work to resolve billing exceptions and enhance accuracy using RPA. Our analytics investment will also include a payment risk profile to inform proactive customer outreach if a payment is not received. These analytics will also lead to productivity improvements with route optimizations, meter reading frequency optimization, and additional self-service improvements. We intend to equip of field employees with tablet computers such as an Apple iPad. This will enable our employees to have real-time or near real-time information to them in the field such as GIS mapping of our facilities, the abilities to capture information electronically on a form and send that information back to our corporate systems without the need for paper and the need to reenter the information into another system.

Q: Why are these investments being made now?

A: NiSource's technology footprint is highly complex and includes highly customized group of systems that are outdated and sometimes have redundant capabilities. To meet the future needs of our customers and employee workforce, and to reduce the cost and timelines to implement new system changes, NiSource must transition to new technologies as soon as possible. As part of this transition, NiSource will not only replace the outdated technology of its current legacy systems, but will also consolidate a significant amount of functionality that is currently being supported by duplicate systems. This will result in systems that are easier to manage and reduce or eliminate costs associated with licensing and support of these duplicate systems.

Q: What is the future state IT architecture strategy?

A: To accomplish the goals of NiSource's modernization initiatives, a future state technology architecture is being established. The guiding principles of this "To-Be" architecture is to simplify the technology footprint at NiSource while enabling flexibility for future features to be added without high technology costs. First, NiSource seeks to reduce the number of applications that are needed to run the operations of the company and eliminate redundant features. Second, NiSource seeks to establish an architecture that is adaptable and capable of being tailored to meet NiSource's functionality needs, but also does so without the need of customization through complex programming to implement each new program change. In addition, NiSource intends to align with the software industry trend towards subscription-based software delivery models hosted in public or private clouds. Cloud computing is becoming more common in the industry, as it allows for more flexibility for peak loads. Most software vendors are specifically delivering their products to run in a cloud environment verses traditional on-premise data centers. We plan to be more biased toward Software-as-a-Service (SaaS) offerings in the market. These products offer rapid innovation through frequent release schedules while encouraging standardization of business processes, thereby reducing overall technology complexity and enhancing both the customer and employee experience. NiSource plans to leverage modern development approaches using an Agile framework. Agile allows for better control and productivity due to shorter development cycles and more frequent deployment timelines. We also find that Agile produces better quality because problems are surfaced and resolved more quickly and efficiently.

Q: What is the resourcing plan?

A: These IT projects will be staffed with a mix of NiSource and non-NiSource labor. NiSource employees will fulfill roles as subject matter experts, project governance, information security, and user acceptance testing leadership. In addition, the team will be supplemented with third-party resources to fill key roles such as quality assurance, legacy data migration developers, infrastructure support, functional and technical experts from our legacy systems. A System Integrator (SI) with industry best practice experience will be brought on to advise and implement the larger scale efforts. The SI will conduct activities such as leading workshops to document the overall design and architecture and configure the solution. They will provide their experience, product-specific implementation methodology, and product-specific expertise to support all phases of the projects.

Q: How does NiSource manage costs for these projects?

A: NiSource leverages several controls to ensure the costs are in line with industry standards. We have a formal IT Governance Steering Committee process to ensure that project costs are reviewed and compared against the value and benefits of the investment. Finally, The IT costs are shared among all other NiSource operating companies. Columbia Gas of Kentucky benefits from being part of a larger family of NiSource companies.

Q: Does this complete your Prepared Direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony.

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Jennifer Harding attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky’s President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Jennifer Harding

Columbia Exhibit No. 29

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUEANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

PREPARED DIRECT TESTIMONY OF
JENNIFER HARDING
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:	)	
	)	
THE ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

VERIFICATION OF JENNIFER HARDING

STATE OF OHIO	)
	)
COUNTY OF FRANKLIN	)

Jennifer Harding, Director, Income Tax Operations for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of her Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Jennifer Harding

The foregoing Verification was signed, acknowledged and sworn to before me this 19th day of May, 2021, by Jennifer Harding.

Notary Commission No. N/A

Commission expiration: N/A

John R Ryan III
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

PREPARED DIRECT TESTIMONY OF JENNIFER HARDING

Q: Please state your name and business address.

A: My name is Jennifer Harding. My business address is 290 W. Nationwide Blvd, Columbus, Ohio 43215.

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

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Director, Income Tax Operations at NCSC.

Q. Please briefly describe your professional experience.

A. I began my career with KPMG LLP as a Senior Associate in the tax department in Baltimore, Maryland in 2005. In 2009, I joined Constellation Energy as a Tax Manager responsible for all aspects of income tax and non-income tax for the generation segment and managed the IRS Federal tax audit CAP ("Compliance Assurance Process") program. Constellation was acquired by Exelon Corporation in 2012, and I moved to Chicago, Illinois as the Tax Manager of the electric utility responsible for income tax accounting, forecasting income taxes, and income tax and non-income tax return filings. In 2014, I moved to the Netherlands and worked for Mead Johnson Nutrition BV as the

Tax Manager for the European region with responsibility for all aspects of income tax and non-income tax accounting, tax research and tax return filings. In 2016, I moved to Columbus, Ohio and worked for Cardinal Health as the Director of International Tax Operations with a responsibility for income tax accounting, forecasting, mergers & acquisitions, tax research and tax return filings in Cardinal Health's foreign jurisdictions. In 2018, I worked as the Head of Tax for Hyperion Materials & Technologies with full responsibility for all global income and non-income tax accounting, tax return filings, research, mergers & acquisitions and forecasting. In January 2020, I joined NiSource in my current position.

Q. Please describe your educational background.

A. I received a Bachelor in Business Administration with a concentration in Accounting in 2007 from the Notre Dame of Maryland University in Baltimore, Maryland.

Q. What are your responsibilities in your current position?

A. In my current position as Director of Tax Operations, I am responsible for the operational income tax activities for NiSource Inc. and Subsidiaries, including

Columbia Gas of Kentucky ("Columbia" or "the Company"). My responsibilities include oversight and review of the preparation of income tax accrual and deferred tax entries, forecasting income taxes, preparation and filing income tax returns, technical income tax research and preparation of income tax data and related testimony for rate proceedings.

Q. Have you previously testified before this or any other regulatory agency?

A. Yes. I have submitted direct testimony with the Pennsylvania Public Utility Commission for Columbia Gas of Pennsylvania's application to increase rates in 2020 and 2021 and submitted direct testimony with the Public Service Commission of Maryland for Columbia Gas of Maryland's application to increase rates in 2020 and 2021.

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to present and support Columbia's income tax and other tax expense included in the cost of service for the base period and test period. The filing includes federal and state income tax recovery, reduction of rate base for accumulated deferred income taxes ("ADIT") for the base period and test period and incorporation of the tax effects of the enacted Tax Cuts and Jobs Act of 2017 ("TCJA") and the 2018 decrease in the Kentucky state income tax rate, including the excess ADIT. I will also sponsor and support the following Filing Requirements:

Filing Requirement	Description
807 KAR 5:001 Section 16-(6)(a)	Financial Data
807 KAR 5:001 Section 16-(6)(b)	Forecasted Adjustments
807 KAR 5:001 Section 16-(7)(c)	Factors Used in Preparing Forecast
807 KAR 5:001 Section 16-(8)(b)	Rate Base Summaries
807 KAR 5:001 Section 16-(8)(e)	Federal and State Income Tax Summaries

Q. Will you explain the basis for the income tax calculations included in the cost of service for the base period and test period?

A. Yes, the tax calculations were made under the provisions of the Internal Revenue Code ("IRC") of 1986, effective with the passage of the Tax Reform Act of 1986 as amended by the TCJA and any tax legislation enacted since, and the Kentucky Revised Statutes ("KRS"), Title XI Revenue and Taxation, Chapter 141, Income Taxes.

Q. What federal income tax rate has been utilized for the test period?

A. The IRC provides for a flat tax rate of 21% for corporations which became effective January 1, 2018 with the enactment of the TCJA on December 22,

2017. I acknowledge that on March 31, 2021 President Biden announced the "Made in America Tax Plan" containing a proposed corporate income tax increase from 21% to 28% as part of the "American Jobs Plan". Columbia has not reflected any assumption of an increase in federal income tax rate in this case. However, later in my testimony I explain a proposed rider mechanism to adjust rates for future changes in Federal and or state income tax rates.

Q. What rate was utilized for Kentucky Income taxes?

A. Pursuant to KRS 141.040(2), the applicable Kentucky statutory tax rate for taxable years beginning on or after January 1, 2018 is 5%, which has been used for all test year calculations.

Q. Please explain the Federal income tax calculations shown on Schedule E-1.1.

A. This schedule shows the computation of federal income taxes for the base period ending August 31, 2021 and forecasted test period ending December 31, 2022, including the necessary adjustments to arrive at the pro forma amounts appropriate for inclusion in the calculation of income tax expense for the customer cost of service. The tax calculation begins with operating income before income taxes presented on Schedule E-1.1, Sheet 1, Line 1 adjusted by interest expense for rate purposes presented on Schedule E-1.1, Sheet 1, Line 2 to compute the book net income before income taxes. The calculated interest expense represents the product of rate base multiplied by the weighted average cost of short-term and long-term debt (See computation on Schedule E-1.1, Sheet 1, Footnote 1 for the base period and forecasted period). The book net income before income taxes is adjusted by permanent and temporary statutory tax adjustments on Schedule E-1.1, Sheet 1, Lines 5 and 6, respectfully, and reduced by the State income tax on Schedule E-1.1, Sheet 1, Line 15 to compute the Federal taxable income. The Federal taxable income is tax effected at the Federal income tax rate of 21% to determine Federal income tax expense on Schedule E-1.1, Sheet 1, Line 21. The Provision for deferred Federal income taxes on Schedule E.1-1, Sheet 1, Line 29 is computed by tax effecting the converse of the temporary timing differences on Schedule E-1.1, Sheet 1, Line 6 and Federal net operating loss ("NOL") Schedule E-1.1, Sheet 1, Line 6 multiplied by the Federal income tax rate of 21%. The Federal benefit for the deferred state income tax is depicted on Schedule E-1.1, Sheet 1, Line 30. The total Federal tax expense computed on Schedule E-1.1, Sheet 1, Line 45 for the forecasted text period at proposed rates included on Schedule C-1, Sheet 1, Line 8 is $5,464,876.

Q. Please explain the necessary adjustments to arrive at the pro forma amounts appropriate for inclusion in the calculation of income tax expense for the customer cost of service?

A. The Company has removed non-deductible expenses related to lobbying, parking and employee stock purchase plan (See Schedule E-1.1, Sheet 2, Lines 1 through 9). Additionally, the Company has included an adjustment to the non-deductible meals and entertainment as a result of temporary relief from the Consolidated Appropriations Act of 2021 signed into law on December 27, 2020 that allows 100% deduction for business meal expenses during 2021 and 2022. Additionally, the Company has removed amounts related to certain temporary differences with the exception of amounts related to customer advances for construction, capitalized inventory, provisions for pension and other post-employment benefits (OPEB), and the book/tax differences related to plant in service.

Q. Are there any Federal flow through excess or deficient deferred taxes included in rates?

A. In accordance with the Commission's Order issued for Case No. 2018-00041 as a result of the investigation of the impact of the TCJA, the Company has a regulatory liability for federal excess deferred taxes as a result of the decrease of the federal income tax rate from 35% to 21% as a result of the TCJA, before gross up, of ($24,307,926) as of December 31, 2022 depicted on Schedule B-6, Sheet 2, Line 134. The excess ADIT amortization for the twelve months ended December 31, 2022 of ($790,253) is included in Schedule E-1.1, Sheet 1, Line 31. Additionally, other components of Federal income tax include certain flow through adjustments that reduce Federal income tax expense, including amortization of the Federal investment tax credit of ($12,816) on Schedule E-1.1, Sheet 1, Line 33 and flow through for excess book over tax depreciation of $48,893 on Schedule E-1.1, Sheet 1, Line 32.

Q. Please explain the state income tax calculations shown on Schedule E-1.1.

A. This schedule shows the computation of state income taxes for the base period ending August 31, 2021 and forecasted test period ending December 31, 2022, including the necessary adjustments to arrive at the pro forma amounts appropriate for inclusion in the calculation of income tax expense for the customer cost of service. The tax calculation begins with operating income before income taxes presented on Schedule E-1.1, Sheet 1, Line 1 adjusted by interest expense for rate purposes presented on Schedule E-1.1, Sheet 1, Line 2 to compute the book net income before income taxes. The book net income before income taxes is adjusted by permanent and temporary statutory tax adjustments and state modification for federal bonus depreciation taken in years prior to 2018 on Schedule E-1.1, Sheet 1, Lines 5 through 7 to compute the state taxable income on Schedule E-1.1, Sheet 1, Line 9. The state taxable income is tax effected at the state income tax rate of 5% to determine state income tax expense on Schedule E-1.1, Sheet 1, Line 15. The Provision for deferred state income taxes on Schedule E.1-1, Sheet 1, Line 37 is computed by tax effecting the converse of the temporary timing differences and state modification for federal bonus depreciation multiplied by the state income tax rate of 5%. The total state tax expense computed on Schedule E-1.1, Sheet 1, Line 47 for the forecasted text period at proposed rates included on Schedule C-1, Sheet 1, Line 9 is $1,454,518.

Q. Are there any State flow through excess or deficient deferred taxes included in rates?

A. As discussed below, the Company recorded a reserve for the obligation of the net state excess deferred income taxes to be passed back to customers as a result of decrease of the state income tax rate from 6% to 5% stemming from the state tax reform of House Bill 487 that become law on April 27, 2018 with a retroactive effective date of January 1, 2018, before gross up, of ($2,343,500). The excess ADIT amortization of ($95,291) for the twelve months ending

December 31, 2022 is included in Schedule E-1.1, Sheet 1, Line 38. Additionally, the other component that reduces state income tax expense represents flow through for excess book over tax depreciation of ($8,851) on Schedule E-1.1, Sheet 1, Line 39.

Q. Will you explain the components of ADIT and excess ADIT included in rate base and balance sheet analysis for the base period and forecasted test period included in Schedules B-6?

A. These schedules present the 13-month average of ADIT and excess ADIT for the base period ending August 31, 2021 and forecasted test period ending December 31, 2022, including the necessary adjustments to arrive at the pro forma amounts appropriate for inclusion in the calculation of accumulated deferred income tax expense included in rate base and working capital. The Company's ADIT for the base period and forecasted test period is comprised of various book/tax temporary differences that are depicted on Schedules B-6, Sheets 1 and 2, Lines 29 through 127, excess ADIT related re-measurement of deferred income taxes as a result of TCJA and House Bill 438 are depicted on Schedules B-6, Sheets 1 and 2, Lines 129 through 140, and the ADIT balance for Federal investment tax credits is depicted on Schedules B-6, Sheets 1 and 2, Line 146.

The ADIT balances that are included in rate base include the Federal NOL carryforward (Schedule B-6, Sheet 1 and 2, Line 30), customer advances for construction (Schedule B-6, Sheet 1 and 2, Lines 34 and 35), capitalized inventory (Schedule B-6, Sheet 1 and 2, Lines 36 and 37) and book/tax difference for plant in service (Schedule B-6, Sheet 1 and 2, Lines 83 and 84). Additionally, the excess ADIT balances depicted on Schedules B-6, Sheets 1 and 2, Lines 129 through 140 are also included in rate base.

The Company has also summarized the 13-month average ADIT balances for the base period associated with amounts in the Company's Balance Sheet Analysis discussed in Witness K. L. Johnson's testimony (Attachment KLJ-CWC-1, Sheets 1 and 2) for deferred income taxes recorded to account 190 of $832,925 and account 283 ($1,274,153) presented on Schedules B-6, Sheets 1 and 2, Lines 11-17, respectively. The 13-month average ADIT balances for the forecasted test period associated with amounts in the Company's Balance Sheet Analysis for deferred income taxes recorded to account 190 of $889,216 and account 283 ($1,266,912) presented on Schedules B-6, Sheets 1 and 2, Lines 11-17, respectively.

The ADIT not included in the Company's rate base, balance sheet analysis and lead lag analysis for the base period and forecasted test period depicted on Schedules B-6, Sheets 1 and 2 include deferred income taxes recorded in Account 190 attributed to Charitable Contributions (Line 32), Federal Tax Credits (Line 33), Reg Liab Curr-Other (Lines 62 and 63), Reg Liab Curr-AMRP (Lines 70 and 71), Deferred Intercom Gain/Loss (Lines 72 and 73), Oblig Operating Lease (Lines 74 and 75), ITC-Reg Liab (Lines 76 and 77), and ASC 740 Fed Gross-Up (Lines 78 and 79); deferred income taxes recorded in Account 282 attributed to Other Basis Adjustments (Lines 85 and 86) and State FAS 109 ST Gross-Up (Line 87); and deferred income taxes recorded in Account 283 attributed to Reg Asset GTI Funding (Lines 103 and 104) Reg Aset EAP (Lines 105 and 106), Reg Asset-PRF Base Rt Adj PBRA (Lines 107 and 108), NC Reg Asset Rate Case Non-Cur (Lines 111 and 112), NC Reg Asset Def Depre Cap Lse (Lines 115 and 116), Reg Liab Curr-DSM Uncollect (Lines 117 and 118) and Right of Use Asset (Lines 123 and 124).

Q. Will you explain the impacts of the TCJA resulting in a decrease in the Federal income tax rate from 35% to 21% effective January 1, 2018 and how the impacts have been incorporate in this rate case?

A. Yes, on December 22, 2017, the Tax Cut and Jobs Act of 2017 ("TCJA") was signed into law. The TCJA includes several provisions that impact the Company's tax provision such as the corporate rate reduction, modification of bonus depreciation, modification of the federal NOL and preservation of the normalization rules.

Effective January 1, 2018, the corporate income tax rate is reduced from 35% to 21%. The Company has reflected the new rate in the income tax calculation on Schedule E-1.1, Sheet 1, Line 21, included in the cost of service calculation on Schedule C-1, accumulated deferred income taxes on Schedule B-6 included in rate base and in the revenue conversion factor on Schedule H-1. The decrease in the Federal income tax rate requires the Company to re-measure the accumulated deferred income tax balances as of the balance sheet date just prior to the effective date of the new Federal income tax rate, which resulted in the creation of net excess deferred income taxes.

Secondly, the TCJA modified bonus depreciation. Under prior law, 50% bonus depreciation was allowed for assets placed in service in 2016, and 2017, 40% bonus depreciation for assets placed in service in 2018 and 30% bonus depreciation for assets placed in service in 2019. The TCJA modified bonus depreciation to allow 100% bonus depreciation for assets placed in service from September 27, 2017 to January 1, 2023, with a phase down thereafter for most corporations. However for public utilities such as Columbia, that are not subject to the limitations on interest expense under the TCJA, bonus depreciation is eliminated effective January 1, 2018. Kentucky generally follows federal depreciation rules, however, requires a modification for federal bonus depreciation under KRS Section 141.0101(16)(a).

Additionally the TCJA modified the carrying rules and imposed a limit on the Federal NOL. Under prior law, with some exceptions, corporations could carry NOLs back for two years and forward for twenty years. Under the TCJA, NOLs arising in taxable years ending after December 31, 2017, cannot be carried back at all, but can be carried forward indefinitely. Under prior law, there is no general limit on the amount of NOLs that can be used to offset regular taxable income. The TCJA limits the deduction for NOLs arising in any taxable year beginning after December 31, 2017, to 80% of taxable income in the carryforward year. Kentucky adopted to NOL changes in conformity with TCJA. The impact of the Federal NOL Accumulated Deferred Income Taxes ("ADIT") has been reflected in Schedule B-6, Sheets 1 and 2, Line 30.

Q. Will you explain the impacts of the state tax reform in House Bill 487 enacted on April 27, 2018 resulting in a decrease in the State income tax rate from 6% to 5% effective January 1, 2018 and how the impacts have been incorporate in this rate case?

A. Yes, on April 27, 2018 House Bill 487 was enacted which included the most substantial changes in Kentucky tax law since 2005. House Bill 487 includes several provisions that were retroactively effective as of January 1, 2018 and impact the Company's tax provision such as the flat corporation income tax rate of 5%, conformity with the TCJA modification of the federal NOL, decoupling from the TCJA modifications of bonus depreciation,. Additionally under House Bill 487, unitary combined reporting and elective consolidated group filing is effective January 1, 2019 resulting in a mandatory requirement for the affiliated group members with nexus in Kentucky to file a consolidated return and an option for elective consolidated return filing for members of the Federal affiliated group.

At the time of the decrease of the State income tax rate to a flat 5%, the Company anticipated filing a rate case to incorporate the impact of the excess ADIT to be passed back to customers. The Company recorded a reserve for the obligation of the net excess deferred state income taxes to be passed back to customers the excess deferred tax of $1,672,909 (grossed up) presented on Attachment JH-2, Sheet A. The Company is proposing a six year amortization for non-property deficient ADIT and 35-yr amortization under Reverse South Georgia (RSG) method to capture stub period amortization to capture stub period amortization from flat 5% state income tax effective date of January 1, 2018 to rates effective date of January 1, 2022 for this rate case. The amortization schedule based on the proposed amortization periods is presented on Attachment JH-2, Sheet B. NiSource made the election to file a Kentucky Unitary Combined Corporation Income Tax and LLET Return for all members of the Federal affiliated group, including Columbia. The Company's Kentucky income taxes are computed on a separate company basis for rate making purposes.

Q. Are you sponsoring any other tax matters?

A. Yes. I am also sponsoring the illustrative calculations, methodology and mechanism developed for the Tax Act Adjustment Factor ("TAAF") tariff that is referenced in Witness J. Cooper's testimony to apply tax charge or tax (credit) for the recovery or pass back of the impact of a future increase or decrease of the Federal and or state income tax rates as of the effective date of such change based on the most recent base rates approved by the Commission.

Q. Why are you requesting the new TAAF tariff?

A. The enactment of the TCJA taught us that Federal income tax rate changes can be very material and take effect abruptly resulting in volatility that is completely outside of the Company's control. Accordingly, the Company is taking a proactive approach to account for the impact of future increase or decrease in Federal and or state income tax rates based on "lessons learned" from the enactment of the TCJA. The Company has prepared illustrative schedules (discussed below) based on the scenario of an increase in the Federal tax rate for simplicity purposes.

Q. How does the Company expect to compute the impact of future increase or decrease in the Federal and or state income tax rates and what is the mechanism developed by the Company?

A. The Company notes that an increase or decrease in the Federal and or state income tax rates based on tax reform would result in a recovery from customers or pass back to customers related to the increase of income tax expense or reduction of income tax expense, respectively. Currently, the Company does not have an indication of the timing of enactment of tax reform that would result in a change in the Federal income tax rate that have been proposed by the Biden Administration. However, to alleviate the administrative burden and lag in timing, the Company is proposing utilizing the TAAF for a tax charge or tax (credit) for the recovery or pass back of the impact of a future increase or decrease of the Federal and or state income tax rates as of the effective date of such change based on the most recent base rates approved by the Commission.

For simplicity purposes, the Company has prepared illustrative schedules utilizing a scenario of a 7% increase in the Federal income tax rate from 21% to 28% proposed by the Biden administration using an effective date of January 1, 2022 for illustrative purposes based on the rate case forecasted test period. These schedules are provided with my testimony as Attachment JH-1. There are two components of tax expense impacted from a change in the Federal income tax rate that the Company has captured in illustrative schedules based on computations of the forecasted test year ended December 31, 2022: 1) total current and deferred tax expense included in the cost of service, including flow through adjustments for (excess)/deficient ADIT amortization, Federal investment tax credits and excess book over tax depreciation and 2) accumulated deferred income taxes (ADIT) included in the rate base which represent future deductible or taxable statutory book/tax temporary differences.

Based on the scenario described above, the impact of an increase in the Federal income tax rate is computed as the difference between the income tax expense included in the revenue requirement submitted for approval by the Commission in the Company's current base rate proceeding computed at 21% and the calculated income tax expense had the increase of the Federal income tax rate at 28% been in effect during the test year as depicted on Attachment JH-1, Sheet A, Page 1, Column 5, Lines 1 through 42. As depicted in the illustrative Attachment JH-1, Sheet A, Page 1, Column 5, Line 34, the impact of the increase in the Federal income tax rate results in increased tax expense (before gross-up) of $2,468,608, which includes the estimated annual amortization of the deficient ADIT of $395,591 on Attachment JH-1, Sheet A, Page 1, Line 24 (See discussion below and computation on Attachment JH-1, Sheet B, Page 2, Column 9, Lines 1-12). The illustrative increase in rate base ADIT for the test year is $1,042,764. For illustrative purposes, the Company multiplied the increase of rate base ADIT by the percentage rate of return presented in the Company's current base rate proceeding of 7.48% resulting in offset to the increased tax expense of $77,999 depicted on Attachment JH-1, Sheet A, Page 1, Column 5, Line 40.

Based on the scenario described above, the ADIT included in rate base which represents future deductible or taxable statutory book/tax temporary differences are required to be re-measured at the new Federal income tax rate as of the ending balance sheet date prior to the enactment of the new

Federal income tax rate. As discussed mentioned previously, the Company established a Regulatory Liability for the excess ADIT related to the TCJA of 2017 decrease of the Federal income tax rate from 35% to 21% effective January 1, 2018 that continues to be passed back to customers [10-years for non-property, 39.2 years for Federal NOL average rate assumption method ("ARAM") for property]. As mentioned above, for illustrative purposes, the Company used an effective date of January 1, 2022 of the increase in the Federal income tax rate which requires ADIT to be re-measured at 28% based on the December 31, 2021 ending balance sheet date on Attachment JH-1, Sheet B, Page 2, Column 7, Lines 1-12 resulting in deficient ADIT as of December 31, 2021 of $17,208,502. The Company has presented the deficient ADIT as a Regulatory Asset that is included in rate base on Attachment JH-1, Sheet B, Page 1, Column 4, Lines 14-19 to illustrate that the re-measurement of ADIT does not have an immediate impact on rate base as of the balance sheet re-measurement date. Consistent with amortization periods agreed to under the TCJA of 2017 Federal rate change, the Company has applied the same amortization periods (10-years for non-property, 39-years for Federal NOL and ARAM for property which is estimated at 40-years based on the book depreciation composite rate). The estimated annual amortization of the deficient ADIT is $395,591 (See Attachment JH-1, Sheet B, Page 2, Column 9, Lines 1-

12. This annual amortization of the deficient ADIT is included in total Federal tax expense in the cost of service on Attachment JH-1, Sheet A, Page 1, Column 4, Line 24.

The Company notes that the total illustrative impact of increased tax expense is $2,390,610 presented on Attachment JH-1, Sheet A, Page 1, Column 5, Line 42. The Company applied the statutory tax rate gross up factor of 1.46198830 (See computation on Attachment JH-1, Sheet A, Page 1, Lines 48 through 54 based on the increased Federal income tax rate of 28%) resulting in an illustrative gross revenue requirement of $3,495,043. The Federal tax charge to apply prospectively to customer bills would represent the product of the illustrative gross revenue requirement multiplied by the most recent approved revenue allocation for all Kentucky rate schedules approved by the Commission in the Company's most recent base rate proceeding. The Company acknowledges that the illustrative schedules and computation of a Federal tax charge is subject to the Commission approval of the final revenue requirement in the Company's current rate base proceeding for the test year ended December 31, 2022.

Q: As proposed, will the TAAF have any impact on customer bills?

A: No, this rider is being set at zero as proposed. It will only be populated in the event of a change to the Federal or state income tax rates applicable to the Company are enacted.

Q. Does this conclude your testimony?

A. Yes, however, I reserve the right to file rebuttal testimony.

ATTACHMENT JH-1
ILLUSTRATIVE IMPACT OF TAX CHANGES

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021-00183
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
ILLUSTRATIVE COMPUTATION OF FEDERAL AND STATE INCOME TAX
BASE PERIOD: TWELVE MONTHS ENDED AUGUST 31, 2021
FORECASTED TEST PERIOD: TWELVE MONTHS ENDED DECEMBER 31, 2022

EXHIBIT JH-1
ATTACHMENT A
SHEET 1 OF 1
WITNESS: J. Harding

LINE NO.	DESCRIPTION	REFERENCE	FEDERAL INCOME TAX AT 21% FORECASTED RETURN AT PROPOSED RATES ADJ JURISDICTION (1) $	FEDERAL INCOME TAX AT 28% FORECASTED RETURN AT PROPOSED RATES ADJ JURISDICTION (2) $	CHANGE IN FEDERAL FEDERAL TAX EXPENSE FORECASTED RETURN AT PROPOSED RATES ADJ JURISDICTION (3) = (2 - 1) $
1	OPERATING REVENUES	C-1, SHT 1, LN 1	174,059,847	174,059,847	0
2	OPERATING DEDUCTIONS	C-1, SHT 1, LN 2 to LN 6	133,726,466	133,726,466	0
3	OPERATING INCOME BEFORE INCOME TAX & INTEREST	C-1, SHT 1, LN 2 to LN 7	40,333,382	40,333,382	0
4	INTEREST CHARGES	E-1.1, SHT 1 & 2, LN 2	9,192,200	9,192,200	0
5	OPERATING INCOME BEFORE INCOME TAXES	= LN 3 - LN 4	31,141,182	31,141,182	0
6					
7	FEDERAL FLOW-THROUGH STATUTORY ADJUSTMENTS	E-1.1, SHT 1 & 2, LN 5	32,010	32,010	0
8	FEDERAL TIMING STATUTORY ADJUSTMENTS	E-1.1, SHT 1 & 2, LN 6	(15,967,877)	(15,967,877)	0
9	STATE BONUS DISALLOWANCE	E-1.1, SHT 1 & 2, LN 7	(5,457,018)	(5,457,018)	0
10					
11	STATE TAXABLE INCOME	= LN 5 + SUM (LN 7 TO LN 9)	9,748,298	9,748,298	0
12	STATE INCOME TAX RATE		5.000%	5.000%	0.000%
13	**STATE INCOME TAX**	**= LN 11 * LN 12**	**487,415**	**487,415**	**0**
14					
15	FEDERAL TAXABLE INCOME (BEFORE NOL)	E-1.1, SHT 1, CL 10, LN 17	14,717,901	14,717,901	0
16	FEDERAL NET OPERATING LOSS CARRYFORWARD		0	0	0
17	FEDERAL TAXABLE INCOME		14,717,901	14,717,901	0
18	FEDERAL INCOME TAX RATE		21.000%	28.000%	7.000%
19	**FEDERAL INCOME TAX**	E-1.1, SHT 1, CL 10, LN 25	**3,090,759**	**4,121,012**	**1,030,253**
20					
21	PROVISION FOR DEFERRED FEDERAL INCOME TAX	= - LN 8 - LN 17 * LN 18	3,353,254	4,471,005	1,117,751
22	FEDERAL BENEFIT OF PROVISION FOR DEFERRED STATE INCOME TAX	E-1.1, SHT 1, CL 10, LN 30	(224,961)	(299,949)	(74,987)
23	AMORTIZATION OF EXCESS ADIT-FEDERAL	E-1.1, SHT 1, CL 10, LN 31	(790,253)	(790,253)	0
24	AMORTIZATION OF DEFIDIENT ADIT - FEDERAL	EXH JH-1, ATT B, SH 2, LN 12		395,591	395,591
25	OTHER ADJUSTMENTS TO DEFERRED FEDERAL INCOME TAX	E-1.1, SHT 1, CL 10, LN 33	48,893	48,893	0
26	AMORTIZATION OF INVESTMENT TAX CREDIT	E-1.1, SHT 1, CL 10, LN 34	(12,816)	(12,816)	0
27	**DEFERRED FEDERAL INCOME TAX**	**= SUM LN 21 - 26**	**2,374,117**	**3,812,472**	**1,438,355**
28					
29	PROVISION FOR DEFERRED STATE INCOME TAX	= - LN 8 - LN 9 * LN 12	1,071,245	1,071,245	0
30	AMORTIZATION OF EXCESS ADIT-STATE	E-1.1, SHT 1, CL 10, LN 38	(95,291)	(95,291)	0
31	OTHER ADJUSTMENTS TO DEFERRED STATE INCOME TAX	E-1.1, SHT 1, CL 10, LN 39	(8,851)	(8,851)	0
32	**DEFERRED STATE INCOME TAX**	**= SUM LN 29-31**	**967,103**	**967,103**	**0**
33					
34	**TOTAL FEDERAL INCOME TAX**	**= SUM LN 19 and LN 27**	**5,464,876**	**7,933,484**	**2,468,608**
35	**TOTAL STATE INCOME TAX**	**= SUM LN 13 and LN 32**	**1,454,518**	**1,454,518**	**0**
36	**TOTAL INCOME TAX EXPENSE**	**= SUM LN 34-35**	**6,919,393**	**9,388,002**	**2,468,608**
37					
38	ACCUMULATED DEFERRED INCOME TAXES	EXH JH-1, ATT A, SH1, -LN 21 & -LN 22			(1,042,764)
39	% RATE OF RETURN EARNED ON RATE BASE				7.48%
40	**REVENUE REQUIREMENT**				**(77,999)**
41					
42	**ILLUSTRATIVE IMPACT OF INCREASED TAX EXPENSE AND ADIT, NET**				**2,390,610**
43					
44	STATUTORY TAX RATE GROSS-UP FACTOR				1.46198830
45					
46	**GROSS REVENUE REQUIREMENT**				**3,495,043**
47					
48	**COMPUTATION OF STATUTORY TAX RATE GROSS-UP FACTOR**				
49	FEDERAL INCOME TAX RATE				28.00%
50	STATE INCOME TAX RATE				5.00%
51	FEDERAL BENEFIT OF STATE INCOME TAX RATE				-1.40%
52	TOTAL STATUTORY INCOME TAX RATE				31.60%
53					
54	STATUTORY TAX RATE GROSS-UP FACTOR				1.46198830

NOTES

/ 1 - Illustrative schedule prepared based on a scenario of an increase in the Federal tax rate for the Forecasted Test Period effective January 1, 2022 resulting in remeasurement of ADIT at the new Federal tax rate as of the end of December 31, 2021 balance sheet date

/ 2 - Illustrative schedule prepared reflects no change in the pass back of Excess ADIT related to TCJA of 2017. The permanent benefit will continue to be passed back to customers over the respective amortization periods. However, the 254 Regulatory Liability balance and 190 Deferred Tax (Gross-Up) will be remeasured based on the new Statutory Tax Rate Gross-Up Factor due to the new Federal tax rate. The entry would result in net zero deferred tax expense.
DR 254 Regulatory Liability and CR 411 Deferred Tax Benefit / CR 190 Deferred Tax (Gross-Up) and DR 410 Deferred Tax Expense

/ 3 - Illustrative schedule prepared for the Forecasted Test Period Deficient ADIT annual amortization consistent with the amortization periods agreed to for Excess ADIT from TCJA decrease in Federal tax rate (See Attachment B, Page 2, Lines 1-12 for computation)

/ 4 - Illustrative schedule prepared applies 7.48% rate of return which represents the rate of return fro the 2021 Rate Case Forecasted Test Period at Proposed Rates. The Company would update based on the final rate of return approved by the commission.

/ 5 - Illustrative schedule prepared applies a statutory tax rate gross-up factor based on the new Federal income tax rate (See computation on lines 48 to 54)

/ 6 - Illustrative schedule prepared applies the operating revenue which represent revenue for the 2021 Rate Case Forecasted Test Period at Proposed Rates. The Company would updated based on the final revenue approved by the commission.

EXHIBIT JH-1
ATTACHMENT B
SHEET 1 OF 2
WITNESS: J. Harding

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021-00183
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
ILLUSTRATIVE ACCUMULATED DEFERRED INCOME TAX (ADIT) / (EXCESS) DEFICIENT ADIT
BASE PERIOD: TWELVE MONTHS ENDED AUGUST 31, 2021
FORECASTED TEST PERIOD: TWELVE MONTHS ENDED DECEMBER 31, 2022

LINE NO.	DESCRIPTION	REFERENCE	ADIT at 21% FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	ADIT at 28% FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	CHANGE IN ADIT FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	ADIT at 28% FORECASTED DECEMBER 31, 2022 RETURN AT PROPOSED RATES
	(1)	(2)	(3)	(4)	(5) = (4 - 3)	(6)
				/ 1		
1	ACCUMULATED DEFERRED INCOME TAXES (ADIT)					
2	ACCOUNT 190 - DEFERRED INCOME TAXES	Exh B-6, Sht 1-2, Ln 4	6,870,189	9,014,226	2,144,036	8,989,659
3	ACCOUNT 282 - DEFERRED INCOME TAXES - DEPRECIATION	Exh B-6, Sht 1-2, Ln 5	(70,296,229)	(89,648,767)	(19,352,538)	(89,648,767)
4	Total ADIT		(63,426,039)	(80,634,542)	(17,208,502)	(80,659,108)
5				/ 2		/ 5
6	(TCJA) EXCESS ADIT (BEFORE GROSS UP)					
7	CUSTOMER ADVANCES	Exh B-6, Sht 1-2, Ln 130 & 137	292,855	292,855	-	244,046
8	LIFO INVENTORY & CAPITALIZED INVENTORY	Exh B-6, Sht 1-2, Ln 131 & 138	696,839	696,839		580,699
9	NET OPERATING LOSS - FED	Exh B-6, Sht 1-2, Ln 132	920,772	920,772		894,464
10	EXCESS ACCELERATED DEPRECIATION - FED	Exh B-6, Sht 1-2, Ln 133	(26,923,567)	(26,923,567)		(25,956,237)
11	EXCESS ACCELERATED DEPRECIATION - STATE	Exh B-6, Sht 1-2, Ln 139	(2,513,617)	(2,513,617)		(2,414,398)
12	Total EXCESS ADIT		(27,526,718)	(27,526,718)	-	(26,651,426)
13				/ 3		
14	(FTRA) DEFIDIENT ADIT (BEFORE GROSS UP)	/ 7				
15	ACCOUNT 190 - DEFERRED INCOME TAXES			(2,144,036)	(2,144,036)	(2,045,940)
16	ACCOUNT 282 - DEFERRED INCOME TAXES - DEPRECIATION			19,352,538	19,352,538	18,858,851
17	Total DEFICIENT ADIT			17,208,502	17,208,502	16,812,911
18						/ 6
19	Total ADIT & (EXCESS) / DIFICIENT ADIT		(90,952,757)	(90,952,757)	-	(90,497,623)
				/ 4		

NOTES

/ 1 - Illustrative schedule prepared based on a scenario of an increase in the Federal tax rate for the Forecasted Test Period effective January 1, 2022 resulting in remeasurement of ADIT at the new Federal tax rate as of the end of December 31, 2021 balance sheet date
/ 2 - Illustrative schedule prepared reflects ADIT as of December 31, 2021 remeasured at new Federal tax rate (See Attachment B, Page 2, Lines 1-12 for computation of the remeasurement)
/ 3 - Illustrative schedule prepared reflects no change in the pass back of Excess ADIT related to TCJA of 2017. The permanent benefit will continue to be passed back to customers over the respective amortization periods
/ 4 - Illustrative schedule prepared reflects no change in total ADIT & (Excess) / Deficient ADIT as of the balance sheet date when deferred taxes are remeasured at the new Federal tax rate as the permanent difference is recorded as a Regulatory Asset to be amortized over respective periods
/ 5 - Illustrative schedule prepared reflects the Forecasted Test Period ADIT remeasured at new Federal tax rate (See Attachment B, Page 2, Lines 21-34 for computation of the remeasurement)
/ 6 - Illustrative schedule prepared reflects decrease in Deficient ADIT from December 31, 2021 to December 31, 2022 based on estimated annual amortization (See Attachment B, Page 2, Lines 1-12)
/ 7 - Illustrative schedule prepared reflects the Base Period and Forecasted Test Period Deficient ADIT as a balance separate from Excess ADIT attributed to TCJA of 2017 for illustrative purposes only (actual accounting may be presented as a net balance)

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021-00183
ILLUSTRATIVE IMPACT OF FUTURE FEDERAL TAX RATE CHANGE
ILLUSTRATIVE ACCUMULATED DEFERRED INCOME TAX (ADIT) / (EXCESS) DEFICIENT ADIT
BASE PERIOD: TWELVE MONTHS ENDED AUGUST 31, 2021
FORECASTED TEST PERIOD: TWELVE MONTHS ENDED DECEMBER 31, 2022

EXHIBIT JH-1
ATTACHMENT B
SHEET 2 OF 2
WITNESS: J. Harding

LINE NO.	DESCRIPTION	REFERENCE	ADIT at 21% FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	Current Tax Rates FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	Gross ADIT FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	Illustrative Tax Rates FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	ADIT at 28% FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	/ 1 Excess)/Deficient ADIT FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	/ 2 Amortizable Period FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES	(Excess)/Deficient ADIT Amort FORECASTED DECEMBER 31, 2021 RETURN AT PROPOSED RATES
		(1)	(2)	(3)	(4) = (2 / 3)	(5)	(6) = (4 X 5)	(7) = (2 - 6)	(8)	(9) = (7 / 8)
1	ACCOUNT 190 - DEFERRED INCOME TAXES									
2	CUSTOMER ADVANCES - FED		562,032	19.95%	2,817,203	26.60%	749,376	(187,344)	10.00	(18,734)
3	CUSTOMER ADVANCES - STATE		140,860	5.00%	2,817,200	5.00%	140,860	0	10.00	-
2	LIFO INVENTORY & CAPITALIZED INVENTORY - FED		1,185,914	19.95%	5,944,431	26.60%	1,581,219	(395,305)	10.00	(39,530)
3	LIFO INVENTORY & CAPITALIZED INVENTORY -STATE		297,221	5.00%	5,944,420	5.00%	297,221	0	10.00	-
4	NET OPERATING LOSS - FED		4,684,162	21.00%	22,305,535	28.00%	6,245,550	(1,561,387)	39.20	(39,831)
5	TOTAL ACCOUNT 190		6,870,189		39,828,789		9,014,226	(2,144,036)		(98,096)
6										
7	ACCOUNT 282 - DEFERRED INCOME TAXES - DEPRECIATION									
8	EXCESS ACCELERATED DEPRECIATION - FED		(58,057,615)	19.95%	(291,015,615)	26.60%	(77,410,153)	19,352,538	39.20	493,687
9	EXCESS ACCELERATED DEPRECIATION - STATE		(12,238,614)	5.00%	(244,772,273)	5.00%	(12,238,614)	0		
10	TOTAL ACCOUNT 282		(70,296,229)		(535,787,887)		(89,648,767)	19,352,538		493,687
11										
12	TOTAL ACCUMULATED DEFERRED INCOME TAXES		(63,426,039)		(495,959,098)		(80,634,542)	17,208,502		395,591
13										
14										

LINE NO.	DESCRIPTION	REFERENCE	ADIT at 21% FORECASTED DECEMBER 31, 2022 RETURN AT PROPOSED RATES	Current Tax Rates FORECASTED DECEMBER 31, 2022 RETURN AT PROPOSED RATES	Gross ADIT FORECASTED DECEMBER 31, 2022 RETURN AT PROPOSED RATES	Illustrative Tax Rates FORECASTED DECEMBER 31, 2022 RETURN AT PROPOSED RATES	ADIT at 28% FORECASTED DECEMBER 31, 2022 RETURN AT PROPOSED RATES
15-19							
20		(1)	(2)	(3)	(4) = (2 / 3)	(5)	(6) = (4 X 5)
21	ACCOUNT 190 - DEFERRED INCOME TAXES						
22	CUSTOMER ADVANCES - FED		562,032	19.95%	2,817,203	26.60%	749,376
23	CUSTOMER ADVANCES - STATE		140,860	5.00%	2,817,200	5.00%	140,860
24	LIFO INVENTORY & CAPITALIZED INVENTORY - FED		1,185,914	19.95%	5,944,431	26.60%	1,581,219
25	LIFO INVENTORY & CAPITALIZED INVENTORY -STATE		297,221	5.00%	5,944,420	5.00%	297,221
26	NET OPERATING LOSS - FED		4,665,738	21.00%	22,217,799	28.00%	6,220,984
27	TOTAL ACCOUNT 190		6,851,765		39,741,053		8,989,659
28							
29	ACCOUNT 282 - DEFERRED INCOME TAXES - DEPRECIATION						
30	EXCESS ACCELERATED DEPRECIATION - FED		(58,057,615)	19.95%	(291,015,615)	26.60%	(77,410,153)
31	EXCESS ACCELERATED DEPRECIATION - STATE		(12,238,614)	5.00%	(244,772,273)	5.00%	(12,238,614)
32	TOTAL ACCOUNT 282		(70,296,229)		(535,787,887)		(89,648,767)
33							
34	TOTAL ACCUMULATED DEFERRED INCOME TAXES		(63,444,464)		(496,046,834)		(80,659,108)
35							
36							

LINE NO.	STATUTORY TAX RATES	CURRENT TAX RATES	ILLUSTRATIVE TAX RATES
37			
38	FEDERAL INCOME TAX RATE	21.000%	28.000%
39	STATE INCOME TAX RATE	5.000%	5.000%
40	FEDERAL BENEFIT OF STATE INCOME TAX RATE	-1.050%	-1.400%
41	FEDERAL INCOME TAX RATE, NET	19.950%	26.600%
42	TOTAL STATUTORY RATE	24.950%	31.600%

NOTES

/ 1 - Illustrative schedule prepared based on a scenario of an increase in the Federal tax rate for the Forecasted Test Period resulting in remeasurement of ADIT at the new Federal tax rate as of the end of December 31, 2021 balance sheet date

/ 2 - Illustrative schedule prepared for the Forecasted Period Computation of Deficient ADIT estimated annual amortization consistent with the amortization periods agreed to for Excess ADIT from TCJA decrease in Federal tax rate

Non-Property - 10-yr
Federal NOL - 39-yr
Property - ARAM (Illustrative example reflects 39.20 yr which represents the FTY book depre composite rate - Actuals will be based on ARAM computed in PowerTax)

ATTACHMENT JH-2
IMPACT OF HOUSE BILL 487

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021 - 00183
IMPACT OF HOUSE BILL 487 5% FLAT STATE INCOME TAX RATE
BASE PERIOD: TWELVE MONTHS ENDED AUGUST 31, 2021
FORECASTED TEST PERIOD: TWELVE MONTHS ENDED DECEMBER 31, 2022

EXHIBIT JH-2
ATTACHMENT A
SHEET 1 OF 1
WITNESS: J. Harding

LINE NO.	DESCRIPTION	ACCT #	1/ 12/31/2017 ADIT BALANCE AT 6% STATE TAX RATE (1)	1/ 12/31/2017 ADIT BALANCE AT 5% STATE TAX RATE (2)	EXCESS / (DEFICIENT) ADIT DIFFERENCE (3)	AMORTIZATION PERIOD (4)	ANNUAL AMORTIZATION (5)	
1	NON-PROPERTY RELATED ADIT IN RATE BASE							
2	INVENTORY CAPITALIZATION	190	19,605	16,337	(3,267)	6-YR	545	2/
3	LIFO STORAGE ADJUSTMENT	190	339,810	283,175	(56,635)	6-YR	9,439	2/
4	CUSTMR ADVN FOR CONSTR NONCUR	190	151,048	125,873	(25,175)	6-YR	4,196	2/
5	SUBTOTAL (LINES 1-3)		510,462	425,385	(85,077)		14,180	
6								
7	PROPERTY RELATED ADIT IN RATE BASE (RSG)	282	(8,043,577)	(6,702,981)	1,340,596	35-YR (RSG)	(38,303)	3/
8								
9	TOTAL (LINE 4 + LINE 6)		$ (7,533,115)	$ (6,277,596)	$ 1,255,519		$ (24,123)	
10								
11	GROSS CONVERSION FACTOR (LINE 21)				1.3324450		1.3324450	
12								
13	REGULATORY LIABILITY / REVENUE REQUIREMENT DECREASE (LINE 8 X LINE 10)				$ 1,672,909		$ (32,143)	
14								
15	COMPUTATION OF STATUTORY INCOME TAX RATE GROSS-UP FACTOR							
16	FEDERAL INCOME TAX RATE		21.00%					
17	STATE INCOME TAX RATE		5.00%					
18	FEDERAL BENEFIT OF STATE INCOME TAX RATE		-1.05%					
19	TOTAL STATUTORY INCOME TAX RATE		24.95%					
20								
21	STATUTORY INCOME TAX RATE GROSS-UP FACTOR		$\boxed{1.3324450}$					

1/ ADIT balance is presented net of the federal benefit of state tax computed using the 21% enacted federal income tax rate
2/ Proposed 6 year amortization for non-property deficient ADIT to capture stub period amortization from flat 5% state income tax effective date of 1/1/2018 to rates effective date of 1/1/22 for this rate case
3/ Proposed 35-yr amortization under Reverse South Georgia (RSG) method to capture stub period amortization from flat 5% state income tax effective date of 1/1/2018 to rates effective date of 1/1/22 for this rate case

COLUMBIA GAS OF KENTUCKY, INC.
CASE NO. 2021 - 00183
IMPACT OF HOUSE BILL 487 5% FLAT STATE INCOME TAX RATE
BASE PERIOD: TWELVE MONTHS ENDED AUGUST 31, 2021
FORECASTED TEST PERIOD: TWELVE MONTHS ENDED DECEMBER 31, 2022

EXHIBIT JH-2
ATTACHMENT B
SHEET 1 OF 1
WITNESS: J. Harding

				HOUSE BILL 487 KY STATE RATE DECREASE FROM 6% TO 5%						
LINE	YEAR	YEAR END	DESCRIPTION	PROPERTY	INVENTORY CAPITALIZATION	LIFO STORAGE ADJUSTMENT	CUSTMR ADVN FOR CONSTR NONCUR	TOTAL	CUMULATIVE	CUMULATIVE GROSSED-UP
				(1)	(2)	(3)	(4)	(5)	(6)	(7)
1			**AMORTIZATION PERIOD**	**35-YR (RSG)**	**6-YR**	**6-YR**	**6-YR**			
2				$	$	$	$	$	$	$
3		12/31/2017	(EXCESS) DEFICIENT ADIT	(1,340,596)	3,267	56,635	25,175	(1,255,519)	(1,255,519)	(1,672,909)
4	Year 1	12/31/2018	EDIT/DDIT AMORTIZATION					-	(1,255,519)	(1,672,909)
5	Year 2	12/31/2019	EDIT/DDIT AMORTIZATION					-	(1,255,519)	(1,672,909)
6	Year 3	12/31/2020	EDIT/DDIT AMORTIZATION					-	(1,255,519)	(1,672,909)
7	Year 4	12/31/2021	EDIT/DDIT AMORTIZATION					-	(1,255,519)	(1,672,909)
8	Year 5	12/31/2022	EDIT/DDIT AMORTIZATION	38,303	(545)	(9,439)	(4,196)	24,123	(1,231,395)	(1,640,767)
9	Year 6	12/31/2023	EDIT/DDIT AMORTIZATION	38,303	(545)	(9,439)	(4,196)	24,123	(1,207,272)	(1,608,624)
10	Year 7	12/31/2024	EDIT/DDIT AMORTIZATION	38,303	(545)	(9,439)	(4,196)	24,123	(1,183,149)	(1,576,481)
11	Year 8	12/31/2025	EDIT/DDIT AMORTIZATION	38,303	(545)	(9,439)	(4,196)	24,123	(1,159,026)	(1,544,338)
12	Year 9	12/31/2026	EDIT/DDIT AMORTIZATION	38,303	(545)	(9,439)	(4,196)	24,123	(1,134,903)	(1,512,196)
13	Year 10	12/31/2027	EDIT/DDIT AMORTIZATION	38,303	(545)	(9,439)	(4,196)	24,123	(1,110,780)	(1,480,053)
14	Year 11	12/31/2028	EDIT/DDIT AMORTIZATION	38,303				38,303	(1,072,477)	(1,429,016)
15	Year 12	12/31/2029	EDIT/DDIT AMORTIZATION	38,303				38,303	(1,034,174)	(1,377,980)
16	Year 13	12/31/2030	EDIT/DDIT AMORTIZATION	38,303				38,303	(995,871)	(1,326,944)
17	Year 14	12/31/2031	EDIT/DDIT AMORTIZATION	38,303				38,303	(957,569)	(1,275,908)
18	Year 15	12/31/2032	EDIT/DDIT AMORTIZATION	38,303				38,303	(919,266)	(1,224,871)
19	Year 16	12/31/2033	EDIT/DDIT AMORTIZATION	38,303				38,303	(880,963)	(1,173,835)
20	Year 17	12/31/2034	EDIT/DDIT AMORTIZATION	38,303				38,303	(842,660)	(1,122,799)
21	Year 18	12/31/2035	EDIT/DDIT AMORTIZATION	38,303				38,303	(804,358)	(1,071,762)
22	Year 19	12/31/2036	EDIT/DDIT AMORTIZATION	38,303				38,303	(766,055)	(1,020,726)
23	Year 20	12/31/2037	EDIT/DDIT AMORTIZATION	38,303				38,303	(727,752)	(969,690)
24	Year 21	12/31/2038	EDIT/DDIT AMORTIZATION	38,303				38,303	(689,449)	(918,653)
25	Year 22	12/31/2039	EDIT/DDIT AMORTIZATION	38,303				38,303	(651,147)	(867,617)
26	Year 23	12/31/2040	EDIT/DDIT AMORTIZATION	38,303				38,303	(612,844)	(816,581)
27	Year 24	12/31/2041	EDIT/DDIT AMORTIZATION	38,303				38,303	(574,541)	(765,545)
28	Year 25	12/31/2042	EDIT/DDIT AMORTIZATION	38,303				38,303	(536,238)	(714,508)
29	Year 26	12/31/2043	EDIT/DDIT AMORTIZATION	38,303				38,303	(497,936)	(663,472)
30	Year 27	12/31/2044	EDIT/DDIT AMORTIZATION	38,303				38,303	(459,633)	(612,436)
31	Year 28	12/31/2045	EDIT/DDIT AMORTIZATION	38,303				38,303	(421,330)	(561,399)
32	Year 29	12/31/2046	EDIT/DDIT AMORTIZATION	38,303				38,303	(383,027)	(510,363)
33	Year 30	12/31/2047	EDIT/DDIT AMORTIZATION	38,303				38,303	(344,725)	(459,327)
34	Year 31	12/31/2048	EDIT/DDIT AMORTIZATION	38,303				38,303	(306,422)	(408,290)
35	Year 32	12/31/2049	EDIT/DDIT AMORTIZATION	38,303				38,303	(268,119)	(357,254)
36	Year 33	12/31/2050	EDIT/DDIT AMORTIZATION	38,303				38,303	(229,816)	(306,218)
37	Year 34	12/31/2051	EDIT/DDIT AMORTIZATION	38,303				38,303	(191,514)	(255,182)
38	Year 35	12/31/2052	EDIT/DDIT AMORTIZATION	38,303				38,303	(153,211)	(204,145)
39	Year 36	12/31/2053	EDIT/DDIT AMORTIZATION	38,303				38,303	(114,908)	(153,109)
40	Year 37	12/31/2054	EDIT/DDIT AMORTIZATION	38,303				38,303	(76,605)	(102,073)
41	Year 38	12/31/2055	EDIT/DDIT AMORTIZATION	38,303				38,303	(38,303)	(51,036)
42	Year 39	12/31/2056	EDIT/DDIT AMORTIZATION	38,303				38,303	0	0
43										
44			TOTAL	0	-	-	-	0		
45										
46			COMPUTATION OF STATUTORY INCOME TAX RATE GROSS-UP FACTOR							21.00%
47			FEDERAL INCOME TAX RATE							5.00%
48			STATE INCOME TAX RATE							-1.05%
49			FEDERAL BENEFIT OF STATE INCOME TAX RATE							19.95%
50			TOTAL STATUTORY INCOME TAX RATE							24.95%
51										
52			STATUTORY INCOME TAX RATE GROSS-UP FACTOR							$\boxed{1.3324450}$

Columbia Gas of Kentucky, Inc.
CASE NO. 2021-00183
Forecasted Test Period Filing Requirements
807 KAR 5:001 Section 16-(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program;

Response:

Please see the testimony of Kimberly Cartella attached. Please also see the testimonies attached at Tabs 17 through 30 including the testimony of Columbia Gas of Kentucky's President and Chief Operating Officer at Tab 17.

Responsible Witnesses:

Kimberly Cartella

Sure w Columbia Exhibit No. 30

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the matter of:	)	
	)	
ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF	)	Case No. 2021-00183

PREPARED DIRECT TESTIMONY OF
KIMBERLY CARTELLA
ON BEHALF OF COLUMBIA GAS OF KENTUCKY, INC.

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Attorneys for Applicant
COLUMBIA GAS OF KENTUCKY, INC.

May 28, 2021

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF COLUMBIA GAS OF KENTUCKY, INC. FOR AN ADJUSTMENT OF RATES; APPROVAL OF DEPRECIATION STUDY; APPROVAL OF TARIFF REVISIONS; ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY; AND OTHER RELIEF

Case No. 2021-00183

VERIFICATION OF KIMBERLY CARTELLA

STATE OF OHIO)
)
COUNTY OF LORAIN)

Kimberly Cartella, Director Compensation for NiSource Corporate Services Company, on behalf of Columbia Gas of Kentucky, Inc., being duly sworn, states that she has supervised the preparation of her Direct Testimony and certain filing requirements in the above-referenced case and that the matters and things set forth therein are true and accurate to the best of her knowledge, information and belief, formed after reasonable inquiry.

Kimberly Cartella

Kimberly Cartella

The foregoing Verification was signed, acknowledged and sworn to before me this 20th day of May, 2021, by Kimberly Cartella.

Emily L Brady

Notary Commission No. __________

Commission expiration: No exp.

Emily L. Brady, Attorney at Law
Resident Summit County
Notary Public, State of Ohio
My Commission Has No Expiration Date
Sec 147.03 RC

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kimberly K. Cartella. My business address is 3101 N. Ridge Rd., Lorain, OH 44055.

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

A. I am employed by NiSource Corporate Service Company ("NCSC") as Director Compensation. I develop and implement strategies for broad based compensation and incentive programs provided to the employees of NiSource Inc. ("NiSource") and its subsidiaries, including Columbia Gas of Kentucky ("CKY" or the "Company").

Q: What is your educational background?

A: I received a Bachelor of Science degree in Financial Planning from Purdue University in 1992. I am a certified Professional in Human Resources ("PHR") and a Certified Compensation Professional ("CCP").

Q: What is your employment history?

A: I have worked for NiSource in a human resources capacity since 1999. I have held the position of Director Compensation at NiSource since January 2019. Prior to that, I was Manager Compensation, Senior Compensation Analyst, Senior Human Resource Consultant, and College Recruiter.

Q: Have you previously testified before the Kentucky Public Service Commission?

A. No.

Q: Have you previously testified before any other Utility Commissions?

A: I have provided direct and written testimony before the Massachusetts Department of Public Utilities on multiple occasions supporting compensation and benefits strategies and costs. Additionally, I have provided written testimony supporting compensation and benefits in Columbia Gas of Pennsylvania and Columbia Gas of Maryland base rate cases.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports NiSource total rewards which includes supporting details for total rewards programs, policies, and philosophies including base compensation/wages, incentive compensation, and employee benefits such as healthcare and dental coverage. Also, my testimony puts forth a comparative analyses to establish the reasonableness of the wages, salaries, incentive compensation provided to employees.

Q. Are you including any attachments to your testimony?

A. Yes. They are as follows:

Attachment No.	Description
Attachment KKC-1	CKY Union Wage Analysis
Attachment KKC-2	CKY Non-Union Salary Analysis
Attachment KKC-3	NCSC Salary Analysis
Attachment KKC-4	Non-Union Merit Increase Market Data

Q. How is your testimony organized?

A. The remainder of my testimony is organized as follows. Section II discusses the Company's overall approach to employee compensation including base pay (wages and salaries) and incentive compensation as part of total cash compensation. Section III presents documentation to support the reasonableness of the Company's compensation expenses. Sections IV through VI describe the Company's union wages, non-union compensation, all incentive compensation, merit increases, and profit sharing components. Section VII provides detailed analysis that demonstrates that the total cash compensation paid to employees by CKY and NCSC is reasonable in relation to other utilities and general industry employers in the general areas where CKY operates. Section VIII describes the Company's health and dental benefit plans and associated cost-containment efforts.

II. EMPLOYEE COMPENSATION AND BENEFITS

Q. Please describe NiSource's total rewards philosophy.

A. NiSource's total rewards philosophy is to compensate employees and provide benefits that are competitive in comparison to the utility industry, as well as general industry employers, in order to attract, retain and motivate employees who are qualified to perform the functions needed by the Company. This philosophy enables the Company to meet its obligations to provide safe, reliable and affordable service to its customers. This philosophy is consistent across all NiSource companies.

Q. In defining and implementing the total rewards strategy and programs, does NiSource obtain any assistance from outside human resource experts?

A. Yes. For compensation and certain health and welfare benefits, NiSource regularly relies on the advice and guidance provided by Mercer, a global consulting leader in talent, health, retirement, and investments. Mercer assists NiSource in setting competitive salary ranges and evaluating and recommending changes to employee health and welfare benefit plans. Mercer supports NiSource's policy of compensating employees within a range determined for base pay and total compensation and benefits when compared to other employers.

In addition, Aon and Alight Solutions, global human resource consulting firms, assist NiSource in actuarial analysis and administration of pension and health and welfare benefits.

Q. What are the various elements of a competitive total rewards program?

A. A competitive total rewards program includes market-driven base compensation (rewarding employees in a manner that is competitive with the external job market), market-driven performance adjustments/merits, long- and short-term incentives, profit sharing, and health and welfare benefits. The mix of these elements differs for various levels in the organization. For purposes of my testimony, I will focus on merit increases, long-term incentives, short-term incentives, health and welfare benefits, and profit sharing, which are all included in the total rewards program.

Q. What is your conclusion about the competitiveness of the Company's compensation and benefits package?

A. The Company's compensation is competitive when compared to the compensation at a similar group of employers for the North Central and Southeast United States. The Company's benefits are also competitive when compared to a similar group of employers. I provide support for these conclusions throughout the remainder of my testimony.

III. <u>REASONABLENESS OF COMPENSATION EXPENSE</u>

Q. What analysis have you conducted that confirms the reasonableness of CKY's wages, salaries and total compensation?

A. Attachment KKC-2 through Attachment KKC-5 support the Company's test-year levels for total compensation. Gas utility and general industry data was used to allow for comparison of CKY and NCSC's compensation to the relevant labor markets. The Company's supporting attachments are as follows:

<u>Attachment KKC-2: CKY Union Wage Analysis</u> – compares CKY union average hourly rates and hourly rates including incentive to the average hourly rates and hourly rates including incentive paid by employers in the Southeast.

<u>Attachment KKC-3: CKY Non-Union Salary Analysis</u> - compares CKY non-union average base salaries and total cash compensation to the average salaries and total cash compensation paid by Southeast utilities and general industry companies.

<u>Attachment KKC-4: NCSC Salary Analysis</u> - compares NCSC average base salaries and total cash compensation to the average base salaries and total cash compensation of utilities and general industry companies in the North Central regions.

<u>Attachment KKC-5: Non-Union Merit Increase Market Data</u> – compares CKY's granted 2020 and 2021 merit increases for employee groups to national, utility, and regional actual increases for 2020 and 2021.

IV. <u>UNION COMPENSATION</u>

Q. How many unions represent employees at CKY?

A. CKY manages relationships with one union: United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Worker International Union United Steelworkers of America Local 372.

Q. How are the Company's union wage rates set?

A. Union wage rates are established through the collective-bargaining process. Collective bargaining consists of negotiations between an employer and a union in order to establish wages, benefits and conditions of employment. The result of the collective-bargaining process is a collective-bargaining agreement that establishes the terms for increases in wages and benefits for affected employees.

Q. How does CKY determine that its union wages are competitive with the labor market?

A. In Attachment KKC-2, the analysis shows 2021 CKY average hourly wage rates compared to other employers in the Southeast, which includes Alabama, Arkansas, Florida, Georgia, Indiana, Kentucky, Mississippi, North Carolina, Ohio, South Carolina, Tennessee, West Virginia, and Virginia. The results of the analysis indicate that the hourly rates paid to CKY's union employees are comparable to the average hourly rates of other Southeast employers and that the hourly rates including incentives are comparable to the average of other Southeast employers.

Q. How are total compensation and benefits determined for the Company's union employees?

A. The total compensation and benefits for union employees are determined through collective bargaining, in a similar fashion as union wages. During the collective-bargaining process, CKY assesses changes in the overall compensation packages offered to union employees to ensure that the total compensation and benefits levels remain reasonable and commensurate to other union and non-union employees at similar levels within NiSource. Wherever possible, CKY encourages its union employees to join in the benefit programs offered to non-union employees in order to streamline the administration of the benefit programs and provide the most value to the employees and their families at the least cost.

Q. When do wage increases under the collective-bargaining contract take effect?

A. The current union contract will expire November 30, 2021. As of the writing of this testimony, negotiations for the new contract have not yet begun. The negotiations are anticipated to be conducted during 2021. While a 3.0 percent increase estimate is budgeted effective December 1, 2021 and another 3.0 percent estimate is budgeted effective December 1, 2022, actual increase amounts will depend upon the final outcome of the collective bargaining process. The Company will provide an update and adjust the budget, as necessary, upon completion of these contract negotiations.

V. NON-UNION COMPENSATION

Q. How is base compensation for non-union employees determined?

A. The base compensation for the Company's non-union employees is measured against base compensation for employees in similar positions at other employers. More specifically, internal positions have been aligned to an external market position by comparing the positions at CKY and NCSC to external labor marketplace positions. In order to establish parity with other employers vying for qualified workers in NiSource's labor markets, base compensation is set within a range that is established around the market median for individual jobs.

Q. How does NCSC establish the range within which non-union base pay can fluctuate around the market median?

A. The established salary range is 75 percent to 125 percent of the market median. This range allows individual leaders to differentiate base pay compensation among employees in similar jobs with varied skills, experiences and level of responsibility.

Q. How does the Company determine that its compensation is competitive with the labor market?

A. Attachment KKC-3 compares CKY base salaries and total cash compensation to utility and general industry companies in the Southeast. Attachment KKC-4 compares NCSC base salaries and total cash compensation to utility and general industry companies in the North Central regions. I will explain in more detail later in my testimony.

Q. Have you compared the Company's non-union merit adjustments to those of other utility and general industry companies to determine if they are reasonable?

A. Yes. The Company has provided Attachment KKC-5, which compares the Company's granted merit increases and the increases projected for employee groups regionally and nationally and for utilities and general industry in 2020 and 2021. The results show that the Company's exempt and non-union, non-exempt salary adjustments are aligned with the actual 2020 and projected 2021 market increases. 2022 projections are not yet available, and based upon historic market data, the Company has budgeted 3.0 percent for March 1, 2022.

VI. <u>INCENTIVE COMPENSATION AND PROFIT SHARING</u>

Q. Explain the Company's incentive compensation and profit sharing programs as part of the total rewards program.

A. As part of the total rewards program explained earlier in my testimony, NiSource maintains two incentive compensation programs and one profit sharing program. The two incentive compensation programs include the Corporate Incentive Plan (CIP) and the Long-Term Incentive Plan (LTI). The purpose of CIP and LTI is to align rewards with the Company's vision and strategies surrounding safety, customer, and financial. Participants are eligible to receive incentive awards based on their performance and the performance of NiSource and the Company. The Profit Sharing plan is an element of the Company's Retirement Savings Plan and supports employees' saving for retirement.

Q. Is CIP an important component of total compensation for CKY and NCSC to be effective in recruiting and retaining employees?

A. Yes. CIP is designed to drive and reinforce strategies important to the Company which includes safety, customer, and financial. Specific goals are included in exempt employees' annual objective plan. These goals are critical in reinforcing key Company initiatives, including safety, customer, financial, execution, and people. Secondly, incentive compensation is an element of competitive total rewards in the labor market both within the utility industry and within the broader general industry. This is evidenced by a recent survey conducted by Aon. The following is an excerpt from the Highlights and Trends section of The Aon 2019 Variable Compensation Measurement ("VCM") Report-U.S. Edition:

> Even with the changing economic environment variable pay budgets have continued to remain significantly higher than amounts budgeted for salary increases. While salary increases have hovered at or around 3% for the past six

> years, variable pay budgets have consistently been in double digits.
>
> Highlights and Trends
>
> Variable pay plans continue to be a critical component of most VCM participants' total compensation offerings. The Aon VCM report continues to support the trend that organizations are increasingly turning to variable pay as a means to attract, retain, and reward performance while traditional merit increase budgets remain at record low levels. In 2019, a median 99% of total US employees who were eligible for at least one type of variable pay actually received an award.
>
> Prevalence of Variable Compensation
>
> The frequency of companies with at least one broad-based variable pay plan continues to increase since 1994 when we first started recording this information. According to Aon's Salary Increase Survey, in 1995, 59% of U.S. organizations indicated they had at least one broad-based variable pay plan in place. By 2019, 90% of U.S. organizations had implemented a broad-based variable pay plan.
>
> Not only have more U.S. organizations in the database introduced broad-based variable compensation in recent years, organizations also have changed the look of their variable pay plans.
>
> Individual performance plan measures or modifiers give managers the power to reward and retain their top performers.

Therefore, to remain competitive in the labor market, it is important to provide CIP compensation as part of total compensation. If the Company maintains a competitive base compensation but does not provide incentive compensation, it follows that total compensation will lag the competition and employees will have larger total compensation opportunities at other employers providing competitive compensation inclusive of incentives.

Q. Is individual employee performance a factor for CIP?

A. Yes for exempt (salaried) employees. A portion of each exempt employee's annual total rewards is tied to the performance results of the measures in the CIP and individual performance. Under the terms of the incentive plan, a discretionary amount is available to exempt employees based on individual performance as determined by an employee's supervisor. I describe the employee incentive level and performance evaluation process below.

Q. How are incentive levels and incentive ranges determined?

A. Each employee is placed in a job scope level, which is based generally on their responsibility level within the organization. Each job scope level has an associated incentive level and incentive opportunity range, beginning at a threshold or "trigger" level, which provides an incentive of 50 percent of a "target." The incentive opportunity range increases through the "target" level up to the "stretch" level, which provides an incentive of 150 percent of the "target."

Here is an example of how incentive levels and ranges are utilized. Front line supervisors are in a job scope level that provides a target incentive opportunity of 12 percent of base pay. The trigger and stretch levels are 50 percent below and above the target percentage, respectively. Therefore the incentive range for a front line supervisor is:

Trigger	Target	Stretch
6%	12%	18%

Q. How does the incentive level factor into the appropriate level of total cash compensation for each employee?

A. The job scope level structure provides a framework for overall compensation, career advancement and leveling across the enterprise. The incentive opportunity is one component of an employee's total cash compensation, along with base pay, and therefore affects the potential value of total cash compensation. An incentive opportunity range is associated with each broad level, which determines the minimum and maximum incentive payout opportunity as a percentage of base pay for exempt employees and as a percentage of base pay plus overtime and other premium pay for non-exempt employees. Increases to base pay for an individual job may occur through merit increases, promotions from one job scope level to the next, progressions within a job scope level, and market adjustments if deemed necessary. The sum of the value of base pay and incentive compensation determines the overall total cash compensation opportunity available to employees.

Q. How does CKY ensure that employees are committed to meeting the needs of customers, such as service quality and service reliability, and how does this fit into the incentive program?

A. The discretionary portion of the incentive program is based on individual performance linked to goals in safety, customer, financial, execution, and people categories. Performance management is executed through the annual evaluative process embodied in the Objectives Form.

A CKY employee's Objectives Form contains annual performance objectives and articulates the means of measuring the employee's progress in relation to the established objectives. Each employee is actively involved in the development of his or her objectives, with input from his or her supervisor, and the employee's progress is reviewed and discussed with the employee periodically throughout the year. The annual performance objectives are also used as an aid in determining the amount of a merit increase for an employee.

The use of the objectives process to establish goals to measure employees' performance against these goals is important in reinforcing the proper focus on key initiatives and goals designed to continuously remain focused on safety and customer service and reinforce cost containment. Examples of goals that support improved customer service include: reduce emergency response time to 45 minutes to serve customers in a timely manner, communicate with the customer and stakeholders around project work and planned outages, and achieve targets for percent of customer appointments met. Examples of safety goals include: meet individual target of zero recordable safely incidents, DART injuries (days away, restricted, or transferred), and preventable vehicle collisions; execute to a safety driven culture by conducting weekly safety meetings with assigned front line workers.

Q. In general, how is incentive compensation awarded?

A. If incentive plan measures are met, an incentive pool is established. The percentage of an individual employee's base pay that is available for the cash incentive is dependent upon their job scope level. For exempt employees, the employee's individual performance and achievement of predetermined goals as determined by his or her supervisor is also factored into the amount of the incentive awarded. Incentive payments are made in February or March of the year following the year for which performance is measured, *e.g.*, 2020 plan year incentive was paid in 2021.

Q. Has CKY included incentive plan costs in the budget?

A. Yes. As it is an important piece to overall compensation earned by CKY employees, incentive compensation is included in the test year expenses. Columbia Witnesses Susan Taylor and Chun-Yi Lai support Columbia's proposed test year expense for incentive compensation.

Q. Is LTI an important component of total compensation for CKY and NCSC to be effective in recruiting and retaining employees?

A. Yes. As mentioned earlier in this section and as supported by the Aon survey results, LTI is designed to attract and retain executive talent. LTI awards are a common element of compensation at key management levels of organizations throughout the United States, including major utilities and, as such, the costs should be allowed for ratemaking purposes. These LTI awards allow NiSource and the Company to attract and retain individuals at executive levels. It would be difficult for NiSource to accomplish this objective without this element of compensation.

Q. Please explain how NiSource awards LTI.

A. LTI is part of the Company's total rewards package and was in place during the current test year. Performance Share Units and Restricted Stock Units are granted to employees at the level of Vice President and above. Performance shares are vested after achieving specific performance goals that include customer, safety, environmental, diversity, cumulative net operating earnings per share, and relative total shareholder return. Restricted Stock Units are vested based upon achievement of individual conditions as outlined in an award agreement, which includes restrictions based upon the continued service of the employee.

Q. Do the Company's LTI awards provide customer benefits?

A. Yes. As mentioned above, a portion of the LTI awards are directly tied to the achievement of customer, safety, environmental, diversity, and financial goals. For the reasons I have previously described, LTI is a key component of the Company's total rewards program. If the Company is to provide high-quality service to its customers, it is imperative that it be able to attract and retain high quality talent, and to do so, all aspects of the total rewards package, including LTI for executive level employees, must be competitive with other industry employers. If not, the Company places itself at high risk of losing talent to competitors. This would create a loss of valuable skills and would have a significant financial impact in the form of turnover costs, which would ultimately be borne by the Company's customers. It also would have an impact on safety and customer service goals, as less experienced leaders could be brought into the organization.

Q. What are the customer, safety, environmental, and diversity goals?

A. The Company recognizes that the award of LTI should not be based upon financial metrics alone, but should also include the achievement of goals that are beneficial to customers. Non-financial goals include customer, safety, environmental, and diversity. Examples of goals included in the LTI program are: top decile results in the National Safety Council Barometer Survey, top quartile performance in the J.D. Power Gas Utility and Electric Residential Customer Satisfaction Studies, reduce greenhouse gas emissions, and improve diversity of the workforce.

Q. Has CKY included long-term incentive plan costs in the budget?

A. Yes. As it is an important piece to overall compensation earned by CKY employees, long-term incentive compensation is included in the test year expenses. Columbia Witnesses Susan Taylor and Chun-Yi Lai support Columbia's proposed test year expense for long-term incentive compensation.

Q. Does the Company have a Profit Sharing Plan?

A. Yes. As part of the total rewards package, the Profit Sharing Plan is an element of the Company's Retirement Savings Plan and, as such, supports employees' saving for retirement. Company contributions for Profit Sharing are deposited into employees' Retirement Savings Plan accounts, which provide an important element of employee savings. The Profit Sharing Plan supplements employees' contributions to their retirement accounts. These contributions to the Retirement Savings Plan have become even more important as more traditional elements of retirement savings, including defined benefit plans, are no longer offered to exempt new hires on or after January 1, 2010, and non-exempt new hires on or after January 1, 2013. Absent these contributions, the Company would have to make other adjustments to its compensation package, such as increases to base pay, to remain competitive in the market for quality employees. As an element of a balanced competitive benefits program, the cost of profit sharing contributions into the Retirement Savings Plan should be allowed for ratemaking purposes.

Q. Has CKY included profit sharing plan costs in the budget?

A. Yes. As it is an important piece to overall compensation earned by CKY employees, profit sharing is included in test year expenses. Columbia Witnesses Susan Taylor and Chun-Yi Lai support Columbia's proposed test year expense for profit sharing costs.

VII. DETAIL OF COMPARATIVE COMPENSATION ANALYSES

Q. Has CKY performed a comparative analysis to demonstrate the reasonableness of its salaries/ wages and total cash compensation levels?

A. Yes. As mentioned previously, gas utility and general industry data was used to allow for comparison between CKY and NCSC's compensation in the relevant labor markets. Reasonable compensation is defined as salaries/wages and total cash compensation levels being within +/-10% of market based salaries/wages and total cash compensation. The following analyses show that compensation levels for CKY and NCSC are reasonable when compared with other regional utilities and general industry employers.

Q. What source material did you rely upon preparing these analyses?

A. I used utility and general industry surveys that provided survey job descriptions, a list of participating organizations, a variety of levels in multiple functional areas, clearly defined data elements (base salary, total cash) and appropriate scope data (geographic location, industry, etc.). The survey data, as outlined below, is relied upon by the Company to establish market-driven base pay on an ongoing basis.

A. <u>Comparative Analysis for Union Employee Wages</u>

Q. Please review the comparative analysis that was performed in relation to union total cash compensation.

A. Attachment KKC-1, CKY Union Wage Analysis, provides the Company's average hourly rates and hourly rates including cash incentive compensation compared to the average hourly rates and average hourly rate including cash incentive compensation paid by employers in the Southeast.

Q. What source material was used in creating Attachment KKC-1?

A. The American Gas Association ("AGA"), Mercer ("MBD"), and Willis Towers Watson General Industry Compensation Survey Results ("CSR") salary surveys were the basis for Attachment KKC-1. These surveys provide competitive salary information by region for comparable jobs and reasonably represent the labor market for which CKY competes for skilled employees.

Q. Is this the type of material generally relied upon by compensation professionals?

A. Yes. These surveys are regarded as reliable survey sources that provide salary information for comparable Company jobs.

Q. How did you determine which Company jobs to include in the analysis in Attachment KKC-1?

A. The criteria of the analysis was that each Company job had to have multiple incumbents and had to have a valid survey match to a Southeast job included within the survey data. All jobs that met the criteria of the analysis were included.

Q. What were the results of your analysis contained in Attachment KKC-1?

A. Attachment KKC-1 demonstrates that the average hourly rate paid by the Company is $35.62, with the average hourly rate including cash incentive compensation at $36.47, as compared to an average hourly rate of $35.34 paid by employers located in the Southeast, with the average hourly rate including cash incentives at $36.58. When compared based upon the average hourly rate, the Company's union wages are in line with the average for the Southeast. If computed on an hourly basis with incentive, the Company's total compensation is also very comparable to the average for the Southeast. In conclusion, Attachment KKC-1 demonstrates that CKY's union wages and cash compensation are within the appropriate range.

B. Comparative Analysis for Non-Union Compensation

Q. What source material was used in creating Attachment KKC-2 and Attachment KKC-3?

A. I relied on the AGA, MBD and Total Compensation for the Energy Sector, and Willis Towers Watson CSR Compensation Database surveys to develop Attachment KKC-2 and Attachment KKC-3. The surveys provide competitive salary information by region for jobs within the gas utility industry and the general industry. These surveys include salary information from the Southeast and North Central regions.

Q. Please review the comparative analyses performed in relation to non-union total cash compensation.

A. Attachment KKC-2, titled CKY Non-Union Salary Analysis, provides a comparison of CKY's average non-union base salaries and total cash compensation to the average base salaries and total cash compensation of utility and general industry employers in the Southeast United States.

Q. What were the results of your analysis?

A. Attachment KKC-2 shows that the average annual base salary paid by the Company for study positions is $96,584, with total cash compensation of $99,776, as compared to an average base salary of $90,280 paid by employers in the Southeast, with average total cash compensation of

$97,010. When compared based on base salary and total cash compensation, the Company is paying near competitive levels for utilities and general industries in the Southeast. Specifically, the Company is 7 percent above the market in base pay and 2.9 percent above in total cash compensation.

Q. Please describe Attachment KKC-3, titled NCSC Salary Analysis.

A. I analyzed the salaries for non-union NCSC staff as compared to utility and general industry salaries in the North Central region. Attachment KKC-3 compares average NCSC staff base salaries and total cash compensation to the average salaries and total cash compensation of North Central utility and general industry companies.

Q. Why did you include the North Central region in your analysis?

A. The reason for the comparison to the North Central region is that a large number of NCSC positions are staffed either in Merrillville, Indiana or in Columbus, Ohio, which are both included in the North Central region data.

Q. What conclusions can be drawn from Attachment KKC-3?

A. Attachment KKC-3 shows that the average annual base salary paid by NCSC for the study positions is $74,832, and total cash compensation was $77,643. The average base salary paid by North Central employers is

$78,262, and total cash compensation was $84,640. NCSC base salaries were 4.4 percent below and total cash compensation was 8.3 percent below companies in the North Central region.

C. <u>Performance Adjustments (Merit Increases)</u>

Q. Have the Company and NCSC granted or planned to grant performance adjustments to non-union employees in 2021 and 2022, and are these costs included in the cost of service?

A. Non-union employees of the Company and NCSC received an annual merit increase in 2021. In 2021, the merit increase for exempt and non-exempt, non-union employees was 3.0 percent (see Attachment KKC-4). This increase was effective March 1, 2021. The Company budgeted a merit increase in 2022 for non-union employees. In 2022, the merit increase for exempt and non-exempt non-union employees is budgeted at 3.0 percent on March 1, 2022.

Q. Please explain Attachment KKC-4 (Non-Union/Merit Increase Market Data).

A. Attachment KKC-4 provides a comparison between the Company's merit increases, as a percent of base pay, for non-union employees in 2020 and 2021, and those for other utilities and general industry employers. The data is categorized nationally and regionally. 2022 data is not yet available.

Q. **What data source did you rely upon in creating Attachment KKC-3?**

A. I relied upon two survey sources that covered a large number of companies within the utility and general industry sectors, provided data for the Midwest and Southeast regions, and provided median merit increase information. These surveys were the 2020-2021 Salary Budget Survey by WorldatWork and 2020-2021 Salary Increase and Turnover Study by Aon. The data was divided into industry groups and regions where available.

Q. **What results are demonstrated by Attachment KKC-4?**

A. Attachment KKC-4 demonstrates that the Company's merit increase in 2021 was 3.0 percent for exempt employees and non-exempt employees. For exempt and nonexempt employees in 2021, these increases were at market with other companies within the region and the utility industry. While 2022 merit increase data is not yet available, merit increases have been at 3% for the past decade, so the Company budgeted 3% for 2022.

VIII. EMPLOYEE BENEFITS

Q. What are the benefits offered by the Company to attract and retain qualified employees?

A. Benefits are an important component of any compensation structure and are necessary to ensure the Company is able to attract and retain qualified employees. The Company's benefit plans correspond to the plans offered throughout the NiSource system, including health and welfare plans (health care coverage, dental coverage, vision care, term life insurance and disability insurance), retirement savings plans, and paid time off (vacation, holiday and sick pay).

Q. How does the Company and NCSC ensure the reasonableness of its benefit offerings?

A. With regard to employee benefits, NCSC ensures the reasonableness of the level of such benefits by periodically comparing them, at an individual plan level and as a package, against the benefit programs of other employers. As part of this process, the benefits offered by the Company through its affiliation with NiSource are compared to the benefits offered at energy companies, including investor-owned utilities. The total value and the employer-paid portion of the benefits are rated on a standardized value scale that reflects the deviation of the NiSource primary benefit offerings from the average offered by other employers.

Q. Is it necessary to provide health care and dental coverage to employees?

A. Yes. Health care coverage, including dental care coverage, is important to Company employees and their families. The Company's experience has demonstrated that quality health care and dental coverage helps to attract and retain employees and encourages longevity with the Company. Therefore, health care and dental coverage plans are offered to all employees of the Company, from field personnel to executives.

Q. Does the Company incur its own health care and dental care costs or are these costs incurred by NCSC on behalf of the Company?

A. NCSC obtains health care coverage for Company employees and retirees.

Q. How does NCSC obtain such coverage?

A. Benefit coverage is competitively bid through a request-for-proposal process. Proposals are solicited from insurance carriers and/or third party administrators. These proposals are reviewed and finalists are selected based upon the financial stability of the carrier or third-party administrator, the breadth of its provider network, network provider discounts, administrative capabilities, and price. Finalists are interviewed and further negotiations take place regarding pricing for the services offered. Carriers and third-party administrators are selected based upon their ability to provide quality service in the most cost-efficient manner.

Q. How has the Company attempted to reduce and control its health care costs?

A. NCSC, on behalf of the Company, has undertaken many initiatives to limit the cost of providing health and dental care to Company employees. NCSC continues to review plan coverage and to search for more efficient ways to offer and administer plan coverage. More costly health care indemnity plans have been replaced with more efficient preferred provider organization ("PPO" and "High Deductible ("HD") PPO") plans, and the Company self-insures many of its plans, which reduces underwriting margins. Plans that offer coverage through provider networks are used as often as possible to take advantage of provider discounts. Opt-out credits are paid to those employees who have alternative health care coverage and elect not to participate in the plans. These credits are offered at a fraction of the cost that would otherwise be required to provide coverage for the employees who opt-out. Such programs have been offered to both union and non-union employees. Additionally, the Company offers two high deductible PPOs and a health savings account for participants in these two high deductible plans.

As with other parts of its business, the Company enjoys some purchasing power due to its affiliation with NiSource in order to ensure competitive rates from its carriers. In addition, corporate-wide programs offer a larger pool of covered participants, which provides for a larger spread of risk. The larger risk pool helps contain increases in health and dental care costs.

Q. How are costs of the health care plans determined?

A. NCSC engages a consultant to help determine the estimated cost of health care plans for the upcoming year. NCSC is self-insured, which means that the Company's actual plan experience is used to determine estimates of future costs.

The standard methodology used by the Company's consultant when projecting self-funded plan costs is described below. The consultant's methods represent general underwriting techniques and adjustments to methodology may be made in certain situations. Examples of situations that may result in an adjustment include changes to plan design, significant increases or decreases in the covered population due to acquisitions or divestitures, or when specific language is negotiated into a union collective bargaining agreement.

The Company’s consultant uses underwriting techniques, based on actuarial guidelines, to project the future plans’ costs for the self-funded plans. The key factor in projecting future results is the prior experience of a group, especially when the group consists of a large population. This experience is specific to NiSource’s entire covered population. The process of forecasting past claims experience into the future takes into account plan designs, trends and group credibility. These processes are widely accepted within the insurance market as the standard to establishing budget and premium levels that are appropriate to cover future risks.

As a starting point to developing the projection period working rates, the Company’s consultant collects monthly paid claims and enrollment for NiSource's medical and pharmacy self-funded plans from the appropriate vendors. They utilize the information provided by NiSource and/or the vendors to develop these budget projections. The average cost per enrolled employee is then calculated by dividing the total claims paid by the average number of enrolled employees in each plan offered by the Company.

Once the average claims costs per employee is calculated, claims costs are projected to the projection period by application of trend factors. The trend factors used in the projections fall within the framework established by the Actuarial Standards Board of the American Academy of Actuaries, which has responsibility for the development of actuarial standards of practice used by all professional organizations. The primary components of medical trend include the following:

- Inflation in unit prices for the same services
- Changes in utilization of the same services
- Out-of-pocket leveraging
- New technology/services (increases or decreases depending on the mix and cost of services)
- Cost shifting from public payors (Medicare and Medicaid) to private plan payors
- Population aging

Credibility reflects a degree of confidence and accuracy in using the past group's specific information in projecting future costs. A mixture of the size of the group and the period of time the data reflects determines a group's credibility. Generally, the larger the group and/or the longer the period of available historical information, the greater the degree of confidence and accuracy of using a past group's specific data to project the future costs. NiSource working rates are projected using experience based on over 3,000 member life years. This amount of experience is fully credible based on generally accepted actuarial guidelines. Higher margin levels are required for smaller groups since it is designed to cover the potential variation and volatility in actual cost relative to the projected costs.

The last step is the addition of the administrative fees to the projected claims costs. Administrative fees are typically paid on a per employee per month basis to the claims administrator and covers services such as claims processing, claims invoicing, and member services. This fee may also include a component for network access which allows NiSource to access the discount pricing that the claims administrator has negotiated with the various providers in the provider network. Minor additional fees may also be paid to other vendors for items including but not limited to case management and utilization management, government fees such as Transitional Reinsurance which sunset in 2017, other vendor fees for additional programs/services, and consulting services.

The combination of the administrative fees and trended claims costs allows for the establishment of rigorously estimated funding levels that are appropriate to cover the Company's future risks. These calculations are prepared using generally accepted actuarial methods and procedures and in accordance with the relevant Actuarial Standards of Practice.

Q. How has COVID-19 impacted the Company's health care costs?

A. The Company's health care costs in 2020 were lower than expected and a direct reflection of the COVID pandemic, consistent with what was occurring overall in the healthcare space with individuals postponing doctor visits and medical procedures. Currently, our expectations are that healthcare costs will resume to more normal ranges in the 2021and 2022 plan years.

Q. How does the Company assess how its employee benefit programs compare to other companies?

A. On behalf of the Company, NCSC through Aon performs a benefit index study to compare benefits at a program level and as a package against the benefit programs of a market basket of similar offerings at other employers. The standard Company benefit offerings are compared to the benefits offered at other energy companies, including investor-owned utilities, and against general industry companies. The most recent study was conducted in July 2019 by Aon.

Company employees share in a percentage-of-cost basis in the cost of the health plans made available to them. The percentage of the costs employees share is 25% for non-exempt non-union, while exempt employees pay 30% of the costs. For employees in the bargaining units, their percentage cost share is 25% and is subject to collect bargaining.

Q. What were the results of the latest Aon study regarding NiSource and the Company's benefits offerings?

A. The study shows that the overall employer-paid value of NiSource's benefits plans is 4.8 percent below the median of the selected energy industry cohort. The Company has concluded from the results of the study that its benefits are reasonable as compared with the offerings from other employers in the labor markets.

Q. Has the Company pursued any benefit cost containment measures?

A. The Company has pursued a number of cost containment measures. The Company has also increased PPO medical plan deductibles, co-pays and co-insurance and has actively promoted and increased enrollment in high deductible medical plans. The Company uses Anthem's, the company's benefits administrator, medical provider network for the PPO and

HDPPO self-insured plans. Anthem provides very competitive medical provider discounts compared to other national carriers. The Company has converted from a Final Average Pay pension formula to a less costly Account Balance pension formula. This conversion for nonexempt, non-union employees was effective January 1, 2013, and for union employees varies from January 1, 2013 through 2015. Exempt employees were converted on January 1, 2010. Pension and post-retiree medical and life insurance for the majority of new hires have been eliminated. This took place for exempt employees effective January 1, 2010, non-exempt nonunion effective January 1, 2013, and for union employees from January 1, 2011 through January 1, 2014.

Q. What is your conclusion about the competitiveness of the Company's compensation and benefits package?

A. As supported throughout my testimony and attachments, the Company's compensation and benefits are competitive when compared to the compensation at a similar group of employers.

IX. CONCLUSION

Q. Does this conclude your direct testimony?

A: Yes, however, I reserve the right to file rebuttal testimony.

ATTACHMENT KKC-1
CKY UNION WAGE ANALYSIS

Columbia Gas of Kentucky (CKY) Union Wage Analysis[1]
Comparison of CKY Union Hourly Rates & Incentives Paid to Utilities in the Southeast

Job Title (2)	CKY Hourly Rate (Average) (3)	CKY Hourly Rate Including Incentive (Average) (3), (4)	Survey Hourly Rate (Average) (5)	Survey Hourly Rate Including Incentive (Average) (4), (5)
Construction Coordinator	$38.14	$39.07	$37.42	$38.71
Customer Service A	$36.54	$37.46	$37.73	$38.54
Customer Service B	$34.77	$35.37	$32.87	$34.14
M&R Tech 1	$40.07	$41.02	$38.29	$40.20
M&R Tech 2	$37.88	$38.77	$37.89	$39.03
Plant/Service Combination	$38.09	$39.08	$38.53	$39.72
Street Service A	$34.72	$35.58	$33.17	$34.66
Utility A	$24.74	$25.39	$26.81	$27.65
Overall Average	$35.62	$36.47	$35.34	$36.58
% Above/(Below) Market			0.8%	-0.3%

Footnotes

(1) Columbia Gas of Kentucky Data as of 3/31/21

(2) These jobs were utilized because the Company had multiple incumbents matched to the NiSource job title on 3/31/2021.

(3) The average hourly rate was calculated by aggregating the hourly rates of all CKY employees matched to the NiSource job title and dividing it by the number of CKY employees matched to the title.

(4) Hourly rate including incentive equals base salary plus actual incentive paid to employees

(5) Survey data shown is from the 2019 Mercer Benchmark Database (MBD), Willis Towers Watson American Gas Association (AGA) and Willis Towers Watson General Industry Compensation Surveys Results (CSR) surveys. Survey data is aged to March 31, 2021 and includes companies from the Southeast region, which consists of the following states:
Mercer: Alabama, Arkansas, Florida, Georgia, Indiana, Kentucky, Mississippi, North Carolina, Ohio, South Carolina, Tennessee, West Virginia, and Virginia.
Willis Towers Watson: Kentucky, North Carolina, South Carolina, Tennessee, West Virginia, Florida, Alabama, Mississippi, and Georgia.

ATTACHMENT KKC-2
CKY NON-UNION
SALARY ANALYSIS

Columbia Gas of Kentucky (CKY) Non-Union Salary Analysis[1]
Comparison of CKY Non-Union Base Salaries & Total Cash Compensation to Survey Data in the Southeast

Job Title (2)	CKY Annual Base Salary (Average) (3)	CKY Annual Total Cash Compensation (Average) (3), (4)	Survey Annual Base Salary (Average) (5)	Survey Annual Total Cash Compensation (Average) (4), (5)
Assoc Field Eng 1	$75,133	$76,298	$70,411	$73,284
Coach On-The-Job Training 2	$92,300	$95,837	$86,057	$93,875
Construction Specialist	$91,537	$93,391	$85,629	$90,538
Crossbore Restoration Spec	$91,784	$93,641	$77,842	$80,517
Leader Field Operations	$97,913	$101,679	$97,714	$106,503
Leader Front Line Constr Serv	$101,284	$106,109	$97,714	$106,503
Sr Field Engineer	$126,135	$131,480	$116,593	$127,850
Overall Average	$96,584	$99,776	$90,280	$97,010
% Above/(Below) Market			7.0%	2.9%

Footnotes
(1) Columbia Gas of Kentucky Data as of 3/31/21
(2) These jobs were utilized because the Company had multiple incumbents matched to the NiSource job title on 3/31/21.
(3) The average annual base salary and total cash compensation were calculated by aggregating the annual base pay and total cash compensation of all CKY employees matched to the NiSource job title and dividing it by the number of CKY employees matched to the title.
(4) Total Cash Compensation equals base salary plus actual annual incentive.
(5) Survey data shown is from the 2019 Mercer Benchmark Database (MBD), Willis Towers Watson American Gas Association (AGA) and Willis Towers Watson General Industry Compensation Surveys Results (CSR) surveys. Survey data is aged to March 31, 2021 and includes companies from the Southeast region, which consists of the following states:
Mercer: Alabama, Arkansas, Florida, Georgia, Indiana, Kentucky, Mississippi, North Carolina, Ohio, South Carolina, Tennessee, West Virginia, and Virginia.
Willis Towers Watson: Kentucky, North Carolina, South Carolina, Tennessee, West Virginia, Florida, Alabama, Mississippi, and Georgia. Data is not available specific to a state.

ATTACHMENT KKC-3
NCSC SALARY ANALYSIS

NiSource Corporate Service Company (NCSC) Salary Analysis[1]
Comparison of NCSC Base Salaries & Total Cash Compensation to Survey Data in the North Central Region

Job Title (2)	NCSC: Annual Base Salary (Average) (3)	NCSC: Annual Total Cash Compensation (Average) (3) (4)	North Central Region (5): Annual Base Salary (Average)	North Central Region (5): Annual Total Cash Compensation (Average) (4)
Assigner 1	$49,756	$50,991	$56,571	$60,827
Communications Mgr	$100,200	$104,814	$108,307	$113,962
Customer Service Rep 1	$32,726	$33,264	$40,691	$41,899
Customer Service Rep 2	$35,811	$36,423	$40,691	$41,899
Customer Service Rep 4	$45,344	$46,184	$40,691	$41,899
Executive Admin Assistant	$70,665	$72,104	$66,660	$68,470
HR Coordinator	$45,005	$45,977	$56,328	$58,018
Lead Financial Analyst	$98,774	$102,878	$109,141	$119,925
Lead Regulatory Analyst	$98,186	$102,713	$109,141	$119,925
Principal Engineer	$124,394	$129,101	$99,909	$108,895
Quality Assurance Specialist	$50,686	$51,622	$60,800	$64,546
Remote Customer Service Rep	$30,548	$30,648	$40,691	$41,899
Sr Counsel	$167,021	$177,928	$152,560	$178,882
Sr Customer Service Rep	$43,827	$44,709	$44,765	$46,995
Sr Financial Analyst	$77,163	$80,070	$81,433	$86,838
Sr HR Consultant	$99,622	$104,274	$109,802	$119,792
Team Leader CCC	$60,588	$62,609	$79,269	$86,360
Technical Support Specialist 2	$99,428	$103,401	$104,639	$113,734
Technical Trainer 2	$92,060	$95,498	$84,888	$93,397
Overall Average	$74,832	$77,643	$78,262	$84,640
% Above/(Below) Market - North Central			-4.4%	-8.3%

Footnotes

(1) NiSource Corporate Service Company Data as of 3/31/21

(2) These jobs were utilized because the Company had multiple incumbents matched to the NiSource job title on 3/31/21.

(3) The average annual base salary and total cash compensation were calculated by aggregating the annual base pay and total cash compensation of all NCSC employees matched to the NiSource job title and dividing it by the number of NCSC employees matched to the title.

(4) Total Cash Compensation equals base salary plus actual annual Incentive

(5) Survey data shown is from the 2019 Mercer Benchmark Database (MBD), US Mercer Total Compensation Survey for the Energy Sector (MTCS), Willis Towers Watson American Gas Association (AGA), Willis Towers Watson General Industry Compensation Surveys Results (CSR), and Willis Towers Watson CDB General Industry Compensation Survey surveys. Survey data is aged to March 31, 2021 and includes companies from the North Central region, which consists of the following states (this regional data was used because this region contains a majority of the NCSC employees):
Mercer: Iowa, Illinois, Indiana, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, Nebraska, North Dakota, Ohio, South Dakota, West Virginia, Wisconsin and Wyoming
Willis Towers Watson: Idaho, Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Montana, Nebraska, North Dakota, Ohio, South Dakota, Wisconsin and Wyoming.

ATTACHMENT KKC-4
MERIT MARKET DATA

Columbia Gas of Kentucky (CKY) Non-Union Merit Increase Market Data

	Actual 2020 % Merit Increase (Median)	Projected 2021 % Merit Increase (Median)
2020-2021 WorldatWork Salary Budget Survey		
National		
Officers & Executives	3.0%	3.0%
Exempt Salaried	3.0%	3.0%
Non-Exempt Salaried	3.0%	3.0%
Non-Exempt Hourly Nonunion	3.0%	3.0%
Utilities		
Officers & Executives	3.0%	3.0%
Exempt Salaried	3.0%	3.0%
Non-Exempt Salaried	3.0%	3.0%
Non-Exempt Hourly Nonunion	3.0%	3.0%
2020-2021 Salary Increase and Turnover Study - AON		
National	(Excluding Zeros)	
Executives	3.2%	3.0%
Management	3.1%	3.0%
Professional- Individual Contributor	3.0%	3.0%
Support - Individual Contributor	3.0%	2.9%
Hourly	2.9%	2.9%
Utilities		
Executives	3.5%	2.9%
Management	2.9%	2.8%
Professional- Individual Contributor	2.9%	2.7%
Support - Individual Contributor	2.9%	2.8%
Hourly	2.8%	2.8%
Central/Midwest States (Includes OH, IN, MI, IL, MO, IA, MIN, WI, KS, NE, SD, ND)		
Executives	3.2%	3.0%
Management	3.0%	2.9%
Professional- Individual Contributor	3.0%	2.9%
Support - Individual Contributor	2.9%	2.9%
Hourly	2.9%	2.9%
Southeast States (Includes KY, TN, NC, SC, GA, AL, FL, MS, LA, AR)		
Executives	3.1%	2.9%
Management	3.0%	2.9%
Professional- Individual Contributor	2.8%	2.9%
Support - Individual Contributor	2.8%	2.9%
Hourly	2.6%	2.8%
NiSource	**Actual**	**Actual**
Executive	0.0%	3.0%
Director	0.0%	3.0%
All Other Exempt	3.0%	3.0%
Non-Exempt & Nonunion Hourly	3.0%	3.0%