BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:
In re: DOCKET NO. 20250029-GU

Petition for rate increase by
Peoples Gas & System, Inc.
_______________________________/

VOLUME 3
PAGES 586 - 823

PROCEEDINGS: HEARING

COMMISSIONERS
PARTICIPATING: CHAIRMAN MIKE LA ROSA
COMMISSIONER GARY F. CLARK
COMMISSIONER ANDREW GILES FAY
COMMISSIONER GABRIELLA PASSIDOMO SMITH

DATE: Tuesday, October 7, 2025

TIME: Commenced: 10:00 a.m.
Concluded: 10:30 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for
the State of Florida at Large

APPEARANCES: (As heretofore noted.)

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TALLAHASSEE, FLORIDA
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I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 2.)

(Whereupon, prefiled direct testimony of John Taylor was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250029-GU
IN RE: PETITION FOR RATE INCREASE
BY PEOPLES GAS SYSTEM, INC.

PREPARED DIRECT TESTIMONY AND EXHIBIT
OF
JOHN TAYLOR

ON BEHALF OF
PEOPLES GAS SYSTEM, INC.

DOCKET NO. 20250029-GU
FILED: 03/31/2025

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JOHN TAYLOR

ON BEHALF OF PEOPLES GAS SYSTEM, INC.

I. INTRODUCTION

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

A. My name is John D. Taylor, and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Peoples Gas System, Inc. ("Peoples" or the "company").

Q. By whom are you employed and in what capacity?

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner.

Q. Please describe your educational background and professional experience.

A. My professional experience and educational background are presented in Exhibit No. JT-1, Document No.6.

Q. What are the purposes of your prepared direct testimony in this proceeding?

A. The purposes of my prepared direct testimony are to present the embedded class cost of service study ("COSS"), discuss its results, present the proposed revenue increase apportionment, and discuss the rate design proposals filed by the company in this proceeding. My direct testimony consists of this introduction and summary section and the following additional sections:

- Embedded Class Cost of Service Study
- Principles of Sound Rate Design
- Proposed Consolidation of Existing Residential Rate Schedules
- Development of Proposed Class Revenues
- Proposed Rate Design
- Subsequent Year Adjustment

Q. Are you sponsoring any Minimum Filing Requirement ("MFR") Schedules?

A. Yes. I am sponsoring MFR Schedules E-1, E-2, E-4, E-5, E-

7, E-8, G-2 (Pages 09-11), H-1, H-2, and H-3.

Q. Please provide a summary of the MFR Schedules you are sponsoring.

A. A summary of the MFR Schedules I am sponsoring is provided below.

- E-1: This schedule summarizes sales and revenue computed using proposed rates and projected billing determinants.
- E-2: This schedule provides revenue calculation at present and proposed rates summarizing data shown within the E-1 schedules.
- E-4: This schedule demonstrates monthly sales for the historical years of 2021, 2022, 2023, 2024, and the projected test year 2026. It also shows the historical sales that occurred, by rate schedule, coincident with each historical peak month.
- E-5: This schedule illustrates monthly bill comparisons under present and proposed rates by rate class.
- E-7: This schedule develops the average meter set and service cost by the current and proposed rate classes.
- E-8: This schedule is used for documenting the direct assignment of facilities.
- G-2 Pages 9-11: This schedule provides the calculation

- for revenue and cost of gas under the proposed rates for the test year 2026.
- H Schedules: These schedules reflect the Florida Public Service Commission's ("Commission") provided MFR template for the COSS displaying the cost for providing service to each rate class.

Q. In addition to the MFR Schedules you listed, are you sponsoring any exhibits as part of your direct testimony?

A. Yes. I am sponsoring Exhibit JT-1, entitled "Exhibit of John Taylor" Document Nos. 1 through 6, prepared by me or under my direct supervision. The documents are as follows:

Document No. 1:	List of MFR Schedules Sponsored Or Co-Sponsored by John Taylor
Document No. 2:	Peak and Average Methodology Schedules H-1, H-2, and H-3 COSS based on the prior case methodology
Document No. 3:	Peoples' Allocation of Proposed Revenue Increase to Rate Classes
Document No. 4:	2027 Subsequent Year Adjustment Supplemental Schedules
Document No. 5:	Referenced Endnotes for the Prepared Direct Testimony of John Taylor

Document No. 6: Curriculum Vitae of John Taylor

II. EMBEDDED CLASS COST OF SERVICE STUDY

Q. What is the general purpose and use of a COSS in regulatory proceedings?

A. The purpose of a COSS is to allocate the local distribution company's ("LDC's") overall adjusted test year costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. The requirement to develop a COSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of gas throughput, while variable costs change directly with changes in gas throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains, service lines, meters, and regulators.

Finally, COSS provides insights into the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing

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costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each rate class, help determine the individual class revenue responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and energy developed in the COSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. Are there factors that influence a gas utility's overall cost allocation framework when performing a COSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation to allocate costs to customer groups. Cost causation addresses the question - which customer or group of customers causes the utility to incur particular costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The factors which can influence the cost allocation methods used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility. It is important to understand these considerations because they influence the overall context of a utility's cost of service study and indicate where efforts should be focused to conduct a more detailed analysis of the utility's gas system.

Q. Are cost of service studies an application of economic theory to cost allocation?

A. The allocation of costs using COSS is not a theoretical economic exercise. Rather, it is a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers and recover their operating expenses. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information in the COSS to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

Q. What principles are used in the allocation of common costs?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of cost causation. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a linkage between a LDC's customers and the particular costs incurred by the utility in serving those customers. An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off peak gas service.

Q. Why are the relationships between customer requirements, load profiles, and usage characteristics significant to cost causation?

A. The company's distribution system is designed to meet three primary objectives: (1) to extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate design day peak capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer-related costs are incurred to attach a customer to the distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand - or capacity-related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the company's requirements for serving their customers.

Commodity-related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity related to the extent they vary with the amount of gas volumes purchased by the company for its sales service customers.

Where costs are incurred for a customer or class of customers and can be so identified, direct assignment of costs can be utilized. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service.

III. PEOPLES' COSS

A. PROCESS STEPS AND STRUCTURE OF THE COSS

Q. Please describe the process of performing Peoples' COSS analysis.

A. In this case, the company prepared two COSS: (1) the Peak and Average Study and (2) the Customer/Demand Study. The Peak and Average Study was conducted in accordance with methods used in prior cases and is presented in Document No. 2 of my exhibit. The Customer/Demand Study reflects the company's proposed classification and allocation of mains investments, which I will discuss later in my direct testimony.

Q. Please describe the cost of service model utilized to develop the COSS?

A. The company used the Commission's required Excel-based cost of service model within the MFR H Schedules. The required cost of service model within the MFR H Schedules consists of several pages utilized to allocate various components of the company’s revenue requirements. The MFR H-1 Schedule summarizes the results of these allocations showing the current rate of return for each rate class and the revenue requirement at proposed rate of return.

Q. What was the source of the cost data analyzed in the COSS?

A. All cost of service data was extracted from the company’s total revenue requirement and schedules in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the company and information provided by company personnel.

Q. Please describe the organization of the COSS?

A. The COSS starts with the population of MFR Schedule H-3.

Within MFR Schedule H-3, all projected expenses (operating, maintenance, depreciation, amortization, income taxes, and taxes other than income taxes), rate base, and accumulated depreciation are listed by the Federal Energy Regulatory Commission general ledger and plant account classifier. MFR Schedule H-3 classifies costs as Customer, Capacity, and Commodity. Then, MFR Schedule H-2 allocates these classified costs to each rate class included in the COSS. MFR Schedule H-1 summarizes these allocations, illustrating the deficiency for each rate class and the current rate of return.

Q. Please describe the content of MFR Schedule H-1, which summarizes the results of the COSS?

A. The difference between the computed revenue requirement and the revenue that would be derived without making any rate changes equals the company's Net Operating Income deficiency, MFR Schedule H-1 Schedule D. The rate of return is determined by subtracting the revenue derived from each rate class from the expenses attributable to each rate class and then dividing the result by the rate base attributed to each rate class. MFR Schedule H-1 Schedule C within the Commission provided MFR H Schedule contains two pages. Page one contains the rate of return projected to be otherwise realized by rate class, absent a rate increase in the results for the projected test year. Page two shows the rate of return resulting from each rate class, providing the company's proposed revenue targets by rate class, further described in Section V below. Lastly, MFR Schedule H-1 Schedule A contains the company's proposed revenue targets by rate class, customer charge rates, and volumetric rates.

Q. How are the rate classes structured for purposes of conducting the cost of service model?

A. The rate classes in the COSS are structured based on customer characteristics, usage patterns, and system demand contributions. The company grouped customers into distinct rate classes to reflect similarities in cost causation and service requirements. These classes typically include Residential, Commercial, Industrial, and Interruptible Service categories, with further segmentation based on annual consumption levels or demand characteristics. This structure ensures that costs are allocated equitably among customer classes based on how they utilize the company's infrastructure and resources. Additionally, customers with negotiated rates are classified under the Special Contract customer class.

Q. Were direct assignments of plant made in the COSS?

A. Yes. A special study was performed to directly assign a portion of distribution plant installed to serve specific customers within SIS, IS, and SP classes. The costs related to these facilities from the various plant accounts were directly assigned to this class as shown on MFR Schedule H-3.

B. <u>DEVELOPMENT OF WEIGHTED CUSTOMER ALLOCATOR</u>

Q. Please discuss the development of the Weighted Customer Allocator.

A. The Meter-Regulators and Services studies are used to calculate the "Weighted Customer Allocator" that is being used to allocate some customer-related costs in the COSS. The weighted customer-related allocation factor is derived based on the results of Meter-Regulators and Services studies. It's a composite allocation factor that incorporates the unit costs for meters, regulators, and services into one factor and is applied to account balances to allocate costs to the customer classes.

Q. Please discuss the development of the Meter and Regulator study.

A. The study was developed using the quantities and types of meters installed per premise or rate schedule as the primary basis for analysis. However, historical cost data at the premise or rate schedule level was not available at that level. Since historical cost information was unavailable, the study instead utilized the estimated replacement cost of each meter type. The average meter and regulator replacement costs were then linked to the meter records dataset, which includes a comprehensive count of all meter types associated with each rate schedule.

Using this data, the study determined the total replacement cost for each customer class. The relative unit cost for each customer class was then developed. This process allowed for an accurate allocation of costs and ensured that each customer class was assigned an appropriate share of the total cost of meters and regulators.

Q. Please discuss the development of the Service Study.

A. The Service Study was developed by allocating investment in service lines to customer classes based on the number of customers, with weighting factors applied to account for relative differences in unit investment cost and service line length. The investment incurred to connect customers is determined by the average service line length and the unit cost per foot of service line.

To ensure accuracy, service lines were categorized into three groups based on diameter: (1) small services, which included diameters of up to one inch; (2) medium services, which included diameters between one and two inches; (3) large services, which included service lines with diameters over two inches. The original cost data for service lines was indexed to current dollars (2024) using the Handy-Whitman Index for the South Atlantic Region. This adjustment ensured that all costs reflected replacement cost values rather than historical costs.

Customers were then grouped based on meter size into small meters, medium meters, and industrial meters. Service unit costs were applied to the number of customers in each group to calculate the total estimated service costs by customer class and the corresponding cost per customer. The unit costs for meters, regulators, and services were added to derive the total unit cost. The relative weighting factor was then calculated using the Residential Class as a baseline. This factor was then

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multiplied by the test year customer count for each customer class to derive the final allocation factors.

C. <u>CLASSIFICATION AND ALLOCATION OF DISTRIBUTION MAINS</u>

Q. How does the company categorize investment in Distribution Mains for purposes of COSS analysis?

A. Following the approach from the prior rate case, for purposes of COSS analysis the company categorizes its investment in Distribution Mains into three primary groups based on pipe diameter: Small, Medium, and Large Diameter Mains. This categorization allows for a more accurate allocation of costs, ensuring that customer classes are charged in proportion to their usage and the infrastructure required to serve them.

To determine the appropriate categorization, the company calculates the total investment cost for each category by multiplying the estimated unit cost per foot (utilizing actual book investment costs) by the total length of mains within that size classification. The study findings indicate that approximately 40 percent of the total mains investment is attributed to small diameter mains, 21 percent to medium and 39 percent to large diameter mains.

The classification system also aligns with cost causation principles by recognizing that different customer groups place varying demands on the distribution system. Smaller diameter mains primarily serve residential and small commercial customers, providing localized distribution, whereas medium-sized mains act as intermediaries between transmission pipelines and neighborhood distribution networks, serving both residential, small commercial, and larger commercial and industrial users. The largest diameter mains function as the backbone of the distribution system, delivering capacity and reliability for high-demand areas and ensuring overall system integrity. By structuring the allocations in this manner, the company ensures that costs are assigned fairly and proportionally to each customer class based on their use of the system.

Q. How did the company's COSS classify and allocate investment in Distribution Mains?

A. As discussed above, the company conducted two sets of COSS analyses to evaluate the classification and allocation of distribution mains investment. Consistent with past filings, the company presented a study using the Peak and Average methodology for allocating distribution mains for informational purposes as shown on Document No. 2 of my exhibit. However, the company is proposing a shift toward a Customer/Demand classification and allocation methodology to refine cost allocation to better match cost causation.

Since this represents a new approach for the company, the company proposes to implement the Customer/Demand classification and allocation methodology only to small diameter mains while continuing to allocate larger diameter mains using the Peak and Average method.

In the Customer/Demand COSS, small diameter mains are classified as 48 percent customer-related and 52 percent demand-related, as further detailed in my direct testimony. The customer-related portion is allocated based on the number of customers, while the demand-related portion is allocated according to peak period requirements.

Q. Were there any other differences in methodology between the Peak and Average and Customer/Demand Studies proposed in this case?

A. No. The only difference between the studies is the application of the distribution mains allocation factors and their impact on the calculation of related allocation factors.

Q. Please discuss the primary difference between the two methods.

A. The use of a commodity-based allocation factor (such as the Peak and Average Method) assigns more cost to higher load factor customers and less cost to lower load factor customers. On most gas distribution systems, the result of such an allocation is to reduce costs for residential customers and increase costs for industrial or large volume customers. The rationale for using a commodity-based allocation factor, usually discussed by cost analysts supporting such a method, is that the gas distribution system would not be built if it were not for customers' commodity consumption throughout the year. Their argument relies upon the "annual gas delivery function" concept; a notion that a gas distribution utility delivers a gas commodity through its distribution system throughout the year. These cost analysts view the "annual gas delivery function" as the reason for the existence of gas distribution utilities, and it is the reason why those facilities were originally installed.

They then conclude that the allocation of costs using cost causation principles should match the use of the system across the year regardless of how that usage relates to specific investments. While it is obvious that all customers utilize the utility’s gas distribution system to receive delivery service throughout the year, that fact provides little to no insight into the manner in which the utility actually incurs costs to provide such service. In reality, there are two cost factors that influence the level of distribution mains installed by an LDC. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the LDC's gas system by its customers. Second, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the LDC.

Q. Is annual throughput a reasonable basis for assigning costs to a gas utility’s customers?

A. No. In my opinion, there is no cost causative basis for using annual throughput to allocate the costs of a gas utility such as Peoples, to its classes of service. It is easy to demonstrate from a number of different considerations that throughput does not cause distribution main costs. First, there is the regulatory test: whenever costs are related to throughput, regulators recognize that the level of those costs must be adjusted for the test year in the rate case to normalize the costs for weather. If distribution main costs were a function of throughput, there would be a weather normalization adjustment required to determine the test year level of costs to be included in the utility's rates. There is no regulatory body that adjusts the cost of distribution mains for normal weather because no one can demonstrate that mains cost varies with throughput. Second, there is a logical argument that proves no distribution main costs are caused by throughput. Once this amount of capacity is installed, the costs are fixed and do not change for any amount of gas flowing through the utility's gas system on any other days. So long as the design day requirements of the system do not change and no new customers are added to the system, the cost for mains will not change regardless of the annual changes in throughput that result from weather and conservation. A simple example will illustrate this fundamental principle. Consider two customers that impose the same design day demand on the gas utility's distribution system but have different annual load factors. To serve the identical demand or capacity requirements of these customers, the gas utility must provide sufficient distribution mains capacity for each based on the design characteristics of their loads. Therefore, the demand-related costs are the same to serve these two customers because their design day demands are the same. However, each customer would be allocated a different level of costs if an annual throughput allocation factor was used. This occurs because the customer with the higher load factor (and higher annual usage) would receive a greater share of costs relative to the customer with the lower load factor (and lower annual usage). In effect, the customer with a high load factor, who is using the company's gas system most efficiently, is penalized for his efficiency.

Q. Is the method used by the company to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes. Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners ("NARUC"), and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities. The use of a customer component for distribution facilities, particularly distribution mains, is a widely accepted approach in the gas industry.

The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and (2) the most commonly installed, minimum-sized unit of plant investment.

Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the LDC's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of the customer's peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system.

For purposes of determining the customer component of distribution mains to be used in Peoples' COSS, the zero-intercept method was utilized. The zero-intercept method resulted in a 48 percent customer component.

Q. Would one expect there to be a strong correlation between the number of customers served by Peoples and the cost of its system of distribution mains?

A. Yes. Development of the company's distribution system over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of Peoples distribution mains facilities, it is appropriate to analyze the cost causation factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a zero-intercept approach for classifying distribution mains simply reflects the fact that the average customer serviced by the company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by Peoples represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and separate cost category that has much support from an engineering and operating standpoint.

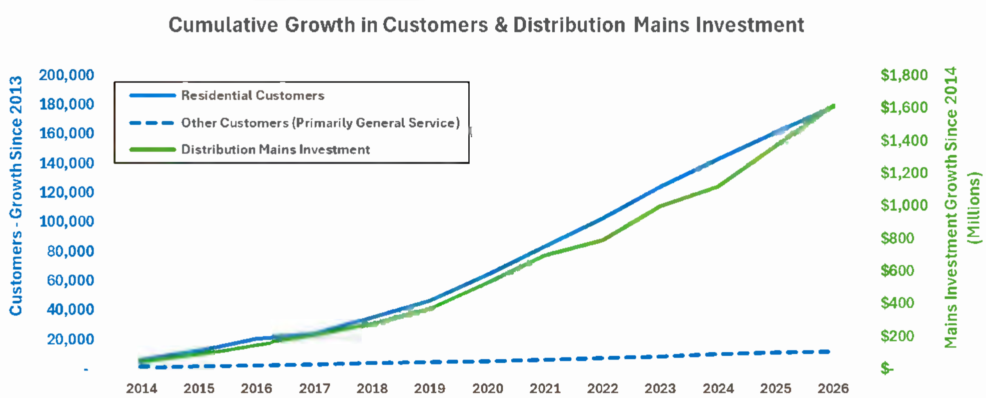
Q. Have you analyzed the relationship between the number of customers served by Peoples and its level of investment in distribution mains?

A. Yes. I analyzed both customer growth and the investment in distribution mains. The results of the analysis are presented in Table 1 below. The graph illustrates the relationship between customer growth and distribution mains investment over the 12-year period from 2014 to 2026. The two primary customer segments — Residential Customers and Other Customers (Primarily General Service), show a steady increase in investment and customer count, with residential customers experiencing the most significant growth. It is important to note that the correlation coefficient between mains investment and customer growth is 0.99.

The Total Distribution Mains investment closely follows the trend of customer growth, indicating that infrastructure expansion has been aligned with rising customer segment. This suggests that as more customers were added, there was a proportional increase in investment to support the necessary distribution infrastructure.

This data underscores a strong correlation between customer growth—primarily in the residential sector—and the ongoing investment in distribution mains, ensuring reliability and capacity for future expansion.

Table 1 – Customer Growth and Distribution Mains Investments



Q. How does this analysis support the company's proposal to introduce customer components in the classification of the distribution mains?

A. The analysis highlights a strong correlation between customer growth and investment in distribution mains, demonstrating that as the number of customers increases, so too does the total investment in infrastructure. This relationship highlights how customer expansion drives mains investment rather than being driven solely by peak demand or annual usage. This relationship highlights how customer expansion drives mains investment rather than being driven solely by peak demand or annual usage.

Among all customer segments, residential customers exhibit the most significant growth, aligning closely with increases in distribution mains investment. This trend suggests that a substantial portion of mains investment relates to connecting customers rather than merely accommodating higher consumption levels. The infrastructure expansion, therefore, is not just a response to increased gas usage but a direct function of growing customer numbers.

This observed relationship supports the argument that part of the cost of distribution mains is properly classified as customer-related.

The expansion of the distribution network is primarily driven by the need to connect new customers, rather than just ensuring capacity for peak demand or to serve average annual usage. This approach aligns with regulatory principles that emphasize cost causation—allocating costs based on what drives the investment in the first place.

Recognizing that customer growth, particularly in the residential sector, is a key driver of distribution mains expansion, the analysis makes a compelling case for introducing a customer component in cost allocation. This classification ensures a fairer distribution of costs, particularly for small-diameter mains, which are predominantly installed to serve new residential customers. By incorporating a customer component into the classification of distribution mains, the study provides a more accurate reflection of the underlying cost drivers and supports a more equitable rate structure.

D. OPERATION & MAINTENANCE, CUSTOMER ACCOUNTS & SERVICES, AND ADMINISTRATIVE & GENERAL EXPENSES

Q. How were operations and maintenance ("O&M") expenses classified and allocated in the COSS?

A. Generally, the classification and allocation of the O&M expenses followed the treatment of the related plant accounts. For example, the treatment of FERC Account 879 (Customer Installations Expense), was allocated using the weighted customer allocation factor. Similarly, FERC Account 874 (Mains and Services Expenses) was allocated based on the allocation methodology applied to the Plant accounts for Mains and Services. This approach ensures that O&M expenses are assigned in a manner consistent with cost causation principles and the underlying infrastructure they support.

Q. Please describe the classification and allocation of customer accounts and customer service expenses in the COSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class. One exception to this treatment was FERC Account 904 (Uncollectible Accounts). Uncollectible Accounts expenses were assigned to the customer classes based on number of customers, reflecting historical uncollectible expense trends.

Q. Please explain the treatment of Administrative and General ("A&G") expenses in the COSS.

A. The majority of the A&G expenses were classified and allocated based on the internally generated allocation factor of total O&M expenses. Taxes Other than Income Taxes and their corresponding allocation basis include Property taxes, and Payroll, and Other taxes. Income taxes were allocated based on rate base.

E. <u>COST OF SERVICE RESULTS</u>

Q. Please summarize the results of the company's proposed COSS.

A. Table 2 below presents a summary of the results of the COSS. The COSS shows an overall revenue requirement of $579.9 million and a deficiency of $103.6 million

Table 2 - Summary Results Proposed COSS

Line No.	Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve	Current Rate of Return	Current Relative Rate of Return	Current Revenue to Cost Ratio	Current Parity Ratio
1	Residential	$ 187,866,055	$ 260,823,871	$ (72,957,816)	38.8%	2.5%	0.51	0.72	0.88
2	Residential Standby Generators	568,576	756,354	(187,778)	33.0%	3.1%	0.63	0.75	0.92
3	Residential Heat Pump	1,839	3,835	(1,996)	108.5%	-0.2%	(0.04)	0.48	0.58
4	Commercial Heat Pump	16,034	14,982	1,052	-6.6%	9.0%	1.82	1.07	1.30
5	Commercial Street Lighting	214,317	153,796	60,521	-28.2%	13.7%	2.75	1.39	1.70
6	Small General Service	12,627,843	15,443,063	(2,815,220)	22.3%	4.9%	0.98	0.82	1.00
7	General Service - 1	64,774,046	63,304,152	1,469,894	-2.3%	8.3%	1.67	1.02	1.25
8	General Service - 2	69,070,292	74,022,081	(4,951,789)	7.2%	7.0%	1.40	0.93	1.14
9	General Service - 3	33,353,034	36,806,156	(3,453,122)	10.4%	6.6%	1.32	0.91	1.10
10	General Service - 4	15,587,462	20,153,213	(4,565,751)	29.3%	4.7%	0.94	0.77	0.94
11	General Service - 5	39,036,466	52,106,046	(13,069,580)	33.5%	4.3%	0.87	0.75	0.91
12	Commercial Standby Generators	958,224	1,715,984	(757,761)	79.1%	0.6%	0.11	0.56	0.68
13	Small Interruptible Service	5,638,148	7,049,789	(1,411,641)	25.0%	5.1%	1.02	0.80	0.97
14	Interruptible Service	8,295,277	10,331,387	(2,036,110)	24.5%	5.1%	1.03	0.80	0.98
15	Wholesale	652,202	1,231,838	(579,636)	88.9%	1.0%	0.21	0.53	0.64
16	Special Contract	37,695,908	36,028,352	1,667,556	-4.4%	8.6%	1.74	1.05	1.27
17	**Total System**	**$ 476,355,723**	**$ 579,944,901**	**$ (103,589,178)**	**21.7%**	**5.0%**	**1.00**	**0.82**	**1.00**

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Table 2 presents the revenue deficiency/(surplus) for each rate class and the class rate of return on the net rate base at present rates. As shown on Table 2 the resulting rate class revenue levels, as measured under a revenue-to-cost ("R:C") ratio (at the proposed system rate of return) and parity ratio (at the current system rate of return), show that the majority of the rate classes are being charged rates that recover less than their indicated cost of service. Only Commercial Heat Pump, Commercial Street Lighting, General Service 1, and Special Contract classes currently provide revenues in excess of their indicated cost of service at both the R:C ratio at the proposed system rate of return ("ROR") and the parity ratio at the current system ROR.

Q. Have you prepared a summary of COSS results prepared using methodology from the prior case.

A. Yes. Table 3 below summarizes results of COSS using methodology used in the prior case. As stated previously in my direct testimony, the methodology in the prior case classified distribution mains as capacity related only and allocated costs based on peak and average allocation factor. As the results demonstrate, despite refinements in methodology and adjustments to cost classification and allocation for distribution mains, the results remain fundamentally consistent with prior cases. The same customer classes continue to exhibit deficiencies, reaffirming the persistence of cost recovery imbalances.

Table 3 - Summary Results of COSS (Prior Case Methodology)

Line No.	Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve	Current Rate of Return	Current Relative Rate of Return	Current Revenue to Cost Ratio	Current Parity Ratio
1	Residential	$ 187,866,055	$ 225,555,231	$ (37,689,176)	20.1%	4.5%	0.90	0.83	1.01
2	Residential Standby Generators	568,576	639,408	(70,832)	12.5%	5.6%	1.13	0.89	1.08
3	Residential Heat Pump	1,839	4,542	(2,702)	146.9%	-1.3%	(0.26)	0.40	0.49
4	Commercial Heat Pump	16,034	19,481	(3,447)	21.5%	5.3%	1.06	0.82	1.00
5	Commercial Street Lighting	214,317	208,771	5,545	-2.6%	8.3%	1.68	1.03	1.25
6	Small General Service	12,627,843	15,250,978	(2,623,135)	20.8%	5.0%	1.01	0.83	1.01
7	General Service - 1	64,774,046	71,914,105	(7,140,059)	11.0%	6.4%	1.29	0.90	1.10
8	General Service - 2	69,070,292	88,112,959	(19,042,666)	27.6%	4.8%	0.96	0.78	0.95
9	General Service - 3	33,353,034	45,364,751	(12,011,717)	36.0%	4.1%	0.82	0.74	0.90
10	General Service - 4	15,587,462	25,640,893	(10,053,431)	64.5%	2.3%	0.46	0.61	0.74
11	General Service - 5	39,036,466	51,373,717	(12,337,251)	31.6%	4.5%	0.91	0.76	0.93
12	Commercial Standby Generators	958,224	1,679,077	(720,853)	75.2%	0.7%	0.14	0.57	0.69
13	Small Interruptible Service	5,638,148	6,951,544	(1,313,395)	23.3%	5.3%	1.06	0.81	0.99
14	Interruptible Service	8,295,277	10,196,703	(1,901,426)	22.9%	5.3%	1.07	0.81	0.99
15	Wholesale	652,202	1,471,486	(819,284)	125.6%	-0.2%	(0.03)	0.44	0.54
16	Special Contract	37,695,908	35,561,255	2,134,653	-5.7%	8.8%	1.78	1.06	1.29
17	**Total System**	**$ 476,355,723**	**$ 579,944,901**	**$ (103,589,178)**	**21.7%**	**5.0%**	**1.00**	**0.82**	**1.00**

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. What guiding principles inform Peoples' rate design proposals?

A. Peoples' rates seek to balance a number of policy objectives for its customers while providing the company the ability to recover its prudently incurred costs and an opportunity to earn its authorized ROR. The following rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in his work, Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate design proposals of Peoples and provides a roadmap that help guide utilities and regulators when considering how to achieve utility rates that are fair, efficient and practical. The foundation of rates should include:

- Fairness: Rates should be fair to all customer classes, avoiding undue discrimination.
- Efficiency: Rates should promote the efficient use of resources and encourage conservation while avoiding undue restriction of economic use.
- Simplicity: Rates should be simple and understandable for customers.
- Stability: Rates should provide revenue stability for the utility and bill stability for customers.
- Reflective of Costs: Rates should reflect the cost of providing service to different customer classes.
- Revenue Sufficiency: Rates should generate enough revenue to cover the utility’s costs, including a reasonable return on investment.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity, the rate design process must be, in part, influenced by judgmental evaluations.

Q. How did Peoples incorporate these principles in their vision of rate design?

A. In the context of these principles, the company envisions a rate design that aligns its revenue allocation and rate design with its cost of service (i.e., cost-based rates). In doing so, this will better ensure that customers are paying for their cost of energy services and result in rates that are more equitable and understandable, lead to more stable utility bills, and send the appropriate price signals to its customers, which also promotes rational conservation.

From the perspective of the customer, cost-based rates provide a more reliable means of determining future levels of natural gas costs. If rates are based on factors other than the cost to serve, it becomes much more difficult for customers to translate expected utility-wide cost changes, such as expected increases in overall revenue requirements, into changes in the rates charged to particular customer classes and to customers within the class. This situation reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for future energy costs.

From the perspective of the utility, when rates are closely tied to costs, the impact on the utility's revenues due to changes in customer use patterns will be minimized. Rates that are designed to track changes in the level of costs result in revenue changes that mirror cost changes. Thus, cost-based rates provide an important enhancement to a utility's earnings stability. A key element within cost-based rate design is a Straight-Fixed-Variable ("SFV") characteristic, which perfectly aligns fixed costs, costs that do not change with energy usage, with fixed charges and variable costs, costs that do change due to energy usage, with variable charges. An

SFV rate design would reduce volatility for both customers and the company. However, the company recognizes that movement to an SFV rate design is a departure from current practice and, at this time, is proposing higher fixed charges without full movement to an SFV rate design.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach to apportion Peoples' proposed revenue increase to its rate classes.

A. As discussed above, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines related to the design of utility rates. The various criteria that were considered in the process included: (1) class contribution to present revenue levels, (2) customer impact considerations, and (3) cost of service. These criteria were evaluated for the company's rate classes to facilitate the development of the proposed class revenue targets. The first step in this process is to analyze the current return and R:C ratios by each customer class (i.e., the amount of revenue Peoples is receiving in comparison to the costs to serve each customer class).

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Peoples interclass revenue proposal?

A. Yes. Using Peoples proposed revenue increase and the results of the COSS, Atrium evaluated a few options for the assignment of that increase among its customer classes and, in conjunction with Peoples personnel and management, ultimately decided upon one of those options as the preferred method. The first benchmark option I evaluated was to set revenues to the cost to serve for each rate class resulting from the methods employed in the Peoples Proposed COSS, as shown in Document No. 3 of my exhibit. Under this method, the revenue level for each customer class was set so that the revenue-to-cost for each class was equal to 1.00 (Unity). As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

A second option I considered was assigning the increase in revenues to Peoples' customer classes based on an equal percentage basis of its current non-gas revenues. By definition, this option resulted in each customer class receiving an increase in revenues. However, when this option was evaluated against the COSS results (as measured by changes in the R:C ratio for each customer class) there was no movement towards cost for most of Peoples' customer classes (i.e., there was no convergence of the resulting R:C ratios towards unity). While this option was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provides further guidance to develop Peoples' class revenue proposal.

Q. What was the result of this process?

A. To ensure a fair and balanced distribution of revenue adjustments across various customer classes, Peoples' is proposing an approach that takes into account the cost to serve each class while maintaining a degree of rate stability and gradualism. The principles guiding this revenue distribution approach are as follows:

- Principle 1: No Decreases to Any Classes - Ensuring that no customer class experiences a reduction in its revenue contribution prevents undue disruptions to the existing rate structure and helps maintain the financial stability of the system.

- Principle 2: No Increases Greater Than 1.5 Times the System Increase - To prevent any class from bearing a disproportionate burden of the overall revenue adjustment, rate increases are capped at 1.5 times the system-wide percentage increase.
- Principle 3: Bring All Classes to Their Cost to Serve If They Require Less Than 1.5 Times the System Increase - One of the core objectives of the revenue allocation process is to align each customer class's rates with its actual cost of service. If a class requires an increase lower than 1.5 times the system increase to reach its cost to serve, its rate adjustment is set to this cost-reflective level.
- Principle 4: Reallocate the Remaining Delta to Classes That Receive Less Than 1.5 Times the Increase - Any remaining revenue gap, after applying the above principles, is redistributed among the customer classes that have not yet reached the maximum allowable increase of 1.5 times the system increase.

This structured approach balances the need for cost-based rates with customer impact considerations, ensuring that rate adjustments are fair, sustainable, and aligned with industry best practices.

Table 4- Proposed Class Revenue Apportionment

Line No.	Customer Classes	Current Revenues	Proposed Revenue	Proposed Revenue Change	Proposed Percentage Change	Proposed Rate of Return	Proposed Revenue to Cost Ratio	Applied Principles
1	Residential	$ 187,866,055	$ 248,565,095	$ 60,699,040	32.3%	6.7%	0.95	Princ. 2
2	Residential Standby Generators	568,576	753,864	185,287	32.6%	7.5%	1.00	Princ. 2
3	Residential Heat Pump	1,839	2,449	610	33.1%	2.1%	0.64	Princ. 2
4	Commercial Heat Pump	16,034	16,792	758	4.7%	9.3%	1.12	Princ. 1 & 4
5	Commercial Street Lighting	214,317	224,460	10,143	4.7%	14.0%	1.46	Princ. 1 & 4
6	Small General Service	12,627,843	16,008,703	3,380,860	26.8%	8.2%	1.04	Princ. 3 & 4
7	General Service - 1	64,774,046	67,816,114	3,042,068	4.7%	8.6%	1.07	Princ. 1 & 4
8	General Service - 2	69,070,292	77,272,610	8,202,317	11.9%	8.2%	1.04	Princ. 3 & 4
9	General Service - 3	33,353,034	38,383,367	5,030,334	15.1%	8.2%	1.04	Princ. 3 & 4
10	General Service - 4	15,587,462	20,804,679	5,217,217	33.5%	8.0%	1.03	Princ. 2
11	General Service - 5	39,036,466	51,996,594	12,960,128	33.2%	7.5%	1.00	Princ. 2
12	Commercial Standby Generators	958,224	1,262,020	303,796	31.7%	3.3%	0.74	Princ. 2
13	Small Interruptible Service	5,638,148	7,513,852	1,875,704	33.3%	8.5%	1.07	Princ. 2
14	Interruptible Service	8,295,277	10,724,491	2,429,214	29.3%	8.1%	1.04	Princ. 3 & 4
15	Wholesale	652,202	857,626	205,424	31.5%	3.3%	0.70	Princ. 2
16	Special Contract	37,695,908	37,742,186	46,278	0.1%	8.3%	1.05	Princ. 1
17	**Total System**	**$ 476,355,723**	**$ 579,944,901**	**$ 103,589,178**	**21.7%**	**7.6%**	**1.00**	

Q. How do customer classes transition toward their cost of service under the proposed revenue distribution?

A. The proposed revenue apportionment follows a structured and measured approach to moving customer classes closer to their cost of service while mitigating potential rate shocks. As demonstrated in the summary Table 5 below, the adjustments are designed to ensure gradual progress toward cost parity rather than implementing abrupt changes that could create financial hardship for customers. A full and immediate alignment of rates with cost-to-serve would result in substantial increases for some customer classes, leading to significant bill impacts. To avoid this, the proposed distribution strategy incorporates a phased approach, balancing revenue recovery with rate stability.

Table 5 - Cost of Service and Rate of Return Under Present and Proposed Rates

Line No.	Customer Classes	Current Total Revenues	Total Revenues at Proposed	Current Return	Proposed Return	Current Revenue to Cost Parity Ratio	Proposed Revenue to Cost Parity Ratio
1	Residential	$ 187,866,055	$ 248,565,095	2.5%	6.7%	0.88	0.95
2	Residential Standby Generators	568,576	753,864	3.1%	7.5%	0.92	1.00
3	Residential Heat Pump	1,839	2,449	-0.2%	2.1%	0.58	0.64
4	Commercial Heat Pump	16,034	16,792	9.0%	9.3%	1.30	1.12
5	Commercial Street Lighting	214,317	224,460	13.7%	14.0%	1.70	1.46
6	Small General Service	12,627,843	16,008,703	4.9%	8.2%	1.00	1.04
7	General Service - 1	64,774,046	67,816,114	8.3%	8.6%	1.25	1.07
8	General Service - 2	69,070,292	77,272,610	7.0%	8.2%	1.14	1.04
9	General Service - 3	33,353,034	38,383,367	6.6%	8.2%	1.10	1.04
10	General Service - 4	15,587,462	20,804,679	4.7%	8.0%	0.94	1.03
11	General Service - 5	39,036,466	51,996,594	4.3%	7.5%	0.91	1.00
12	Commercial Standby Generators	958,224	1,262,020	0.6%	3.3%	0.68	0.74
13	Small Interruptible Service	5,638,148	7,513,852	5.1%	8.5%	0.97	1.07
14	Interruptible Service	8,295,277	10,724,491	5.1%	8.1%	0.98	1.04
15	Wholesale	652,202	857,626	1.0%	3.3%	0.64	0.70
16	Special Contract	37,695,908	37,742,186	8.6%	8.3%	1.27	1.05
17	**Total System**	**$ 476,355,723**	**$ 579,944,901**	**5.0%**	**7.6%**	**1.00**	**1.00**

VI. PROPOSED RATE DESIGN

A. RESIDENTIAL RATE SCHEDULE CONSOLIDATION

Q. Please summarize the proposed rate design.

A. The company proposes to consolidate its existing Residential-2 (RS-2) and Residential-3 (RS-3) customer classifications into a single, unified residential rate schedule. Additionally, the Residential-1 (RS-1) rate schedule will be closed to new customers. Consequently, all new residential customers connecting to Peoples' system will be automatically served under the newly established residential rate schedule.

Q. Please describe specifics around the proposal to close RS-1 rate schedule.

A. Peoples' proposal includes maintaining service for existing RS-1 customers under the current rate schedule while restricting any new customers from enrolling. Customers remaining on the RS-1 rate schedule will continue to receive service in accordance with existing tariff provisions, including an annual volume review to determine their eligibility. Once a customer is removed from the RS-1 rate schedule, whether due to changes in service requirements, relocation, or other qualifying events, they shall not be eligible for re-enrollment into this rate schedule.

Q. Why does the company propose to close the smallest residential classes to new customers?

A. The company's primary objective in rate consolidation is to move customers closer to their cost to serve by consolidating three residential rate schedules into one class and reduce intra-class subsidization. However, the initial analysis indicated that this approach would lead to significant bill increases for customers in the smaller usage categories. To prevent such bill impacts on these customers, the company has selected to take a phased approach, starting with closing the smallest residential class to new customers.

Q. Why is there a need to consolidate the existing three residential schedules?

A. The necessity to consolidate the three existing residential rate schedules (RS-1, RS-2, and RS-3) arises from several critical factors related to the economic and usage trends among residential customers.

There has been a consistent downward trend in the average Use Per Customer ("UPC"). This decline reduces the revenue generated from variable charges, which are based on the volume of gas consumed. As UPC decreases, so does the revenue from these charges, potentially leading to revenue shortfalls. Additionally, per Peoples' current policy of annual consumption review, more customers are being transferred to RS-1 and RS-2 than are transferred to RS-3. The customer charge for these classes has lower customer charge rates which contributes to continued cost under-recovery. This means that these customers are not contributing enough to cover the costs associated with providing service. The growth in customer numbers within the RS-1 and RS-2 classes, coupled with the under-recovery of fixed costs, indicates that the current rate structure fails to properly recover costs for providing services to these customers.

Peoples expects these trends of declining UPC and the mismatch in cost recovery will persist in the coming years. Without corrective measures, these financial imbalances are likely to continue. This projection necessitates action to prevent further financial imbalances across customers.

By consolidating these schedules into a single, more uniform rate structure, and determining appropriate cost responsibilities among classes, Peoples plans to modify rate design to better reflect the actual cost of service delivery. Overall, the company's proposal not only addresses the current revenue shortfall but also provides a more sustainable model for revenue collection in the face of ongoing consumption trends.

Q. Are there other considerations relating to the movement towards consolidating the residential rate classes?

A. The consolidation of residential rate classes by Peoples is based on the fact that the cost of providing gas service to residential customers is largely independent of their consumption levels. The primary cost of providing service to residential customers involves fixed infrastructure such as pipelines, meters, and maintenance. These costs are incurred whether a customer uses a little or a lot of gas. Similarly, the delivery of gas to each residential property involves similar activities regardless of consumption: meter reading, billing, customer service, and emergency response. These operational costs do not scale directly with usage volume but are more uniform across all customers.

The consolidation promotes fairness in cost distribution among customers, as different rates based on consumption do not necessarily reflect the true cost of service and provides more equitable rate designs, ensuring rates reflect actual service delivery costs.

B. <u>CUSTOMER CHARGES</u>

Q. Please describe the process to determine the proposed changes to the Customer Charges and the other rate components for the respective tariff schedules.

A. Once revenue targets per class are set, the process of determining the rate components for each tariff schedule begins with establishing the Customer Charge. Once the Customer Charge was set, the revenues to be recovered through this charge for each rate schedule were deducted. The remaining revenue requirement was then allocated to the Distribution Charge, which was calculated by dividing the remaining revenue by the projected sales volume under the applicable rate schedule. The detailed calculations for each rate schedule are provided in MFR Schedule G2-08.

Q. Please further discuss the importance of the Customer Charge component.

A. To properly recover fixed costs that the utility incurs to provide service to its customers, the Customer Charge component of each rate schedule needs to be set at or near the cost per customer component identified in the COSS.

The customer-based charge can be characterized as a connection charge for access to service. It is imperative that appropriate fixed costs be collected through the monthly charge in order to minimize intra-class subsidies

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and provide customers with the appropriate economic price signals. Increasing the Customer Charge to the amount identified as necessary to recover at least the customer-related fixed costs does not provide a disincentive to use energy wisely. Customers' conservation efforts are rewarded through lower bills because of lower energy consumption. Other benefits of better aligning cost recovery with cost causation include:

- Mitigating the impact of significantly colder or warmer than normal weather on customers' bills;
- Mitigating the impact abnormal weather has on the company's ability to recover fixed costs in the customers' regular monthly bills.;
- Providing more stability in residential customers' bills as a higher percentage of the total bill will be fixed each month and not subject to changes in weather; and
- Providing a better match of revenues to the investment made to serve each customer.

If fixed costs are not recovered from fixed charges, average or higher than average use customers subsidize low use customers, regardless of the reason a customer uses less gas than average.

Q. How were proposed monthly customer changes determined?

A. The proposed customer charge adjustments were determined by considering multiple factors. The customer-related unit cost, as calculated in MFR Schedule H-1, served as the baseline. The proposed customer charge for residential classes reflects a strategic effort to consolidate rate classes and ensure that fixed costs are more accurately recovered while considering bill impacts.

In general, the customer charge rates were adjusted to align more closely with the unit cost. Some classes received a monthly customer charge increase that was set at either the system-wide increase percentage or the class-specific percentage increase.

Table 6 below summarizes the results of the customer costs in the COSS and compares them to Peoples' current customer charges.

Table 6 – Customer Costs in COSS Compared to Peoples' Current Customer Charges

Line No.	Customer Classes	Current Basic Facilities Charge	Proposed Basic Facilities Charge	Customer Related Unit Cost
1	Residential - 1	$ 19.10	$ 26.50	
2	Residential - 2	$ 24.41	$ 35.50	$ 33.97
3	Residential - 3	$ 31.54	$ 35.50	
4	Residential Standby Generators	$ 31.54	$ 41.00	$ 41.45
5	Residential Heat Pump	$ 31.54	$ 56.00	$ 55.78
6	Commercial Heat Pump	$ 52.64	$ 64.00	$ 58.06
7	Commercial Street Lighting	$ -	$ -	
8	Small General Service	$ 43.07	$ 63.00	$ 63.13
9	General Service - 1	$ 66.05	$ 81.00	$ 79.74
10	General Service - 2	$ 123.47	$ 151.00	$ 153.43
11	General Service - 3	$ 502.52	$ 615.00	$ 307.67
12	General Service - 4	$ 952.39	$ 1,272.00	$ 379.54
13	General Service - 5	$ 2,101.00	$ 2,805.00	$ 540.64
14	Commercial Standby Generators	$ 52.64	$ 70.00	$ 102.74
15	Small Interruptible Service	$ 2,440.80	$ 3,259.00	$ 638.13
16	Interruptible Service	$ 2,823.66	$ 3,652.00	$ 2,856.96
17	Interruptible Service Large Volume	$ 3,110.82	$ 4,024.00	n/a
18	Wholesale	$ 665.24	$ 888.00	$ 276.00

Q. Have you provided a schedule detailing the proposed rates and corresponding revenues?

A. Yes. MFR Schedule H-1 Schedule A contains the proposed customer charges and volumetric charges and the corresponding revenues generated for each of the proposed rate classes. Each of these three sections follows the same format of developing rates. First, the portion of revenues recovered through the customer charge is calculated. Then, the remaining targeted revenues are recovered through the volumetric charges.

Q. What are the corresponding bill comparisons for Peoples customers?

A. As required by MFR Schedule E-5, the company's prepared total bill impacts for each of the rate classes.

VII. SUBSEQUENT YEAR ADJUSTMENT

Q. Have you developed a set of illustrative customer rates that reflect the proposed 2027 Subsequent Year Adjustment ("SYA")?

A. Yes. Document No. 4 of my exhibit contains supplemental Schedules E-1, E-2, and E-5 showing how adding the proposed 2027 SYA annual revenue increase to the company's proposed 2026 revenue increase would impact customer rates in 2027. These schedules for 2027 were prepared using the COSS, class revenue allocation percentages, and billing determinants that I used to develop the company's proposed 2026 customer rates and charges. These schedules are included in the company's petition filed on March 31, 2025, in Document No. 16 (2027 Subsequent Year Adjustment Supplemental Schedules), and are for illustrative purposes only. If the Commission approves a SYA in this case, the company proposes to file proposed 2027 SYA rates and tariffs in September 2026 so that they will reflect the then-current billing determinants and the approved 2027 SYA revenue increase. This will allow the Commission to approve the tariffs implementing the 2027 SYA in time to become effective with the first billing cycle in January 2027.

Q. Please discuss a process of SYA revenue increase appointment.

A. The SYA revenue increase requirement is addressed by Peoples witness Jeff Chronister in his prepared direct testimony. The SYA revenue increase is primarily driven by capital investment updates, reflecting year-end balances as of December 31, 2026, whereas the test year in the filing is based on a 13-month average investment balance. Given this distinction, it is appropriate to utilize the company's proposed COSS for the 2026 test year as the foundation for revenue allocation.

Peoples proposes that SYA revenue increases align with the revenue apportionment established for the 2026 test year, with minor adjustments. Specifically, customer classes that required a revenue decrease in the 2026 COSS—such as Commercial Heat Pump, Commercial Street Lighting, and General Service 1 will not receive any revenue increases in 2027. For all other customer classes, revenue increases will be allocated in proportion to the 2026 test year revenue apportionment.

Table 7 below summarizes the proposed 2027 SYA revenue increase distribution.

Table 7 – 2027 SYA Revenue Apportionment

Line No.	Customer Classes	Current Base Revenue	2026 Required Increase Under EROR	2026 Proposed Revenue Change	2026 Revenue Change Allocation	2027 Proposed Revenue Change	2027 Revenue Change Allocation
1	Residential	$ 187,866,055	$ 72,957,816	$ 60,699,040	58.6%	$ 16,041,564	60.1%
2	Residential Standby Generators	568,576	187,778	185,287	0.2%	49,031	0.2%
3	Residential Heat Pump	1,839	1,996	610	0.0%	163	0.0%
4	Commercial Heat Pump	16,034	(1,052)	758	0.0%	-	0.0%
5	Commercial Street Lighting	214,317	(60,521)	10,143	0.0%	-	0.0%
6	Small General Service	12,627,843	2,815,220	3,380,860	3.3%	901,584	3.4%
7	General Service - 1	64,774,046	(1,469,894)	3,042,068	2.9%	-	0.0%
8	General Service - 2	69,070,292	4,951,789	8,202,317	7.9%	2,197,753	8.2%
9	General Service - 3	33,353,034	3,453,122	5,030,334	4.9%	1,349,594	5.1%
10	General Service - 4	15,587,462	4,565,751	5,217,217	5.0%	1,400,040	5.2%
11	General Service - 5	39,036,466	13,069,580	12,960,128	12.5%	3,477,924	13.0%
12	Commercial Standby Generators	958,224	757,761	303,796	0.3%	81,043	0.3%
13	CNG/RNG	-	-	-	0.0%	-	0.0%
14	Small Interruptible Service	5,638,148	1,411,641	1,875,704	1.8%	503,356	1.9%
15	Interruptible Service	8,295,277	2,036,110	2,429,214	2.3%	651,904	2.4%
16	Interruptible Service Large Volume	-	-	-	0.0%	-	0.0%
17	CNG -Service	-	-	-	0.0%	-	0.0%
18	Wholesale	652,202	579,636	205,424	0.2%	55,122	0.2%
19	Special Contract	37,695,908	(1,667,556)	46,278	0.0%	-	0.0%
20	**Total System**	**$ 476,355,723**	**$ 103,589,178**	**$ 103,589,178**	**100.0%**	**$ 26,709,076**	**100.0%**

VIII. SUMMARY

Q. Please summarize your direct testimony

A. My testimony provides an overview of the company's Class Cost of Service Study, the apportionment of the proposed revenue increase, and the rate design proposals submitted in this proceeding.

Q. Does this conclude your prepared direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Rebecca Washington was inserted.)

TECO PEOPLES GAS
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250029-GU

IN RE: PETITION FOR RATE INCREASE

BY PEOPLES GAS SYSTEM, INC.

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

REBECCA WASHINGTON

PEOPLES GAS SYSTEM, INC.
DOCKET NO. 20250029-GU
FILED: 03/31/2025

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PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

REBECCA WASHINGTON

PEOPLES GAS SYSTEM, INC.
DOCKET NO. 20250029-GU
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

REBECCA WASHINGTON

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

A. My name is Rebecca Washington. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric") as Director of Customer Experience Revenue Operations. I work on behalf of Tampa Electric and Peoples Gas System, Inc. ("Peoples" or the "company").

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for and lead the following functional areas within Customer Experience for the company: (1) Billing Operations, (2) Payments, (3) Credit and Collections and (4) Customer Assistance. My duties include: (1) ensuring timely and accurate billing and payment processing for our customers, (2) aligning our processes and procedures with the requirements of the Florida Public Service Commission ("Commission"), (3) adhering to federal and state regulations regarding customer privacy and identity laws, (4) assisting our most vulnerable customers in identifying available assistance while making long term arrangements for those who experience difficulty paying by the due date, and (5) delivering an excellent customer experience on behalf of Peoples and Tampa Electric.

Q. Please provide a brief outline of your educational background and business experience.

A. I have a bachelor's degree in business administration from Saint Leo University in Tampa, Florida. I began my utility career 20 years ago with Tampa Electric as a Customer Service Professional in the Customer Experience Center located in Ybor City. I held various positions within Customer Experience over the years including CE Training Administrator, where I was responsible for designing training courses for Customer Service Professionals and new team members. I served as Director of Business Planning before returning to my customer experience roots in November 2024 to assume my current role.

Q. What are the purposes of your prepared direct testimony in this proceeding?

C10-1026

A. The purposes of my direct testimony are to: (1) highlight Peoples' commitment to ongoing excellence and achievement in customer satisfaction, including our J.D. Power customer satisfaction scores; (2) explain the company's plans for continuing to enhance its customer experience; (3) describe the improvements to customer experience we have made since the company's last rate case; and (4) demonstrate that the level of Customer Experience operations and maintenance (O&M") expenses and capital investments in the company's 2026 test year are reasonable and prudent.

Q. Did you prepare any exhibits in support of your prepared direct testimony?

A. Yes. Exhibit RW-1, entitled "Exhibit of Rebecca Washington," was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of five documents as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Co-sponsored by Rebecca Washington

Document No. 2	Contact Center Improvements 2020-2024
Document No. 3	Peoples' Award History 2013-2024
Document No. 4	Peoples' J.D. Power Scores 2020-2024
Document No. 5	Capital Budget for Customer Experience

I. CUSTOMER EXPERIENCE OVERVIEW

Q. What is Peoples' philosophy with respect to customer experience?

A. Peoples is dedicated to delivering a customer experience that is simple, personalized, and flexible, ensuring that every interaction is seamless, convenient, and tailored to individual needs.

Simple: We strive to act prudently making every process straightforward and hassle-free, removing unnecessary complexities so customers can easily access our products and services. From intuitive digital tools to clear and transparent communication, we focus on delivering an effortless experience.

Personalized: We recognize that every customer is unique and are committed to offering solutions that align with their specific needs and preferences. We use insights and customer feedback to tailor our services to provide meaningful interactions and customized solutions that enhance satisfaction and trust.

Flexible: Life is ever-changing, and we believe our customers deserve services that adapt to their evolving needs. Whether through customizable options, responsive customer support, or innovative service models, we provide the flexibility necessary to accommodate different lifestyles and circumstances.

We are committed to fostering a relationship built on ease, personalization, and adaptability, ensuring that every customer feels valued and empowered.

Q. Please describe how Peoples implements customer experience and the major functional areas in the department.

A. We deliver customer experience as a shared service through an intercompany agreement with the company's affiliate, Tampa Electric. The Customer Experience department consists of thirteen major functional areas, with eight areas supporting both Peoples and Tampa Electric. Five functional areas are dedicated to Tampa Electric and not included in the Peoples distribution of cost.

As of December 31, 2024, the Customer Experience area had approximately 397 team members, with 302 team members supporting both Tampa Electric and Peoples, and approximately 95 team members dedicated to Tampa Electric. Through this structure, Peoples provides customer experience in a streamlined manner and has access to a larger workforce.

Q. Please describe the eight Customer Experience functional areas that support Peoples and how these benefit the company's customers.

A. Our functional areas include:

1. Customer Experience Centers: Supports Residential and Commercial customers through call center activities. Customer Experience Centers are central hubs for customer connection and manage all types of incoming channels of communication, including telephone, email, and social media. These centers operate 24 hours a day, 7 days a week, 365 days a year. The team also delivers training, policy and procedure development, and improvement programs for

the Customer Experience team members.

2. Billing Operations: Delivers accurate and timely billing information including coordination with Peoples to receive meter reading information and resolve meter-related issues.

3. Payments: Processes and balances customer payments from several vendor options and ensures payments are applied to customers' accounts timely.

4. Credit and Collections: Supports positive customer identification, including fraud investigation, debt collection, research/maintenance of customer deposit securitization and bankruptcies.

5. Customer Assistance: Networks with social service agencies to assist customers who qualify for local, state, and federal funds.

6. Customer Experience Strategy & Research: Delivers complaint resolutions, research, voice of the customer programs; and compliance monitoring.

7. Business Solutions: Supports the use of technology

and continual enhancements to the Customer Relationship Management and Billing ("CRMB") solution and other platforms.

8. Communications: Responsible for (a) creating and distributing internal communications, (b) digital customer solutions from strategy to delivery, including customer portal, Interactive Voice Response ("IVR"), and digital outbound communications, and (c) responding to all customer executive escalations, including Commission concerns.

Each of these functions and the teams that perform them enhance overall customer satisfaction and operational efficiency. They are the foundation of our customer experience efforts and directly benefit customers because they establish how the company directly interacts with our customers.

Q. How are O&M expenses associated with the activities and functions described above and the shared CRMB system costs distributed between Peoples and Tampa Electric?

A. Tampa Electric incurs shared O&M expenses associated with

Customer Experience activities and CRMB system costs and distributes costs to Peoples based on customer counts. Following the review in 2024 of the distribution, Tampa Electric and Peoples updated the distribution to reflect the growth in Peoples' customer count.

II. CUSTOMER EXPERIENCE ACCOMPLISHMENTS SINCE THE LAST RATE CASE

Q. Have any changes to the Customer Experience area's organizational structure occurred since the filing of the company's last rate case?

A. Yes. The Customer Experience Center structure changed with the addition of a Texas Customer Experience Center in July 2023. Historically, the company maintained three Florida-based Customer Experience Centers - one in Miami and two in Tampa, one downtown at the company's headquarters and the other in Ybor City. In 2023, the company identified a need for a center outside of Florida to ensure business continuity during hurricane season and address hiring challenges.

The Texas Customer Experience Center provides savings of about $8 per customer service representative per hour. In 2023, the company used 35 to 40 agents from this vendor as Customer Service Professionals ("CSP"). In 2024, the company used between 35 and 45 agents, and in 2025 and 2026, we budgeted for 35-40 Texas CSPs.

Q. Have the duties of the CSPs who work at the Customer Experience Centers changed?

A. No. Our CSPs continue to serve customers by helping with (1) emergencies; (2) credit arrangements; (3) turn-on and turn-off service requests; (4) billing and remittance inquiries; and (5) miscellaneous customer account inquiries.

Q. What metrics are used to measure the success of the Customer Experience Centers, and how did the company perform on these internal metrics in 2023 and 2024?

A. The main Customer Experience Center performance metrics include:

<u>Telephone Service Level ("SVL"):</u> The percentage of calls answered within a specified time frame.

<u>Email Service Level:</u> The percentage of emails answered within a specified time frame.

Average Speed of Answer ("ASA"): The average amount of time it takes for a particular Customer Experience Center to answer a phone call from a customer. The time it takes for a customer to navigate through the Interactive Voice Response is not factored into the average speed of answer.

Call Volume and Abandonment Rate: The Call Volume is the number of incoming calls offered to a Customer Experience Center over a period of time. The Abandonment Rate is the percentage of inbound phone calls made to the Customer Experience Center that are abandoned by the customer prior to speaking to an agent.

The company's contact center improvements for phone calls from 2020 to 2024 are shown in Document No. 2 of my exhibit. Overall, the internal metrics show a decrease in the Average Speed of Answer by 67.35 percent to 2 minutes and 55 seconds. The percentage of calls answered increased by 17 percent to 90 percent, reducing the Abandonment Rate to 10 percent.

Q. In the company's last rate case, the major Customer Experience project included in the 2024 projected test year was the Customer Experience and Digitalization project, which included implementing two main features:

the Transactional Chatbot and the Mobile Application. Did the company implement these features?

A. No. The Transactional Chatbot and Mobile Application features were not implemented due to reprioritization of dollars to better align with customer expectations in a shifting industry, particularly as it relates to the use of AI technologies and improvements to better service our customers.

Q. Please describe the capital projects the Customer Experience chose to invest in during 2024, the cost associated with these projects, and why these projects are prudent.

A. Peoples invested $1.1 million in 2024 in (1) the implementation of an AI-driven customer segmentation platform, (2) the implementation of an AI-driven, cloud-based contact center solution that will minimize technology obsolescence challenges while enhancing customer satisfaction through faster issue resolution and improved system usability, (3) enhancing the current IVR system, (4) establishing a new self-service solution for initiating and transferring service, and (5) beginning the implementation of an identification credit check system. These projects delivered value to our customers by improving communication channels, using insights to create more tailored customer experiences, expanding digital and self-service capabilities, and simplifying customer interactions.

Q. How have the replacement of the IVR and enhancements to the company's Contact Center Management ("CCM") system discussed in the company's testimony in the last rate case continued to benefit customers in 2023 and 2024?

A. The IVR and CCM systems continue to manage millions of customer calls annually for both Tampa Electric and Peoples, with approximately 50 percent of customers taking advantage of self-service options within the IVR.

The integration of these systems via agent-facing desktop software helps CSPs to assist customers more efficiently and effectively as the customer information is made available through desktop software. We continually refine the self-service payment options to provide a seamless experience for customers using check-by-phone or credit card payments. The company optimized the IVR system by using advanced natural speech technology, which learns and adapts to common customer phrases, enabling faster and more accurate call routing.

Q. Has the company continued its low-income programs since the last rate case?

A. Yes. We continue to advocate for the Low-Income Energy Assistance Program ("LIHEAP") funding through its participation in the LIHEAP Action Day and through the National Energy and Utility Affordability Coalition.

Additionally, the company maintains its Share Program which is administered through the Salvation Army, Catholic Charities, and Metropolitan Ministries (partnership began in January 2025). Peoples, together with Tampa Electric, helps match donations from customers and employees in the Share Program up to $500,000 annually. In 2023 and 2024, low-income customers were able to apply to the Share Program in person at any Salvation Army location within Florida and online via Catholic Charities, Diocese of St. Petersburg. Our Customer Assistance team contacted customers who were in arrears to let them know about available Share Program assistance and how to apply. Customer Experience will continue the outbound calling support in 2025 and 2026. Customers are also provided with community resources for bill assistance beyond utility services.

In 2023, a total of 1,565 customers (0.32 percent) received a total of $238,822.65 in agency assistance. In 2024, a total of 539 customers (0.11 percent) received a total of $126,185.24 in agency assistance. Despite our support efforts, a large portion of the LIHEAP money available to our low-income customers went unclaimed in 2024.

Q. In the last rate case, the company enumerated four specific customer experience goals for 2023: customer safety (emergency response rate), transactional satisfaction, outstanding and proactive communications, and customer journey mapping. Did the company achieve these goals?

A. The company achieved three of the four goals around customer experience discussed in the last rate case. The company did not quite achieve its goal of meeting a 60-minute emergency response time 98.5 percent of the time, primarily as a result of traffic congestion in two service areas. The emergency response time begins the instant an order is created and terminates the moment the Technician arrives on site. While the company met the 98.5 percent response rate in 12 of its 14 service areas, the final emergency response rate across all service areas for 2023 was 96.65 percent.

The company achieved its goal around Transactional Satisfaction, which focused on customer satisfaction with the field visit experience. We measured this goal through an automated transactional survey conducted the day after a field visit which assessed satisfaction of the customers' interaction with the Field Technicians, as well as the work performed. Peoples achieved a 92 percent customer rating of "excellent."

We met the third goal for 2023: Outstanding and Proactive Communications. This proactive communication plan was developed by the end of the first quarter of 2023 and implemented throughout the year, meeting quarterly goals. We designed the plan to educate internal and external stakeholders about the value of natural gas in the context of the last rate case and the value/cost of sustainability. Studies show that clear and consistent communication to stakeholders about the business, the value of our product, and any changes, including new rates, create customer satisfaction.

Lastly, we successfully met the Customer Journey Mapping goal in 2023, which focused on the service initiation process which is extremely important to new customers as it sets the tone for future interactions and builds trust. The customer journey often begins with a builder-developer and then traverses through various areas within the company, which can include engineering, real estate and customer experience. By mapping out the customer journey, Peoples better understands key service initiation milestones and areas for improvement.

We also completed mapping the "sign-up to meter-set in" and developed and completed an action plan to improve three areas: (1) development of a Service to Installation Roadmap, (2) development of an autogenerated messaging aligned with the Work and Asset Management Service Order Statuses to support customer communications at key milestones, and (3) defined the certain roles to help establish clear responsibilities, and interdepartmental handoffs.

Q. What customer experience goals did the company accomplish in 2024?

A. In 2024, the company achieved these goals: (1) performed a best practice review of the meter-to-cash process and (2) implemented customer journey plan improvements for commercial customers.

Q. What are the company's customer experience focused goals for 2025?

A. The company set the following five customer experience focused goals for 2025:

1. Customer Journey Mapping for scattered Residential customers.
2. Customer Safety – Emergency Response Rate.
3. Develop and implement reporting mechanisms to achieve zero revenue and rate code discrepancy.
4. Achieve scattered Residential pilot results in the Tampa service area targeting process for customer sign-up to meter set with a minimum of 50 customer work orders.
5. Achieve the number one national ranking in the 2025 J.D. Power Residential Customer Satisfaction study.

III. EXCELLENCE IN CUSTOMER SATISFACTION

Q. Did the company receive any industry awards for customer service since the company's last rate case?

A. Yes. In 2024, Cogent/Escalent recognized the company for the eleventh time as one of the nation’s most trusted utilities in its Syndicated utility Trusted Brand and Customer Engagement Residential study. Peoples achieved high scores in this study in the Environmental Dedication and Customer Effort Indexes, demonstrating our commitment to a clean energy future. Additionally, this same study named Peoples as a Customer Champion - for the eleventh consecutive year - highlighting our commitment to building engaged customer relationships. Peoples’ full award history can be found in Document No. 3 of my exhibit.

Q. How did the company perform in J.D. Power surveys since the last rate case?

A. Peoples’ J.D. Power ranking for Residential customer overall satisfaction slightly decreased from 798 in 2023 to 781 in 2024. Despite this, Peoples remains in the top quartile and early signs in 2025 indicate positive upward movement in both our segment and nationwide. For business customers, the company placed third in our segment and in the nation in 2023 and ended fifth in our segment and sixth in the nation for 2024. Peoples’ J.D. Power Scores dating back to 2020 can be found in Document No. 4 of my exhibit.

IV. MEASURING THE CUSTOMER EXPERIENCE

Q. How does the company measure its performance in the Customer Experience area?

A. The company measures its performance in the customer area based on customer satisfaction scores as measured by J.D. Power, internal performance metrics, and by tracking Commission complaints.

Q. How has Peoples performed in Commission customer complaints?

A. Customer complaints filed with the Commission against Peoples remained relatively flat, going from 87 in 2023 to 90 in 2024, equating to approximately 0.02 percent of our customers. Commission consumption or high bill complaints went from six in 2023 to seven in 2024. The majority of the complaints in 2024 addressed "new construction and installation," which includes of a range of concerns around the initiation of service such as the cost of service, the timing of service, and permitting schedules. Nine of the 90 complaints were related to low pressure concerns associated with home generators. Seven of these nine involved pressure concerns that arose during Hurricanes Helene and Milton. Peoples responded to these concerns with targeted communications to our residential customers in the area that seemed to experience the most disruption, South Tampa.

Q. Has the company received any formal infractions from the Commission?

A. Yes. In June 2024, the company received its first Commission infraction in almost nine years for a fast meter violation of Rule 25-7.063, Florida Administrative Code, Meter Accuracy at Installation. The complaint involved a master meter at a small apartment community of nine units.

On December 18, 2023, a customer contacted Peoples about an unusually high bill and a possible gas leak. Their bill had increased from an average of $60 per month to $146.87 in December. A company technician went to the customer’s premises, discovered a gas leak on the customer's side of the range, “red-tagged” the appliance for safety, and turned off and capped the appliance valve. This leak and the resulting consumption affected the customer's December 2023 and January 2024 invoices.

On January 19, 2024, the customer reached out to the company again about a high bill, noting the gas leak and requesting a reduction. The customer also mentioned a water heater leak that needed repair and expected a credit similar to what the water company provided. However, the company representative explained that since the gas had passed through the meter and the leak was on the house line, no adjustment could be made.

On February 13, 2024, the customer reported another possible leak as their bills for January and February were $293.43 and $321.93, respectively. A Peoples' technician performed a leak test on both the meter and the gas appliances, which returned negative results (no leaks or issues found). Despite this, the customer contacted the Commission regarding high consumption. A Peoples' technician performed another leak test on February 14, found no issues, but decided to replace the current meter (RHC8924) with a new one (AIX75413).

On February 26, 2024, the company sent the initial meter (RHC8924) to Precision Meter Repair for testing. The meter tested within one percent accuracy, complying with Rule 25-7.063, Florida Administrative Code.

The customer's bills on February 29 and April 4 remained higher than average under the new meter (AIX75413), at $216.47 and $181.75, respectively. On April 14, 2024, the customer contacted the Commission to request a credit and that the initial meter (RHC8924) be retested. A company representative made contact with the customer to advise the meter (RHC8924) was tested by an independent company and no issues were found, and that a credit would not be given in light of the negative meter test.

On April 15, 2024, the customer filed a formal complaint with the Commission and requested a Commission representative witness a meter test pursuant to Rule 25-7.066, Florida Administrative Code. On May 13, 2024, Precision Meter Repair tested the initial meter (RHC8924) twice in the presence of the Commission’s representative. Both tests indicated the meter was more than one percent fast, violating Rule 25-7.063, Florida Administrative Code. Following these results, the company adjusted the customer’s bill to account for the 1 percent higher read over the previous twelve months, resulting in a total adjustment of $16.94.

The company notes that the customer’s bill in May, under the meter installed in February (AIX75413), was $49.33, after the twelve-month adjustment. This result seems to indicate that the customer's higher consumption from December 2023 through April 2024 was due to appliance issues and/or a leak on the customer side.

V. CUSTOMER EXPERIENCE RATE BASE AND O&M EXPENSES – 2026 TEST YEAR

A. RATE BASE

Q. How does Peoples determine its capital budget for Customer Experience?

A. Customer Experience identifies capital improvement opportunities based on system continuity requirements, regulatory and federal requirements, analysis of industry best practices/process improvements, customer feedback through our Voice of the Customer program and identification of points of customer concern and gaps in customer satisfaction through customer journey mapping.

Q. How much capital investment did the Commission approve for Customer Experience in the last rate case for the year 2024, and how does that compare to the company's actual capital investment in Customer Experience for 2024?

A. The Commission approved $3.4 million of capital investment in the Customer Experience area for 2024. Peoples spent $1.1 million in 2024, which is $2.3 million less than projected in the last rate case. This variance is largely due to a restructuring of our capital portfolio as discussed earlier in my testimony.

Q. What is Peoples' capital budget for Customer Experience in 2025 and 2026?

A. As mentioned in the testimony of Peoples witness Christian Richard, the capital budget for Customer Experience for 2025 and 2026 is $2.0 million and $2.9 million, respectively. The projects reflected in this budget are shown in Document No. 5 of my exhibit.

Q. Please explain the projects associated with the capital budget for Customer Experience in 2025 and 2026.

A. In 2025 and 2026 the Customer Experience area plans to invest in projects in the following categories: (1) Communications, (2) Data, (3) Digital and Artificial Intelligence ("AI"), and (4) Process Enablement.

Q. Please explain the project related to Communications, the expected cost and why the expenditure is prudent.

A. We will invest $165,000 and $358,875 in 2025 and 2026, respectively, in the “Notifications and Preference Center” project to implement a new centralized system enabling customers to manage their communication preferences. This platform centralizes all preferences in one location, ensuring that every communication adheres to the customer’s specified rules for channel (phone, email, or short message service (“SMS”), frequency, and timing. The platform will improve customer satisfaction and engagement by enabling customers to have more control over their communications such as the channel (phone, email, or SMS), and frequency and timing of receiving communications. This project is reflected under the Spend Type “Technology Projects (Shared)” in Document No. 5 of my exhibit.

Q. Please explain the Data-related project, the expected cost and why the expenditure is prudent.

A. The "System Segmentation Personas” project initiative provides deeper insights into customer behavior, preferences, pain points, and satisfaction. This includes System Segmentation Personas, an AI-driven customer segmentation platform will support informed decision-making, personalized interactions, and tailored services. By using segmentation data, we can tailor communications and service offerings, maximizing impact by identifying key gaps and opportunities for improvement. The company will invest $33,000 in 2025 and $717,750 in the System Segmentation Personas project which is reflected under the Spend Type "Technology Projects (Shared)" in Document No. 5 of my exhibit.

Q. Please explain the Data and AI-related project, the expected cost and why the expenditure is prudent.

A. We will invest $990,000 in 2025 on the "AWS Proof of Concept (FKA Intrado)" project which will replace the current IVR system, providing a scalable, cloud-based contact center solution with AI-driven capabilities. This project is reflected in Spend type "Technology Project (Shared): Intrado Replacement" of Document No. 5 of my exhibit.

Q. Please explain the projects related to the Process Enablement, the expected cost, and why the expenditure is prudent.

A. There are three projects in this area: (1) "Move In Reimagine"; (2) "Equifax/POS ID & CCR Replacement" (2025 only); and (3) "Payment Arrangement Reimagine."

Move In Re-imagine This project can be found under the Spend Type "Technology Project (Shared): Move In Re-Imagine - PE" in Document No. 5 of my exhibit. Peoples will invest an additional $330,000 in 2025 for this project, a new self-service solution that offers customers the option to start service by calling or applying online. Previously, the online process for initiating service took about 11 hours to reach confirmation due to software bot functionality. Now, customers receive immediate responses, providing a real-time experience. For agents, the project has improved efficiency by allowing seamless transfers and single-step combination move-ins, streamlining operations and enhancing the customer experience.

Equifax/POS ID & CCR Replacement In 2025, Peoples will implement the "Equifax/POS ID & CCR Replacement" project with an investment of $330,000. This project will ensure compliance with the Identity Theft Red Flags Rule (the "Rule") under the Fair Credit Reporting Act, 16 C.F.R. Section 681 which requires each company to develop and implement a written Identity Theft Prevention Program ("Program") that (1) identifies "Red Flags" (patterns, practices, or specific activities that indicate identity theft), (2) detects Red Flags, (3) responds appropriately to any Red Flags detected to prevent and mitigate identity theft, and (4) ensures the Program is updated regularly.

This project will meet the Rule's Program requirements in detecting and preventing identity theft. Specifically, the project will enable Peoples to (1) verify the identity of customers when opening a new account or making revisions to existing accounts, (2) adhere to any alerts or notifications placed on customer's accounts such as fraud alerts or credit freezes, (3) implement Knowledge-Based Authentication to ensure only authorized individuals can access or modify account information, (4) monitor accounts for unusual or suspicious activity, and (5) train employees to recognize and respond to Red Flags. This project can be found under the Spend Type "Technology Project (Shared): Equifax/POSID Check Replacement" in Document No. 5 of my exhibit.

The company notes that this project was proposed in Tampa Electric's 2024 rate case and denied by the Commission in Order No. PSC-2025-0038-FOF-EI. Peoples includes this project in this case because it is critical that the company comply with the Rule by identifying, detecting, and responding to Red Flags indicating potential identity theft, as explained above.

Payment Arrangement Reimagine The "Payment Arrangement Reimagine" project creates a consistent and frictionless omnichannel experience for customers seeking payment assistance, leveraging best practices for eligibility criteria, risk profiling, and transparency. The company will invest $165,000 in 2025 in this project which is listed under the Spend Type "Technology Project (Shared)" in Document No. 5 of my exhibit.

Q. Is Customer Experience's projected level of capital investment in 2025 and 2026 reasonable and prudent?

A. Yes. This amount represents the Customer Experience rate base that will be in-service and used and useful by the company to provide safe, reliable service to our customers.

B. O&M

Q. What are the main causes of the company's Customer Experience related O&M expenses?

A. The main causes of the company's Customer Experience related O&M expenses include labor, outside services and other operational expenses. The operational expenses include but are not limited to: (1) customer billing fees (vendor fees and postage); (2) processing fees associated with customer payments; (3) high-volume call answering fees; (4) IVR virtual hold fees; and (5) other expenses associated with maintenance of our systems.

Q. What O&M expense did Peoples incur for Customer Experience in 2023?

A. Customer Experience costs primarily reside in FERC Account 903, Customer Records and Collection expenses. In FERC Account 903, Peoples incurred $14.4 million in 2023.

Q. What amount of O&M expense was approved by the Commission for the Customer Experience area for 2024 and what was the actual O&M expense for 2024.

A. The Commission approved $14.9 million in O&M expense and the actual O&M expense for 2024 was $15.1 million. This 1.0 percent variance is driven by the cost of customer communications and maintaining the Customer Experience Operations service level performance, including answering customer calls in a timely manner (ASA), handling customer calls more efficiently (AHT), and answering more calls received (percent answered).

Q. What are the forecasted amounts of Customer Experience O&M for 2025 and 2026, and are those amounts reasonable?

A. As shown on MFR Schedule G-2, page 14, in FERC Account 903, the company projects Customer Experience charges will be approximately $17.9 million and $18.7 million for 2025 and 2026, respectively. The overall level of Customer Experience O&M for 2025 and 2026 is reasonable.

Q. Please explain why the level of O&M expense is increasing in 2025 and 2026.

A. The increase in FERC Account 903, as described on line 11 of MFR Schedule G-2, page 19b, is a result of the increased distribution to Peoples of shared Customer Experience O&M expense which accounts for the company's current customer count. It is also partially due to inflation.

Lastly, as shown on line 12 of MFR Schedule G-2, page 19b, the CRMB asset usage fees are increasing from $2.2

million in 2024 to $2.6 million in 2026. As described in Peoples witness Jeff Chronister’s prepared direct testimony, Peoples is charged for its use of the shared CRMB system through an asset-usage fee that is also recorded as O&M expense in FERC Account 903. The distribution of the CRMB system costs to Peoples through the asset-usage fee increased from 33 percent to 37 percent, effective January 1, 2025.

Q. What is the Customer Experience performance against the O&M benchmark for 2026?

A. As identified in Peoples witness Andrew Nichols’ prepared direct testimony, Document No. 10 of Exhibit No. AN-1, the company is over the 2026 O&M benchmark for Customer Account and Collection. FERC Account 903 within Customer Account and Collection exceeds the O&M benchmark due to the higher distribution to Peoples of shared Customer Experience O&M expense. In other words, if the 2024 Customer Experience distribution was normalized for the updated customer counts, the variance would not exist, and the company would not be above the benchmark. Thus, the expense is reasonable. Customer Experience is below the industry standard for cost per bill, cost per payment, cost per call handled and cost per credit and collection.

Q. What steps has the company taken to reduce O&M expense in the Customer Experience area?

A. The company has reduced O&M expense in the Customer Experience area by:

1. <u>Outsourcing Staffing for Customer Experience Center</u>. Engaging with the vendor for the Texas Customer Experience Center allowed the company to temporarily augment staffing and maintain service levels during peak periods, while controlling labor costs.

2. <u>Process Re-engineering</u>. In 2024, Customer Experience used a dedicated team to review our processes to discover ways to eliminate inefficiencies. This team identified automation improvements of manual processes for Move In Reimagine and Payment Arrangement processes. Customer Experience conducted workshops to identify pain points and brainstorm solutions. We compiled a list of requirements and documented both qualitative and quantitative benefits. Using our prioritization scorecard, we identified the top opportunities that would have the greatest positive impact on our customers and agents. Among the opportunities identified were the

automation of self-serve installment plan requests and improved handling of broken payment arrangements.

3. Adoptions of Technology and Automation. The company invests in technology and automation to streamline operation including implementing digital capabilities to help customers self-serve. These technologies improve efficiency and reduce the need for customers to call.

Collectively, these actions contributed to avoided costs and efficiency gains that enabled the organization to operate more efficiently and cost-effectively.

Q. What steps has the Customer Experience area taken to promote affordability?

A. Customer Experience promotes affordability by managing and controlling costs and seeking improved efficiencies, as outlined above. Additionally, we ensure system continuity to avoid failures. We provide payment assistance programs, including payment plans and emergency assistance funds, to support those in need. We also educate customers on managing their usage and partner with local organizations to offer education and wrap-around services.

Q. How many employees did the Customer Experience area have in 2023 and 2024?

A. In 2023 and in 2024, the number of team members at the end of the year in the Customer Experience area was 400 and 397, respectively.

Q. Does the Customer Experience area plan to increase employee count in 2025 and 2026?

A. No. With the use of the Texas Customer Experience Center, the implementation of several process improvements and automation designed to improve productivity and efficiency, we plan to continue to decrease the overall employee count to 390 team members through 2026.

Q. How have uncollectible account expenses varied in 2023 and 2024 and is the company's proposed level of uncollectible expenses reasonable for the 2026 test year?

A. Bad debt expense decreased from 2020 by 13 percent and is expected to remain relatively flat through 2026. In 2023 and 2024, the amount of bad debt expense was $1.4 million and $1.6 million, respectively. The company’s proposed level of bad debt expense for the 2026 test year is $1.8 million, which is reasonable based on past experience and expected economic conditions for the test year. This also represents 0.27 percent of revenue, which is below the industry average of 0.73 percent.

Q. Is the company’s proposed overall level of Customer Experience related O&M expense for 2026 reasonable?

A. Yes. The overall level of Customer Experience related O&M expense for 2026 is reasonable. The company remains focused on prudently investing in strategic functions that lead to reduced cost and a simplified cost.

MFR SCHEDULES

Q. Are you sponsoring any MFR Schedules?

A. Yes, I am co-sponsoring MFR Schedules C-38, G-2, and G-6.

Q. Please provide an explanation of the MFR Schedules you are sponsoring.

A. The MFR Schedules I am co-sponsoring detail O&M expenses for Customer Experience. MFR Schedule C-38, page 2, details Total Customer Account Expenses, which contains FERC Account 903. MFR Schedule G-2, pages 14 and 19a, break down payroll and other O&M expenses related to FERC Account 903. MFR Schedules G-2, page 19b, and G-6 both show Peoples' Customer Experience Distribution.

VI. SUMMARY

Q. Please summarize your prepared direct testimony.

A. Peoples is deeply committed to delivering exceptional customer satisfaction and continually enhancing the customer experience. Our dedication to excellence is evident through our J.D. Power customer satisfaction achievements, which have consistently recognized the company as best in class over the past eleven years. We prioritize providing a simple, personalized, and flexible experience for our customers, with a strong emphasis on safety for both our customers and team members. As safety stewards, we recognize our vital role in the communities we serve, which are also home to our team members. We pride ourselves on 24 hours a day 7 days a week response to all gas emergency calls, including gas leak calls; which are handled locally in Florida, with priority and optimal response times by live agents.

Since the company’s last rate case Customer Experience invested capital in (1) the implementation of an AI-driven customer segmentation platform, (2) the implementation of an AI-driven, cloud-based contact center solution, which will minimize technology obsolescence challenges, while enhancing customer satisfaction through faster issue resolution and improved system usability, (3) enhancing the current IVR system, (4) establishing a new self-service solution for initiating and transferring service, and (5) beginning the implementation of an identification credit check system. Our commitment to customer-centric solutions ensures we provide the best possible service while being mindful of spending. In addition to our operational improvements, we continue to advocate for low-income energy assistance programs and support our Share Program, which provides assistance to low-income customers.

Peoples is passionate about serving our customers and continuously strives to improve our services and customer satisfaction. The company’s proposed levels of Customer Experience capital investment and O&M expenses for 2026 are reasonable and prudent and should be approved so we can continue to provide safe and high-quality service to our customers.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

(Whereupon, prefiled direct testimony of Helen Wesley was inserted.)

TECO PEOPLES GAS
AN EMERA COMPANY

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250029-GU

IN RE: PETITION FOR RATE INCREASE

BY PEOPLES GAS SYSTEM, INC.

PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

HELEN WESLEY

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PREPARED DIRECT TESTIMONY AND EXHIBIT

OF

HELEN WESLEY

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

HELEN WESLEY

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

A. My name is Helen Wesley. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Peoples Gas System, Inc. ("Peoples" or the "company") as its President and Chief Executive Officer ("CEO"). I serve as President and CEO of Peoples' parent company, TECO Gas Operations, Inc., which is a subsidiary of TECO Holdings, Inc. I am also President and CEO of the company's subsidiary, TECO Partners, Inc. ("TPI") and its affiliate, SeaCoast Gas Transmission, LLC ("SeaCoast"). SeaCoast is an intrastate natural gas transmission company and TPI performs sales services for Peoples.

Q. Please describe your duties and responsibilities as President and CEO of Peoples.

A. I have overall responsibility and accountability for every aspect of Peoples. This includes operational functions such as safety and compliance, customer experience, gas supply and development, operations, construction and engineering, and corporate functions such as regulatory affairs, supply chain management, human resources, marketing and communications, external affairs, information technology, finance and accounting, and legal.

I am responsible for managing our organization in a fiscally responsible manner that is accountable to our team members, customers, regulators, shareholders, strategic suppliers, financing partners, and other community partners.

I lead the company to ensure that our customers across the state receive safe and reliable natural gas service, our team members enjoy a high quality of employment, and we serve as a positive force in the communities in which we operate.

I also make certain that Peoples remains financially sound and complies with the numerous rules and regulations that govern businesses in general and local gas distribution companies specifically.

Q. Please provide a brief outline of your educational background and business experience.

A. I earned a Bachelor of Commerce degree in Marketing from the University of Calgary, and a Master of Business Administration degree in International Business from Bentley University in Boston. I have over 30 years of energy industry experience in Canada, the United States, Europe, the Middle East, and Africa.

Since 2010, I have been leading large groups within complex organizations. My energy experience spans both upstream and downstream oil and gas, as well as commodity and specialty chemicals, electric utilities, and gas utilities. Additionally, I served for five years as the Chief Financial Officer for a regulated electric utility.

I joined Peoples in 2020 as Chief Operating Officer, became President in late 2021, and was named President and CEO effective January 1, 2023.

I hold a Chartered Financial Analyst designation and a Directors Designation from the Institute of Corporate Directors.

Q. What are the purposes of your prepared direct testimony?

A. My prepared direct testimony:

1. provides an overview of Peoples, our core values, our commitment to customers, and strategic priorities;
2. describes how we have changed and what we have accomplished since our last rate case;
3. explains our need for the rate increase we are proposing; and
4. introduce the witnesses in the case.

Throughout my testimony, I will explain our ongoing commitment to manage our business in a prudent manner in a dynamic environment where natural gas continues to earn great popularity for its safety, reliability, convenience, and affordability. I will also introduce the other witnesses who filed prepared direct testimony in support of our request.

Q. Have you prepared a document summarizing the witnesses filing prepared direct testimony in support of the company's petition?

A. Yes. Document No. 1 of my exhibit reflects a List of Peoples witnesses and the purposes of their prepared direct testimonies.

Q. Please describe your Exhibit No. HW-1.

A. Exhibit No. HW-1, entitled "Exhibit of Helen Wesley," was prepared under my direction and supervision and consists of five documents:

Document No. 1	Witnesses and Purposes
Document No. 2	Peoples Service Territory Map
Document No. 3	Corporate Structure Diagram
Document No. 4	2025 Balanced Scorecard
Document No. 5	Bill Comparisons at Proposed Rates

The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief.

I. ABOUT PEOPLES

A. OVERVIEW

Q. Please describe Peoples.

A. Peoples was formed in 1895 and is the largest natural gas local distribution company in Florida. Through our 14 service areas, the company safely and reliably serves over 508,000 residential, commercial, industrial, and electric power generation customers in 43 of Florida's 67 counties, including five major metropolitan areas.

As of December 31, 2024, our system included approximately 15,765 miles of gas mains. A map showing the reach of our gas distribution system is included in Document No. 2 of my exhibit.

At year-end 2024, we employed approximately 812 team members to serve our customers. Focusing solely on the number of people we employ provides an incomplete view of the company. Peoples also uses outside contractors to help serve its customers, and we have recently insourced several roles from contractors.

Peoples is an indirect subsidiary of Emera Incorporated ("Emera"), a geographically diverse energy and services company headquartered in Halifax, Nova Scotia, Canada. Emera also indirectly owns our affiliate, Tampa Electric Company ("Tampa Electric"). Peoples' place in the corporate structure of Emera is shown on the diagram included as Document No. 3 of my exhibit.

Q. Please describe the company's customer base.

A. As of December 31, 2024, Peoples served approximately

508,000 customers ranging from residential customers to small businesses to large commercial customers like hospitals, hotels, industrial users, and electricity generators. We are increasingly serving transportation providers, health care providers, and core essential services like waste management companies, all of which are vital to the economy, the tourism industry and day-to-day operations of Florida. At the end of 2024, the distribution of customers across our rate classes was 467,290 Residential, 40,941 Commercial, and 54 Industrial and power generation customers.

Q. How has Peoples grown since its last rate case?

A. Florida continues to be one of the fastest growing states in America, both in terms of population and size of economy, and Peoples serves many of its fastest growing areas. Florida attracts over 1,000 newcomers each day due to its strong economy, appealing lifestyle, and diverse natural resources. This influx of people spurs the construction of new homes, hotels, hospitals, stores, restaurants, and roads, while also prompting redevelopment of existing areas. Additionally, the growing population increases the demand for electricity, with natural gas currently fueling over 70 percent of

Florida's electric generation. This growth increases the demand for natural gas.

To keep up with this demand, we installed approximately 1,260 miles of new main and service gas lines from January 2023 to December 2024, and plan to add another 1,200 miles by December 2026.

If laid end to end, our new gas lines for this period would stretch farther than the driving distance from Tampa to New York City.

In 2023, the company welcomed approximately 20,905 new residential customers and 884 small commercial customers, reflecting increases of 4.9 percent and 2.3 percent, respectively. In 2024, the company added another 17,845 Residential customers and 689 Small Commercial customers, representing increases of 4.0 percent and 1.7 percent, respectively.

Peoples anticipates adding nearly 19,141 new residential customers and 718 new small commercial customers in 2025, followed by an additional 17,642 residential customers and 698 small commercial customers in 2026.

I'm very proud to say that we have continued our strong safety and exceptional customer service record while meeting the challenges associated with this growth.

B. CORE VALUES

Q. What are the company's core values?

A. Our values include a commitment to safety, focusing on customers, fiscal responsibility, and supporting the communities we serve with a strong foundational focus on integrity and respect. We embrace innovation to continuously improve our systems and ways of working. We strive to achieve outstanding results. We promote safety and reliability and deliver exceptional customer experiences. These values are exemplified each day by our team members and help guide our expectations of our partners as we deliver natural gas to customers.

Q. Please describe Peoples' commitment to safety.

A. The safety of Peoples' team members, contractors, customers, and the public is paramount. We focus on the safety of people and our pipeline in everything we do, and our efforts yield strong results. Protecting our gas distribution system from damages caused by third parties during construction and from cyber-attacks is vital, and in turn, protects the public and the communities we serve. Peoples witness Timothy O'Connor, Vice President of Safety, Operations, and Sustainability, will explain, in his prepared direct testimony, our outstanding safety record and the need to continue to invest in the safety of our growing system to maintain the company's high safety performance.

Q. Please describe the company's commitment to customer service.

A. Peoples' commitment to providing exceptional customer service is a hallmark of the company and is inextricably linked to our safety record and prompt responses to possible gas leaks and other service requests. Our Florida Public Service Commission ("FPSC" or "Commission") complaint level is extremely low and we consistently rank at or near the top in national customer surveys on customer satisfaction. Peoples witness Rebecca Washington, Director of Customer Experience Revenue Operations, will explain our very strong customer service results and rankings in her prepared direct testimony.

Q. How is fiscal responsibility integrated into the way

Peoples does business?

A. Sound financial management and good business decision making are vitally important to Peoples and our customers. We work diligently to ensure that the goods and services we use to serve our customers are procured using proven business practices that provide value to our customers. Our commitment to cost discipline is a primary reason that the cost profile for operating our business is reasonable and prudent. We have a mindset of continuous improvement that is evidenced across many areas of the business and reflected in our annual Balanced Scorecard ("BSC").

The business practices and controls we employ and the supply chain management improvements we have implemented are described in the prepared direct testimony of Peoples witnesses Christian Richard, Vice President of Engineering, Construction & Technology, and Andrew Nichols, Director, Business Planning. Our other operating witnesses will also discuss our success in managing our cost profile. As I explain later, we use our BSC to make prudent financial management the business of each Peoples team member.

C. <u>OUR ROLE IN FLORIDA AND THE COMMUNITIES WE SERVE</u>

Q. How does Peoples support the communities it serves?

A. For over a century, Peoples has worked alongside various organizations to build stronger and safer communities. Peoples has an established history of helping its customers navigate challenges related to public health crises, economic volatility, and severe weather conditions. To support customers with their utility bills, Peoples operates the Share program in partnership with Tampa Electric. This program is administered by the Salvation Army, Metropolitan Ministries, and Catholic Charities. Peoples helps to match donations made by customers and employees, contributing up to $500,000 annually; the cost of these donations is borne by the company's shareholders, not its customers.

Peoples also makes a concerted effort to connect customers who need financial assistance with organizations like the Low-Income Home Energy Assistance Program ("LIHEAP"). Witness Washington will describe these efforts in her prepared direct testimony.

After Hurricane Helene, Peoples donated $75,000 to United Way organizations aiding impacted communities. Following

Hurricane Milton, the company established an employee assistance program with an initial $50,000 donation.

Collectively in 2024, Peoples contributed over $400,000 to organizations like the American Red Cross, American Cancer Society, United Way, and others across its service areas. Shareholders, not customers, fund these amounts and we consider them investments in the communities we serve. Additionally, our team members annually volunteer many hours to support not-for-profit organizations in communities throughout Florida.

Q. How does Florida depend on Peoples?

A. The businesses and entities that drive Florida's economy depend on Peoples for safe and reliable natural gas every hour of every day and every day of the year. Our distribution system provides services to the food service, hospitality, and tourism industries. Critical infrastructure such as hospitals, healthcare facilities, nursing homes, schools, law enforcement, ports, and the military rely on natural gas to serve the public. Commercial and Industrial enterprises, along with electric power generators, are crucial for Florida's economic growth and depend on natural gas from Peoples.

We are proud to serve both small businesses and large-volume customers, all of whom contribute to the state's economy and development, and military bases, which support national security. Peoples' capital investments also generate property tax revenue that supports schools, infrastructure, and community services.

Q. How does Peoples help Florida during extreme weather events?

A. Natural gas service is extremely important during emergencies. According to the Commission's website, Hurricanes Helene and Milton left over 1.3 million and 3.3 million Florida electric customers without power, respectively; however, fewer than 1,500 of Peoples' over 500,000 customers (less than 0.5 percent) experienced a gas service interruption. None of our 53 Compressed Natural Gas customers, providing waste management and transportation services to thousands of Floridians, experienced fuel disruptions.

As electric utilities worked to restore electricity to their customers, Peoples' gas distribution system provided fuel for vital emergency backup electric generation for homes, businesses, emergency shelters, and healthcare facilities. When ports impacted by electric outages could not deliver gasoline or diesel to critical transportation services, Peoples was able to support waste management and other vehicles fueled by compressed natural gas. Resilience and reliability are now the cornerstones of Florida’s energy policy, and our electric generating customers are increasingly focused on those two goals. Natural gas is essential to Florida's energy resilience and reliability.

Q. How have customer usage patterns changed and how do those changes impact how Peoples evaluates and manages the capacity and capabilities of its distribution system?

A. Our customers (including residential, small and large businesses, nursing homes, and hospitals) continue to use our service to cook, heat water, launder, run boilers, and heat swimming pools; however, power outages caused by extreme weather have caused many of our customers to become more focused on reliability and resilience, and to install natural gas generators for backup power. This additional power source requires safe and reliable delivery of natural gas, and also, at times, requires an upgrade in system infrastructure to serve these expanding needs. We are also experiencing higher demand in some parts of our service territory that have been re-developed since we originally installed our facilities. Witness Richard will explain the steps we are taking to improve the capability of our system to accommodate re-development and to meet weather emergencies as more customers seek alternative sources of power to contend with the effects of extreme weather.

D. STRATEGIC PRIORITIES

Q. What are the company's strategic priorities?

A. The company's strategic priorities are anchored by three pillars: safety and risk management; foundational improvements; and strategic shifts, all of which are aimed at enabling us to continue to effectively serve customer needs today and tomorrow. These three pillars serve as a long-term compass for our company while we also navigate the more near-term priorities outlined in our BSC, which I will describe further later. Every company needs a "true north," and ours is reflected in these pillars as we keep safety and risk at the forefront of our minds, we strive to make our business better every day, and we make strategic shifts to anticipate what lies ahead for our customers and the company.

The BSC anchors us in achieving the day-to-day outcomes that lead us toward this "true north." At Peoples, every team member is connected to the BSC, which aligns our strategic pillars and near-term priorities. This synergy propels us forward thoughtfully and strategically, allowing us to create value for customers and other stakeholders.

Q. Please describe the company's focus on safety and risk management.

A. The safety of customers, the public, our employees, and contractors continues to be our top priority. The company has robust safety management and pipeline safety systems, with specific goals for occupational and public safety, vehicle safety, damage prevention, emergency management, and leak responses. Witness O'Connor explains these systems and goals in his prepared direct testimony.

In addition to these safety measures, we also address other risks associated with operating a regulated local natural gas distribution company. These risks include global and domestic political and economic developments, cyber and physical security, possible fuel supply and supply chain disruptions, and extreme weather events. We

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regularly assess these and other risks to ensure that our business plans and ability to serve customers are not harmed by activities we cannot control in the changing world around us.

These increasing risks require us to invest in protecting our information technology and distribution plant assets and to be ready for extreme weather events. For example, the Automated Meter Infrastructure Project we are piloting holds promise in mitigating operational challenges and safety risks by enabling us to remotely shut off the supply of gas in emergency situations. The company's approach to addressing these risks is discussed by witnesses Richard and O'Connor.

Q. What do you mean by "foundational improvements?"

A. Peoples has a sound system of business practices but always strives to be more efficient, and to find new ways for our employees to better serve our customers. Our program for foundational improvements focuses on the "nuts and bolts" of our business and includes more training for our employees, pursuing process improvements, making smart investments in technology (e.g. customer facing platforms), evaluating reliance on outside service providers, continued implementation of our work and asset management system ("WAM"), and establishing baseline productivity measures across the business. Our efforts in these areas are explained in the prepared direct testimony of Peoples witnesses Donna Bluestone, Vice President of Human Resources, O'Connor, and Richard. The testimony of our witnesses shows our focus on streamlining operations while we serve growing and changing customer demand.

Q. What strategic shifts is the company making as it continues to see strong demand for natural gas in Florida?

A. We are fortunate to serve in one of the fastest growing states in America, with substantial customer growth, which impacts Peoples in multiple ways. We must manage this customer growth effectively to ensure we also consider the affordability of our service among the myriad of household expenses for residential customers, and business expenses for commercial and industrial customers.

Adding gas lines to serve new neighborhoods requires significant capital investment. The vastness of Florida and the availability of green space to build new residential and small commercial developments contribute to the additional capital and operating and maintenance ("O&M") expenses incurred with a more extensive distribution system.

In addition, we are investing in improving the reliability and resilience of the company's existing system, which is costly. Peoples is continually evaluating and upgrading existing facilities to meet demand not anticipated when the facilities were installed initially, such as redevelopment of existing service areas, greater customer additions, and higher volume requirements for backup electricity generators. These demands on our existing system impose new and higher costs.

These factors, together with increasing compliance costs and the inflationary pressures facing all businesses and consumers in Florida put substantial pressure on our ability to earn a reasonable rate of return on our rate base investments and contribute to our need for rate relief more frequently than we would prefer. Peoples is working to find the right balance for growth, working within available regulatory processes to address our needs for rate relief, while ensuring the affordability of our services.

Q. What is Peoples doing to manage this growth effectively for customers?

A. We are focused in three areas.

First, we are focused on enhancing the resilience, reliability, and efficiency of our existing distribution system. The importance of reliability and resilience of our gas distribution facilities became clearer during Hurricanes Helene and Milton in 2024. We must ensure that our system has the ability in the right places to meet growing demand from existing customers. We have implemented an enhanced integrated resource planning process ("IRP") to prioritize our work in this area. Witness Richard will explain our IRP process and how we will invest capital for reliability, resilience, and efficiency to improve the capacity on portions of our system, both for storm resilience and for the purposes of meeting new anticipated demand.

Second, in 2024 we developed, and are currently executing, a "focused growth" strategy aimed specifically at serving Large Commercial customers such as ports, military bases, healthcare institutions, hotels, and restaurants so they can use gas to optimize their own energy usage. Focusing on these types of customers will diversify our revenue sources and will generate additional revenues that will help recover the fixed costs of our operations. This will benefit all customers as fixed costs can be spread over a larger number of customers and our capital becomes more efficiently deployed.

Finally, serving new residential and small commercial customers will always be important to us. We continue to see strong demand for our services from these customer classes.

Q. How is Peoples working within available regulatory processes to address its needs for rate relief?

A. We have made several petitions before the Commission to provide for other avenues of timely rate relief. We have filed a petition with the Commission that is currently pending and is designed to moderate residential bills and the portion of our overall revenue requirement to be recovered through base rates. Specifically, we are requesting changes to our swing service charge and off-system sales mechanism that would reduce the amount of upstream capacity costs allocated to residential customers in our purchase gas adjustment and increase the incentives as we pursue off-system capacity sales (Docket No. 20250026-GU). The updated incentive will continue to provide benefits to the general body of customers.

To help moderate the impact of our rate increase in this proceeding, we filed a petition requesting that the amortization life for our WAM system be extended from the 15 years approved in our last rate case to 20 years but dismissed it without prejudice so we could make the same request in this case. Granting this request would lower the annual amortization expense associated with WAM and our proposed 2026 base rate increase.

Witness Nichols explains how we have accounted for both off-system sales and the WAM amortization in our 2026 test year forecast in his prepared direct testimony. Witness Richard explains why the amortization period for WAM assets should be extended to 20 years in his testimony.

Finally, we have been actively involved in the Commission's efforts to adopt Rule 25-7.150, Florida Administrative Code. This rule will create a Natural Gas Facilities Relocation Cost Recovery Clause that would allow the company to recover costs associated with relocating natural gas facilities when required by a government authority for road and other public infrastructure projects.

This new clause will allow the company to recover significant governmentally imposed relocation costs through a clause mechanism rather than through a full or limited base rate proceeding. Witness Nichols explains how we have accounted for natural gas facility relocation costs in our 2026 test year forecast in his prepared direct testimony.

We are hopeful that these efforts, among others, will moderate our need to file future general base rate increases and the size of the requests when we make them. With ongoing customer demand that far outpaces our ability to effectively recover costs in a timely manner and to manage our company in a prudent manner, we need to keep exploring these and similar mechanisms. As always, we are open to further conversation and welcome the Commission's input.

Q. How does the company align its day-to-day activities with these strategic priorities?

A. Our strategic pillars set the tone for and are reflected in our 2025 Balanced Scorecard, which is included as Document No. 4 of my exhibit (with specific and confidential financial targets redacted). Our BSC applies to all of our approximately 812 team members and serves to align them around our strategic pillars as they are translated into the company's annual goals.

Our BSC reflects a balance of safety, people, customer, asset management, and financial goals that promote the interests of our customers. This balance was key to our strong safety, operational, and financial performance in 2024.

How our BSC goals focus the efforts of our employees and influence employee compensation are explained in the prepared direct testimony of witness Bluestone.

II. CHANGES AND ACCOMPLISHMENTS SINCE LAST RATE CASE

Q. When was the company's last rate case?

A. We filed our last general base rate increase request two years ago on April 4, 2023 ("last rate case"). We requested a net annual revenue increase of approximately $127.6 million and a mid-point return on equity ("ROE") of 11.0 percent based on a forecasted 2024 test year. The Commission issued Order No. PSC-2023-0388-FOF-GU on December 27, 2023 in Docket No. 20230023-GU, which approved our proposed test year, granted a net annual revenue increase of approximately $106.7 million, and set our midpoint ROE at 10.15 percent.

Q. What organizational and people changes has Peoples made since its last rate case?

A. We transferred responsibility for our safety efforts from Luke Buzard, Vice President of Regulatory and External Affairs, to Timothy O'Connor and responsibility for External Affairs from witness O'Connor to witness Buzard.

We improved our supply chain management efforts and increased the number of Peoples employees providing information technology support by moving them from Tampa Electric to Peoples. These changes streamline functions and benefit our customers as described in the prepared direct testimony of witnesses O'Connor, Buzard, and Richard.

Jon DeVries, Vice President of Finance, joined the company in late 2023 to succeed Rachel Parsons and recently left the company. Andrew Nichols and Jeff Chronister, Vice President of Finance for Tampa Electric and TECO Holdings, Inc. (parent company of TECO Gas Operations, Inc.) are testifying on budgeting, finance, and revenue requirement issues in this case. Witness Buzard has taken on interim leadership of the Finance function.

Q. Has Peoples had any significant accomplishments since its last rate case?

A. Yes. Among other things, the company's safety record continues to be strong. The company has one of the lowest OSHA Lost Time Injury rates for team members and contractors in the gas industry. Peoples received the Industry Leader Accident Prevention Award from the American Gas Association for maintaining a DART (Days Away, Restricted, or Transferred) rate below the industry average in 2023.

Since 2022, Peoples' intense focus on reducing pipeline damages through public education and locator training has resulted in fewer operator-caused, no-notification, and high-risk damages, all of which improve public safety.

We continue to have a solid driving record, which is important, because we drive over 9 million miles a year to serve our customers. Witness O'Connor explains these accomplishments further in his prepared direct testimony.

In the customer service area, according to J.D. Power 2024 studies, customers ranked Peoples first in brand appeal for gas utilities in the South, as well as second overall in customer satisfaction for gas utilities in the South Mid-Size Segment. That same year Cogent Syndicated named Peoples a Most Trusted Brand and Customer Champion. The company also received high scores from Cogent for ease of doing business.

Peoples received fewer than 100 FPSC complaints (just 0.02 percent of our over 508,000 customers) annually in the past three years. Witness Washington explains these accomplishments further in her prepared direct testimony.

We have further developed our talent management and development processes and experienced low attrition in 2024.

Finally, I am also very proud of our project execution, capital management and financial management process improvements. Our Design and Construction Performance

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Improvement ("DCPI") Project yielded approximately $6.5 million in annualized capital and efficiency savings for customers. In addition, our enhanced supply chain ("SC") organization has also realized value savings of approximately $4 million. Witness Richard provides additional details regarding both the DCPI and SC value creation in his prepared direct testimony.

Each of these accomplishments is a critical performance indicator as we continue to grow and advance as a company.

Q. How was the company's financial performance in 2024?

A. The company's jurisdictional revenues in 2024 were $460.8 million, which is within about half a percent of the Commission approved 2024 test year revenues in our last rate case. Our O&M expenses for 2024 were $138.1 million, or about $2.0 million (1.4 percent) lower than the O&M expense level approved by the Commission in our last rate case. We earned 10.37 percent ROE, which is slightly above our FPSC-approved mid-point ROE.

Q. Do you consider the company's 2024 financial performance to be an accomplishment?

A. Yes. It is reasonable for a utility to earn close to its mid-point ROE in the first year new base rates go into effect; however, it was not clear in January 2024 that we would be able to do that.

Q. Why wasn't it clear?

A. As part of our routine management activities, we prepared a re-forecast of 2024 operating revenues in January 2024. Our updated forecast pointed to lower 2024 revenues than those reflected in the forecast we used in our rate case, which was prepared in the fall of 2022. We also became aware that certain forecasted costs for 2024, such as transportation, insurance, and labor and employee benefits, would be higher than expected compared to our last rate case forecast, which by then was 16 months old. It also became clear that costs associated with renewing long-term contracts with construction and other outside service providers would be higher than those reflected in the existing contracts. The combination of these factors pointed to an unexpectedly challenging 2024. While the increases are consistent with the inflationary environment in Florida, the extent of the inflation could not have been foreseen in late 2022 when we prepared the budget used in our last rate case.

Q. What actions did the company take in early January 2024 in response to these challenges?

A. We took several steps, each of which are more fully explained by witnesses Nichols, Chronister, Bluestone, O'Connor, and Richard in their prepared direct testimony. They included aggressive actions to identify incremental revenue from large customers, moderating our employee hiring, evaluating our approach for charging and allocating costs to SeaCoast, reviewing our accounting policies for capitalizing operations and maintenance expenses, and pushing our team to be even more efficient. We were also cognizant that interest rates were above recent levels in early 2024, so like other utilities in North America, we made modest adjustments to our capital spending plans.

Q. Should Peoples be criticized for adjusting in January 2024 the 2024 forecast it prepared in late 2022 for its last rate case?

A. No. The leadership team at Peoples makes decisions to manage our business every day as new information becomes available and conditions change. However, we always review our core priorities, i.e., safely and reliably serving both our current and new customers. Updating the forecasts we use to manage our operations and to serve customers is part of running our business. We took reasonable actions to modestly adjust our business plans to ensure that we could provide excellent customer service, executed the plans, and had reasonable financial results in 2024. I am proud of the work we accomplished in 2024 and expect to continue managing our operations to provide safe, reliable, and high-quality customer service in 2025, 2026, and beyond.

III. NEED AND REQUEST FOR RATE INCREASE

Q. What is the company’s financial outlook for 2025 and 2026?

A. Based on current rates, base revenues are expected to increase from 2024 by 3.8 percent or $16.6 million to approximately $459.1 million in the 2026 projected test year. In part because a high proportion of our new customer growth is residential, the associated revenue growth will not be sufficient to cover the cost increases our business is experiencing (labor, materials, insurance, property taxes, and cost of capital), nor will it allow the company to earn a reasonable return on its investments to serve our customers. Despite our efforts to manage our cost profile in light of this revenue reality, the company projects that it will earn below the bottom of our currently approved ROE range of 9.15 percent in 2025 and approximately a 5.70 percent ROE in 2026 without rate relief.

Q. What rate increases does the company propose in this proceeding?

A. Peoples requests that the Commission approve new base rates and charges to be effective with the first billing cycle in January 2026 to generate a net incremental base rate revenue increase of approximately $96.9 million with a subsequent year adjustment ("SYA") to be effective with the first billing cycle of 2027 of approximately $26.7 million. As discussed by witness Chronister, the company's proposed 2027 SYA will allow the company to recover the revenue requirement associated with the annualized incremental capital investment at the end of 2026 and an associated adjustment for related operating expenses. The company's 2026 request includes about $6.7 million in revenue requirements that will be transferred from the current Cast Iron/Bare Steel Replacement Rider ("Rider CI/BSR") into base rates.

Witness Nichols will explain the calculation of the company's proposed 2026 base rate increase in his prepared direct testimony. Witness Chronister will explain the calculation of and reasons to approve our proposed 2027 SYA in his prepared direct testimony. Witness Buzard and company witness John Taylor will present the base rates and charges the company proposes to implement in its 2026 base rate increase and 2027 SYA in their direct testimony.

Q. What factors contribute to the company's need for a base rate increase in 2026?

A. Rate base growth to support new customers and maintain appropriate safety, reliability, and resiliency standards, related depreciation and property tax expense increases, pipeline safety and compliance costs, and higher costs affecting all aspects of the company's operations are the major factors contributing to our need for a rate increase.

Q. How does rate base growth contribute to the company's need for a rate increase in 2026?

A. Peoples operates its system across the state of Florida and is expanding to serve residential and small commercial development while expectations of natural gas service have evolved. To meet this demand and new expectations, Peoples must invest capital to serve the next home or business while ensuring the safety, reliability, resiliency, and efficiency of the existing distribution system. Peoples expects to invest over $831 million in capital projects in 2025 and 2026. About $362 million will be invested to support customer growth and about $369 million will be directed towards enhancing reliability, resilience, and efficiency.

This includes approximately $66.9 million (excluding AFUDC charges) for the total capital costs associated with our move to a new corporate office. Of this, $14.8 million has been budgeted for capital expenditures in 2025. The new building is not located in a potential flood zone and is designed to promote reliable service during weather events when our customers need us the most.

The remaining $101 million will be spent to replace legacy pipe under the company's Rider CI/BSR.

Rate base growth and related impacts will account for more than 70 percent of the company's proposed base rate increase.

Witness Richard will further explain the company's capital spending plans in his prepared direct testimony.

Q. How does depreciation expense contribute to the company's need for a rate increase in 2026?

A. Using the company's currently approved depreciation rates, depreciation and amortization expense is projected to increase by 21 percent, rising from $87 million in 2024 to $106 million in 2026. This increase is attributed to the projected growth in rate base described above. Witness Nichols will further explain the company's projected 2026 level of depreciation and amortization expense in his prepared direct testimony.

Q. How do pipeline safety and compliance contribute to the company's need for a rate increase in 2026?

A. As Peoples' customer base and distribution system grow, so do the company's efforts and costs to ensure safety and compliance. Evolving federal safety and security requirements add to the need for more activities and investments. Peoples' safety and compliance programs prevent incidents by establishing rigorous safety standards and procedures for the design, construction, operation, and maintenance of the natural gas distribution system.

Essential safety and maintenance activities like locating, leak and atmospheric surveillance, emergency response, and cathodic protection continue to expand in volume and breadth as the system grows to serve Florida.

Although revenue from new customers helps offset some of these costs, the influence of distance, labor costs and contractor pricing, among many other inflationary factors, make operating and maintaining our system safely and in compliance with applicable pipeline safety requirements more expensive. Witness O'Connor will explain this further in his prepared direct testimony.

Q. How do higher prices for the goods and services Peoples uses to serve customers contribute to the company's need for a rate increase in 2026?

A. Higher prices continue to add to the cost of doing business, and Peoples is not immune to these impacts. These higher prices are reflected in O&M and capital costs during 2025 and our proposed 2026 test year. The long-term blanket contracts Peoples had with vendors shielded its customers from increases in construction costs over the last five years. However, in 2025, the company anticipates a significant rise in costs due to renegotiated blanket contract rates.

O&M expenses have also been subject to market inflationary pressures. However, the company’s process improvement initiatives, supply chain efficiencies, updated capitalization policies, and avoided costs will keep its forecasted 2026 O&M expenses below the Commission's benchmark on an overall basis. As further discussed by witness Nichols, the company’s forecasted total 2026 adjusted O&M expenses are below the calculated total 2026 O&M benchmark by about $1.7 million when using the Commission’s O&M compound multiplier methodology. This shows that the company’s overall 2026 O&M expense level is reasonable.

Nevertheless, rising expenses related to higher labor costs, contractors, materials, insurance, and healthcare benefits continue to exert considerable upward pressure on the company’s overall business costs. Peoples’ witnesses O’Connor, Richard, and Nichols will further explain how higher costs impact our need for a rate increase in their prepared direct testimony.

Q. How do changes to the cost of capital contribute to the company's need for a rate increase in 2026?

A. A reasonable ROE is essential for a regulated utility to attract the capital necessary to make long-term investments, maintain and improve the company's quality of service, and control costs for customers over time. Peoples believes that its currently approved mid-point ROE is too low and requests that the Commission approve an authorized midpoint ROE of 11.1 percent, with a range of plus or minus 100 basis points. This proposed 95 basis point increase accounts for approximately $18.3 million or 17.7 percent of the company's 2026 requested revenue increase. Company witness Dylan D'Ascendis explains the basis for this recommendation in his prepared direct testimony.

Q. Why is the company proposing an SYA for 2027?

A. As I previously noted, Peoples is working to find the right balance for growth and a way to work within available regulatory processes to address our needs for rate relief as we continue to see significant demand from new customers. Fundamentally, we believe that approving a SYA as part of this proceeding is a more efficient and cost-effective process than filing another time consuming and expensive base rate increase proceeding as soon as this one is over. Witness Chronister explains other reasons to approve our proposed 2027 SYA in his prepared direct testimony.

Q. What actions and measures has Peoples taken to avoid requesting or minimizing its request for rate relief?

A. Peoples continues to search for ways to boost efficiency and control costs in running its growing distribution system. Peoples has allocated resources and implemented process improvements to efficiently operate its business and will continue to do so.

More specifically, Peoples has taken the following steps to avoid requesting rate relief and to moderate the amount of the increase that we are requesting:

1. Our Design and Construction Performance Improvement project achieved capital cost savings by enhancing inspector productivity and improving processes, which resulted in reduced labor and consulting expenses. Witness Richard explains this project further in his prepared direct testimony.

2. We employ a strategy for hiring that includes insourcing capabilities required of a growing, increasingly complex company when appropriate. We have avoided cost increases by insourcing various operations activities previously conducted by outside contractors, including locators, meter readers, and inspectors. We also hire corporate roles to focus on things like change management and process improvements that otherwise would be fulfilled through the use of more expensive external contractors. The company has also delayed planned hiring to accommodate rising costs that are influencing our business. Witnesses Richard, O'Connor, and Bluestone explain these efforts further in their prepared direct testimonies.

3. We have made smart use of technology to be more efficient, which moderates operating and maintenance expenses. Our new WAM system has improved operating efficiency as predicted in our last rate case when we agreed to adjust O&M expenses to reflect future efficiencies. Witnesses Richard and O'Connor explain these efforts further in their prepared direct testimonies.

4. Through our Supply Chain team, Peoples has attained

cost savings by negotiating better contracts, finding more favorable material pricing, and capturing rebates. Witness Richard explains this effort further in his prepared direct testimony.

5. Peoples has evaluated labor and corresponding costs and updated assumptions used to allocate costs to capital. These updates better align accounting treatment with the cost causes, which benefited customers through lower O&M by over $6 million in 2024. Witness Nichols explains these changes further in his prepared direct testimony.

Q. Which witnesses will be testifying on the key elements of the company's proposed 2026 test revenue requirement and 2027 SYA?

A. The prepared direct testimony of Peoples witnesses Chronister, D'Ascendis and Eric Fox support the equity ratio, ROE, and load forecast components of our proposal, respectively. Witness Buzard explains how the company used the load forecast prepared by the company's forecasting team, which was evaluated by witness Fox to develop its 2026 test year revenue forecast.

Witnesses Washington, O'Connor, Richard, and Bluestone, Buzard, and Nichols support the level of test year rate base and O&M expenses in their areas.

Witness Nichols presents and explains our revenue requirement calculation, which includes our 2026 financial forecast (and all of its major elements) and proposed overall rate of return in his prepared direct testimony. He will also explain why 2026 is a reasonable test year for ratemaking and how our forecasting process yields a test-year budget that is appropriate for ratemaking purposes. He will also explain the work we did on cost allocations to SeaCoast and the capitalization of administrative and general expenses. Witness Chronister will present the calculation of our 2027 proposed SYA.

Q. Is the company proposing any cost-of-service methodology or major tariff changes as part of its petition?

A. The rapid growth of our distribution system has led Peoples to reevaluate the appropriateness of the cost-of-service methodology and rate design it has used for many years. The company’s proposed base rate increases will rely on an updated cost of service study and rate design changes to simplify customer bills, promote fairness based on cost-causation principles, improve administrative efficiency, and enhance revenue stability. These improvements will simplify billing classes and better allocate growth-related costs to customers. Witnesses Buzard and Taylor will explain these proposed changes in their prepared direct testimonies.

Our filing also includes proposed tariff wording changes and updated service charges all of which will be explained by witness Buzard in his direct testimony.

Q. What impact will the requested 2026 base rate increase have on typical Residential and Small Commercial customers' bills?

A. Based on the company's current gas commodity price forecast and our proposed 2026 base rate increase, we expect the typical monthly bill for Residential (RS-2) customers to be approximately $72. For Small Commercial (GS-1) customers, we expect our typical monthly bill in 2026 to be approximately $306, not including gas commodity costs. On a percentage basis, our typical Residential (RS-2) and Small Commercial (GS-1) monthly bills will be about 18 percent and 4 percent higher than in 2025, respectively.

Q. What impact will the company's proposed 2027 SYA have on the bills of typical Residential and Small Commercial customers?

A. If the Commission approves our 2026 base rate increase and 2027 SYA as requested, and using the company's current gas commodity price forecast, we expect our typical monthly bill for Residential (RS-2) customers in 2027 to be approximately $75. For Small Commercial (GS-1) customers, we expect our typical monthly bill in 2027 to be about $306 (without gas commodity), which is the same as in 2026. On a percentage basis, our 2027 typical Residential (RS-2) bill will be about 23 percent over 2025 bills and about 4 percent over 2026 bills. Our typical Small Commercial monthly bill for 2027 will be about the same as in 2026. These bill impacts are reflected in Document No. 5 of my exhibit.

Witness Buzard explains our proposed base rates and charges for 2026 and 2027 (with the SYA) and other typical bill information in his prepared direct testimony and exhibit.

Q. Has Peoples considered the impact its proposed rate changes will have on the affordability of its services?

A. Yes. Peoples understands that our customers choose to use natural gas and has been mindful of the affordability of our services long before the Legislature introduced the concept of "affordability" into Florida's energy policy in 2024. We believe that our services remain affordable for our current and future customers if our rate increase requests are granted.

Q. How does Peoples think about affordability?

A. We generally agree with the Commission's view of affordability reflected in Order No. PSC-2025-0038-FOF-EI, dated February 3, 2025 in Docket No. 20240026-EI ("Tampa Electric Final Order"). Therein, the Commission noted that "affordability" must be considered within the confines of the "fair, just, and reasonable" rates standard in Section 366.06(1), Florida Statutes, and that the Commission must consider a number of factors when applying that standard.

Peoples believes the term "affordable" is difficult to describe because its meaning varies from person to person and what may be "affordable" varies from household to household. We also believe that the affordability of utility bills depends on many factors beyond the control of a utility or the Commission, such as: individual perceptions, income levels, financial obligations, spending priorities, and spending decisions. Indeed, two families with the same income and utility bills may view the affordability of natural gas differently based on their different circumstances.

We also note that there is no universally accepted definition or metric for affordability of gas rates or bills.

Q. What factors does Peoples consider when evaluating whether its services are affordable?

A. We begin our consideration of "affordability" by noting that our customers must choose to use gas and that only about three percent of our Residential customers live in zip codes that are identified as "low-income" for purposes of accessing LIHEAP.

We listen to the feedback we get from customers via our customer experience team members and from home builders and developers. We also consider changes in the level of our bad debt expense and the demand we are experiencing from our customers for LIHEAP assistance.

Q. Do those factors point to an affordability issue?

A. No. The slight increase in bad debt expense for 2024 was in line with our overall revenue increase and below industry average, and we do not expect unusual increases in 2025 and 2026. In addition, a large portion of the LIHEAP money available to our low-income customers went unclaimed in 2024. Witness Washington will provide more information on these points in her prepared direct testimony.

Q. Are the company's proposed 2026 base rates and charges fair, just and reasonable?

A. Yes. We understand that our customers do not like rate increases, but we believe the total proposed price, along with our proposed base rates and charges, are fair, just, and reasonable. We further believe that our proposed rates, if approved, will continue to position our gas service as a valuable alternative to other energy choices and that our services will continue to be cost-effective, affordable, and provide value for current and future customers in all of our customer classes.

While affordability is frequently considered from the viewpoint of Residential customers, it is equally crucial for Commercial and Industrial customers. Natural gas promotes energy security for all of our customers and enhances economic efficiency for many businesses, both of which contribute to the safety, success, and economic health of Florida.

IV. SUMMARY

Q. Please summarize your prepared direct testimony.

A. I am proud of the progress Peoples has made since our last rate case and believe we are continuing to improve the way be provide safe and reliable gas service to our customers. Our proposed rate increase request reflects the level of resources we need to: continue growing with Florida; to improve the reliability, resilience, and efficiency of our system; and to maintain our financial integrity. Our proposed rates reflect a fair return on equity, prudent capital investments, and reasonable levels of operations and maintenance expenses, and are fair, just, and reasonable.

Q. Does this conclude your prepared direct testimony?

A. Yes.

(Whereupon, prefiled direct testimony of David J. Garrett was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Rate Increase by Peoples Gas System, Inc.	Docket No. 20250029-GU Filed: June 30, 2025

DIRECT TESTIMONY

OF

DAVID J. GARRETT

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

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DIRECT TESTIMONY

OF

DAVID J. GARRETT

On Behalf of the Office of Public Counsel

before the

Florida Public Service Commission

DOCKET NO: 20250029-GU

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is David J. Garrett. I am a consultant specializing in public utility regulation. I am the managing member of Resolve Utility Consulting PLLC.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a B.B.A. with a major in Finance, an M.B.A., and a Juris Doctor from the University of Oklahoma. I worked in private legal practice for several years before accepting a position as assistant general counsel at the Oklahoma Corporation Commission in 2011. At the Oklahoma commission, I worked in the Office of General Counsel in regulatory proceedings. In 2012, I began working for the Public Utility Division as a regulatory analyst providing testimony in regulatory proceedings. After leaving the Oklahoma commission, I formed Resolve Utility Consulting PLLC, where I have represented various consumer groups and state agencies in utility regulatory proceedings, primarily in the areas of cost of capital and depreciation. I am a Certified Depreciation Professional with the Society of Depreciation Professionals. I am also a Certified Rate of Return Analyst with the Society of Utility and Regulatory Financial Analysts. I am a member of the Oklahoma Bar, but I am not providing legal advice in this proceeding or the State of Florida. A more complete description of my qualifications and regulatory experience is included in my curriculum vitae.[1]

Q. DESCRIBE THE PURPOSE AND SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING.

A. I am testifying on behalf of the Florida Office of Public Counsel ("OPC") in response to the petition for rate increase by Peoples Gas System ("PGS" or the "Company"). Specifically, I address the cost of capital and fair rate of return for PGS in response to the direct testimony of Company witness Dylan D'Ascendis.

II. EXECUTIVE SUMMARY

Q. DESCRIBE PGS'S POSITION REGARDING THE AWARDED RATE OF RETURN IN THIS CASE.

A. PGS proposes an awarded ROE of 11.1%.[2] PGS also proposes a capital structure consisting of approximately 55% equity and 45% debt.[3] Mr. D'Ascendis relies on the

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[1] Exhibit DJG-1.

[2] Direct Testimony of Dylan W. D'Ascendis, p. 5, lines 1-12.

[3] *Id.* PGS is proposing a capital structure with investor-provided funding sources consisting of 41.69% long-term debt, 3.61% short-term debt, and 54.70% equity. Throughout my testimony, I refer to these figures in rounded

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Discounted Cash Flow Model ("DCF Model"), the Capital Asset Pricing Model ("CAPM"), and other risk premium models as part of his recommendation.

Q. PLEASE SUMMARIZE YOUR ANALYSES AND CONCLUSIONS REGARDING PGS'S COST OF EQUITY.

A. PGS has proposed an excessive awarded ROE in this case. Analysis of an appropriate awarded ROE for a utility should begin with a reasonable estimation of the utility's cost of equity. In estimating PGS's cost of equity, I performed a cost of equity analysis on a proxy group of utility companies with relatively similar risk profiles. Based on this proxy group, I evaluated the results of the two most widely used and widely accepted financial models for calculating cost of equity in utility rate proceedings: the CAPM and DCF Model. I conducted two variations of both the CAPM and DCF Model. The results are shown in the figure below.

numbers, and I refer to the Company's proposed total debt ratio as 45% and equity ratio as 55% from investor-supplied sources.

Figure 1:
Cost of Equity Model Results

Model	Cost of Equity
CAPM (at Proxy Debt Ratio)	9.0%
Hamada CAPM (at Company-Proposed Debt Ratio)	8.6%
DCF Model (Analyst Growth)	7.8%
DCF Model (Sustainable Growth)	7.4%
Model Average	**8.2%**
Model Range	**7.4% -- 9.0%**
Recommended ROE	**9.0%**

As shown in this figure, the results of my modeling range from 7.4% - 9.0%.[4]

Q. BASED ON YOUR COST OF EQUITY ANALYSES, WHAT IS YOUR PROPOSED ROE FOR PGS?

A. I propose an authorized ROE of 9.0% for PGS, which represents the top end of my cost of equity modeling range. The result of my traditional CAPM is 9.0%. However, in order for this result to be accurate, an adjustment must be made to PGS's ratemaking capital structure, as further discussed below.

[4] Exhibit DJG-12.

Q. WHAT RATEMAKING CAPITAL STRUCTURE DO YOU PROPOSE FOR PGS?

A. In the process of determining a fair rate of return for PGS, not only must the authorized ROE be considered, but also the ratemaking capital structure. PGS's proposed debt ratio of 45% is notably lower than the average debt ratio of the proxy group, which is 51%. This means that PGS has less financial risk relative to the proxy group. Thus, in order for the indicated cost of equity under the CAPM to be correct, we must adjust the result based on PGS's lower risk profile. We can accomplish this through a mathematical model called the Hamada model. Application of the Hamada model shows that PGS's cost of equity under its equity-rich capital structure is only 8.6% once its lower debt ratio is accounted for.

Q. BASED ON THE RESULTS OF YOUR COST OF EQUITY ANALYSES, WHAT IS YOUR RECOMMENDATION TO THE COMMISSION PGS'S AUTHORIZED RATE OF RETURN.

A. PGS's cost of equity estimate of 9.0% under the CAPM is only accurate if it is assumed the Company's total debt ratio is 51%. Otherwise, under PGS's proposed capital structure, its indicated cost of equity under the CAPM is only 8.6%. Thus, along with my recommended ROE of 9.0%, I also recommend a ratemaking capital structure for

PGS consisting of 51% total debt, and 49% common equity. My recommendations are presented in the following figure.[5]

Figure 2:
Awarded Return Recommendation

Capital Component	Proposed Ratio	Cost Rate	Weighted Cost
Long-Term Debt	47.39%	5.64%	2.67%
Short-Term Debt	3.61%	4.55%	0.16%
Common Equity	49.00%	9.00%	4.41%
Total	100.00%		7.25%

These issues are discussed in more detail in my testimony.

III. REGULATORY STANDARDS

Q. PLEASE DISCUSS THE LEGAL STANDARDS GOVERNING THE AWARDED RATE OF RETURN ON CAPITAL INVESTMENTS FOR REGULATED UTILITIES.

A. In *Wilcox v. Consolidated Gas Co. of New York*, the U.S. Supreme Court first addressed the meaning of a fair rate of return for public utilities.[6] The Court found that "the amount of risk in the business is a most important factor" in determining the appropriate

[5] *See also* Exhibit DJG-16. This weighted average cost of capital is based on investor-supplied sources of capital and reflects PGS's requested costs of short-term and long-term debt. For OPC's recommended cost of debt and consolidation of all OPC cost of capital adjustments, please see the direct testimony of OPC witness Lane Kollen, who presents a recommended weighted average cost of capital based on all capital components.

[6] *Wilcox v. Consolidated Gas Co. of New York*, 212 U.S. 19 (1909).

allowed rate of return.[7] In the two landmark cases that followed, the Court set forth the standards by which public utilities are allowed to earn a return on capital investments. First, in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, the Court held:

> 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. . . but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[8]

Second, in *Federal Power Commission v. Hope Natural Gas Company*, the Court expanded on the guidelines set forth in *Bluefield* and stated:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses <u>*but also for the capital costs of the business*</u>. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[9]

While I am not testifying as an attorney, I believe the cost of capital models I have employed in this case are in accordance with the foregoing legal standards.

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[7] *Id.* at 48.

[8] *Bluefield Water Works & Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679, 692-93 (1923).

[9] *Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (emphasis added) (internal citations omitted).

Q. SHOULD THE AWARDED RATE OF RETURN BE BASED ON THE COMPANY'S ACTUAL COST OF CAPITAL?

A. Yes. The *Hope* Court makes it clear that the awarded return should be based on the actual cost of capital. Moreover, the awarded return must also be fair, just, and reasonable under the circumstances of each case. Under the rate base rate of return model, a utility should be allowed to recover all its reasonable expenses, its capital investments through depreciation, and a return on its capital investments sufficient to satisfy the required return of its investors. The "required return" from the investors' perspective is synonymous with the "cost of capital" from the utility's perspective. Scholars agree that the allowed rate of return should be based on the actual cost of capital:

> Since by definition the cost of capital of a regulated firm represents precisely the expected return that investors could anticipate from other investments while bearing no more or less risk, and since investors will not provide capital unless the investment is expected to yield its opportunity cost of capital, the correspondence of the definition of the cost of capital with the court's definition of legally required earnings appears clear.[10]

The models I have employed in this case closely estimate the Company's market-based cost of equity. If the Commission sets the awarded return based on my lower, and more reasonable, rate of return, it will comply with the U.S. Supreme Court's standards, allow the Company to maintain its financial integrity, and satisfy the claims of its investors. On the other hand, if the Commission sets the allowed rate of

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[10] A. Lawrence Kolbe, James A. Read, Jr. & George R. Hall, *The Cost of Capital: Estimating the Rate of Return for Public Utilities*, p. 21 (The MIT Press 1984).

return *higher* than the true cost of capital, it arguably results in an inappropriate transfer of wealth from ratepayers to the utility's shareholders.

Q. WHAT DOES THIS LEGAL STANDARD MEAN FOR DETERMINING THE AWARDED RETURN AND THE COST OF CAPITAL?

A. It is important to understand that the *awarded* return and the *cost* of capital are related but different concepts. The two concepts are related in that the legal and technical standards encompassing this issue require that the awarded return reflect the true cost of capital. On the other hand, the two concepts are different in that the legal standards do not mandate that awarded returns exactly match the cost of capital. Awarded returns are set through the regulatory process and may be influenced by factors other than objective market drivers. The cost of capital, on the other hand, should be evaluated objectively and be closely tied to economic realities. In other words, the cost of capital is driven by stock prices, dividends, growth rates, and — most importantly — it is driven by risk. The cost of capital can be estimated by financial models used by firms, investors, and academics around the world for decades. The problem is, with respect to regulated utilities, there has been a trend in which awarded returns fail to closely track with actual market-based cost of capital, as further discussed below. To the extent this occurs, the results are detrimental to ratepayers and the state's economy.

Q. DESCRIBE THE ECONOMIC IMPACT THAT OCCURS WHEN THE AWARDED RETURN STRAYS TOO FAR FROM THE U.S. SUPREME COURT'S COST OF EQUITY STANDARD.

A. When the awarded ROE is set far above the *cost* of equity, it runs the risk of violating the U.S. Supreme Court's standards that the awarded return should be *based on the cost of capital*. If the Commission were to adopt the Company's position in this case, it would be permitting an excess transfer of wealth from customers to shareholders. Moreover, establishing an awarded return that far exceeds the true cost of capital effectively prevents the awarded returns from changing along with economic conditions. This is especially true given the fact that regulators tend to be influenced by the awarded returns in other jurisdictions, regardless of the various unknown factors influencing those awarded returns. This is yet another reason why it is crucial for regulators to focus on the target utility's actual *cost* of equity, rather than awarded returns from other jurisdictions. Awarded returns may be influenced by settlements and other political factors not based on true market conditions. In contrast, the market-based cost of equity as estimated through objective models is not influenced by these factors but is instead driven by market-based factors. If regulators rely too heavily on the awarded returns from other jurisdictions, it can create a cycle over time that bears little relation to the market-based cost of equity.

IV. COST OF EQUITY METHODOLOGY

Q. DISCUSS YOUR APPROACH TO ESTIMATING THE COST OF EQUITY IN THIS CASE.

A. While a competitive firm must estimate its own cost of capital to assess the profitability of competing capital projects, regulators determine a utility's cost of capital to establish a fair rate of return. The legal standards set forth above do not include specific guidelines regarding the models that must be used to estimate the cost of equity. Over the years, however, regulatory commissions have consistently relied on several models. The models I have employed in this case have been the two most widely used and accepted in regulatory proceedings for many years. These models are the DCF Model and the CAPM. The specific inputs and calculations for these models are described in more detail below.

Q. PLEASE EXPLAIN WHY MULTIPLE MODELS ARE USED TO ESTIMATE THE COST OF EQUITY.

A. The models used to estimate the cost of equity attempt to measure the return on equity required by investors by estimating several different inputs. It is preferable to use multiple models because the results of any one model may contain a degree of imprecision, especially depending on the reliability of the inputs used at the time of running the model. By using multiple models, the analyst can compare the results of the models and look for outlying results and inconsistencies. Likewise, if multiple models produce a similar result, it may indicate a narrower range for the cost of equity estimate.

Q. PLEASE DISCUSS THE BENEFITS OF CHOOSING A PROXY GROUP OF COMPANIES IN CONDUCTING COST OF CAPITAL ANALYSES.

A. The cost of equity models in this case can be used to estimate the cost of capital of any individual, publicly traded company. There are advantages, however, to conducting cost of capital analysis on a "proxy group" of companies that are comparable to the target company. First, it is better to assess the financial soundness of a utility by comparing it to a group of other financially sound utilities. Second, using a proxy group provides more reliability and confidence in the overall results because there is a larger sample size. Finally, the use of a proxy group is often a pure necessity when the target company is a subsidiary that is not publicly traded. This is because the financial models used to estimate the cost of equity require information from publicly traded firms, such as stock prices and dividends.

Q. DESCRIBE THE PROXY GROUP YOU SELECTED IN THIS CASE.

A. In this case, I chose to use the same proxy group used by Mr. D'Ascendis. There could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups.[11] By using the same proxy group, we can remove a relatively insignificant variable from the equation and focus on the primary factors driving the Company's excessive cost of equity estimate in this case.

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[11] *See* Exhibit DJG-2.

V. RISK AND RETURN CONCEPTS

Q. DISCUSS THE GENERAL RELATIONSHIP BETWEEN RISK AND RETURN.

A. As discussed above, risk is the most important factor for the Commission to consider when determining the allowed return and there is a direct relationship between risk and return: the more (or less) risk an investor assumes, the larger (or smaller) return the investor will demand. There are two primary types of risk: firm-specific risk and market risk. Firm-specific risk affects individual companies, while market risk affects all companies in the market to varying degrees.

Q. DISCUSS THE DIFFERENCES BETWEEN FIRM-SPECIFIC RISK AND MARKET RISK.

A. Firm-specific risk affects individual companies, rather than the entire market. For example, a competitive firm might overestimate customer demand for a new product, resulting in reduced sales revenue. This is an example of a firm-specific risk called "project risk."[12] There are several other types of firm-specific risks, including: (1) "financial risk" — the risk that equity investors of leveraged firms face as residual claimants on earnings; (2) "default risk" — the risk that a firm will default on its debt securities; and (3) "business risk" — which encompasses all other operating and managerial factors that may result in investors realizing less than their expected return in that particular company. While firm-specific risk affects individual companies,

[12] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 62-63 (3rd ed., John Wiley & Sons, Inc. 2012).

market risk affects all companies in the market to varying degrees. Examples of market risk include interest rate risk, inflation risk, and the risk of major socio-economic events. When there are changes in these risk factors, they affect all firms in the market to some extent.[13]

Analysis of the U.S. market in 2001 provides a good example for contrasting firm-specific risk and market risk. During 2001, Enron Corp.'s stock fell from $80 per share to less than $1 per share, and the company filed for bankruptcy at the end of the year. If an investor's portfolio had held only Enron stock at the beginning of 2001, this irrational investor would have lost the entire investment by the end of the year due to assuming the full exposure of Enron's firm-specific risk (in that case, imprudent management). On the other hand, a rational, diversified investor who invested the same amount of capital in a portfolio holding every stock in the S&P 500 would have had a much different result that year. The rational investor would have been relatively unaffected by the fall of Enron because her portfolio included about 499 other stocks. Each of those stocks, however, would have been affected by various *market* risk factors that occurred that year, including the terrorist attacks on September 11th, which affected all stocks in the market. Thus, the rational investor would have incurred a relatively minor loss due to market risk factors, while the irrational investor would have lost everything due to firm-specific risk factors.

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[13] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 149 (9th ed., McGraw-Hill/Irwin 2013).

Q. CAN INVESTORS MINIMIZE FIRM-SPECIFIC RISK?

A. Yes. A fundamental concept in finance is that firm-specific risk can be eliminated through diversification.[14] If someone irrationally invested all their funds in one firm (such as Enron), they would be exposed to all the firm-specific risk *and* the market risk inherent in that single firm. Rational investors, however, are risk-averse and seek to eliminate risk they can control. Investors can essentially eliminate firm-specific risk by adding more stocks to their portfolio through a process called "diversification." There are two reasons why diversification eliminates firm-specific risk. First, each stock in a diversified portfolio represents a much smaller percentage of the overall portfolio than it would in a portfolio of just one or a few stocks. Thus, any firm-specific action that changes the stock price of one stock in the diversified portfolio will have only a small impact on the entire portfolio.[15]

The second reason why diversification eliminates firm-specific risk is that the effects of firm-specific actions on stock prices can be either positive or negative for each stock. Thus, in large, diversified portfolios, the net effect of these positive and negative firm-specific risk factors will be essentially zero and will not affect the value of the overall portfolio.[16] Firm-specific risk is also called "diversifiable risk" because it can be easily eliminated through diversification.

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[14] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 179-80 (3rd ed., South Western Cengage Learning 2010).

[15] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 64 (3rd ed., John Wiley & Sons, Inc. 2012).

[16] *Id.*

Q. IS IT WELL-KNOWN AND ACCEPTED THAT, BECAUSE FIRM-SPECIFIC RISK CAN BE EASILY ELIMINATED THROUGH DIVERSIFICATION, THE MARKET DOES NOT REWARD SUCH RISK THROUGH HIGHER RETURNS?

A. Yes. Because investors eliminate firm-specific risk through diversification, they know they cannot expect a higher return for assuming the firm-specific risk in any one company. Thus, the risks associated with an individual firm's operations are not rewarded by the market. In fact, firm-specific risk is also called "unrewarded" risk for this reason. Market risk, on the other hand, cannot be eliminated through diversification. Because market risk cannot be eliminated through diversification, investors expect a return for assuming this type of risk. Market risk is also called "systematic risk." Scholars recognize the fact that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing:

> If investors can cheaply eliminate some risks through diversification, then we should not expect a security to earn higher returns for risks that can be eliminated through diversification. Investors can expect compensation *only* for bearing systematic risk (i.e., risk that cannot be diversified away).[17]

These important concepts are illustrated in the figure below. Some form of this figure is found in many financial textbooks:

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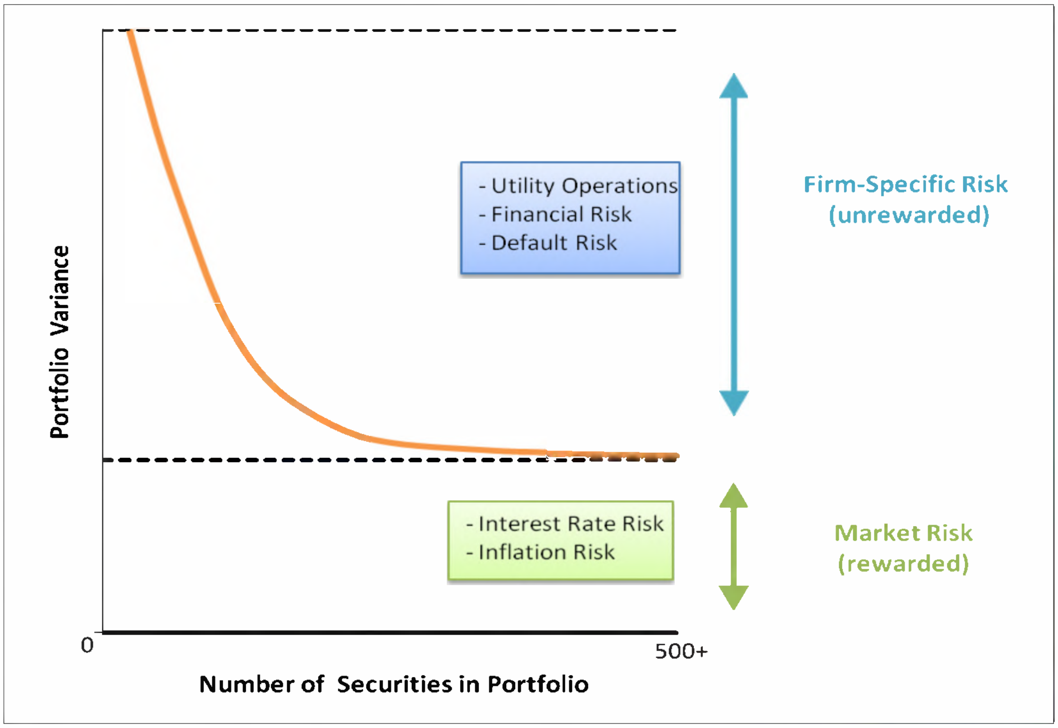
[17] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180 (3rd ed., South Western Cengage Learning 2010).

Figure 3:
Effects of Portfolio Diversification



This figure shows that as stocks are added to a portfolio, the amount of firm-specific risk is reduced until it is essentially eliminated. No matter how many stocks are added, however, there remains a certain level of fixed market risk. The level of market risk will vary from firm to firm. Market risk is the only type of risk that is rewarded by the market and is thus the type of risk the Commission should consider when determining the allowed return.

Q. DESCRIBE HOW MARKET RISK IS MEASURED.

A. Investors who want to eliminate firm-specific risk must hold a fully diversified portfolio. To determine the amount of risk that a single stock adds to the overall market portfolio, investors measure the covariance between a single stock and the market portfolio. The result of this calculation is called "beta."[18] Beta represents the sensitivity of a given security to the market as a whole. The market portfolio of all stocks has a beta equal to one. Stocks with betas greater than one are relatively more sensitive to market risk than the average stock. For example, if the market increases (decreases) by 1.0%, a stock with a beta of 1.5 will, on average, increase (decrease) by 1.5%. In contrast, stocks with betas of less than one are less sensitive to market risk, such that if the market increases (decreases) by 1.0%, a stock with a beta of 0.5% will, on average, only increase (decrease) by 0.5%. Thus, stocks with low betas are relatively insulated from market conditions. The beta term is used in the CAPM to estimate the cost of equity, which is discussed in more detail later.[19]

Q. ARE PUBLIC UTILITIES CHARACTERIZED AS DEFENSIVE FIRMS THAT HAVE LOW BETAS, LOW MARKET RISK, AND ARE RELATIVELY INSULATED FROM OVERALL MARKET CONDITIONS?

A. Yes. Although market risk affects all firms in the market, it affects different firms to varying degrees. Firms with high betas are affected more than firms with low betas, which is why firms with high betas are riskier. Stocks with betas greater than one are generally known as "cyclical stocks." Firms in cyclical industries are sensitive to recurring patterns of recession and recovery known as the "business cycle."[20] Thus,

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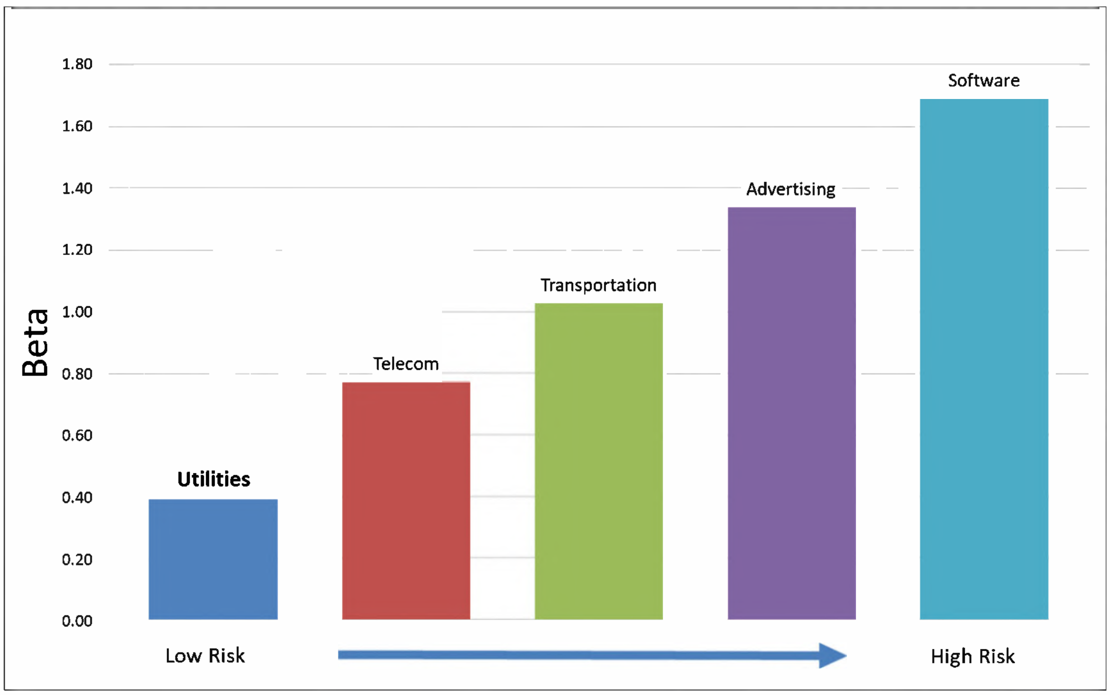
[18] *Id.* at 180-81.

[19] Though it will be discussed in more detail later, Exhibit DJG-9 shows that the average beta of the proxy group was less than 1.0. This confirms the well-known concept that utilities are relatively low-risk firms.

[20] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 382 (9th ed., McGraw-Hill/Irwin 2013).

cyclical firms are exposed to a greater level of market risk. Securities with betas less than one, on the other hand, are known as "defensive stocks." Companies in defensive industries, such as public utility companies, "will have low betas and performance that is comparatively unaffected by overall market conditions."[21] In fact, financial textbooks often use utility companies as prime examples of low-risk, defensive firms. The figure below compares the betas of several industries and illustrates that the utility industry is one of the least risky industries in the U.S. market.[22]

Figure 4:
Beta by Industry



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[21] *Id*. at 383.

[22] *See* Betas by Sector (US) available at http://pages.stern.nyu.edu/~adamodar/ (2018). (After clicking the link, click "Data" then "Current Data" then "Risk / Discount Rate" from the drop down menu, then "Total Beta by Industry Sector"). The exact beta calculations are not as important as illustrating the well-known fact that utilities are very low-risk companies. The fact that the utility industry is one of the lowest risk industries in the country should not change from year to year.

The fact that PGS, like other utilities, is a relatively low-risk company means that its cost of equity will be lower than the higher-beta firms in other industries.

VI. DISCOUNTED CASH FLOW ANALYSIS

Q. DESCRIBE THE DCF MODEL.

A. The DCF Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. The various assumptions, theories, and equations involved in the DCF Model are discussed further in the supplemental material provided in Appendix A.

Q. DESCRIBE THE INPUTS TO THE DCF MODEL.

A. There are three primary inputs in the DCF Model: (1) stock price; (2) dividend; and (3) the long-term growth rate. The stock prices and dividends are known inputs based on recorded data, while the growth rate projection must be estimated. I discuss each of these inputs separately below.

A. Stock Price

Q. HOW DID YOU DETERMINE THE STOCK PRICE INPUT OF THE DCF MODEL?

A. For the stock price (P_0), I used 30-day averages of adjusted closing stock prices for each company in the proxy group.[23] Analysts sometimes rely on average stock prices for longer periods (*e.g.*, 60, 90, or 180 days). According to the efficient market hypothesis, however, markets reflect all relevant information available at a particular time, and prices adjust instantaneously to the arrival of new information.[24] Past stock prices, in essence, reflect outdated information. The DCF Model used in utility rate cases is a derivation of the dividend discount model, which is used to determine the current value of an asset. Thus, according to the dividend discount model and the efficient market hypothesis, the value for the "P_0" term in the DCF Model should technically be the current stock price, rather than an average.

Q. WHY DID YOU USE A 30-DAY AVERAGE FOR THE CURRENT STOCK PRICE INPUT?

A. Using a short-term average of stock prices for the current stock price input adheres to market efficiency principles while avoiding any irregularities that may arise from using a single current stock price. In the context of a utility rate proceeding, there is a

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[23] Exhibit DJG-3.

[24] Eugene F. Fama, *Efficient Capital Markets: A Review of Theory and Empirical Work*, Vol. 25, No. 2 The Journal of Finance 383 (1970); *see also Corporate Finance: Linking Theory to What Companies Do*, p. 357. The efficient market hypothesis was formally presented by Eugene Fama in 1970 and is a cornerstone of modern financial theory and practice.

significant length of time from when an application or advice letter is filed and testimony is due. Choosing a current stock price for one particular day could raise a separate issue concerning which day was chosen to be used in the analysis. In addition, a single stock price on a particular day may be unusually high or low. It is arguably ill-advised to use a single stock price in a model that is ultimately used to set rates for several years, especially if a stock is experiencing some volatility. Thus, it is preferable to use a short-term average of stock prices, which represents a good balance between adhering to well-established principles of market efficiency while avoiding any unnecessary contentions that may arise from using a single stock price on a given day. The stock prices I used in my DCF analysis are based on 30-day averages of adjusted closing stock prices for each company in the proxy group.[25]

Q. WHY DID YOU USE ADJUSTED CLOSING STOCK PRICES FOR YOUR DCF ANALYSIS?

A. Adjusted closing prices, rather than actual closing prices, are ideal for analyzing historical stock prices. The adjusted price provides an accurate representation of the firm's equity value beyond the mere market price because it accounts for stock splits and dividends.

[25] Exhibit DJG-3.

B. Dividend

Q. DESCRIBE HOW YOU DETERMINED THE DIVIDEND INPUT OF THE DCF MODEL.

A. The dividend term in the DCF Model represents dividends per share (d_0). I used forward-looking annualized dividends published by Yahoo! Finance for the dividend input to my constant growth DCF Model.[26] Dividing these dividends by the stock prices for each proxy company results in the dividend yield for each company.

Q. ARE THE STOCK PRICE AND DIVIDEND INPUTS FOR EACH PROXY COMPANY A SIGNIFICANT ISSUE IN THIS CASE?

A. No. Although my stock price and dividend inputs are more recent than those used by Mr. D'Ascendis, there is not a statistically significant difference between them because utility stock prices and dividends are generally quite stable because of their low-risk nature. This is another reason that cost of capital models such as the CAPM and the DCF Model are well-suited to be conducted on utilities. The differences between the DCF Model results in this case are primarily affected by the difference in growth rate estimates.

[26] Exhibit DJG-4.

C. Growth Rate

Q. PLEASE SUMMARIZE THE GROWTH RATE INPUT IN THE DCF MODEL.

A. The most critical input in the DCF Model is the growth rate. Unlike the stock price and dividend inputs, the growth rate input (g) must be estimated. As a result, the growth rate is often the most contentious issue related to DCF Model inputs in utility rate cases. The DCF Model used in this case is based on the sustainable growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a sustainable growth rate. As stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a sustainable rate forever. For young, high-growth firms, estimating the growth rate to be used in the model can be especially difficult, and may require the use of multi-stage growth models. For mature, low-growth firms such as utilities, however, estimating the sustainable growth rate is more transparent. The growth term of the DCF Model is one of the most important, yet least understood, aspects of cost of equity estimations in utility regulatory proceedings. I provide a more detailed explanation on the various determinants of growth below.

Q. DESCRIBE THE VARIOUS DETERMINANTS OF GROWTH THAT CAN BE CONSIDERED FOR THE GROWTH RATE INPUT IN THE DCF MODEL.

A. Although the DCF Model directly considers the growth of dividends, there are a variety of growth determinants that should be considered when estimating growth rates. It should be noted that these various growth determinants are used primarily to determine the short-term growth rates in multi-stage DCF models. For utility companies, it is necessary to focus primarily on a long-term growth rate in dividends. This is also known as a "sustainable" growth rate, since this is the growth rate assumed for the company's dividends in perpetuity. That is not to say that these growth determinants cannot be considered when estimating sustainable growth; however, as discussed below, sustainable growth must be constrained much more than short-term growth, especially for young firms with high growth opportunities. Additionally, I briefly discuss these growth determinants here because it may reveal some of the sources of confusion in this area.

(1) *Historical Growth*

Looking at a firm's actual historical experience may theoretically provide a good starting point for estimating short-term growth. However, past growth is not always a good indicator of future growth. Some metrics that might be considered here are a historical growth in revenues, operating income, and net income. Since dividends are paid from earnings, historical earnings growth may provide an indication of future earnings and dividend growth.

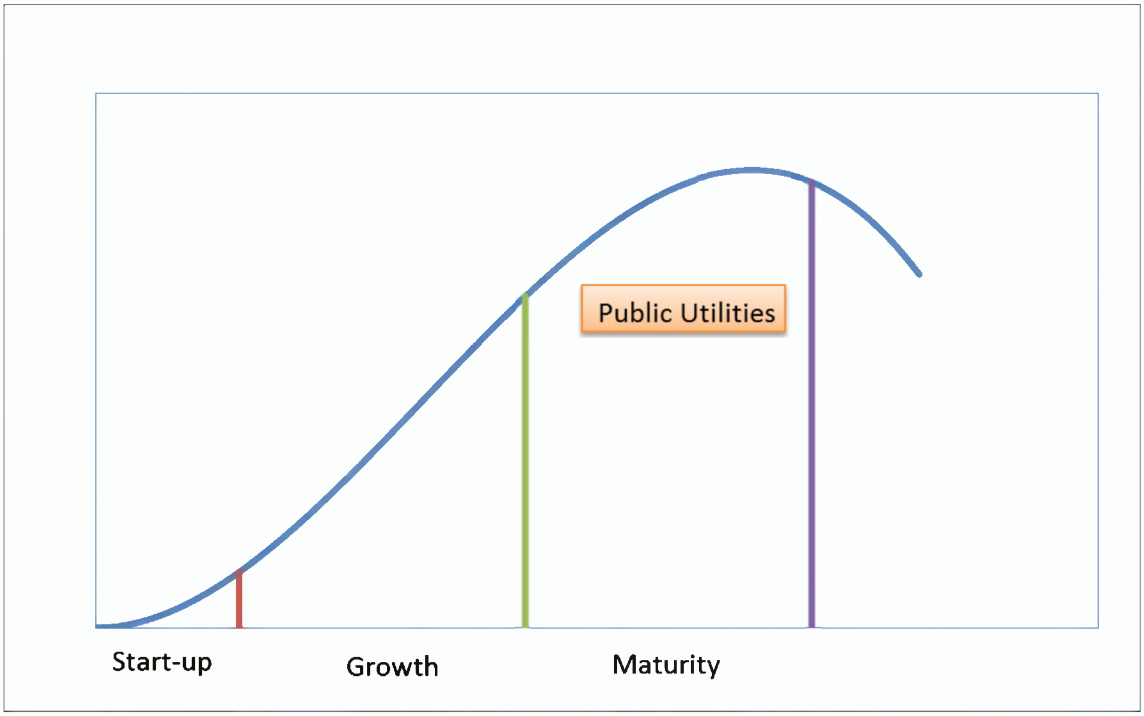
(2) *Analyst Growth Rates*

Analyst growth rates refer to short-term projections of earnings growth published by institutional research analysts such as Value Line and Bloomberg. Analyst growth rates, including the limitations with using them in the DCF Model to estimate utility cost of equity, are discussed in more detail below.

(3) Sustainable Growth Rates

In order to make the DCF Model a viable, practical model, an infinite stream of future cash flows must be estimated and then discounted back to the present. Otherwise, each annual cash flow would have to be estimated separately. Some analysts use "multi-stage" DCF Models to estimate the value of high-growth firms through two or more stages of growth, with the final stage of growth being sustainable. However, it is not necessary to use multi-stage DCF Models to analyze the cost of equity of regulated utility companies. This is because regulated utilities are already in their "sustainable," low growth stage. Unlike most competitive firms, the growth of regulated utilities is constrained by physical service territories and limited primarily by ratepayer and load growth within those territories. The figure below illustrates the well-known business/industry life-cycle pattern.

Figure 5:
Industry Life Cycle



In an industry's early stages, there are ample opportunities for growth and profitable reinvestment. In the maturity stage however, growth opportunities diminish, and firms choose to pay out a larger portion of their earnings in the form of dividends instead of reinvesting them in operations to pursue further growth opportunities. Once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one sustainable growth rate.

Q. SHOULD THE ANNUAL SUSTAINABLE GROWTH RATE USED IN THE DCF MODEL EXCEED THE ANNUAL GROWTH RATE OF THE AGGREGATE ECONOMY?

A. No. A fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates.[27] Thus, the sustainable growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true when the DCF Model is conducted on public utilities because these firms have defined service territories. As stated by Dr. Damodaran: "[i]f a firm is a purely domestic company, either because of internal constraints . . . or external constraints (such as those imposed by a government), the growth rate in the domestic economy will be the limiting value."[28]

In fact, it is reasonable to assume that a regulated utility would grow at a rate that is <u>less</u> than the U.S. economic growth rate. Unlike competitive firms, which might increase their growth by launching a new product line, franchising, or expanding into new and developing markets, utility operating companies with defined service territories are comparatively limited in their growth opportunities. Gross Domestic Product ("GDP") is one of the most widely used measures of economic production and is used to measure aggregate economic growth. According to the Congressional

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[27] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset*, 306 (3rd ed., John Wiley & Sons, Inc. 2012).

[28] *Id.*

Budget Office's 2025 Long-Term Budget Outlook, the long-term forecast for nominal U.S. GDP growth is 3.7%.[29]

Q. PLEASE DESCRIBE THE SUSTAINABLE GROWTH RATES YOU USED IN YOUR DCF MODELS.

A. For my "sustainable growth" variation of the DCF Model, I used the projected long-term, nominal GDP growth rate of 3.7%. As discussed above, it is reasonable to conclude that the long-term growth of a domestic firm cannot outpace the growth rate of the aggregate economy in which it operates (as measured by U.S. GDP in this case). For the sustainable growth variation of the DCF Model, it is reasonable to consider nominal GDP as a limit or "ceiling" for long-term earnings or dividend growth. This is because nominal GDP, unlike real GDP, accounts for inflation. So in nominal terms, it is reasonable to assume that a company's earnings and/or dividend growth would be limited by the growth rate of the aggregate economy including inflation, as measured by nominal GDP.

Q. DID YOU CONSIDER ANY OTHER TYPES OF GROWTH RATES OTHER THAN THE SUSTAINABLE GROWTH RATES DETAILED ABOVE?

A. Yes. I also conducted the "analyst growth" variation of the DCF Model. To do so, I considered projected short-term dividend growth rate estimates published by Value

[29] https://www.crfb.org/blogs/cbo-releases-march-2025-long-term-budget-and-economic-outlook.

Line.[30] I show this variation of the DCF Model because it is often presented in rate cases by ROE witnesses and considered by regulators when assessing the awarded ROE.

Q. WHAT ARE THE FINAL RESULTS OF YOUR DCF MODELS?

A. For my DCF Models, I considered two variations: one using a sustainable growth rate and one using analysts' growth rates. The sustainable growth rate DCF Model indicates a cost of equity for PGS of 7.4%. The analyst growth variation of the DCF produced a result of 7.8%.[31]

D. Response to Mr. D'Ascendis's DCF Model

Q. PLEASE SUMMARIZE THE RESULTS OF MR. D'ASCENDIS'S DCF MODEL.

A. The DCF Model conducted by Mr. D'Ascendis produced a median result of 10.50%.[32]

Q. DO THE RESULTS OF MR. D'ASCENDIS'S DCF MODEL INDICATE A REASONABLE COST OF EQUITY FOR PGS?

A. No. The results of Mr. D'Ascendis's DCF Model are overstated primarily because his reliance on non-sustainable growth rate assumptions. Mr. D'Ascendis used long-term

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[30] Exhibit DJG-6.

[31] Exhibit DJG-6.

[32] Direct Testimony of Dylan W. D'Ascendis, Exhibit No. DD-1.

growth rates in his proxy group as high as 10.0%.[33] This growth rate is more than two times the rate of projected U.S. GDP growth. Many of his other growth rates are unsustainably high. This means Mr. D'Ascendis's growth rate assumption violates the basic principle that no company can grow at a greater rate than the economy in which it operates over the long term, especially a regulated utility company with a defined service territory. Furthermore, Mr. D'Ascendis used short-term, quantitative growth estimates published by analysts. These analysts' estimates are inappropriate to use in the DCF Model as long-term growth rates because they are estimates for *short-term* growth. For example, Mr. D'Ascendis considered a growth rate estimate as high as 10.0% for Southwest Gas Holdings ("SWG") from Value Line.[34] This means that an analyst at Value Line believes SWG's earnings will quantitatively increase by 10.0% each year over the next *several* years (*i.e.*, the short-term). However, it is Mr. D'Ascendis, not the commercial analyst, who is suggesting that SWG's earnings will grow by more than two times projected GDP growth each year, and every year for many decades into the future (*i.e.*, long-term growth).[35] Thus, Mr. D'Ascendis is extrapolating the analyst's conclusions well beyond what the analyst actually reported. Furthermore, this assumption is simply not realistic, and it contradicts fundamental concepts of long-term growth. Many of Mr. D'Ascendis's other short-term growth rate estimates also exceed projected GDP growth.

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[33] *Id.*

[34] *Id.*

[35] *Id.* Technically, the constant growth rate in the DCF Model grows dividends each year to "infinity." Yet even if we assumed that the growth rate applied to only a few decades, the annual growth rate would still be too high to be considered realistic.

VII. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. DESCRIBE THE CAPM.

A. The CAPM is a market-based model founded on the principle that investors expect higher returns for incurring additional risk.[36] The CAPM estimates this expected return. The various assumptions, theories, and equations involved in the CAPM are discussed further in the supplemental material provided in Appendix B. Using the CAPM to estimate the cost of equity of a regulated utility is consistent with the legal standards governing the fair rate of return. The U.S. Supreme Court recognized that "the amount of *risk* in the business is a most important factor" in determining the allowed rate of return,[37] and that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding *risks*."[38] The CAPM is a useful model because it directly considers the amount of risk inherent in a business. It is arguably the strongest of the models usually presented in rate cases because, unlike the DCF Model, the CAPM directly measures the most important component of a fair rate of return analysis: *risk*.

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[36] William F. Sharpe, *A Simplified Model for Portfolio Analysis*, Management Science IX, pp. 277-93 (1963); *see also Corporate Finance: Linking Theory to What Companies Do*, p. 208.

[37] *Wilcox*, 212 U.S. at 48 (emphasis added).

[38] *Hope Natural Gas Co.*, 320 U.S. at 603 (emphasis added).

Q. DESCRIBE THE INPUTS FOR THE CAPM.

A. The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the equity risk premium. Each input is discussed separately below.

A. The Risk-Free Rate

Q. EXPLAIN THE RISK-FREE RATE.

A. The first term in the CAPM is the risk-free rate. The risk-free rate is simply the level of return investors can achieve without assuming any risk. The risk-free rate represents the bare minimum return that any investor would require on a risky asset. Even though no investment is technically free of risk, investors often use U.S. Treasury securities to represent the risk-free rate because they accept that those securities essentially contain no default risk. The Treasury issues securities with different maturities, including short-term Treasury Bills, intermediate-term Treasury Notes, and long-term Treasury Bonds.

Q. IS IT PREFERABLE TO USE THE YIELD ON LONG-TERM TREASURY BONDS FOR THE RISK-FREE RATE IN THE CAPM?

A. Yes. In valuing an asset, investors estimate cash flows over long periods of time. Common stock is viewed as a long-term investment, and the cash flows from dividends are assumed to last indefinitely. Thus, short-term Treasury bill yields are rarely used in the CAPM to represent the risk-free rate, as short-term rates are subject to greater volatility and thus can lead to unreliable estimates. Instead, long-term Treasury bonds are usually used to represent the risk-free rate in the CAPM. I considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury bonds in my risk-free rate estimate, which resulted in a risk-free rate of 4.58%.[39]

B. The Beta Coefficient

Q. HOW IS THE BETA COEFFICIENT USED IN THIS MODEL?

A. As discussed above, beta represents the sensitivity of a given security to movements in the overall market. The CAPM states that in efficient capital markets, the expected risk premium on each investment is proportional to its beta. Recall that a security with a beta greater (or less) than one is more (or less) risky than the market portfolio. An index such as the S&P 500 Index is used as a proxy for the market portfolio. The historical betas for publicly traded firms are published by various institutional analysts. Beta may also be calculated through a linear regression analysis, which provides additional statistical information about the relationship between a single stock and the market portfolio. As discussed above, beta also represents the sensitivity of a given security to the market as a whole.

Q. DESCRIBE THE SOURCE FOR THE BETAS YOU USED IN YOUR CAPM ANALYSIS.

A. In this case, I used two different sources for my beta estimates. First, I used adjusted betas published by Value Line. I also incorporated adjusted betas published by

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[39] Exhibit DJG-7.

Bloomberg. Mr. D'Ascendis also used these sources for his beta estimates. As a result, the betas we both used in our CAPM analyses are substantially similar. Also like Mr. D'Ascendis, I took an average of the Value Line and Bloomberg betas and used the average beta for each proxy company in the final results of my CAPM analysis.

C. <u>The Equity Risk Premium</u>

Q. DESCRIBE THE EQUITY RISK PREMIUM.

A. The final term of the CAPM is the equity risk premium ("ERP"), which is the required return on the market portfolio less the risk-free rate. In other words, the ERP is the level of return investors expect above the risk-free rate in exchange for investing in risky securities. Many experts would agree that "the single most important variable for making investment decisions is the equity risk premium."[40] Likewise, the ERP is arguably the single most important factor in estimating the cost of capital in this matter. There are three basic methods that can be used to estimate the ERP: (1) calculating a historical average; (2) taking a survey of experts; and (3) calculating the implied ERP. I will discuss each method in turn, noting advantages and disadvantages of these methods.

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[40] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Cptimists: 101 Years of Global Investment Returns*, Princeton University Press, p. 4 (2002).

(1) Historical Average

Q. DESCRIBE THE HISTORICAL ERP.

A. The historical ERP may be calculated by simply taking the difference between returns on stocks and returns on government bonds over a certain period of time. Many practitioners rely on the historical ERP as an estimate for the forward-looking ERP because it is easy to obtain. However, there are disadvantages to relying on the historical ERP.

Q. WHAT ARE THE LIMITATIONS OF RELYING SOLELY ON A HISTORICAL AVERAGE TO ESTIMATE THE CURRENT OR FORWARD-LOOKING ERP?

A. Many investors use the historic ERP because it is convenient and easy to calculate. But what matters in the CAPM model is the *current* and *forward-looking* risk premium, not the actual risk premium from the past.[41] And there is empirical evidence to suggest the forward-looking ERP is actually *lower* than the historical ERP.

In *Triumph of the Optimists*, a landmark publication on risk premiums around the world, the authors suggest through extensive empirical research that the prospective ERP is lower than the historical ERP.[42] This is due in large part to what is known as "survivorship bias," or "success bias," a tendency for failed companies to be excluded

[41] *Corporate Finance: Linking Theory to What Companies Do*, p. 330.

[42] *Triumph of the Optimists: 101 Years of Global Investment Returns*, p. 194.

from historical indices.[43] From their extensive analysis, the authors make the following conclusion regarding the prospective ERP:

> The result is a forward-looking, geometric mean risk premium for the United States . . . of around 2½ to 4 percent and an arithmetic mean risk premium . . . that falls within a range from a little below 4 to a little above 5 percent.[44]

Indeed, these results are lower than many reported historical risk premiums. Other noted experts agree:

> The historical risk premium obtained by looking at U.S. data is biased upwards because of survivor bias. . . . The true premium, it is argued, is much lower. This view is backed up by a study of large equity markets over the twentieth century (*Triumph cf the Cptimists*), which concluded that the historical risk premium is closer to 4%.[45]

Regardless of the variations in historic ERP estimates, many scholars and practitioners agree that simply relying on a historic ERP to estimate the risk premium going forward is not ideal.

Q. DID YOU RELY ON THE HISTORICAL ERP AS PART OF YOUR CAPM ANALYSIS IN THIS CASE?

A. No. Due to the limitations of this approach, I relied on the ERP reported in expert surveys and the implied ERP method, both of which are discussed below.

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[43] *Id.* at 34.

[44] *Id.* at 194.

[45] Aswath Damodaran, *Equity Risk Premiums: Determinants, Estimation and Implications – The 2015 Edition*, New York University, p. 17 (2015).

(2) Expert Surveys

Q. DESCRIBE THE EXPERT SURVEY APPROACH TO ESTIMATING THE ERP.

A. As its name implies, the expert survey approach to estimating the ERP involves conducting a survey of experts including professors, analysts, chief financial officers, and other executives around the country and asking them what they think the ERP is. The IESE Business School regularly conducts a survey of experts regarding the ERP. Its 2024 expert survey reported an average ERP of 5.5%.[46]

(3) Implied Equity Risk Premium

Q. DESCRIBE THE IMPLIED ERP APPROACH.

A. The third method of estimating the ERP is arguably the best. The implied ERP relies on the stable growth model proposed by Gordon, often called the "Gordon Growth Model," which is a basic stock valuation model widely used in finance for many years.[47] This model is a mathematical derivation of the DCF Model. In fact, the underlying concept in both models is the same: the current value of an asset is equal to the present value of its future cash flows. Instead of using this model to determine the discount rate of one company, we can use it to determine the discount rate for the entire

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[46] Pablo Fernandez, et al., Survey: Market Risk Premium and Risk-Free Rate used for 96 countries in 2024, IESE Business School, p. 3 (2015), copy available at https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4754347. IESE Business School is the graduate business school of the University of Navarra. IESE offers Master of Business Administration (MBA), Executive MBA and Executive Education programs. IESE is consistently ranked among the leading business schools in the world.

[47] Myron J. Gordon and Eli Shapiro, *Capital Equipment Analysis: The Required Rate of Profit*, Management Science Vol. 3, No. 1, pp. 102-10 (Oct. 1956).

market by substituting the inputs of the model. Specifically, instead of using the current stock price (P_0), we will use the current value of the S&P 500 (V_{500}). Rather than using the dividends of a single firm, we will consider the dividends paid by the entire market.

Additionally, we should consider potential dividends. In other words, stock buybacks should be considered in addition to paid dividends, as stock buybacks represent another way for the firm to transfer free cash flow to shareholders. Focusing on dividends alone without considering stock buybacks could understate the cash flow component of the model, and ultimately understate the implied ERP. The market dividend yield plus the market buyback yield gives us the gross cash yield to use as our cash flow in the numerator of the discount model. This gross cash yield is increased each year over the next five years by the growth rate. These cash flows must be discounted to determine their present value. The discount rate in each denominator is the risk-free rate (R_F) plus the discount rate (K). The following formula, Equation DJG-1, shows how the implied return is calculated. Since the current value of the S&P is known, we can solve for K: the implied market return.[48]

Equation 1:
Implied Market Return

$$V_{500} = \frac{CY_1(1+g)^1}{(1+R_F+K)^1} + \frac{CY_2(1+g)^2}{(1+R_F+K)^2} + \cdots + \frac{CY_5(1+g)^5 + TV}{(1+R_F+K)^5}$$

where:	V_{500}	=	*current value of index (S&P 500)*
	$CY_{1\text{-}5}$	=	*average cash yield over last five years (includes dividends and buybacks)*
	g	=	*compound growth rate in earnings over last five years*
	R_F	=	*risk-free rate*
	K	=	*implied market return (this is what we are solving for)*
	TV	=	*terminal value* $= CY_5\,(1+R_F)\,/\,K$

[48] *See* Exhibit DJG-9 for detailed calculation.

The discount rate is called the "implied" return here because it is based on the current value of the index as well as the value of free cash flow to investors projected over the next five years. Thus, based on these inputs, the market is "implying" the expected return; or in other words, based on the current value of all stocks (the index price) and the projected value of future cash flows, the market is telling us the return expected by investors for investing in the market portfolio. After solving for the implied market return (K), we simply subtract from it the risk-free rate to arrive at the implied ERP.

Equation 2:
Implied Equity Risk Premium

$$Implied\ Expected\ Market\ Return - R_F = Implied\ ERP$$

Q. DISCUSS THE RESULTS OF YOUR IMPLIED ERP CALCULATION.

A. After collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, I calculated the dividend yield, buyback yield, and gross cash yield for each year. I also calculated the compound annual growth rate (g) from operating earnings. I used these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of 9.9%.[49] I subtracted the risk-free rate to arrive at the implied equity risk premium of 5.0%.[50] Dr. Damodaran, one of the world's leading experts on the ERP,[51] promotes the implied ERP method discussed above. He calculates monthly and annual implied

[49] *See* Exhibit DJG-9.

[50] *Id.*

[51] Damodaran Online, New York University, http://pages.stern.nyu.edu/~adamodar/.

ERPs with this method and publishes his results. Dr. Damodaran's average ERP estimate for June 2025 using several implied ERP variations was 4.3%.[52]

Q. WHAT ARE THE RESULTS OF YOUR FINAL ERP ESTIMATE?

A. For the final ERP estimate I used in my CAPM analysis, I considered the results of the ERP surveys along with the implied ERP calculations and the ERP reported by Kroll (formerly Duff & Phelps).[53] In addition, I included the results of my own independent analyses as well as the ERP estimate published by Dr. Damodaran. The results are presented in the following figure:

Figure 6:
Equity Risk Premium Results

IESE Business School Survey	5.5%
Kroll (Duff & Phelps) Report	5.5%
Damodaran (average)	4.3%
Garrett	5.0%
Average	**5.1%**

The average ERP from these sources is 5.1%, which is the ERP I used in my CAPM analysis.

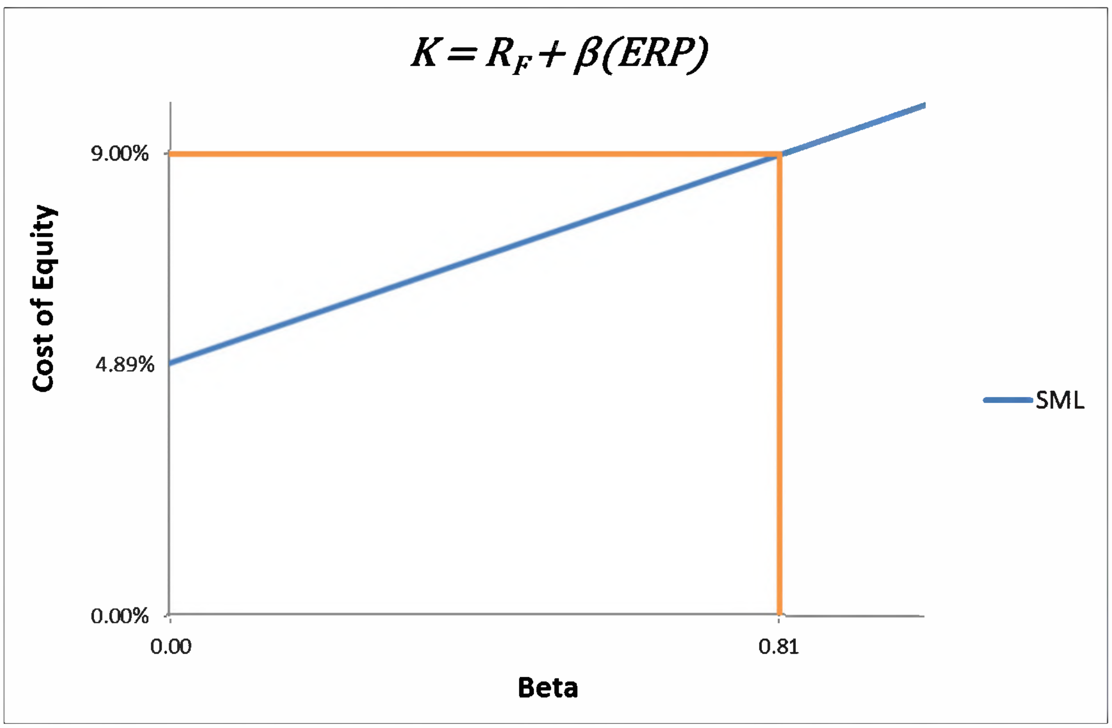
[52] Dr. Damodaran conducts several variations of the implied ERP analysis using various assumptions. The figure I incorporated into my analysis is based on an average of the results of his several implied ERP variations.

[53] *See* Exhibit DJG-10.

Q. PLEASE EXPLAIN THE FINAL RESULTS OF YOUR CAPM ANALYSIS.

A. Using the inputs for the risk-free rate, beta, and ERP discussed above, the CAPM indicates a cost of equity of 9.0% for PGS. However, this result is accurate only if the average capital structure of the proxy group is imputed for PGS, which consists of much higher debt than the debt ratio proposed by PGS. The CAPM may be displayed graphically through what is known as the Security Market Line ("SML"). The following figure shows the expected return (or cost of equity) on the y-axis, and the average beta for the proxy group on the x-axis. The SML intercepts the y-axis at the level of the risk-free rate. The slope of the SML is the equity risk premium.

Figure 7:
CAPM Graph



The SML provides the rate of return that will compensate investors for the beta risk of that investment.

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D. Response to Mr. D'Ascendis's CAPM Analysis

Q. PLEASE SUMMARIZE THE RESULTS OF MR. D'ASCENDIS'S CAPM ANALYSIS.

A. The traditional CAPM conducted by Mr. D'Ascendis produced a median result of 11.00%.[54]

Q. DO THE RESULTS OF MR. D'ASCENDIS'S CAPM ANALYSIS INDICATE A REASONABLE COST OF EQUITY FOR PGS?

A. No. The primary problem with Mr. D'Ascendis's CAPM cost of equity result stems from his ERP estimate. In addition, Mr. D'Ascendis conducts another variation of the CAPM called the "empirical" CAPM ("ECAPM"). Finally, Mr. D'Ascendis also presents another type of risk premium analysis. I will address each of these issues below.

1. Equity Risk Premium

Q. DID MR. D'ASCENDIS RELY ON A REASONABLE MEASURE FOR THE ERP?

A. No. Mr. D'Ascendis used an input as high as 8.41% for the ERP.[55] The ERP is one of only three inputs in the CAPM equation, and it is one of the single most important factors for estimating the cost of equity in this case. As discussed above, I used three

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[54] Direct Testimony of Dylan W. D'Ascendis, Exhibit No. DD-1.

[55] Direct Testimony of Dylan W. D'Ascendis, Exhibit No. DD-1.

widely accepted methods for estimating the ERP, including consulting expert surveys, calculating the implied ERP based on aggregate market data, and considering the ERPs published by reputable analysts. The average ERP calculated from my sources is 5.1%. This means that Mr. D'Ascendis's ERP is significantly higher than the ERP estimate reported by thousands of expert survey respondents and other sources.

Q. PLEASE DISCUSS AND ILLUSTRATE HOW MR. D'ASCENDIS'S ERP COMPARES WITH OTHER ESTIMATES FOR THE ERP.

A. As discussed above, the 2025 IESE Business School expert survey reports an average ERP of 5.5%. Similarly, Kroll recently estimated an ERP of 5.5%.[56] Dr. Damodaran, , recently estimated an average ERP of only 4.3%.[57] The following figure illustrates that Mr. D'Ascendis's ERP estimate is far out of line with other reasonable, objective estimates for the ERP.

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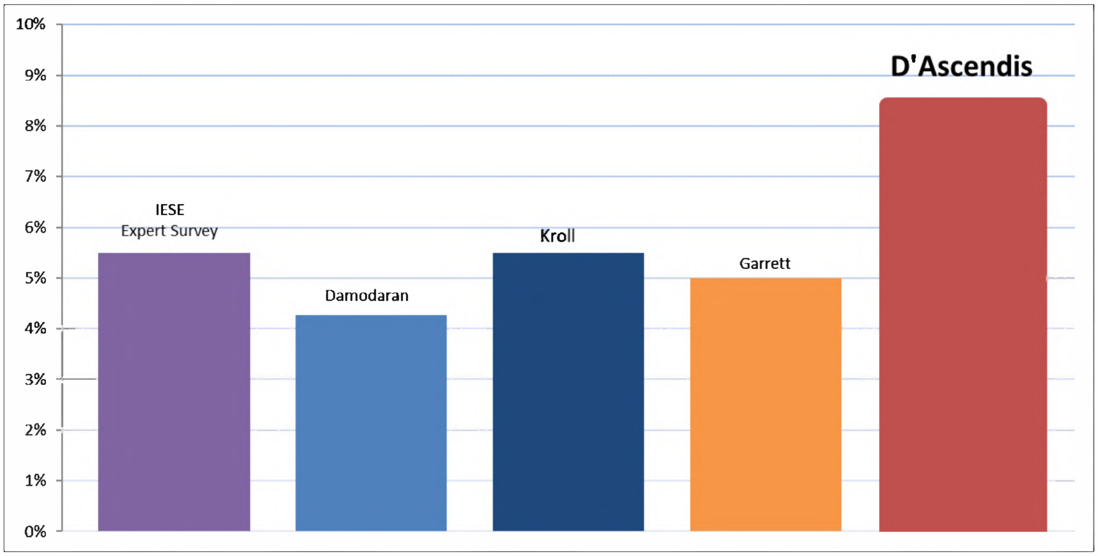
[56] Exhibit DJG-10.

[57] Damodaran Online, http://pages.stern.nyu.edu/~adamodar/. Dr. Damodaran estimates several ERPs using various assumptions.

Figure 8:
Equity Risk Premium Comparison



When compared with other independent sources for the ERP (as well as my estimate), Mr. D'Ascendis's ERP estimate is clearly not within the range of reasonableness. As a result, his CAPM cost of equity estimate is overstated.

2. <u>Empirical CAPM</u>

Q. PLEASE DESCRIBE MR. D'ASCENDIS'S ECAPM RESULTS.

A. Mr. D'Ascendis conducted a variation of the CAPM called the ECAPM, which is based on the premise that the traditional CAPM will underestimate the betas of low-beta securities such as utility stocks. The ECAPM conducted by Mr. D'Ascendis produced a median result of 11.46%.[58]

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[58] Direct Testimony of Dylan W. D'Ascendis, Exhibit No. DD-1.

Q. DO THE RESULTS OF MR. D'ASCENDIS'S ECAPM INDICATE A REASONABLE COST OF EQUITY FOR PGS?

A. No. First, Mr. D'Ascendis's ECAPM relies on the same unreasonably high ERP input as does his traditional CAPM. For that reason alone, the Commission should reject the results of his ECAPM analysis. Furthermore, the premise of Mr. D'Ascendis's ECAPM is that the real CAPM underestimates the return required from low-beta securities, such as those of the proxy group. There are several problems with this concept, however. First, the betas both Mr. D'Ascendis and I used in the real CAPM already account for the theory that low-beta stocks might tend to be underestimated. In other words, the raw betas for each of the utility stocks in the proxy groups have already been adjusted by Value Line to be higher. Second, there is empirical evidence suggesting that the type of beta-adjustment method used by Value Line actually overstates betas from consistently low-beta industries like utilities.[59] For these reasons, the Commission should reject the results of the ECAPM conducted by Mr. D'Ascendis as indicating a reasonable cost of equity for PGS.

[59] *See* Appendix B.

3. Other Risk Premium Analysis

Q. PLEASE SUMMARIZE THE RESULTS OF MR. D'ASCENDIS'S OTHER RISK PREMIUM ANALYSIS.

A. In addition to the CAPM and ECAPM, Mr. D'Ascendis conducted an additional risk premium model, which produced a result of 10.84%.[60]

Q. DO THE RESULTS OF MR. D'ASCENDIS'S RISK PREMIUM MODEL INDICATE A REASONABLE COST OF EQUITY FOR PGS?

A. No. I disagree with the premise of the analysis itself, in that this model does not actually estimate cost of equity (like the CAPM and DCF Model do). As part of his risk premium analysis, Mr. D'Ascendis considered authorized ROEs dating back to 1980. Data nearly half-a-century old is not relevant for estimating the current and forward-looking cost of equity for PGS. Furthermore, relying on authorized ROEs from other jurisdictions as part of this model means that it is not entirely market-based. Unlike the CAPM, which is a risk premium model that has been used around the world for decades and resulted in a Nobel Prize, Mr. D'Ascendis's risk premium model does not actually estimate cost of equity. The CAPM starts with the risk-free rate, which is based on U.S. Treasury securities, then adds an estimated equity risk premium to develop the required return on the market; from there, a firm's individual beta is used to develop its cost of equity. In contrast, the risk premium model presented by Mr. D'Ascendis starts with a corporate bond yield (a rate higher than the risk-free rate),

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[60] Direct Testimony of Dylan W. D'Ascendis, Exhibit No. DD-1.

then adds a risk premium based on a number of factors (including authorized ROEs more than 40 years old) to ultimately arrive at a risk premium that is higher than the objective estimates I discuss earlier in my testimony. The cost of equity for a utility should be estimated using the same models used to estimate the cost of equity for any company, such as the CAPM and DCF Model, rather than the unusual model presented by Mr. D'Ascendis.

VIII. OTHER ISSUES

Q. ARE THERE OTHER ISSUES RAISED BY MR. D'ASCENDIS IN HIS TESTIMONY YOU WOULD LIKE TO ADDRESS?

A. Yes. Mr. D'Ascendis conducted cost of equity modeling on a group of non-utility companies. In addition, Mr. D'Ascendis added a flotation cost premium and a size premium to his cost of equity results. I will address these issues below.

A. Non-Utility Company Proxy Group

Q. PLEASE SUMMARIZE THE RESULTS OF MR. D'ASCENDIS'S COST OF EQUITY MODELS CONDUCTED ON A GROUP OF NON-UTILITY COMPANIES.

A. Mr. D'Ascendis conducted additional cost of equity modeling using a group of non-utility companies. This modeling produced a median result of 11.41%.[61]

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[61] Direct Testimony of Dylan W. D'Ascendis, Exhibit No. DD-1.

Q. DO THE RESULTS OF THE COST OF EQUITY MODELS CONDUCTED BY MR. D'ASCENDIS ON A GROUP OF NON-UTILITY COMPANIES INDICATE AN ACCURATE COST OF EQUITY ESTIMATE FOR PGS?

A. No. The result of his non-utility modeling is even higher than the results Mr. D'Ascendis arrived at using the utility proxy group. The same unreasonable assumptions and inputs employed by Mr. D'Ascendis on the utility proxy group modeling also apply to his non-utility group modeling. For that reason alone, the results of the non-utility modeling should be rejected. Moreover, this model adds no marginal value to the process of developing a reasonable estimate for PGS's cost of equity. The companies included in Mr. D'Ascendis's non-utility group are undoubtedly less comparable than those included in the utility proxy group. Some examples include Apple Inc., Microsoft Corp., and O'Reilly Automotive.[62] For these reasons, the Commission should reject the results of the non-utility modeling as not providing a meaningful indication of PGS's cost of equity in this case.

B. Flotation Cost Adjustment

Q. PLEASE SUMMARIZE THE FLOTATION COST ADJUSTMENT APPLIED BY MR. D'ASCENDIS.

A. Mr. D'Ascendis adds 0.08% to his cost of equity modeling results to account for flotation costs.[63]

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[62] *Id.*

[63] *Id.*

Q. DO YOU AGREE WITH MR. D'ASCENDIS ON HIS FLOTATION COST POSITION?

A. No. When companies issue equity securities, they typically hire at least one investment bank as an underwriter for the securities. "Flotation costs" generally refer to the underwriter's compensation for the services it provides in connection with the securities offering. However, Mr. D'Ascendis's arguments regarding flotation costs should be rejected for several reasons, as discussed further below.

1. Flotation costs are not actual "out-of-pocket" costs.

The Company has not experienced any out-of-pocket costs for flotation. Underwriters are not compensated in this fashion. Instead, underwriters are compensated through an "underwriting spread." An underwriting spread is the difference between the price at which the underwriter purchases the shares from the firm, and the price at which the underwriter sells the shares to investors.[64] Accordingly, the Company has not experienced any out-of-pocket flotation costs, and if it has, those costs should be included in the Company's expense schedules.

2. The market already accounts for flotation costs.

When an underwriter markets a firm's securities to investors, the investors are aware of the underwriter's fees. The investors know that a portion of the price they are paying for the shares does not go directly to the company, but instead goes to compensate the underwriter for its services. In fact, federal law requires that the underwriter's

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[64] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do*, p. 509 (3rd ed., South Western Cengage Learning 2010).

compensation be disclosed on the front page of the prospectus.[65] Thus, investors have already considered and accounted for flotation costs when making their decision to purchase shares at the quoted price.

As a result, there is no need for shareholders to receive additional compensation to account for costs to which they have already considered and agreed. Similar compensation structures are in other kinds of business transactions. For example, a homeowner may hire a realtor and sell a home for $100,000. After the realtor takes a six percent commission, the seller nets $94,000. The buyer and seller agreed to the transaction notwithstanding the realtor's commission. Obviously, it would be unreasonable for the buyer or seller to demand additional funds from anyone after the deal is completed to reimburse them for the realtor's fees. Likewise, investors of competitive firms do not expect additional compensation for flotation costs. Thus, it would not be appropriate for a commission standing in the place of competition to reward a utility's investors with this additional compensation.

3. It is inappropriate to add any additional basis points to an awarded ROE proposal that is already far above the Company's cost of equity.

For the reasons discussed above, flotation costs should be disallowed from a technical standpoint; they should also be disallowed from a policy standpoint. The Company is asking this Commission to award it a cost of equity that is significantly higher than any reasonable estimate of its market-based cost of equity. Under these circumstances, it

[65] *See* Regulation S-K, 17 C.F.R. § 229.501(b)(3) (requiring that the underwriter's discounts and commissions be disclosed on the outside cover page of the prospectus). A prospectus is a legal document that provides details about an investment offering.

is especially inappropriate to suggest that flotation costs should be considered in any way to increase an already inflated ROE proposal.

C. Size Premium

Q. PLEASE SUMMARIZE THE SIZE PREMIUM ADJUSTMENT APPLIED BY MR. D'ASCENDIS.

A. Mr. D'Ascendis adds 0.20% to his cost of equity modeling results to account for PGS's size relative to the proxy group.[66]

Q. DO YOU BELIEVE PGS'S SIZE SHOULD IMPACT ITS COST OF EQUITY ESTIMATE OR AUTHORIZED ROE?

A. No. The "size effect" phenomenon arose from a 1981 study conducted by Rolf Banz, which found that "in the 1936 – 1975 period, the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[67] According to Ibbotson, Banz's size effect study was "[o]ne of the most remarkable discoveries of modern finance."[68] Perhaps there was some merit to this idea at the time, but the size effect phenomenon was short-lived. Banz's 1981 publication generated much interest in the size effect and spurred the launch of significant new small cap investment funds. However, this "honeymoon period lasted for approximately two

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[66] Direct Testimony of Dylan W. D'Ascendis, Exhibit No. DD-1.

[67] Rolf W. Banz, *The Relationship Between Return and Market Value of Common Stocks*, pp. 3-18 (Journal of Financial Economics 9 (1981)).

[68] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 99 (Morningstar 2015).

years[.]"[69] After 1983, U.S. small-cap stocks actually underperformed relative to large cap stocks. In other words, the size effect essentially reversed. In *Triumph of the Optimists*, the authors conducted an extensive empirical study of the size effect phenomenon around the world. They found that after the size effect phenomenon was discovered in 1981, it disappeared within a few years:

> It is clear . . . that there was a global reversal of the size effect in virtually every country, with the size premium not just disappearing but going into reverse. Researchers around the world universally fell victim to Murphy's Law, with the very effect they were documenting – and inventing explanations for – promptly reversing itself shortly after their studies were published.[70]

In other words, the authors assert that the very discovery of the size effect phenomenon likely caused its own demise. The authors ultimately concluded that it is "inappropriate to use the term 'size effect' to imply that we should automatically expect there to be a small-cap premium," yet, this is exactly what utility witnesses often do in attempting to artificially inflate the cost of equity with a size premium. Other prominent sources have agreed that the size premium is a dead phenomenon. According to Ibbotson:

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[69] Elroy Dimson, Paul Marsh & Mike Staunton, *Triumph of the Optimists: 101 Years of Global Investment Returns*, p. 131 (Princeton University Press 2002).

[70] *Id.* at p. 133.

> The unpredictability of small-cap returns has given rise to another argument against the existence of a size premium: that markets have changed so that the size premium no longer exists. As evidence, one might observe the last 20 years of market data to see that the performance of large-cap stocks was basically equal to that of small cap stocks. In fact, large-cap stocks have outperformed small-cap stocks in five of the last 10 years.[71]

In addition to the studies discussed above, other scholars have had similar results. According to Kalesnik and Beck:

> Today, more than 30 years after the initial publication of Banz's paper, the empirical evidence is extremely weak even before adjusting for possible biases. . . . The U.S. long-term size premium is driven by the extreme outliers, which occurred three-quarters of a century ago. . . . Finally, adjusting for biases . . . makes the size premium vanish. If the size premium were discovered today, rather than in the 1980s, it would be challenging to even publish a paper documenting that small stocks outperform large ones.[72]

For all of these reasons, the Commission should reject the arbitrary and unsupported size premium proposed by Mr. D'Ascendis. This adjustment merely inflates a CAPM result that is already grossly overestimated.

IX. CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE PGS'S PROPOSAL REGARDING ITS CAPITAL STRUCTURE.

A. PGS proposes a ratemaking capital structure consisting of 45% debt and 55% equity.

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[71] 2015 Ibbotson Stocks, Bonds, Bills, and Inflation Classic Yearbook 112 (Morningstar 2015).

[72] Vitali Kalesnik and Noah Beck, *Busting the Myth About Size* (Research Affiliates 2014), available at https://www.researchaffiliates.com/Our%20Ideas/Insights/Fundamentals/Pages/284_Busting_the_Myth_About_Size.aspx (emphasis added).

Q. DOES PGS'S PROPOSED CAPITAL STRUCTURE HAVE AN INCREASING EFFECT TO ITS COST OF CAPITAL?

A. Yes. As discussed in more detail below, PGS's proposed capital structure for ratemaking purposes contains too little debt. By proposing a capital structure with a higher proportion of high-cost equity instead of low-cost debt, PGS's proposed rate of return is not at its lowest reasonable level. The average debt ratio of the proxy group is 51%.

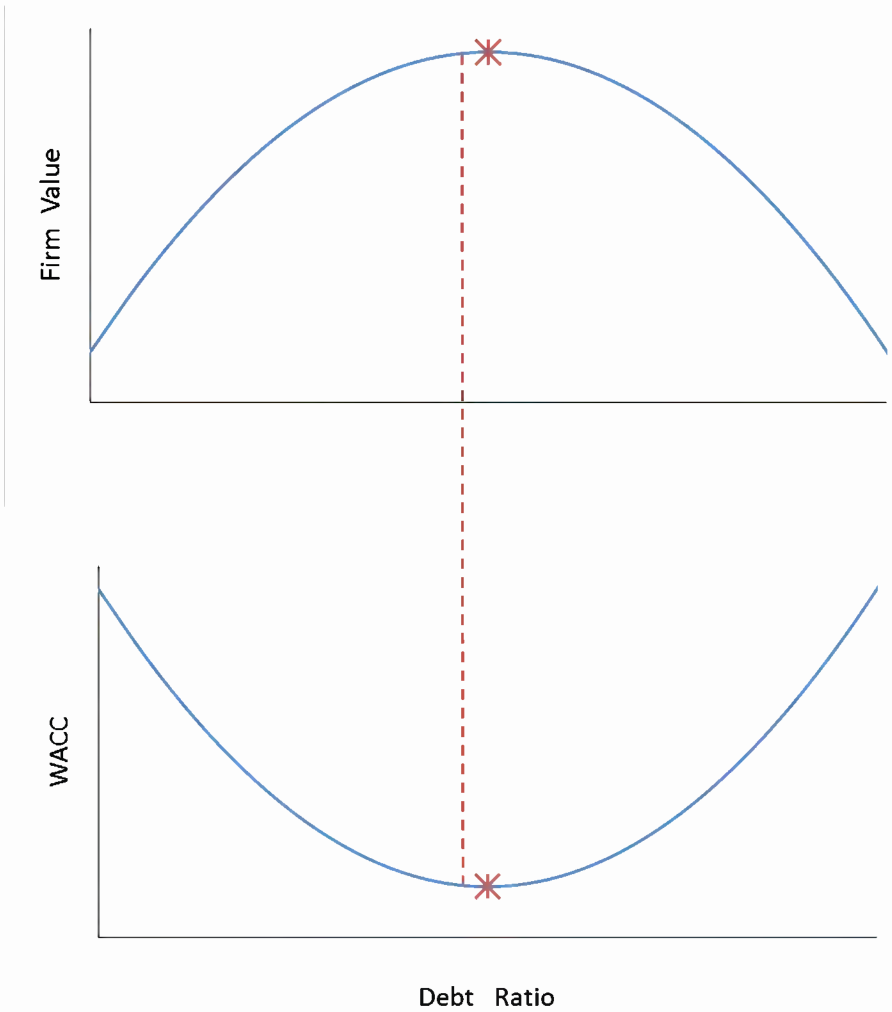
Q. DESCRIBE IN GENERAL THE CONCEPT OF A COMPANY'S CAPITAL STRUCTURE.

A. "Capital structure" refers to the way a company finances its overall operations through external financing. The primary sources of long-term, external financing are debt capital and equity capital. Debt capital usually comes in the form of contractual bond issuances that require the firm to make payments, while equity capital represents an ownership interest in the form of stock. Because a firm cannot pay dividends on common stock until it satisfies its debt obligations to bondholders, stockholders are referred to as "residual claimants." The fact that stockholders have a lower priority to claims on company assets increases their risk and the required return relative to bondholders. Thus, equity capital has a higher cost than debt capital. Firms can reduce their weighted average cost of capital ("WACC") by recapitalizing and increasing their debt financing. In addition, because interest expense is deductible, increasing debt also adds value to the firm by reducing the firm's tax obligation.

Q. IS IT TRUE THAT, BY INCREASING DEBT, COMPETITIVE FIRMS CAN ADD VALUE AND REDUCE THEIR WACC?

A. Yes, it is. A competitive firm can add value by increasing debt. After a certain point, however, the marginal cost of additional debt outweighs its marginal benefit. This is because the more debt the firm uses, the higher interest expense it must pay, and the likelihood of loss increases. This also increases the risk of non-recovery for both bondholders and shareholders, causing both groups of investors to demand a greater return on their investment. Thus, if the level of debt financing is too high, the firm's WACC will increase instead of decrease. The following figure illustrates these concepts:

Figure 9:
Optimal Debt Ratio



As shown in this figure, a competitive firm's value is maximized when the WACC is minimized. In both graphs, the debt ratio is shown on the x-axis. By increasing its debt ratio, a competitive firm can minimize its WACC and maximize its value. At a certain point, however, the benefits of increasing debt do not outweigh the costs of the

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additional risks to both bondholders and shareholders, as each type of investor will demand higher returns for the additional risk they have assumed.[73]

Q. DOES THE RATE BASE RATE OF RETURN MODEL EFFECTIVELY INCENTIVIZE UTILITIES TO OPERATE AT THE OPTIMAL CAPITAL STRUCTURE?

A. No. While it is true that competitive firms maximize their value by minimizing their WACC, this is not the case for regulated utilities. Under the rate base, rate of return model, a higher WACC results in higher rates, all else held constant. The basic revenue requirement equation is as follows:

Equation 3:
Revenue Requirement for Regulated Utilities

$$RR = O + d + T + \boldsymbol{r}(A - D)$$

where:	RR	=	*revenue requirement*
	O	=	*operating expenses*
	d	=	*depreciation expense*
	T	=	*corporate tax*
	$\boldsymbol{r}$	=	***weighted average cost of capital (WACC)***
	A	=	*plant investments*
	D	=	*accumulated depreciation*

As shown in Equation 3, utilities can increase their revenue requirement by <u>increasing</u> their WACC, not by minimizing it. Thus, because there is no incentive for a regulated utility to minimize its WACC, a commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC.

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[73] *See* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 440-41 (3rd ed., South Western Cengage Learning 2010).

Q. CAN UTILITIES GENERALLY AFFORD TO HAVE HIGHER DEBT LEVELS THAN OTHER INDUSTRIES?

A. Yes. Because regulated utilities have large amounts of fixed assets, stable earnings, and low risk relative to other industries, they can afford to have relatively higher debt ratios (or "leverage"). As aptly stated by Dr. Damodaran:

> Since financial leverage multiplies the underlying business risk, it stands to reason that firms that have high business risk should be reluctant to take on financial leverage. It also stands to reason that firms that operate in stable businesses should be much more willing to take on financial leverage. Utilities, for instance, have historically had high debt ratios but have not had high betas, mostly because their underlying businesses have been stable and fairly predictable.[74]

Note that the author explicitly contrasts utilities with firms that have high underlying business risk. Because utilities have low levels of risk and operate a stable business, they should generally operate with relatively high levels of debt to achieve their optimal capital structure.

Q. DESCRIBE THE APPROACH YOU USED TO ASSESS THE REASONABLENESS OF PGS'S CAPITAL STRUCTURE FOR RATEMAKING PURPOSES?

A. To assess a reasonable capital structure for PGS, I examined the capital structures of the proxy group. The cost of equity indicated under the CAPM is inseparable from the

[74] Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 196 (3rd ed., John Wiley & Sons, Inc. 2012).

proxy group capital structures. For comparative purposes, I also looked at debt ratios observed in other industries. I discuss each of these approaches in more detail below.

A. Proxy and Industry Debt Ratios

Q. PLEASE DESCRIBE THE DEBT AND EQUITY RATIOS OF THE PROXY GROUP.

A. According to the debt ratios recently reported in Value Line for the utility proxy group (the same proxy group used by Mr. D'Ascendis), the average debt ratio of the proxy group is 51%.[75] This is notably higher than PGS's proposed debt ratio of only 45%. Conversely, the equity ratio of the proxy group is 49% and PGS's proposed equity ratio is considerably higher at 55%.

Q. WHY IS IT CRITICAL TO CONSIDER THE CAPITAL STRUCTURES OF THE PROXY GROUP WHEN ASSESSING A FAIR CAPITAL STRUCTURE FOR PGS?

A. The cost of equity of any particular company is necessarily connected with its capital structure. This is because there is a direct relationship between risk and return. That is, the higher (lower) risk, the higher (lower) expected return. All else held constant, companies with higher amounts of leverage have higher levels of financial risk. Since we are using a proxy group of companies to assess a fair cost of equity estimate for

[75] Exhibit DJG-13.

PGS, we must also factor in the capital structures of those companies into the analysis – failing to do so is an analytical error. Since PGS's debt ratio is lower and the equity ratio is higher than the proxy group average, it has less financial risk than the proxy group. This discrepancy in debt ratio and equity ratio must be accounted for. This issue will be discussed in more detail below in my Hamada model analysis.

Q. PLEASE DESCRIBE THE DEBT RATIOS RECENTLY OBSERVED IN COMPETITIVE U.S. INDUSTRIES.

A: There are more than 2,000 publicly traded (?) companies in the U.S. with debt ratios of at least 50%.[76] The following figure shows a sample of these industries with debt ratios higher than 56%.

[76] Exhibit DJG-14.

Figure 10:
Industries with Debt Ratios Greater than 56%

Industry	# Firms	Debt Ratio
Financial Svcs. (Non-bank & Insurance)	166	92%
Hotel/Gaming	65	86%
Brokerage & Investment Banking	30	80%
Retail (Automotive)	29	80%
Hospitals/Healthcare Facilities	33	76%
Air Transport	24	76%
Bank (Money Center)	15	71%
Rubber& Tires	3	67%
Recreation	50	66%
Food Wholesalers	14	66%
Transportation	21	66%
Computers/Peripherals	35	65%
Cable TV	9	[redacted] 65%
Advertising	54	64%
Retail (Grocery and Food)	17	64%
Retail (Special Lines)	98	64%
Telecom (Wireless)	11	63%
Power [redacted]	48	62%
R.E.I.T.	192	62%
Oil/Gas Distribution	24	62%
Transportation (Railroads)	4	62%
Telecom. Services	32	62%
Chemical (Diversified)	4	61%
Auto & Truck	34	61%
Aerospace/Defense	67	60%
Broadcasting	22	60%
Packaging & Container	22	60%
Apparel	37	59%
Beverage (Soft)	29	59%
Utility (General)	14	59%
Retail (Distributors)	66	58%
Farming/Agriculture	35	57%
Green & Renewable Energy [redacted]	18	[redacted] 57% [redacted]
Information Services	16	57%
Total / Average	**1,338**	**66%**

Many of the industries shown here, like public utilities, are generally well-established industries with large amounts of capital assets. The shareholders of these industries generally prefer these higher debt ratios to maximize their profits. There are several notable industries that are relatively comparable to public utilities. For example, the Cable TV, Telecom industries have debt ratios of at least 60%.

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR CAPITAL STRUCTURE ANALYSES AND YOUR RECOMMENDATION REGARDING CAPITAL STRUCTURE.

A. The results of my analyses are summarized in the following figure:

Figure 11:
Capital Structure Analysis – Summary of Results

Source	Debt Ratio
Cable TV	65%
Power	62%
Telecom Services	62%
Proxy Group of Utilities	**51%**
Company Proposal (total debt)	**45%**

As shown in this figure, PGS's proposed debt ratio is clearly too low (and its equity ratio is too high). This results in excessively high capital costs and utility rates. My analysis indicates that PGS's total debt ratio for ratemaking should be 51%, and the equity ratio should be no more than 49%.

B. The Hamada Model: Capital Structure's Effect on ROE

Q. HAVE YOU CONSIDERED THE IMPACT THAT YOUR CAPITAL STRUCTURE RECOMMENDATION COULD HAVE ON THE COMPANY'S INDICATED COST OF EQUITY?

A. Yes. I assessed the impact of my capital structure proposal on the Company's cost of equity estimate by using the Hamada model.

Q. WHAT IS THE PREMISE OF THE HAMADA MODEL?

A. The Hamada formula can be used to analyze changes in a firm's cost of capital as it adds or reduces financial leverage, or debt, in its capital structure by starting with an "unlevered" beta and then "relevering" the beta at different debt ratios. As leverage increases, equity investors bear increasing amounts of risk, leading to higher betas. Before the effects of financial leverage can be accounted for, however, the effects of leverage must first be removed, which is accomplished through the Hamada formula. The Hamada formula for unlevering beta is stated as follows:[77]

[77] Damodaran *supra* n. 18, at 197. This formula was originally developed by Hamada in 1972.

Equation 4:
Hamada Formula

$$\beta_U = \frac{\beta_L}{\left[1 + (1 - T_c)\left(\frac{D}{E}\right)\right]}$$

where: β_U = *unlevered beta (or "asset" beta)*
β_L = *average levered beta of proxy group*
T_C = *corporate tax rate*
D = *book value of debt*
E = *book value of equity*

Using Equation 4, the beta for the firm can be unlevered, and then "relevered" based on various debt ratios (by rearranging this equation to solve for β_L).

Q. PLEASE SUMMARIZE THE RESULTS OF THE HAMADA FORMULA BASED ON YOUR PROPOSED CAPITAL STRUCTURE FOR THE COMPANY.

A. The average capital structure of the proxy group consists of 51% debt and 49% equity. Because PGS's debt ratio is so much lower than that of the proxy group, when we "relever" PGS relative to the proxy group, it results in a much lower ROE than if PGS had been operating with a capital structure equal to that of the proxy group. This makes sense because PGS is much less risky relative to the proxy group due to the decreased amount of debt in its capital structure. The results of my Hamada model are presented in the figure below.[78]

[78] Exhibit DJG-15.

Figure 12:
Hamada Model ROE

Unlevering Beta	
Proxy Debt Ratio	51%
Proxy Equity Ratio	49%
Proxy Debt / Equity Ratio	1.0
Tax Rate	21%
Equity Risk Premium	5.1%
Risk-free Rate	4.9%
Proxy Group Beta	0.81
Unlevered Beta	0.44

Relevered Betas and Cost of Equity Estimates

Debt Ratio	D/E Ratio	Levered Beta	Cost of Equity
0%	0.0	0.44	7.1%
20%	0.3	0.53	7.6%
25%	0.3	0.56	7.7%
30%	0.4	0.59	7.9%
45%	0.8	0.73	8.6%
51%	1.0	0.81	9.0%
60%	1.5	0.97	9.8%

According to the results of the Hamada model, if the Commission adopts my capital structure recommendation, PGS's indicated cost of equity estimate (under the CAPM) would be 9.0%. However, if the Commission accepts PGS's proposed capital structure, the Company's cost of equity estimate would be 8.6%.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. To the extent I have not addressed an issue, method, calculation, account, or other matter relevant to the Company's proposals in this proceeding, it should not be construed that I agree with the same.

APPENDIX A:

DISCOUNTED CASH FLOW MODEL THEORY

The Discounted Cash Flow ("DCF") Model is based on a fundamental financial model called the "dividend discount model," which maintains that the value of a security is equal to the present value of the future cash flows it generates. Cash flows from common stock are paid to investors in the form of dividends. There are several variations of the DCF Model. In its most general form, the DCF Model is expressed as follows:[1]

Equation 1:
General Discounted Cash Flow Model

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n}{(1+k)^n}$$

where: P_0 = *current stock price*
$D_1 \ldots D_n$ = *expected future dividends*
k = *discount rate / required return*

The General DCF Model would require an estimation of an infinite stream of dividends. Since this would be impractical, analysts use more feasible variations of the General DCF Model, which are discussed further below.

The DCF Models rely on the following four assumptions:

1. Investors evaluate common stocks in the classical valuation framework; that is, they trade securities rationally at prices reflecting their perceptions of value;
2. Investors discount the expected cash flows at the same rate (K) in every future period;

[1] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 410 (9th ed., McGraw-Hill/Irwin 2013).

3. The K obtained from the DCF equation corresponds to that specific stream of future cash flows alone; and

4. Dividends, rather than earnings, constitute the source of value.

The General DCF can be rearranged to make it more practical for estimating the cost of equity. Regulators typically rely on some variation of the Constant Growth DCF Model, which is expressed as follows:

Equation 2:
Constant Growth Discounted Cash Flow Model

$$K = \frac{D_1}{P_0} + g$$

where:	K	=	*discount rate / required return on equity*
	D_1	=	*expected dividend per share one year from now*
	P_0	=	*current stock price*
	g	=	*expected growth rate of future dividends*

Unlike the General DCF Model, the Constant Growth DCF Model solves directly for the required return (K). In addition, by assuming that dividends grow at a constant rate, the dividend stream from the General DCF Model may be essentially substituted with a term representing the expected constant growth rate of future dividends (g). The Constant Growth DCF Model may be considered in two parts. The first part is the dividend yield (D_1/P_0), and the second part is the growth rate (g). In other words, the required return in the DCF Model is equivalent to the dividend yield plus the growth rate.

In addition to the four assumptions listed above, the Constant Growth DCF Model relies on four additional assumptions as follows:[2]

[2] *Id.* at 254-56.

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APPENDIX A:

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where:	P_0	=	*current stock price*
	$D_1 \dots D_n$	=	*expected future dividends*
	k	=	*discount rate / required return*

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[1] *See* Zvi Bodie, Alex Kane & Alan J. Marcus, *Essentials of Investments* 410 (9th ed., McGraw-Hill/Irwin 2013).

APPENDIX B:

CAPITAL ASSET PRICING MODEL THEORY

The Capital Asset Pricing Model ("CAPM") is a market-based model founded on the principle that investors demand higher returns for incurring additional risk.[1] The CAPM estimates this required return. The CAPM relies on the following assumptions:

1. Investors are rational, risk-adverse, and strive to maximize profit and terminal wealth;
2. Investors make choices based on risk and return. Return is measured by the mean returns expected from a portfolio of assets; risk is measured by the variance of these portfolio returns;
3. Investors have homogenous expectations of risk and return;
4. Investors have identical time horizons;
5. Information is freely and simultaneously available to investors.
6. There is a risk-free asset, and investors can borrow and lend unlimited amounts at the risk-free rate;
7. There are no taxes, transaction costs, restrictions on selling short, or other market imperfections; and,
8. Total asset quality is fixed, and all assets are marketable and divisible.[2]

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[1] William F. Sharpe, *A Simplified Model for Portfolio Analysis* 277-93 (Management Science IX 1963); *see also* John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 208 (3rd ed., South Western Cengage Learning 2010).

[2] *Id*.

While some of these assumptions may appear to be restrictive, they do not outweigh the inherent value of the model. The CAPM has been widely used by firms, analysts, and regulators for decades to estimate the cost of equity capital.

The basic CAPM equation is expressed as follows:

Equation 1:
Capital Asset Pricing Model

$$K = R_F + \beta_i(R_M - R_F)$$

where:	K	=	*required return*
	R_F	=	*risk-free rate*
	β	=	*beta coefficient of asset i*
	R_M	=	*required return on the overall market*

There are essentially three terms within the CAPM equation that are required to calculate the required return (K): (1) the risk-free rate (R_F); (2) the beta coefficient (β); and (3) the equity risk premium ($R_M - R_F$), which is the required return on the overall market less the risk-free rate.

Raw Beta Calculations and Adjustments

A stock's beta equals the covariance of the asset's returns with the returns on a market portfolio, divided by the portfolio's variance, as expressed in the following formula:[3]

Equation 2:
Beta

$$\beta_i = \frac{\sigma_{im}}{\sigma_m^2}$$

where:	β_i	=	*beta of asset i*
	σ_{im}	=	*covariance of asset i returns with market portfolio returns*
	σ^2_m	=	*variance of market portfolio*

[3] John R. Graham, Scott B. Smart & William L. Megginson, *Corporate Finance: Linking Theory to What Companies Do* 180-81 (3rd ed., South Western Cengage Learning 2010).

Betas that are published by various research firms are typically calculated through a regression analysis that considers the movements in price of an individual stock and movements in the price of the overall market portfolio. The betas produced by this regression analysis are considered "raw" betas. There is empirical evidence that raw betas should be adjusted to account for beta's natural tendency to revert to an underlying mean.[4] Some analysts use an adjustment method proposed by Blume, which adjusts raw betas toward the market mean of one.[5] While the Blume adjustment method is popular due to its simplicity, it is arguably arbitrary, and some would say not useful at all. According to Dr. Damodaran: "While we agree with the notion that betas move toward 1.0 over time, the [Blume adjustment] strikes us as arbitrary and not particularly useful."[6] The Blume adjustment method is especially arbitrary when applied to industries with consistently low betas, such as the utility industry. For industries with consistently low betas, it is better to employ an adjustment method that adjusts raw betas toward an industry average, rather than the market average. Vasicek proposed such a method, which is preferable to the Blume adjustment method because it allows raw betas to be adjusted toward an industry average, and also accounts for the statistical accuracy of the raw beta calculation.[7] In other words, "[t]he Vasicek adjustment seeks to overcome one weakness of the Blume model by not applying the same adjustment to every security; rather, a security-specific adjustment is made depending on the

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[4] *See* Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 84-92 (Financial Management Autumn 1990).

[5] See Marshall Blume, *On the Assessment of Risk*, Vol. 26, No. 1, The Journal of Finance 1 (1971).

[6] *See* Aswath Damodaran, *Investment Valuation: Tools and Techniques for Determining the Value of Any Asset* 187 (3rd ed., John Wiley & Sons, Inc. 2012).

[7] Oldrich A. Vasicek, *A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas* 1233-1239 (Journal of Finance, Vol. 28, No. 5, December 1973).

statistical quality of the regression."[8] The Vasicek beta adjustment equation is expressed as follows:

Equation 3:
Vasicek Beta Adjustment

$$\beta_{i1} = \frac{\sigma^2_{\beta_{i0}}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_0 + \frac{\sigma^2_{\beta 0}}{\sigma^2_{\beta 0} + \sigma^2_{\beta_{i0}}}\beta_{i0}$$

where: β_{i1} = *Vasicek adjusted beta for security i*
β_{i0} = *historical beta for security i*
β_0 = *beta of industry or proxy group*
$\sigma^2_{\beta 0}$ = *variance of betas in the industry or proxy group*
$\sigma^2_{\beta i0}$ = *square of standard error of the historical beta for security i*

The Vasicek beta adjustment is an improvement on the Blume model because the Vasicek model does not apply the same adjustment to every security. A higher standard error produced by the regression analysis indicates a lower statistical significance of the beta estimate. Thus, a beta with a high standard error should receive a greater adjustment than a beta with a low standard error. As stated in Ibbotson:

> While the Vasicek formula looks intimidating, it is really quite simple. The adjusted beta for a company is a weighted average of the company's historical beta and the beta of the market, industry, or peer group. How much weight is given to the company and historical beta depends on the statistical significance of the company beta statistic. If a company beta has a low standard error, then it will have a higher weighting in the Vasicek formula. If a company beta has a high standard error, then it will have lower weighting in the Vasicek formula. An advantage of this adjustment methodology is that it does not force an adjustment to the market as a whole. Instead, the adjustment can be toward an industry or some other peer group. *This is most useful in looking at companies in industries that on average have high or low betas*.[9]

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[8] 2012 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook 77-78 (Morningstar 2012).

[9] *Id*. at 78 (emphasis added).

Thus, the Vasicek adjustment method is statistically more accurate, and is the preferred method to use when analyzing companies in an industry that has inherently low betas, such as the utility industry. The Vasicek method was also confirmed by Gombola, who conducted a study specifically related to utility companies. Gombola concluded that "[t]he strong evidence of auto-regressive tendencies in *utility* betas lends support to the application of adjustment procedures such as the . . . adjustment procedure presented by Vasicek."[10] Gombola also concluded that adjusting raw betas toward the market mean of 1.0 is *too high*, and that "[i]nstead, they should be adjusted toward a value that is less than one."[11] In conducting the Vasicek adjustment on betas in previous cases, it reveals that utility betas are even lower than those published by Value Line.[12] Gombola's findings are particular important here, because his study was conducted specifically on utility companies. This evidence indicates that using Value Line's betas in a CAPM cost of equity estimate for a utility company may lead to overestimated results. Regardless, adjusting betas to a level that is *higher* than Value Line's betas is not reasonable, and it would produce CAPM cost of equity results that are too high.

[10] Michael J. Gombola and Douglas R. Kahl, *Time-Series Processes of Utility Betas: Implications for Forecasting Systematic Risk* 92 (Financial Management Autumn 1990) (emphasis added).

[11] *Id*. at 91-92.

[12] *See e.g.* Responsive Testimony of David J. Garrett, filed March 21, 2016 in Cause No. PUD 201500273 before the Corporation Commission of Oklahoma (the Company's 2015 rate case), at pp. 56 – 59.

(Transcript continues in sequence in Volume 4.)

CERTIFICATE OF REPORTER

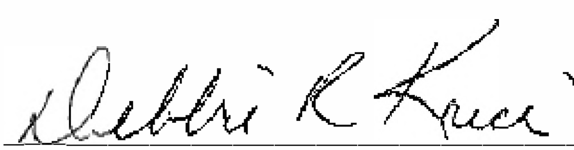
STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 5th day of November, 2025.



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